CENTERPOINT ENERGY INC
Form 10-K
February 28, 2007

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

Form 10-K

(Mark One)

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the fiscal year ended December 31, 2006**
	or
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the transition period from______to______**

Commission File Number 1-31447

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

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

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

Title of each class	Name of each exchange on which registered
Common Stock, $0.01 par value and associated rights to purchase preferred stock	New York Stock Exchange Chicago Stock Exchange

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

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

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

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

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

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 þ Accelerated filer o Non-accelerated filer o

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

The aggregate market value of the voting stock held by non-affiliates of CenterPoint Energy, Inc. (Company) was $3,873,645,799 as of June 30, 2006, using the definition of beneficial ownership contained in Rule 13d-3 promulgated pursuant to the Securities Exchange Act of 1934 and excluding shares held by directors and executive officers. As of February 16, 2007, the Company had 320,079,012 shares of Common Stock outstanding. Excluded from the number of shares of Common Stock outstanding are 166 shares held by the Company as treasury stock.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement relating to the 2007 Annual Meeting of Shareholders of the Company, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2006, are incorporated by reference in Item 10, Item 11, Item 12, Item 13 and Item 14 of Part III of this Form 10-K.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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

Some of the factors that could cause actual results to differ from those expressed or implied by our forward-looking statements are described under Risk Factors in Item 1A of this report.

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

PART I

Item 1. *Business*

OUR BUSINESS

Overview

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

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

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

Prior to repeal of the Public Utility Holding Company Act of 1935 (1935 Act), effective February 8, 2006, we were a registered public utility holding company under that act.

Our reportable business segments are Electric Transmission & Distribution, Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines, Field Services and Other Operations. Prior to the fourth quarter of 2006, our Interstate Pipelines business segment and our Field Services business segment were reported as a single business segment called Pipelines and Field Services. Information from prior periods has been recast to reflect this new presentation. The operations of Texas Genco Holdings, Inc. (Texas Genco), formerly our majority owned electric generating subsidiary, the sale of which was completed in April 2005, are presented as discontinued operations. From time to time, we consider the acquisition or the disposition of assets or businesses.

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

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

- our Code of Ethics for our Chief Executive Officer and Senior Financial Officers;

- our Ethics and Compliance Code;

- our Corporate Governance Guidelines; and

- the charters of our audit, compensation, finance and governance committees.

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

Electric Transmission & Distribution

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

CenterPoint Houston is the only business of CenterPoint Energy that continues to engage in electric utility operations. It is a transmission and distribution electric utility that operates wholly within the state of Texas. Neither CenterPoint Houston nor any other subsidiary of CenterPoint Energy makes sales of electric energy at retail or wholesale or owns or operates any electric generating facilities.

Electric Transmission

On behalf of retail electric providers (REPs), CenterPoint Houston delivers electricity from power plants to substations, from one substation to another and to retail electric customers taking power above 69 kilovolts (kV) in locations throughout the control area managed by ERCOT. CenterPoint Houston provides transmission services under tariffs approved by the Texas Utility Commission.

Electric Distribution

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

ERCOT Market Framework

CenterPoint Houston is a member of ERCOT. ERCOT serves as the regional reliability coordinating council for member electric power systems in Texas. ERCOT membership is open to consumer groups, investor and municipally owned electric utilities, rural electric cooperatives, independent generators, power marketers and REPs. The ERCOT market includes much of the State of Texas, other than a portion of the panhandle, a portion of the eastern part of the state bordering Louisiana and the area in and around El Paso. The ERCOT market represents approximately 85% of the demand for power in Texas and is one of the nation s largest power markets. The ERCOT market includes an aggregate net generating capacity of approximately 70,500 megawatts (MW). There are only limited direct current interconnections between the ERCOT market and other power markets in the United States.

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

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

True-Up Proceeding

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

In March 2004, CenterPoint Houston filed its true-up application with the Texas Utility Commission, requesting recovery of $3.7 billion, excluding interest, as allowed under the Texas electric restructuring law. In December 2004, the Texas Utility Commission issued its final order (True-Up Order) allowing CenterPoint Houston to recover a true-up balance of approximately $2.3 billion, which included interest through August 31, 2004, and providing for adjustment of the amount to be recovered to include interest on the balance until recovery, the principal portion of additional excess mitigation credits returned to customers after August 31, 2004 and certain other matters. CenterPoint Houston and other parties filed appeals of the True-Up Order to a district court in Travis County, Texas. In August 2005, the court issued its final judgment on the various appeals. In its judgment, the court affirmed most aspects of the True-Up Order, but reversed two of the Texas Utility Commission s rulings. The judgment would have the effect of restoring approximately $650 million, plus interest, of the $1.7 billion the Texas Utility Commission had disallowed from CenterPoint Houston s initial request. CenterPoint Houston and other parties appealed the district court s judgment. Oral arguments before the Texas 3rd Court of Appeals were held in January 2007, but a decision is not expected for several months. No amounts related to the district court s judgment have been recorded in our consolidated financial statements.

Among the issues raised in CenterPoint Houston s appeal of the True-Up Order is the Texas Utility Commission s reduction of CenterPoint Houston s stranded cost recovery by approximately $146 million for the present value of certain deferred tax benefits associated with its former electric generation assets. Such reduction was considered in our recording of an after-tax extraordinary loss of $977 million in the last half of 2004. We believe that the Texas Utility Commission based its order on proposed regulations issued by the Internal Revenue Service (IRS) in March 2003 related to those tax benefits. Those proposed regulations would have allowed utilities owning assets that were deregulated before March 4, 2003 to make a retroactive election to pass the benefits of Accumulated Deferred Investment Tax Credits (ADITC) and Excess Deferred Federal Income Taxes (EDFIT) back to customers. However, in December 2005, the IRS withdrew those proposed normalization regulations and issued new proposed regulations that do not include the provision allowing a retroactive election to pass the tax benefits back to customers. In a May 2006 Private Letter Ruling (PLR) issued to a Texas utility on facts similar to CenterPoint Houston s, the IRS, without referencing its proposed regulations, ruled that a normalization violation would occur if ADITC and EDFIT were required to be returned to customers. CenterPoint Houston has requested a PLR asking the IRS whether the Texas Utility Commission s order reducing CenterPoint Houston s stranded cost recovery by $146 million for ADITC and EDFIT would cause a normalization violation. If the IRS determines that such reduction would cause a normalization violation with respect to the ADITC and the Texas Utility Commission s order relating to such reduction is not reversed or otherwise modified, the IRS could require us to pay an amount equal to CenterPoint Houston s unamortized ADITC balance as of the date that the normalization violation is deemed to have occurred. In addition, if a normalization violation with respect to EDFIT is deemed to have occurred and the Texas Utility Commission s order relating to such reduction is not reversed or otherwise modified, the IRS could deny CenterPoint Houston the ability to elect accelerated tax depreciation benefits beginning in the taxable year that the normalization violation is deemed to have occurred. If a normalization violation should ultimately be found to exist, it could have a material adverse impact on our results of operations, financial condition and cash flows. However, we and CenterPoint Houston are vigorously pursuing the appeal of

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this issue and will seek other relief from the Texas Utility Commission to avoid a normalization violation. The Texas Utility Commission has not previously required a company subject to its jurisdiction to take action that would result in a normalization violation.

Securitization

Pursuant to a financing order issued by the Texas Utility Commission in March 2005 and affirmed in August 2005 by a Travis County district court, in December 2005, a subsidiary of CenterPoint Houston issued $1.85 billion in transition bonds with interest rates ranging from 4.84 percent to 5.30 percent and final maturity dates ranging from February 2011 to August 2020. Through issuance of the transition bonds, CenterPoint Houston recovered approximately $1.7 billion of the true-up balance determined in the True-Up Order plus interest through the date on which the bonds were issued.

Competition Transition Charge

In July 2005, CenterPoint Houston received an order from the Texas Utility Commission allowing it to implement a CTC designed to collect approximately $596 million over 14 years plus interest at an annual rate of 11.075 percent (CTC Order). The CTC Order authorizes CenterPoint Houston to impose a charge on REPs to recover the portion of the true-up balance not covered by the financing order. The CTC Order also allows CenterPoint Houston to collect approximately $24 million of rate case expenses over three years without a return through a separate tariff rider (Rider RCE). CenterPoint Houston implemented the CTC and Rider RCE effective September 13, 2005 and began recovering approximately $620 million. Effective September 13, 2005, the return on the CTC portion of the true-up balance is included in CenterPoint Houston s tariff-based revenues.

Certain parties appealed the CTC Order to a district court in Travis County. In May 2006, the district court issued a judgment reversing the CTC Order in three respects. First, the court ruled that the Texas Utility Commission had improperly relied on provisions of its rule dealing with the interest rate applicable to CTC amounts. The district court reached that conclusion on the grounds that the Texas Supreme Court had previously invalidated that entire section of the rule. Second, the district court reversed the Texas Utility Commission s ruling that allows CenterPoint Houston to recover through the Rider RCE the costs (approximately $5 million) for a panel appointed by the Texas Utility Commission in connection with the valuation of the Company s electric generation assets. Finally, the district court accepted the contention of one party that the CTC should not be allocated to retail customers that have switched to new on-site generation. The Texas Utility Commission and CenterPoint Houston disagree with the district court s conclusions and, in May 2006, appealed the judgment to the Texas 3rd Court of Appeals, and if required, plan to seek further review from the Texas Supreme Court. All briefs in the appeal have been filed. Oral arguments were held in December 2006. Pending completion of judicial review and any action required by the Texas Utility Commission following a remand from the courts, the CTC remains in effect. The 11.075 percent interest rate in question was applicable from the implementation of the CTC Order on September 13, 2005 until August 1, 2006, the effective date of the implementation of a new CTC in compliance with the new rule discussed below. The ultimate outcome of this matter cannot be predicted at this time. However, we do not expect the disposition of this matter to have a material adverse impact on our or CenterPoint Houston s financial condition, results of operations or cash flows.

In June 2006, the Texas Utility Commission adopted the revised rule governing the carrying charges on unrecovered true-up balances as recommended by its staff (Staff). The rule, which applies to CenterPoint Houston, reduced the allowed interest rate on the unrecovered CTC balance prospectively from 11.075 percent to a weighted average cost of capital of 8.06 percent. The annualized impact on operating income is a reduction of approximately $18 million per year for the first year with lesser impacts in subsequent years. In July 2006, CenterPoint Houston made a compliance filing necessary to implement the rule changes effective August 1, 2006 per the settlement agreement discussed under CenterPoint Houston Rate Case below.

During the years ended December 31, 2005 and 2006, CenterPoint Houston recognized approximately $19 million and $55 million, respectively, in operating income from the CTC. Additionally, during the years ended December 31, 2005 and 2006, CenterPoint Houston recognized approximately $1 million and $13 million, respectively, of the allowed equity return not previously recorded. As of December 31, 2006, we had not recorded

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an allowed equity return of $234 million on CenterPoint Houston s true-up balance because such return will be recognized as it is recovered in rates.

Refund of Environmental Retrofit Costs

The True-Up Order allowed recovery of approximately $699 million of environmental retrofit costs related to CenterPoint Houston s generation assets. The sale of CenterPoint Houston s interest in its generation assets was completed in early 2005. The True-Up Order required CenterPoint Houston to provide evidence by January 31, 2007 that the entire $699 million was actually spent by December 31, 2006 on environmental programs. The Texas Utility Commission will determine the appropriate manner to return to customers any unused portion of these funds, including interest on the funds and on stranded costs attributable to the environmental costs portion of the stranded costs recovery. In January 2007, we were notified by the successor in interest to CenterPoint Houston s generation assets that, as of December 31, 2006, it had only spent approximately $664 million. On January 31, 2007, CenterPoint Houston made the required filing with the Texas Utility Commission identifying approximately $35 million in unspent funds to be refunded to customers along with approximately $7 million of interest and requesting permission to refund these amounts through a reduction to the CTC, effective March 1, 2007. Such amounts are recorded in regulatory liabilities as of December 31, 2006. In February 2007, the Texas Utility Commission adopted the Staff s recommendation for a slower procedural schedule than that requested by CenterPoint Houston. The current procedural schedule makes it unlikely that the proposed refund would be effective before May 1, 2007. At this time, we cannot predict whether any party will oppose CenterPoint Houston s filing or whether the Texas Utility Commission will approve CenterPoint Houston s request.

Final Fuel Reconciliation

The results of the Texas Utility Commission s final decision related to CenterPoint Houston s final fuel reconciliation were a component of the True-Up Order. CenterPoint Houston has appealed certain portions of the True-Up Order involving a disallowance of approximately $67 million relating to the final fuel reconciliation in 2003 plus interest of $10 million. CenterPoint Houston has fully reserved for the disallowance and related interest accrual. A judgment was entered by a Travis County district court in May 2005 affirming the Texas Utility Commission s decision. CenterPoint Houston filed an appeal to the Texas 3rd Court of Appeals in June 2005, and in April 2006, the Texas 3rd Court of Appeals issued a judgment affirming the Texas Utility Commission s decision. CenterPoint Houston filed an appeal with the Texas Supreme Court in August 2006, and in October 2006, the Texas Supreme Court requested that the Texas Utility Commission and the City of Houston file written responses to CenterPoint Houston s petition for review. Those responses were filed in January 2007. In February 2007, CenterPoint Houston filed an agreement with the Texas Supreme Court indicating that the parties had reached a settlement of the appeal. In order for the settlement to become final, the Texas Supreme Court must abate the pending appeal, and the Texas Utility Commission must issue a final order approving the settlement. If the Texas Utility Commission does not approve the agreement or modifies the agreement in a manner unacceptable to CenterPoint Houston, CenterPoint Houston would be entitled to ask the Texas Supreme Court to reinstate the appeal. If the Texas Utility Commission approves the agreement, the parties will request the Texas Supreme Court to set aside the lower court decisions and remand the case for entry of an order approving that settlement. The Texas Supreme Court is not required to abate the appeal. If the Texas Supreme Court does not abate the appeal, it may request full briefing or deny the petition for review. If the petition is denied, the Court of Appeals judgment would become final. If the petition is granted, the Texas Supreme Court would address the merits of CenterPoint Houston s appeal. There is no deadline for the Texas Supreme Court s decisions. As of December 31, 2006, we have not recorded any amounts related to this decision.

Remand of 2001 Unbundled Cost of Service (UCOS) Order

The Texas 3rd Court of Appeals remanded to the Texas Utility Commission an issue that was decided by the Texas Utility Commission in CenterPoint Houston s 2001 UCOS proceeding. In its remand order, the court ruled that the Texas Utility Commission had failed to adequately explain the basis for its determination of certain projected transmission capital expenditures. The Texas 3rd Court of Appeals ordered the Texas Utility Commission to reconsider that determination on the basis of the record that existed at the time of the Texas Utility Commission s original order. In April 2006, the Texas Utility Commission opined orally that the rate base should be reduced by $57 million and instructed the Staff to quantify the effect on CenterPoint Houston s rates. In the settlement of the CenterPoint Houston rate case described below, the parties to the remand proceeding agreed to settle all issues that could be raised in the remand. Under the terms of that settlement, CenterPoint Houston implemented riders to its tariff rates under which it will provide rate credits to retail and wholesale customers for a total of approximately $8 million per year until a total of $32 million has been credited to customers under those tariff riders. Those riders became effective October 10, 2006. CenterPoint Houston reduced revenues and established a corresponding regulatory liability of $32 million in the second quarter of 2006 to reflect this obligation.

CenterPoint Houston Rate Case

In September 2006, the Texas Utility Commission approved a settlement of a rate proceeding concerning CenterPoint Houston s transmission and distribution service rates, which is discussed in Regulation State and Local Regulation Electric Transmission and Distribution CenterPoint Houston Rate Case.

Customers

CenterPoint Houston serves nearly all of the Houston/Galveston metropolitan area. CenterPoint Houston s customers consist of 68 REPs, which sell electricity in its certificated service area, and municipalities, electric cooperatives and other distribution companies located outside CenterPoint Houston s certificated service area. Each REP is licensed by, and must meet creditworthiness criteria established by, the Texas Utility Commission. Two of the REPs in CenterPoint Houston s service area are subsidiaries of Reliant Energy, Inc. (RRI). Sales to subsidiaries of RRI represented approximately 71%, 62% and 56% of CenterPoint Houston s transmission and distribution revenues in 2004, 2005 and 2006, respectively. CenterPoint Houston s billed receivables balance from REPs as of December 31, 2006 was $140 million. Approximately 53% of this amount was owed by subsidiaries of RRI. CenterPoint Houston does not have long-term contracts with any of its customers. It operates on a continuous billing cycle, with meter readings being conducted and invoices being distributed to REPs each business day.

Distribution Automation (Intelligent Grid)

CenterPoint Houston is pursuing development and possible deployment of an electric distribution grid automation strategy with assistance from IBM that involves the implementation of an Intelligent Grid which would make use of CenterPoint Houston s lines and other facilities to provide on demand data and information about electric usage and the status of facilities on our system. Although this technology is still in the developmental stage, CenterPoint Houston believes it has the potential to enable a significant improvement in metering, grid planning, operations and maintenance of its system. These improvements would be expected to contribute to fewer and shorter outages, better customer service, improved operations costs, improved security and more effective use of our workforce. CenterPoint Houston is making a limited deployment of this technology to help in proving the technology and in validating its potential benefits prior to a full-scale implementation.

In addition to the utility applications discussed above, Intelligent Grid technology has the potential to improve the provision of data to the retail electric market in Texas to enable such enhancements as real-time pricing, real-time switching between REPs, and more timely connection and disconnection of customers. CenterPoint Houston anticipates that the Texas Utility Commission will implement guidelines for establishing minimum functionality requirements for the advanced meter in 2007, and that the Texas Utility Commission will provide a mechanism for timely recovery of costs of implementation. CenterPoint Houston will evaluate the outcome of the limited deployment and the regulatory mechanisms for cost recovery to assess what further expansions, if any, will be made later in 2007 and beyond.

Competition

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

Seasonality

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

Properties

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

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

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

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

As of December 31, 2006, CenterPoint Houston had outstanding $2.0 billion aggregate principal amount of general mortgage bonds under the General Mortgage, including approximately $527 million held in trust to secure pollution control bonds for which CenterPoint Energy is obligated and approximately $229 million held in trust to secure pollution control bonds for which CenterPoint Houston is obligated. Additionally, CenterPoint Houston had outstanding approximately $253 million aggregate principal amount of first mortgage bonds under the Mortgage, including approximately $151 million held in trust to secure certain pollution control bonds for which CenterPoint Energy is obligated. CenterPoint Houston may issue additional general mortgage bonds on the basis of retired bonds, 70% of property additions or cash deposited with the trustee. Approximately $2.2 billion of additional first mortgage bonds and general mortgage bonds in the aggregate could be issued on the basis of retired bonds and 70% of property additions as of December 31, 2006. However, CenterPoint Houston is contractually prohibited, subject to certain exceptions, from issuing additional first mortgage bonds.

Electric Lines Overhead. As of December 31, 2006, CenterPoint Houston owned 27,253 pole miles of overhead distribution lines and 3,603 circuit miles of overhead transmission lines, including 442 circuit miles operated at 69,000 volts, 2,084 circuit miles operated at 138,000 volts and 1,077 circuit miles operated at 345,000 volts.

Electric Lines Underground. As of December 31, 2006, CenterPoint Houston owned 17,904 circuit miles of underground distribution lines and 28.4 circuit miles of underground transmission lines, including 4.5 circuit miles operated at 69,000 volts and 23.9 circuit miles operated at 138,000 volts.

Substations. As of December 31, 2006, CenterPoint Houston owned 226 major substation sites having total installed rated transformer capacity of 50,647 megavolt amperes.

Service Centers. CenterPoint Houston operates 14 regional service centers located on a total of 304 acres of land. These service centers consist of office buildings, warehouses and repair facilities that are used in the business of transmitting and distributing electricity.

Franchises

CenterPoint Houston holds non-exclusive franchises from the incorporated municipalities in its service territory. In exchange for the payment of fees, these franchises give CenterPoint Houston the right to use the streets and public rights-of way of these municipalities to construct, operate and maintain its transmission and distribution

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system and to use that system to conduct its electric delivery business and for other purposes that the franchises permit. The terms of the franchises, with various expiration dates, typically range from 30 to 50 years.

In June 2005, CenterPoint Houston accepted an ordinance granting it a new 30-year franchise to use the public rights-of-way to conduct its business in the City of Houston (New Houston Franchise Ordinance). The New Houston Franchise Ordinance took effect on July 1, 2005, and replaced the prior electricity franchise ordinance, which had been in effect since 1957. The New Houston Franchise Ordinance clarifies certain operational obligations of CenterPoint Houston and the City of Houston and provides for streamlined payment and audit procedures and a two-year statute of limitations on claims for underpayment or overpayment under the ordinance. Under the prior electricity franchise ordinance, CenterPoint Houston paid annual franchise fees of $76.6 million to the City of Houston for the year ended December 31, 2004. For the twelve-month period ended June 30, 2006, the annual franchise fee under the New Houston Franchise Ordinance included a base amount of $88.1 million and an additional payment of $8.5 million. The base amount and the additional amount will be adjusted annually based on the increase, if any, in kilowatt-hours (kWh) delivered by CenterPoint Houston within the City of Houston. Pursuant to the New Houston Franchise Ordinance, the annual franchise fee will be reduced prospectively to reflect any portion of the annual franchise fee that is not included in CenterPoint Houston s base rates in any subsequent rate case.

In connection with its most recent rate case and the settlement discussions related to that case, CenterPoint Houston offered to all of the cities in its service area an opportunity to adopt a new form of franchise (Settlement Franchise) containing terms similar to those in the New Houston Franchise Ordinance. This early renewal effort used a non-negotiable form of franchise and, except as necessary to comply with city charters, offered to all cities substantially equivalent terms and a single, simplified method of calculating and paying franchise fees. The Settlement Franchise was offered regardless of when any existing franchise was scheduled to expire. Of the 92 cities other than Houston in CenterPoint Houston s service area, 59 have passed the Settlement Franchise. On December 31, 2006, CenterPoint Houston terminated its early renewal offer and will pursue new franchises with the remaining cities as their franchises near expiration.

Natural Gas Distribution

CERC Corp. s natural gas distribution business (Gas Operations) engages in regulated intrastate natural gas sales to, and natural gas transportation for, approximately 3.2 million residential, commercial and industrial customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas. The largest metropolitan areas served in each state by Gas Operations are Houston, Texas; Minneapolis, Minnesota; Little Rock, Arkansas; Shreveport, Louisiana; Biloxi, Mississippi; and Lawton, Oklahoma. In 2006, approximately 40% of Gas Operations total throughput was attributable to residential customers and approximately 60% was attributable to commercial and industrial customers.

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

The demand for intrastate natural gas sales to, and natural gas transportation for, residential, commercial and industrial customers is seasonal. In 2006, approximately 68% of the total throughput of Gas Operations business occurred in the first and fourth quarters. These patterns reflect the higher demand for natural gas for heating purposes during those periods.

Supply and Transportation. In 2006, Gas Operations purchased virtually all of its natural gas supply pursuant to contracts with remaining terms varying from a few months to four years. Major suppliers in 2006 included BP Canada Energy Marketing Corp. (23.3% of supply volumes), HPL Marketing (14.6%), Kinder Morgan (11.4%), Tenaska Marketing Ventures (5.1%) and ConocoPhillips Company (4.7%). Numerous other suppliers provided the remaining 40.9% of Gas Operations natural gas supply requirements. Gas Operations transports its natural gas supplies through various intrastate and interstate pipelines, including those owned by our other subsidiaries, under contracts with remaining terms, including extensions, varying from one to sixteen years. Gas Operations anticipates that these gas supply and transportation contracts will be renewed prior to their expiration.

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

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

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

Gas Operations owns and operates an underground storage facility with a capacity of 7.0 billion cubic feet (Bcf). It has a working capacity of 2.1 Bcf available for use during a normal heating season and a maximum daily withdrawal rate of 50 million cubic feet (MMcf). It also owns nine propane-air plants with a total capacity of 192 MMcf per day and on-site storage facilities for 12 million gallons of propane (1.0 Bcf gas equivalent). It owns liquefied natural gas plant facilities with a 12 million-gallon liquefied natural gas storage tank (1.0 Bcf gas equivalent) and a send-out capability of 72 MMcf per day.

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

Assets

As of December 31, 2006, Gas Operations owned approximately 66,000 linear miles of natural gas distribution mains, varying in size from one-half inch to 24 inches in diameter. Generally, in each of the cities, towns and rural areas served by Gas Operations, it owns the underground gas mains and service lines, metering and regulating equipment located on customers premises and the district regulating equipment necessary for pressure maintenance. With a few exceptions, the measuring stations at which Gas Operations receives gas are owned, operated and maintained by others, and its distribution facilities begin at the outlet of the measuring equipment. These facilities, including odorizing equipment, are usually located on the land owned by suppliers.

Competition

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

Competitive Natural Gas Sales and Services

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

In 2006, CES marketed approximately 555 Bcf of natural gas, transportation and related energy services to nearly 7,000 customers (including approximately 36 Bcf to affiliates). CES customers vary in size from small commercial customers to large utility companies in the central and eastern regions of the United States, and are served from offices located in Illinois, Indiana, Louisiana, Minnesota, Missouri, Pennsylvania, Texas and Wisconsin. The business has three operational functions: wholesale, retail and intrastate pipelines, which are further described below.

Wholesale Operations. CES offers a portfolio of physical delivery services and financial products designed to meet wholesale customers supply and price risk management needs. These customers are served directly through interconnects with various inter- and intra-state pipeline companies, and include gas utilities, large industrial customers and electric generation customers.

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

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

CES currently transports natural gas on over 30 interstate and intrastate pipelines within states located throughout the central and eastern United States. CES maintains a portfolio of natural gas supply contracts and firm transportation and storage agreements to meet the natural gas requirements of its customers. CES aggregates supply from various producing regions and offers contracts to buy natural gas with terms ranging from one month to over five years. In addition, CES actively participates in the spot natural gas markets in an effort to balance daily and monthly purchases and sales obligations. Natural gas supply and transportation capabilities are leveraged through contracts for ancillary services including physical storage and other balancing arrangements.

As described above, CES offers its customers a variety of load following services. In providing these services, CES uses its customers purchase commitments to forecast and arrange its own supply purchases, storage and transportation services to serve customers natural gas requirements. As a result of the variance between this forecast activity and the actual monthly activity, CES will either have too much supply or too little supply relative to its customers purchase commitments. These supply imbalances arise each month as customers natural gas requirements are scheduled and corresponding natural gas supplies are nominated by CES for delivery to those customers. CES processes and risk control environment are designed to measure and value imbalances on a real-time basis to ensure that CES exposure to commodity price risk is kept to a minimum. The value assigned to these imbalances is calculated daily and is known as the aggregate Value at Risk (VaR). In 2006, CES VaR averaged $1.6 million with a high of $2.7 million.

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

Assets

CEIP owns and operates approximately 231 miles of intrastate pipeline in Louisiana and Texas and holds storage facilities in Texas under long-term leases.

Competition

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

Interstate Pipelines

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

two interstate natural gas pipelines; and

gas transmission lines primarily located in Arkansas, Illinois, Louisiana, Missouri, Oklahoma and Texas.

CERC s interstate pipeline operations are primarily conducted by two wholly owned subsidiaries that provide gas transportation and storage services primarily to industrial customers and local distribution companies:

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

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

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

In 2006, approximately 26% of CEGT and MRT s total operating revenue was attributable to services provided to Gas Operations and approximately 11% was attributable to services provided to Laclede Gas Company (Laclede), an unaffiliated distribution company that provides natural gas utility service to the greater St. Louis metropolitan area in Illinois and Missouri. Services to Gas Operations and Laclede are provided under several long-term firm storage and transportation agreements. Since October 31, 2006, MRT s contract with Laclede has been terminable upon one year s prior notice. MRT has not received a termination notice and is currently negotiating a long-term contract with Laclede. Agreements for firm transportation, no notice transportation service and storage service in certain of Gas Operations service areas (Arkansas, Louisiana and Oklahoma) expire in 2012.

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

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

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

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

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

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

Assets

Our interstate pipelines business currently owns and operates approximately 7,900 miles of natural gas transmission lines primarily located in Arkansas, Illinois, Louisiana, Missouri, Oklahoma and Texas. It also owns and operates six natural gas storage fields with a combined daily deliverability of approximately 1.2 Bcf per day and a combined working gas capacity of approximately 59.0 Bcf. It also owns a 10% interest in the Bistineau storage facility located in Bienville Parish, Louisiana, with the remaining interest owned and operated by Gulf South Pipeline Company, LP. This facility has a total working gas capacity of 85.7 Bcf and approximately 1.1 Bcf per day of deliverability. Storage capacity in the Bistineau facility is 8 Bcf of working gas with 100 MMcf per day of deliverability. Most storage operations are in north Louisiana and Oklahoma.

Competition

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

Field Services

Beginning in the fourth quarter of 2006, we are reporting our interstate pipelines and field services businesses as two separate business segments. These business segments were previously aggregated and reported as the Pipelines and Field Services business segment. CERC s field services business operates gas gathering, treating, and processing facilities and also provides operating and technical services and remote data monitoring and communication services.

CERC s field services operations are conducted by a wholly owned subsidiary, CenterPoint Energy Field Services, Inc. (CEFS). CEFS provides natural gas gathering and processing services for certain natural gas fields in the Mid-continent region of the United States that interconnect with CEGT s and MRT s pipelines, as well as other interstate and intrastate pipelines. CEFS, either directly or through its 50% interest in the Waskom Joint Venture, processes in excess of 240 MMcf per day of natural gas along its gathering system. CEFS, through its ServiceStar operating division, provides remote data monitoring and communications services to affiliates and third parties. The ServiceStar operating division currently provides monitoring activities at 11,080 locations across Alabama, Arkansas, Colorado, Illinois, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, Texas and Wyoming.

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

Assets

Our field services business owns and operates approximately 3,700 miles of gathering pipelines and processing plants that collect, treat and process natural gas from approximately 150 separate systems located in major producing fields in Arkansas, Louisiana, Oklahoma and Texas.

Competition

Our field services business competes with other companies in the natural gas gathering, treating, and processing business. The principal elements of competition are rates, terms of service and reliability of services. Our field services business competes indirectly with other forms of energy available to our customers, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability of energy and pipeline capacity, the level of business activity, conservation and governmental regulations, the capability to convert to alternative fuels, and other factors, including weather, affect the demand for natural gas in areas we serve and the level of competition for gathering, treating, and processing services. In addition, competition for our gathering operations is impacted by commodity pricing levels because of their influence on the level of drilling activity.

Other Operations

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

Discontinued Operations

In July 2004, we announced our agreement to sell our majority owned subsidiary, Texas Genco, to Texas Genco LLC. In December 2004, Texas Genco completed the sale of its fossil generation assets (coal, lignite and gas-fired plants) to Texas Genco LLC for $2.813 billion in cash. Following the sale, Texas Genco, whose principal remaining asset was its ownership interest in a nuclear generating facility, distributed $2.231 billion in cash to us. The final step of the transaction, the merger of Texas Genco with a subsidiary of Texas Genco LLC in exchange for an additional cash payment to us of $700 million, was completed in April 2005.

We recorded an after-tax loss of $133 million and $3 million for the years ended December 31, 2004 and 2005, respectively, related to the operations of Texas Genco. The consolidated financial statements report these operations for all periods presented as discontinued operations in accordance with Statement of Financial Accounting Standards (SFAS) No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets.

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Financial Information About Segments

For financial information about our segments, see Note 14 to our consolidated financial statements, which note is incorporated herein by reference.

REGULATION

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

Federal Energy Regulatory Commission

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

CenterPoint Houston is not a public utility under the Federal Power Act and therefore is not generally regulated by the FERC, although certain of its transactions are subject to limited FERC jurisdiction. The Energy Act conferred new jurisdiction and responsibilities on the FERC with respect to ensuring the reliability of electric transmission service, including transmission owned by CenterPoint Houston and other utilities within ERCOT. Under the legislation, the FERC is required to designate an Electric Reliability Organization (ERO) which will, under FERC oversight, promulgate standards for all owners, operators and users of the bulk power system (Electric Entities). The ERO and the FERC have authority to impose fines and other sanctions on Electric Entities that fail to comply with the standards. The FERC has designated the North American Electric Reliability Council (NERC) as the ERO. Under the Energy Act the ERO may delegate authority to regional entities. Currently ERCOT is seeking FERC approval for an ERCOT division to be designated as the regional entity for the ERCOT region. The ERO currently is developing standards and the other aspects of the regulatory framework under the Energy Act. CenterPoint Houston does not anticipate that the transmission standards will have a material adverse impact on its operations. To the extent that CenterPoint Houston is required to make additional expenditures to comply with the ERO s transmission standards, it is anticipated that CenterPoint Houston will seek to recover those costs through the transmission charges that are imposed on all distribution service providers within ERCOT for electric transmission provided.

Prior to repeal of the 1935 Act, effective February 8, 2006, we were a registered public utility holding company under the 1935 Act, and we and our subsidiaries were subject to a comprehensive regulatory scheme imposed by the SEC under that Act. Although the SEC did not regulate rates and charges under the 1935 Act, it did regulate the structure, financing, lines of business and internal transactions of public utility holding companies and their system companies.

The Energy Act repealed the 1935 Act , and since that date, we and our subsidiaries have no longer been subject to restrictions imposed under the 1935 Act. The Energy Act includes PUHCA 2005 which grants to the FERC authority to require holding companies and their subsidiaries to maintain certain books and records and make them available for review by the FERC and state regulatory authorities in certain circumstances. In December 2005, the FERC issued rules implementing PUHCA 2005. Pursuant to those rules, in June 2006, we filed with the FERC

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the required notification of our status as a public utility holding company. In October 2006, the FERC adopted additional rules regarding maintenance of books and records by utility holding companies and additional reporting and accounting requirements for centralized service companies that make allocations to public utilities regulated by the FERC under the Federal Power Act. Although we provide services to our subsidiaries through a service company, our service company is not subject to the service company rules.

State and Local Regulation

Electric Transmission & Distribution

CenterPoint Houston conducts its operations pursuant to a certificate of convenience and necessity issued by the Texas Utility Commission that covers its present service area and facilities. The Texas Utility Commission and those municipalities that have retained original jurisdiction have the authority to set the rates and terms of service provided by CenterPoint Houston under cost of service rate regulation. CenterPoint Houston holds non-exclusive franchises from the incorporated municipalities in its service territory. In exchange for payment of fees, these franchises give CenterPoint Houston the right to use the streets and public rights-of-way of these municipalities to construct, operate and maintain its transmission and distribution system and to use that system to conduct its electric delivery business and for other purposes that the franchises permit. The terms of the franchises, with various expiration dates, typically range from 30 to 50 years. As discussed above under Our Business Electric Transmission & Distribution Franchises, a new franchise ordinance for the City of Houston franchise was granted in June 2005 with a term of 30 years and 60 other cities have passed new franchise ordinances following a similar, standardized form.

All REPs in CenterPoint Houston s service area pay the same rates and other charges for the same transmission and distribution services.

CenterPoint Houston s distribution rates charged to REPs for residential customers are based on amounts of energy delivered, whereas distribution rates for a majority of commercial and industrial customers are based on peak demand. Transmission rates charged to other distribution companies are based on amounts of energy transmitted under postage stamp rates that do not vary with the distance the energy is being transmitted. All distribution companies in ERCOT pay CenterPoint Houston the same rates and other charges for transmission services. This regulated delivery charge includes the transmission and distribution rate (which includes municipal franchise fees), a system benefit fund fee imposed by the Texas electric restructuring law, a nuclear decommissioning charge associated with decommissioning the South Texas nuclear generating facility (South Texas Project), transition charges associated with securitization of regulatory assets and securitization of stranded costs, a competition transition charge for collection of the true-up balance not securitized and a rate case expense charge.

CenterPoint Houston Rate Case.

In December 2005, the Texas Utility Commission ordered the commencement of a rate proceeding concerning the reasonableness of CenterPoint Houston s existing rates for transmission and distribution service and required CenterPoint Houston to make a filing by April 15, 2006 to justify or change those rates. In April 2006, CenterPoint Houston filed cost data and other information that supported the rates then in effect.

In July 2006, CenterPoint Houston entered into a settlement agreement with the parties to the proceeding that resolved the issues raised in this matter. CenterPoint Houston filed a Stipulation and Agreement (Settlement Agreement) with the Texas Utility Commission in August 2006 to seek approval of the Settlement Agreement. In September 2006, the Texas Utility Commission issued its final order approving the Settlement Agreement. Revised base rates and other revised tariffs became effective in October 2006.

Under the terms of the Settlement Agreement, CenterPoint Houston s base rate revenues were reduced by a net of approximately $58 million per year. Also, CenterPoint Houston agreed to increase its energy efficiency expenditures by an additional $10 million per year over the $13 million then included in rates. The expenditures will be made to benefit both residential and commercial customers. CenterPoint Houston also will fund $10 million per year for programs providing financial assistance to qualified low-income customers in its service territory.

The Settlement Agreement provides that until June 30, 2010 CenterPoint Houston will not seek to increase its base rates and the other parties will not petition to decrease those rates. This rate freeze is subject to adjustments for changes related to certain transmission costs, implementation of the Texas Utility Commission s recently-adopted change to its CTC rule and certain other changes. The rate freeze does not apply to changes required to reflect the result of currently pending appeals of the True-Up Order, the pending appeal of the Texas Utility Commission s order regarding CenterPoint Houston s final fuel reconciliation, the appeal of the order implementing CenterPoint Houston s CTC or the implementation of transition charges associated with current and future securitizations. In addition, CenterPoint Houston is not required to file annual earnings reports for the calendar years 2006 through 2008, but is required to file an earnings report for 2009 no later than March 1, 2010. CenterPoint Houston must make a new base rate filing not later than June 30, 2010, based on a test year ended December 31, 2009, unless the Staff and certain cities with original jurisdiction notify CenterPoint Houston that such a filing is unnecessary.

Pursuant to the Settlement Agreement, in October 2006 CenterPoint Houston began amortizing expenditures of approximately $28 million related to Hurricane Rita over a seven-year period and regulatory expenses of approximately $7 million over a four-year period. Pursuant to the Settlement Agreement, the Texas Utility Commission determined that franchise fees payable by CenterPoint Houston under new franchise agreements with the City of Houston and certain other municipalities in CenterPoint Houston s service area are deemed reasonable and necessary, along with the revised base rates.

The Settlement Agreement also resolved all issues that could be raised in the Texas Utility Commission s proceeding to review its decision in CenterPoint Houston s 2001 UCOS case discussed above under Our Business Electric Transmission & Distribution Remand of 2001 Unbundled Cost of Service (UCOS) Order.

These and other significant matters currently affecting our financial condition are further discussed in Management s Discussion and Analysis of Financial Condition and Results of Operations Executive Summary Significant Events in 2006 in Item 7 of this report.

Natural Gas Distribution

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

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

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

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

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

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

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

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

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

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

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

Department of Transportation

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

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

We anticipate that compliance with these regulations by our interstate and intrastate pipelines and our natural gas distribution companies will require increases in both capital and operating costs. The level of expenditures required to comply with these regulations will be dependent on several factors, including the age of the facility, the pressures at which the facility operates and the number of facilities deemed to be located in areas designated as HCA. Based on our interpretation of the rules and preliminary technical reviews, we believe compliance will require average annual expenditures of approximately $15 to $20 million during the initial 10-year period.

ENVIRONMENTAL MATTERS

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

- restricting the way we can handle or dispose of wastes;

limiting or prohibiting construction activities in sensitive areas such as wetlands, coastal regions, or areas inhabited by endangered species;

requiring remedial action to mitigate pollution conditions caused by our operations, or attributable to former operations; and

- enjoining the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations.

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

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

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

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

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

Air Emissions

Our operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies.

Water Discharges

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

Hazardous Waste

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

Liability for Remediation

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

Liability for Preexisting Conditions

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

Beginning about 1985, the predecessors of certain CERC Corp. defendants engaged in a voluntary remediation of any subsurface contamination of the groundwater below the property they owned or leased. This work has been done in conjunction with and under the direction of the Louisiana Department of Environmental Quality. The plaintiffs seek monetary damages for alleged damage to the aquifer underlying their property, including the cost of restoring their property to its original condition and damages for diminution of value of their property. In addition, plaintiffs seek damages for trespass, punitive, and exemplary damages. The parties have reached an agreement on terms of a settlement in principle of this matter. That settlement would require approval from the Louisiana Department of Environmental Quality of an acceptable remediation plan that could be implemented by CERC.

CERC currently is seeking that approval. If the currently agreed terms for settlement are ultimately implemented, the Company and CERC do not expect the ultimate cost associated with resolving this matter to have a material impact on the financial condition, results of operations or cash flows of either the Company or CERC.

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

At December 31, 2006, CERC had accrued $14 million for remediation of these Minnesota sites. At December 31, 2006, the estimated range of possible remediation costs for these sites was $4 million to $35 million based on remediation continuing for 30 to 50 years. The cost estimates are based on studies of a site or industry average costs for remediation of sites of similar size. The actual remediation costs will be dependent upon the number of sites to be remediated, the participation of other potentially responsible parties (PRP), if any, and the remediation methods used. CERC has utilized an environmental expense tracker mechanism in its rates in Minnesota to recover estimated costs in excess of insurance recovery. As of December 31, 2006, CERC had collected $13 million from insurance companies and rate payers to be used for future environmental remediation.

In addition to the Minnesota sites, the EPA and other regulators have investigated MGP sites that were owned or operated by CERC or may have been owned by one of its former affiliates. CERC has been named as a defendant in two lawsuits, one filed in the United States District Court, District of Maine and the other filed in the Middle District of Florida, Jacksonville Division, under which contribution is sought by private parties for the cost to remediate former MGP sites based on the previous ownership of such sites by former affiliates of CERC or its divisions. CERC has also been identified as a PRP by the State of Maine for a site that is the subject of one of the lawsuits. In March 2005, the federal district court considering the suit for contribution in Florida granted CERC s motion to dismiss on the grounds that CERC was not an operator of the site as had been alleged. In October 2006, the 11th Circuit Court of Appeals affirmed the district court s dismissal. In June 2006, the federal district court in Maine that is considering the other suit ruled that the current owner of the site is responsible for site remediation but that an additional evidentiary hearing is required to determine if other potentially responsible parties, including CERC, would have to contribute to that remediation. We are investigating details regarding these sites and the range of environmental expenditures for potential remediation. However, CERC believes it is not liable as a former owner or operator of those sites under CERCLA and applicable state statutes, and is vigorously contesting those suits and its designation as a PRP.

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

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

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

Nuclear Decommissioning Fund Collection

Pursuant to regulatory requirements and its tariff, CenterPoint Houston, as collection agent, collects from its transmission and distribution customers a nuclear decommissioning charge assessed with respect to its former 30.8% ownership interest in the South Texas Project, which it owned when it was part of an integrated electric utility. Amounts collected are transferred to nuclear decommissioning trusts maintained by the current owner of that interest in the South Texas Project. During 2004, 2005 and 2006, \$2.9 million, \$3.2 million and \$3.1 million, respectively, was transferred. There are various investment restrictions imposed on owners of nuclear generating stations by the Texas Utility Commission and the U.S. Nuclear Regulatory Commission relating to nuclear decommissioning trusts. Pursuant to the provisions of both a separation agreement and a final order of the Texas Utility Commission relating to the 2005 transfer of ownership to Texas Genco LLC, now NRG, CenterPoint Houston and a subsidiary of NRG were, until July 1, 2006, jointly administering the decommissioning funds through the Nuclear Decommissioning Trust Investment Committee. On June 9, 2006, the Texas Utility Commission approved an application by CenterPoint Houston and an NRG subsidiary to name the NRG subsidiary as the sole fund administrator. As a result, CenterPoint Houston is no longer responsible for administration of decommissioning funds it collects as collection agent.

EMPLOYEES

As of December 31, 2006, we had 8,623 full-time employees. The following table sets forth the number of our employees by business segment:

Business Segment	Number	Number Represented by Unions or Other Collective Bargaining Groups
Electric Transmission & Distribution	2,754	1,170
Natural Gas Distribution	4,147	1,466
Competitive Natural Gas Sales and Services	103	
Interstate Pipelines	555	
Field Services	185	
Other Operations	879	
Total	8,623	2,636

As of December 31, 2006, approximately 31% of our employees are subject to collective bargaining agreements. One agreement, covering approximately 3% of our employees, is covered by a collective bargaining unit agreement with the International Brotherhood of Electrical Workers Local 949, which expires in December 2007. We have a good relationship with this bargaining unit and expect to renegotiate new agreements in 2007.

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EXECUTIVE OFFICERS
(as of February 28, 2007)

Name	Age	Title
David M. McClanahan	57	President and Chief Executive Officer and Director
Scott E. Rozzell	57	Executive Vice President, General Counsel and Corporate Secretary
Gary L. Whitlock	57	Executive Vice President and Chief Financial Officer
James S. Brian	59	Senior Vice President and Chief Accounting Officer
Byron R. Kelley	59	Senior Vice President and Group President and Chief Operating Officer, CenterPoint Energy Pipelines and Field Services
Thomas R. Standish	57	Senior Vice President and Group President Regulated Operations

David M. McClanahan has been President and Chief Executive Officer and a director of CenterPoint Energy since September 2002. He served as Vice Chairman of Reliant Energy, Incorporated (Reliant Energy) from October 2000 to September 2002 and as President and Chief Operating Office of Reliant Energy s Delivery Group from April 1999 to September 2002. He has served in various executive capacities with CenterPoint Energy since 1986. He previously served as Chairman of the Board of Directors of ERCOT and Chairman of the Board of the University of St. Thomas in Houston. He currently serves on the boards of the Edison Electric Institute and the American Gas Association.

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

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

James S. Brian has served as Senior Vice President and Chief Accounting Officer of CenterPoint Energy since August 2002. He served as Senior Vice President, Finance and Administration of the Delivery Group of Reliant Energy from 1999 to August 2002. Mr. Brian has served in various executive capacities with CenterPoint Energy since 1983.

Byron R. Kelley has served as Senior Vice President and Group President and Chief Operating Officer of CenterPoint Energy Pipelines and Field Services since June 2004, having previously served as President and Chief Operating Officer of CenterPoint Energy Pipelines and Field Services from May 2003 to June 2004. Prior to joining CenterPoint Energy he served as President of El Paso International, a subsidiary of El Paso Corporation, from January 2001 to August 2002. He currently serves on the Board of Directors of the Interstate Natural Gas Association of America.

Thomas R. Standish has served as Senior Vice President and Group President-Regulated Operations of CenterPoint Energy since August 2005, having previously served as Senior Vice President and Group President and Chief

Operating Officer of CenterPoint Houston from June 2004 to August 2005 and as President and Chief Operating Officer of CenterPoint Houston from August 2002 to June 2004. He served as President and Chief Operating Officer for both electricity and natural gas for Reliant Energy s Houston area from 1999 to August 2002. Mr. Standish has served in various executive capacities with CenterPoint Energy since 1993. He currently serves on the Board of Directors of ERCOT.

Item 1A. *Risk Factors*

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

Risk Factors Affecting Our Electric Transmission & Distribution Business

CenterPoint Houston may not be successful in ultimately recovering the full value of its true-up components, which could result in the elimination of certain tax benefits and could have an adverse impact on CenterPoint Houston s results of operations, financial condition and cash flows.

In March 2004, CenterPoint Houston filed its true-up application with the Texas Utility Commission, requesting recovery of $3.7 billion, excluding interest, as allowed under the Texas electric restructuring law. In December 2004, the Texas Utility Commission issued its final order (True-Up Order) allowing CenterPoint Houston to recover a true-up balance of approximately $2.3 billion, which included interest through August 31, 2004, and providing for adjustment of the amount to be recovered to include interest on the balance until recovery, the principal portion of additional excess mitigation credits returned to customers after August 31, 2004 and certain other matters. CenterPoint Houston and other parties filed appeals of the True-Up Order to a district court in Travis County, Texas. In August 2005, the court issued its final judgment on the various appeals. In its judgment, the court affirmed most aspects of the True-Up Order, but reversed two of the Texas Utility Commission s rulings. The judgment would have the effect of restoring approximately $650 million, plus interest, of the $1.7 billion the Texas Utility Commission had disallowed from CenterPoint Houston s initial request. CenterPoint Houston and other parties appealed the district court s judgment. Oral arguments before the Texas 3rd Court of Appeals were held in January 2007, but a decision is not expected for several months. No amounts related to the district court s judgment have been recorded in our consolidated financial statements.

Among the issues raised in CenterPoint Houston s appeal of the True-Up Order is the Texas Utility Commission s reduction of CenterPoint Houston s stranded cost recovery by approximately $146 million for the present value of certain deferred tax benefits associated with its former electric generation assets. Such reduction was considered in our recording of an after-tax extraordinary loss of $977 million in the last half of 2004. We believe that the Texas Utility Commission based its order on proposed regulations issued by the Internal Revenue Service (IRS) in March 2003 related to those tax benefits. Those proposed regulations would have allowed utilities owning assets that were deregulated before March 4, 2003 to make a retroactive election to pass the benefits of Accumulated Deferred Investment Tax Credits (ADITC) and Excess Deferred Federal Income Taxes (EDFIT) back to customers. However, in December 2005, the IRS withdrew those proposed normalization regulations and issued new proposed regulations that do not include the provision allowing a retroactive election to pass the tax benefits back to customers. In a May 2006 Private Letter Ruling (PLR) issued to a Texas utility on facts similar to CenterPoint Houston s, the IRS, without referencing its proposed regulations, ruled that a normalization violation would occur if ADITC and EDFIT were required to be returned to customers. CenterPoint Houston has requested a PLR asking the IRS whether the Texas Utility Commission s order reducing CenterPoint Houston s stranded cost recovery by $146 million for ADITC and EDFIT would cause a normalization violation. If the IRS determines that such reduction would cause a normalization violation with respect to the ADITC and the Texas Utility Commission s order relating to such reduction is not reversed or otherwise modified, the IRS could require us to pay an amount equal to CenterPoint Houston s unamortized ADITC balance as of the date that the normalization violation is deemed to have occurred. In addition, if a normalization violation with respect to EDFIT is deemed to have occurred and the Texas Utility Commission s order relating to such reduction is not reversed or otherwise modified, the IRS could deny CenterPoint Houston the ability to elect accelerated tax depreciation benefits beginning in the taxable year that the normalization violation is deemed to have occurred. If a normalization violation should ultimately be found to exist, it could have an adverse impact on our results of operations, financial condition and cash flows. However, we and CenterPoint Houston are vigorously pursuing the appeal of this issue and will seek other relief from the Texas Utility Commission to avoid a normalization violation. The Texas Utility Commission has not previously required a company subject to its jurisdiction to take action that would result in a normalization violation.

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

CenterPoint Houston s receivables from the distribution of electricity are collected from REPs that supply the electricity CenterPoint Houston distributes to their customers. Currently, CenterPoint Houston does business with 68 REPs. Adverse economic conditions, structural problems in the market served by ERCOT or financial difficulties of one or more REPs could impair the ability of these retail providers to pay for CenterPoint Houston s services or could cause them to delay such payments. CenterPoint Houston depends on these REPs to remit payments on a timely basis. Applicable regulatory provisions require that customers be shifted to a provider of last resort if a retail electric provider cannot make timely payments. Reliant Energy, Inc. (RRI), through its subsidiaries, is CenterPoint Houston s largest customer. Approximately 53% of CenterPoint Houston s $140 million in billed receivables from REPs at December 31, 2006 was owed by subsidiaries of RRI. Any delay or default in payment could adversely affect CenterPoint Houston s cash flows, financial condition and results of operations.

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

CenterPoint Houston s rates are regulated by certain municipalities and the Texas Utility Commission based on an analysis of its invested capital and its expenses in a test year. Thus, the rates that CenterPoint Houston is allowed to charge may not match its expenses at any given time. In this connection, pursuant to the Settlement Agreement discussed in Business Regulation State and Local Regulation Electric Transmission & Distribution CenterPoint Houston Rate Case in Item 1 of this report, until June 30, 2010, CenterPoint Houston is limited in its ability to request rate relief. The regulatory process by which rates are determined may not always result in rates that will produce full recovery of CenterPoint Houston s costs and enable CenterPoint Houston to earn a reasonable return on its invested capital.

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

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

CenterPoint Houston s revenues and results of operations are seasonal.

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

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

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

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

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

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

CERC s two interstate pipelines and its gathering systems compete with other interstate and intrastate pipelines and gathering systems in the transportation and storage of natural gas. The principal elements of competition are rates, terms of service, and flexibility and reliability of service. They also compete indirectly with other forms of energy, including electricity, coal and fuel oils. The primary competitive factor is price. The actions of CERC s competitors could lead to lower prices, which may have an adverse impact on CERC s results of operations, financial condition and cash flows.

CERC s 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 CERC s suppliers and customers to meet their obligations or otherwise adversely affect CERC s liquidity.

CERC is subject to risk associated with increases in the price of natural gas. Increases in natural gas prices might affect CERC s ability to collect balances due from its customers and, on the regulated side, could create the potential for uncollectible accounts expense to exceed the recoverable levels built into CERC s tariff rates. In addition, a sustained period of high natural gas prices could apply downward demand pressure on natural gas consumption in the areas in which CERC operates and increase the risk that CERC s suppliers or customers fail or are unable to meet their obligations. Additionally, increasing natural gas prices could create the need for CERC to provide collateral in order to purchase natural gas.

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

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

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

If CERC s credit rating were to decline, it might be required to post cash collateral in order to purchase natural gas. If a credit rating downgrade and the resultant cash collateral requirement were to occur at a time when CERC was experiencing significant working capital requirements or otherwise lacked liquidity, CERC might be unable to obtain the necessary natural gas to meet its obligations to customers, and its results of operations, financial condition and cash flows would be adversely affected.

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

CERC s interstate pipelines and field services businesses largely rely on natural gas sourced in the various supply basins located in the Mid-continent region of the United States. To the extent the availability of this supply is substantially reduced, it could have an adverse effect on CERC s results of operations, financial condition and cash flows.

CERC s revenues and results of operations are seasonal.

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

The actual construction costs of proposed pipelines and related compression facilities may be significantly higher than CERC s current estimates.

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

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

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

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

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

If either or both of these regulatory frameworks become effective, they could have adverse impacts on CERC s ability to operate and provide cost-effective utility service. In addition, if more than one state adopts restrictions like those proposed in Arkansas and Minnesota, it may be difficult for CenterPoint and CERC to comply with competing regulatory requirements.

Risk Factors Associated with Our Consolidated Financial Condition

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

As of December 31, 2006, we had $9.0 billion of outstanding indebtedness on a consolidated basis, which includes $2.4 billion of non-recourse transition bonds. As of December 31, 2006, approximately $875 million principal amount of this debt is required to be paid through 2009. This amount excludes principal repayments of approximately $481 million on transition bonds, for which a dedicated revenue stream exists. In addition, we have cash settlement obligations with respect to $575 million of outstanding 3.75% convertible notes on which holders could exercise their conversion rights during the first quarter of 2007 and in subsequent quarters in which our common stock price causes such notes to be convertible. Our future financing activities may depend, at least in part, on:

- the timing and amount of our recovery of the true-up components, including, in particular, the results of appeals to the courts of determinations on rulings obtained to date;
- general economic and capital market conditions;
- credit availability from financial institutions and other lenders;
- investor confidence in us and the markets in which we operate;
- maintenance of acceptable credit ratings;
- market expectations regarding our future earnings and cash flows;
- market perceptions of our ability to access capital markets on reasonable terms;
- our exposure to RRI in connection with its indemnification obligations arising in connection with its separation from us; and
- provisions of relevant tax and securities laws.

As of December 31, 2006, CenterPoint Houston had outstanding $2.0 billion aggregate principal amount of general mortgage bonds, including approximately $527 million held in trust to secure pollution control bonds for which CenterPoint Energy is obligated and approximately $229 million held in trust to secure pollution control bonds for which CenterPoint Houston is obligated. Additionally, CenterPoint Houston had outstanding approximately $253 million aggregate principal amount of first mortgage bonds, including approximately $151 million held in trust to secure certain pollution control bonds for which CenterPoint Energy is obligated. CenterPoint Houston may issue additional general mortgage bonds on the basis of retired bonds, 70% of property additions or cash deposited with the trustee. Approximately $2.2 billion of additional first mortgage bonds and general mortgage bonds in the aggregate could be issued on the basis of retired bonds and 70% of property additions as of December 31, 2006. However, CenterPoint Houston is contractually prohibited, subject to certain exceptions, from issuing additional first mortgage bonds.

Our current credit ratings are discussed in Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Future Sources and Uses of Cash Impact on Liquidity of a Downgrade in Credit Ratings in Item 7 of 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.

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

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

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

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

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

Risks Common to Our Businesses and Other Risks

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

Our operations are subject to stringent and complex laws and regulations pertaining to health, safety and the environment, as discussed in Business Environmental Matters in Item 1 of this report. As an owner or operator of natural gas pipelines and distribution systems, gas gathering and processing systems, and electric transmission and distribution systems, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

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

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

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

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

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

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

In common with other companies in its line of business that serve coastal regions, CenterPoint Houston does not have insurance covering its transmission and distribution system because CenterPoint Houston believes it to be cost prohibitive. If CenterPoint Houston were to sustain any loss of, or damage to, its transmission and distribution properties, it may not be able to recover such loss or damage through a change in its regulated rates, and any such recovery may not be timely granted. Therefore, CenterPoint Houston may not be able to restore any loss of, or damage to, any of its transmission and distribution properties without negative impact on its results of operations, financial condition and cash flows.

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

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

- those transferred to RRI or its subsidiaries in connection with the organization and capitalization of RRI prior to its initial public offering in 2001; and
- those transferred to Texas Genco in connection with its organization and capitalization.

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

Prior to our distribution of our ownership in RRI to our shareholders, CERC had guaranteed certain contractual obligations of what became RRI s trading subsidiary. Under the terms of the separation agreement between the companies, RRI agreed to extinguish all such guaranty obligations prior to separation, but at the time of separation in September 2002, RRI had been unable to extinguish all obligations. To secure us and CERC against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for the benefit of CERC and us, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. CERC currently holds letters of credit in the amount of $33.3 million issued on behalf of RRI against guaranties that have not been released. Our current exposure under the guaranties relates to CERC s guaranty of the payment by RRI of demand charges related to transportation contracts with one counterparty. The demand charges are approximately $53 million per year through 2015, $49 million in 2016, $38 million in 2017 and $13 million in 2018. RRI continues to meet its obligations under the transportation contracts, and we believe current market conditions make those contracts valuable for transportation services in the near term. However, changes in market conditions could affect the value of those contracts. If RRI should fail to perform its obligations under the transportation contracts, our exposure to the counterparty under the guaranty could exceed the security provided by RRI. We have requested RRI to increase the amount of its existing letters of credit or, in the alternative, to obtain a release of CERC s obligations under the guaranty. In June 2006, the RRI trading subsidiary and CERC jointly filed a complaint at the FERC against the counterparty on the CERC guaranty. In the complaint, the RRI trading subsidiary seeks a determination by the FERC that the security demanded by the counterparty exceeds the level permitted by the FERC s policies. The complaint asks the FERC to require the counterparty to release CERC from its guaranty obligation and, in its place, accept (i) a guaranty from RRI of the obligations of the RRI trading subsidiary, and (ii) letters of credit limited to (A) one year of demand charges for a transportation agreement related to a 2003 expansion of the counterparty s pipeline, and (B) three months of demand charges for three other transportation agreements held by the RRI trading subsidiary. The counterparty has argued that the amount of the guaranty does not violate the FERC s policies and that the proposed substitution of credit support is not authorized under the counterparty s financing documents or required by the FERC s policy. The parties have now completed their submissions to FERC regarding the complaint. We cannot predict what action the FERC may take on the complaint or when the FERC may rule. In addition to the FERC proceeding, in February 2007 CenterPoint and CERC made a formal demand on RRI under procedures provided for by the Master Separation Agreement, dated as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc. That demand seeks to resolve the disagreement with RRI over the amount of security RRI is obligated to provide with respect to this guaranty. It is possible that this demand could lead to an arbitration proceeding between the companies, but when and on what terms the disagreement with RRI will ultimately be resolved cannot be predicted.

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

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

In connection with the organization and capitalization of Texas Genco, Texas Genco assumed liabilities associated with the electric generation assets Reliant Energy transferred to it. Texas Genco also agreed to indemnify, and cause the applicable transferee subsidiaries to indemnify, us and our subsidiaries, including CenterPoint Houston, with respect to liabilities associated with the transferred assets and businesses. In many cases the liabilities assumed were obligations of CenterPoint Houston and CenterPoint Houston was not released by third parties from these liabilities. The indemnity provisions were intended generally to place sole financial responsibility on Texas Genco and its subsidiaries for all liabilities associated with the current and historical businesses and operations of Texas Genco, regardless of the time those liabilities arose. In connection with the sale of Texas Genco s fossil generation assets (coal, lignite and gas-fired plants) to Texas Genco LLC, the separation agreement we entered into with Texas Genco in connection with the organization and capitalization of Texas Genco was amended to provide that all of Texas Genco s rights and obligations under the separation agreement relating to its fossil generation assets, including Texas Genco s obligation to indemnify us with respect to liabilities associated with the fossil generation assets and related business, were assigned to and assumed by Texas Genco LLC. In addition, under the amended separation agreement, Texas Genco is no longer liable for, and we have assumed and agreed to indemnify Texas Genco LLC against, liabilities that Texas Genco originally assumed in connection with its organization to the extent, and only to the extent, that such liabilities are covered by certain insurance policies or other similar agreements held by us. If Texas Genco or Texas Genco LLC were unable to satisfy a liability that had been so assumed or indemnified against, and provided Reliant Energy had not been released from the liability in connection with the transfer, CenterPoint Houston could be responsible for satisfying the liability.

We or our subsidiaries have been named, along with numerous others, as a defendant in lawsuits filed by a large number of individuals who claim injury due to exposure to asbestos. Most claimants in such litigation have been workers who participated in construction of various industrial facilities, including power plants. Some of the claimants have worked at locations we own, but most existing claims relate to facilities previously owned by our subsidiaries but currently owned by Texas Genco LLC, which is now known as NRG Texas LP. We anticipate that additional claims like those received may be asserted in the future. Under the terms of the arrangements regarding separation of the generating business from us and its sale to Texas Genco LLC, ultimate financial responsibility for uninsured losses from claims relating to the generating business has been assumed by Texas Genco LLC and its successor, but we have agreed to continue to defend such claims to the extent they are covered by insurance maintained by us, subject to reimbursement of the costs of such defense by Texas Genco LLC.

Item 1B. ***Unresolved Staff Comments***

Not applicable.

Item 2. ***Properties***

Character of Ownership

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

Electric Transmission & Distribution

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

Natural Gas Distribution

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

Competitive Natural Gas Sales and Services

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

Interstate Pipelines

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

Field Services

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

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Other Operations

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

Item 3. *Legal Proceedings*

For a discussion of material legal and regulatory proceedings affecting us, please read Business Regulation and Business Environmental Matters in Item 1 of this report and Notes 4 and 10(d) to our consolidated financial statements, which information is incorporated herein by reference.

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

There were no matters submitted to the vote of our security holders during the fourth quarter of 2006.

PART II

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

As of February 16, 2007, our common stock was held of record by approximately 51,675 shareholders. Our common stock is listed on the New York and Chicago Stock Exchanges and is traded under the symbol CNP.

The following table sets forth the high and low closing prices of the common stock of CenterPoint Energy on the New York Stock Exchange composite tape during the periods indicated, as reported by *Bloomberg,* and the cash dividends declared in these periods. Cash dividends paid aggregated $0.40 per share in 2005 and $0.60 per share in 2006.

	Market Price		Dividend Declared
	High	**Low**	**Per Share(1)**
2005			
First Quarter			$ 0.20
January 11		$ 10.65	
March 8	$ 12.61		
Second Quarter			$ 0.07
April 20		$ 11.68	
June 30	$ 13.21		
Third Quarter			$ 0.07
August 8		$ 13.04	
September 16	$ 15.13		
Fourth Quarter			$ 0.06
October 3	$ 14.82		
October 21		$ 12.65	
2006			
First Quarter			$ 0.15
January 19	$ 13.28		

March 27		$ 11.92	
Second Quarter			$ 0.15
April 12		$ 11.73	
June 30	$ 12.50		
Third Quarter			$ 0.15
July 3		$ 12.55	
September 1	$ 14.55		
Fourth Quarter			$ 0.15
October 2		$ 14.22	
December 27	$ 16.80		

(1) During 2005, we paid irregular quarterly dividends based on earnings in each specific quarter in order to comply with requirements under the Public Utility Holding Company Act of 1935, as amended (1935 Act). The 1935 Act, with its requirements associated with dividends, was repealed effective as of February 8, 2006.

The closing market price of our common stock on December 31, 2006 was $16.58 per share.

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

On February 1, 2007, we announced a regular quarterly cash dividend of $0.17 per share, payable on March 9, 2007 to shareholders of record on February 16, 2007.

Repurchases of Equity Securities

During the quarter ended December 31, 2006, none of our equity securities registered pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of us or any of our affiliated purchasers, as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934.

Item 6. *Selected Financial Data*

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

	Year Ended December 31,				
	2002	2003(1)	2004(2)	2005(3)	2006
	(In millions, except per share amounts)				
Revenues	$ 6,438	$ 7,790	$ 7,999	$ 9,722	$ 9,319
Income from continuing operations before extraordinary item	482	409	205	225	432
Discontinued operations, net of tax	(4,402)	75	(133)	(3)	
Extraordinary item, net of tax			(977)	30	
Net income (loss)	$ (3,920)	$ 484	$ (905)	$ 252	$ 432
Basic earnings (loss) per common share:					
Income from continuing operations before extraordinary item	$ 1.62	$ 1.35	$ 0.67	$ 0.72	$ 1.39
Discontinued operations, net of tax	(14.78)	0.24	(0.43)	(0.01)	
Extraordinary item, net of tax			(3.18)	0.10	
Basic earnings (loss) per common share	$ (13.16)	$ 1.59	$ (2.94)	$ 0.81	$ 1.39
Diluted earnings (loss) per common share:					

Income from continuing operations before extraordinary item	$ 1.61	$ 1.24	$ 0.61	$ 0.67	$ 1.33
Discontinued operations, net of tax	(14.69)	0.22	(0.37)	(0.01)	
Extraordinary item, net of tax			(2.72)	0.09	
Diluted earnings (loss) per common share	$ (13.08)	$ 1.46	$ (2.48)	$ 0.75	$ 1.33
Cash dividends paid per common share	$ 1.07	$ 0.40	$ 0.40	$ 0.40	$ 0.60
Dividend payout ratio from continuing operations	66%	30%	60%	56%	43%
Return from continuing operations on average common equity	11.8%	25.7%	14.4%	18.7%	30.3%
Ratio of earnings from continuing operations to fixed charges	2.03	1.81	1.43	1.51	1.77
At year-end:					
Book value per common share	$ 4.74	$ 5.77	$ 3.59	$ 4.18	$ 4.96
Market price per common share	8.01	9.69	11.30	12.85	16.58
Market price as a percent of book value	169%	168%	315%	307%	334%
Assets of discontinued operations	$ 4,594	$ 4,244	$ 1,565	$	$
Total assets	20,635	21,461	18,096	17,116	17,633

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	Year Ended December 31,				
	2002	2003(1)	2004(2)	2005(3)	2006
	(In millions, except per share amounts)				
Short-term borrowings(4)	347	63			187
Transition bonds, including current maturities	736	717	676	2,480	2,408
Other long-term debt, including current maturities	9,260	10,222	8,353	6,427	6,592
Trust preferred securities(5)	706				
Capitalization:					
Common stock equity	12%	14%	11%	13%	15%
Trust preferred securities	6%				
Long-term debt, including current maturities	82%	86%	89%	87%	85%
Capitalization, excluding transition bonds:					
Common stock equity	12%	15%	12%	17%	19%
Trust preferred securities	7%				
Long-term debt, excluding transition bonds, including current maturities	81%	85%	88%	83%	81%
Capital expenditures, excluding discontinued operations	$ 566	$ 497	$ 530	$ 719	$ 1,121

(1) Net income for 2003 includes the cumulative effect of an accounting change resulting from the adoption of SFAS No. 143, Accounting for Asset Retirement Obligations ($80 million after-tax gain, or $0.26 and $0.24 earnings per basic and diluted share, respectively), which is included in discontinued operations related to Texas Genco.

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

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

(4) In October 2006, CERC amended its receivables facility and extended the termination date to October 30, 2007. Under the terms of the amended receivables facility, the provisions for sale accounting under SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, were no longer met. Accordingly, advances received by CERC upon the sale of receivables are accounted for as short-term borrowings as of December 31, 2006.

(5) The subsidiary trusts that issued trust preferred securities have been deconsolidated as a result of the adoption of FIN 46 Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51 (FIN 46) and the subordinated debentures issued to those trusts were reported as long-term debt effective December 31, 2003. As of December 31, 2006, these were reported as current portion of long-term debt due to their redemption in February 2007.

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

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

OVERVIEW

Background

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

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

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

Business Segments

In this section, we discuss our results from continuing operations on a consolidated basis and individually for each of our business segments. We also discuss our liquidity, capital resources and critical accounting policies. CenterPoint Energy is first and foremost an energy delivery company and it is our intention to remain focused on this segment of the energy business. The results of our business operations are significantly impacted by weather, customer growth, cost management, rate proceedings before regulatory agencies and other actions of the various regulatory agencies to which we are subject. Our transmission and distribution services are subject to rate regulation and are reported in the Electric Transmission & Distribution business segment, as are impacts of generation-related stranded costs and other true-up balances recoverable by the regulated electric utility. Our natural gas distribution services are also subject to rate regulation and are reported in the Natural Gas Distribution business segment. Beginning in the fourth quarter of 2006, we are reporting our interstate pipelines and field services businesses as two separate business segments, Interstate Pipelines business segment and Field Services business segment. These business segments were previously aggregated and reported as the Pipelines and Field Services business segment. A summary of our reportable business segments as of December 31, 2006 is set forth below:

Electric Transmission & Distribution

Our electric transmission and distribution operations provide electric transmission and distribution services to REPs serving approximately 2.0 million metered customers in a 5,000-square-mile area of the Texas Gulf coast that has a population of approximately 4.8 million people and includes Houston.

On behalf of REPs, CenterPoint Houston delivers electricity from power plants to substations, from one substation to another and to retail electric customers in locations throughout the control area managed by ERCOT, which serves as the regional reliability coordinating council for member electric power systems in Texas. ERCOT membership is open to consumer groups, investor and municipally owned electric utilities, rural electric cooperatives, independent generators, power marketers and REPs. The ERCOT market represents approximately 85% of the demand for power in Texas and is one of the nation s largest power markets. Transmission services are provided under tariffs approved by the Texas Utility Commission.

Operations include construction and maintenance of electric transmission and distribution facilities, metering services, outage response services and other call center operations. Distribution services are provided under tariffs approved by the Texas Utility Commission.

Natural Gas Distribution

CERC owns and operates our regulated natural gas distribution business, which engages in intrastate natural gas sales to, and natural gas transportation for, approximately 3.2 million residential, commercial and industrial customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas.

Competitive Natural Gas Sales and Services

CERC s operations also include non-rate regulated retail and wholesale natural gas sales to, and transportation services for, commercial and industrial customers in the six states listed above as well as several other Midwestern and Eastern states.

Interstate Pipelines

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

Field Services

CERC s field services business owns and operates approximately 3,700 miles of gathering pipelines and processing plants that collect, treat and process natural gas from approximately 150 separate systems located in major producing fields in Arkansas, Louisiana, Oklahoma and Texas.

Other Operations

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

EXECUTIVE SUMMARY

Significant Events in 2006 and 2007

Debt Financing Transactions

In March 2006, we, CenterPoint Houston and CERC Corp. entered into amended and restated bank credit facilities. We replaced our $1 billion five-year revolving credit facility with a $1.2 billion five-year revolving credit facility. The facility has a first drawn cost of London Interbank Offered Rate (LIBOR) plus 60 basis points based on our current credit ratings, as compared to LIBOR plus 87.5 basis points for borrowings under the facility it replaced.

CenterPoint Houston replaced its $200 million five-year revolving credit facility with a $300 million five-year revolving credit facility. The facility has a first drawn cost of LIBOR plus 45 basis points based on CenterPoint Houston s current credit ratings, as compared to LIBOR plus 75 basis points for borrowings under the facility it replaced.

CERC Corp. replaced its $400 million five-year revolving credit facility with a $550 million five-year revolving credit facility. The facility has a first drawn cost of LIBOR plus 45 basis points based on CERC Corp. s current credit ratings, as compared to LIBOR plus 55 basis points for borrowings under the facility it replaced.

Under each of the credit facilities, an additional utilization fee of 10 basis points applies to borrowings any time more than 50% of the facility is utilized, and the spread to LIBOR fluctuates based on the borrower s credit rating.

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

In December 2006, we called our 2.875% Convertible Senior Notes due 2024 (2.875% Convertible Notes) for redemption on January 22, 2007 at 100% of their principal amount plus accrued and unpaid interest to the redemption date. The 2.875% Convertible Notes became immediately convertible at the option of the holders upon our call for redemption and were convertible through the close of business on the redemption date. Substantially all the $255 million aggregate principal amount of the 2.875% Convertible Notes were converted and the remaining amount was redeemed. The $255 million principal amount of the 2.875% Convertible Notes was settled in cash and the excess value due converting holders of $97 million was settled by delivering approximately 5.6 million shares of our common stock.

In February 2007, we redeemed $103 million aggregate principal amount of 8.257% Junior Subordinated Deferrable Interest Debentures at 104.1285% of their aggregate principal amount and the related 8.257% capital securities issued by HL&P Capital Trust II were redeemed at 104.1285% of their $100 million aggregate liquidation value.

In February 2007, we issued $250 million aggregate principal amount of senior notes due in February 2017 with an interest rate of 5.95%. The proceeds from the sale of the senior notes were used to repay debt incurred in satisfying our $255 million cash payment obligation in connection with the conversion and redemption of our 2.875% Convertible Notes as discussed above.

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

Agreement Regarding Tax Settlement

During the second quarter of 2006, we reached agreement with the Internal Revenue Service (IRS) on terms of a settlement regarding the tax treatment of our Zero Premium Exchangeable Subordinated Notes (ZENS) and our former Automatic Common Exchange Securities (ACES). In July 2006, we signed a closing agreement prepared by the IRS and us for the tax years 1999 through 2029 with respect to the ZENS issue. The agreement reached with the IRS and the closing agreement were subject to approval by the Joint Committee on Taxation of the U.S. Congress (JCT). As a result of the agreement reached with the IRS, we reduced our previously accrued tax and related interest reserves by approximately $119 million in the second quarter of 2006, and no longer accrue a quarterly reserve.

In January 2007, following JCT approval of certain revised terms of the agreement, we and the IRS executed a closing agreement on the tax treatment of the ZENS for the tax years 1999 through 2029. The items in dispute with respect to the ZENS and ACES have now been resolved. In the fourth quarter of 2006, we increased our tax and related interest reserve, reducing income by approximately $12 million to reflect the January 2007 closing agreement. Under the terms of the agreement reached with the IRS, we will pay approximately $109 million in previously accrued taxes associated with the ACES and the ZENS and will reduce our future interest deductions associated with the ZENS.

Agreement regarding settlement of the Electric Transmission & Distribution Rate Case and the 2001 Unbundled Cost of Service (UCOS) Remand

In September 2006, the Public Utility Commission of Texas (Texas Utility Commission) gave final approval to a settlement agreement with the parties to the proceeding that resolved the issues raised in CenterPoint Houston s 2006 rate case. Under the terms of the agreement, CenterPoint Houston s base rate revenues were reduced by approximately

$58 million per year. Also, CenterPoint Houston agreed to increase its energy efficiency expenditures by an additional $10 million per year over the $13 million then included in rates. The expenditures will be made to benefit both residential and commercial customers. CenterPoint Houston also will fund $10 million per year for programs providing financial assistance to qualified low-income customers in its service territory. The agreement provides for a rate freeze until June 30, 2010 under which CenterPoint Houston will not seek to increase its base rates and the other parties will not petition to decrease those rates.

The agreement also resolves all issues that could be raised in the Texas Utility Commission proceeding to review its decision in CenterPoint Houston s 2001 UCOS case. Under the terms of the agreement, CenterPoint Houston added riders to its tariff rates under which it will provide rate credits to retail and wholesale customers for a total of approximately $8 million per year until a total of $32 million has been credited to customers under those tariff riders. CenterPoint Houston reduced revenues and established a corresponding regulatory liability for $32 million in the second quarter of 2006 to reflect this obligation.

Competition Transition Charge (CTC) Interest Rate Reduction

In January 2006, the Texas Utility Commission staff (Staff) proposed that the Texas Utility Commission adopt new rules governing the carrying charges on unrecovered true-up balances. In June 2006, the Texas Utility Commission adopted the revised rule as recommended by Staff. The rule, which applies to CenterPoint Houston, reduces the allowed interest rate on the unrecovered CTC balance prospectively from 11.075 percent to a weighted average cost of capital of 8.06 percent. The annualized impact on operating income is expected to be approximately $18 million per year for the first year with lesser impacts in subsequent years. In accordance with the agreement discussed above, CenterPoint Houston implemented the rule change effective August 1, 2006.

Interstate Pipeline Expansion

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

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

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

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

Southeast Supply Header. In June 2006, CenterPoint Energy Southeast Pipelines Holding, L.L.C., a wholly owned subsidiary of CERC Corp. and a subsidiary of Spectra Energy Corp. (Spectra) formed a joint venture (Southeast Supply Header or SESH) to construct, own and operate a 270-mile pipeline that will extend from CEGT s Perryville hub in northeast Louisiana to Gulfstream Natural Gas System, which is 50 percent owned by an affiliate of Spectra. In

August 2006, the joint venture signed an agreement with Florida Power & Light Company (FPL) for firm transportation services, which subscribed approximately half of the planned 1 Bcf per day capacity of the pipeline. FPL s commitment was contingent on the approval of the FPL contract by the Florida Public Service Commission, which was received in December 2006. Subject to the joint venture receiving a certificate from the FERC to construct, own and operate the pipeline, subsidiaries of Spectra and CERC Corp. have committed to build the pipeline. In December 2006, the joint venture signed agreements with affiliates of Progress Energy Florida, Southern Company, Tampa Electric Company, and EOG Resources, Inc. bringing the total subscribed capacity to

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945 MMcf per day. Additionally, SESH and Southern Natural Gas (SNG) have executed a definitive agreement that provides for SNG to jointly own the first 115 miles of the pipeline. Under the agreement, SNG will own an undivided interest in the portion of the pipeline from Perryville, Louisiana to an interconnect with SNG in Mississippi. The pipe diameter will be increased from 36 inches to 42 inches, thereby increasing the initial capacity of 1 Bcf per day by 140 MMcf per day to accommodate SNG. SESH will own assets providing approximately 1 Bcf per day of capacity as initially planned and will maintain economic expansion opportunities in the future. SNG will own assets providing 140 MMcf per day of capacity, and the agreement provides for a future compression expansion that could increase the capacity up to 500 MMcf per day. An application to construct, own and operate the pipeline was filed with the FERC in December 2006. Subject to receipt of FERC authorization and construction in accordance with planned schedule, we currently expect an in service date in the summer of 2008. The total cost of the combined project is estimated to be $800 to $900 million with SESH s net costs of $700 to $800 million after SNG s contribution.

CERTAIN FACTORS AFFECTING FUTURE EARNINGS

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

- the timing and amount of our recovery of the true-up components, including, in particular, the results of appeals to the courts of determinations on rulings obtained to date;
- 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;
- the timing and extent of changes in natural gas basis differentials;
- commercial bank and financial market conditions, our access to capital, the cost of such capital, and the results of our financing and refinancing efforts, including availability of funds in the debt capital markets;
- actions by rating agencies;
- effectiveness of our risk management activities;
- inability of various counterparties to meet their obligations to us;

non-payment for our services due to financial distress of our customers, including Reliant Energy, Inc. (RRI);

the ability of RRI and its subsidiaries to satisfy their obligations to us, including indemnity obligations, or in connection with the contractual arrangements pursuant to which we are their guarantor;

the outcome of litigation brought by or against us;

our ability to control costs;

the investment performance of our employee benefit plans;

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our potential business strategies, including acquisitions or dispositions of assets or businesses, which we cannot be assured to be completed or to have the anticipated benefits to us; and

other factors we discuss under Risk Factors in Item 1A of this report and in other reports we file from time to time with the SEC.

CONSOLIDATED RESULTS OF OPERATIONS

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

	Year Ended December 31,		
	2004	2005	2006
Revenues	$ 7,999	$ 9,722	$ 9,319
Expenses	7,135	8,783	8,274
Operating Income	864	939	1,045
Gain (Loss) on Time Warner Investment	31	(44)	94
Gain (Loss) on Indexed Debt Securities	(20)	49	(80)
Interest and Other Finance Charges	(739)	(670)	(470)
Interest on Transition Bonds	(38)	(40)	(130)
Return on True-Up Balance	226	121	
Other Income, net	20	23	35
Income From Continuing Operations Before Income Taxes and Extraordinary Item	344	378	494
Income Tax Expense	139	153	62
Income From Continuing Operations Before Extraordinary Item	205	225	432
Discontinued Operations, net of tax	(133)	(3)	
Income Before Extraordinary Item	72	222	432
Extraordinary Item, net of tax	(977)	30	
Net Income (Loss)	$ (905)	$ 252	$ 432
Basic Earnings (Loss) Per Share:			
Income From Continuing Operations Before Extraordinary Item	$ 0.67	$ 0.72	$ 1.39
Discontinued Operations, net of tax	(0.43)	(0.01)	
Extraordinary Item, net of tax	(3.18)	0.10	
Net Income (Loss)	$ (2.94)	$ 0.81	$ 1.39
Diluted Earnings (Loss) Per Share:			
Income From Continuing Operations Before Extraordinary Item	$ 0.61	$ 0.67	$ 1.33
Discontinued Operations, net of tax	(0.37)	(0.01)	
Extraordinary Item, net of tax	(2.72)	0.09	

Net Income (Loss)	$ (2.48)	$ 0.75	$ 1.33

2006 Compared to 2005

Income from Continuing Operations. We reported income from continuing operations before extraordinary item of $432 million ($1.33 per diluted share) for 2006 as compared to $225 million ($0.67 per diluted share) for the same period in 2005. As discussed below, the increase in income from continuing operations of $207 million was primarily due to a $200 million decrease in interest expense, excluding transition bond-related interest expense, due to lower borrowing costs and borrowing levels; a $133 million decrease in income tax expense related to our ZENS and ACES; a $19 million increase in operating income from our Field Services business segment; a $17 million increase in operating income from our Competitive Natural Gas Sales and Services business segment; and a $16 million increase in operating income from our Interstate Pipelines business segment.

These increases in income from continuing operations were partially offset by a $121 million decrease in other income related to a reduction in the return on the true-up balance of our Electric Transmission & Distribution business segment recorded in 2005 and a $51 million decrease in operating income from our Natural Gas Distribution business segment. Segment changes are discussed in detail below.

Income Tax Expense. In 2006, our effective tax rate was 12.6%. We reached an agreement with the IRS in January 2007 and have reduced our previously accrued tax and related interest reserves related to the ZENS and ACES by approximately $107 million and no longer accrue a quarterly reserve for this item. The net reduction in the reserves related to ZENS and ACES in 2006 was $92 million. In addition, we reached tentative settlements with the IRS on a number of other tax matters which allowed us to reduce our total tax and related interest reserve for other tax items from $60 million at December 31, 2005 to $34 million at December 31, 2006.

2005 Compared to 2004

Income from Continuing Operations. We reported income from continuing operations before extraordinary item of $225 million ($0.67 per diluted share) for 2005 as compared to $205 million ($0.61 per diluted share) for 2004. The increase in income from continuing operations of $20 million was primarily due to increased operating income of $36 million in our Interstate Pipelines business segment resulting from increased demand for transportation due to increased basis differentials across the system and higher demand for ancillary services, increased operating income of $19 million in our Field Services business segment as a result of increased throughput and demand for services related to our core natural gas gathering operations, increased operating income of $16 million in our Competitive Natural Gas Sales and Services business segment primarily due to higher sales to utilities and favorable basis differentials over the pipeline capacity that we control, a decrease in the operating loss of $14 million in our Other Operations business segment resulting from increased overhead allocated out in 2005 and a $67 million decrease in interest expense due to lower borrowing levels and lower borrowing costs reflecting the replacement of certain of our credit facilities. The above increases were partially offset by a decrease of $105 million in the return on the true-up balance of our Electric Transmission & Distribution business segment as a result of the True-Up Order, partially offset by an increase in operating income of $21 million related to the return on the true-up balance being recovered through the CTC, and decreased operating income of $29 million in our Electric Transmission & Distribution business segment, excluding the CTC operating income discussed above, primarily from increased franchise fees paid to the City of Houston, increased depreciation expense and higher operation and maintenance expenses, including higher transmission costs, the absence of a $15 million partial reversal of a reserve related to the final fuel reconciliation recorded in the second quarter of 2004 and the absence of an $11 million gain from a land sale recorded in 2004, partially offset by increased usage mainly due to weather, continued customer growth and higher transmission cost recovery. Additionally, income tax expense increased $14 million in 2005 as compared to 2004.

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

Income Tax Expense. In 2005, our effective tax rate was 40.6%. The most significant items affecting our effective tax rate in 2005 were an addition to the tax and related interest reserves of approximately $41 million relating to the contention of the IRS that the current deductions for original issue discount (OID) on our ZENS be capitalized, potentially converting what have been ordinary deductions into capital losses at the time the ZENS are settled, partially offset by favorable tax audit adjustments of $10 million.

Interest Expense and Other Finance Charges

In the fourth quarter of 2004, we reduced borrowings under our credit facility by $1.574 billion and retired $375 million of trust preferred securities. We expensed $15 million of unamortized loan costs in the fourth quarter of 2004 that were associated with the credit facility. In accordance with Emerging Issues Task Force (EITF) Issue No. 87-24 Allocation of Interest to Discontinued Operations, we have reclassified interest to discontinued operations of Texas Genco based on net proceeds received from the sale of Texas Genco of $2.5 billion, and have applied the proceeds to the amount of debt assumed to be paid down in each respective period according to the terms

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of the respective credit facilities in effect for those periods. In periods where only the term loan was assumed to be repaid, the actual interest paid on the term loan was reclassified. In periods where a portion of the revolver was assumed to be repaid, the percentage of that portion of the revolver to the total outstanding balance was calculated, and that percentage was applied to the actual interest paid in those periods to compute the amount of interest reclassified.

During the fourth quarter of 2005, CenterPoint Houston retired at maturity its $1.341 billion term loan, which bore interest at LIBOR plus 975 basis points, subject to a minimum LIBOR rate of 3 percent. Borrowings under a CenterPoint Houston credit facility, which bore interest at LIBOR plus 75 basis points, were used for the payment of the term loan and then repaid with a portion of the proceeds of the December 2005 issuance of transition bonds.

Total interest expense incurred was $849 million, $711 million and $600 million in 2004, 2005 and 2006, respectively. We have reclassified $72 million and $1 million of interest expense in 2004 and 2005, respectively, based upon actual interest expense incurred within our discontinued operations and interest expense associated with debt that would have been required to be repaid as a result of our disposition of Texas Genco.

RESULTS OF OPERATIONS BY BUSINESS SEGMENT

The following table presents operating income (in millions) for each of our business segments for 2004, 2005 and 2006. Due to the change in reportable segments in the fourth quarter of 2006, we have recast our segment information for 2004 and 2005 to conform to the 2006 presentation. The segment detail revised as a result of the new reportable business segments did not affect consolidated operating income for any year. Included in revenues are intersegment sales. We account for intersegment sales as if the sales were to third parties, that is, at current market prices.

Operating Income (Loss) by Business Segment

	Year Ended December 31,		
	2004	2005	2006
Electric Transmission & Distribution	$ 494	$ 487	$ 576
Natural Gas Distribution	178	175	124
Competitive Natural Gas Sales and Services	44	60	77
Interstate Pipelines	129	165	181
Field Services	51	70	89
Other Operations	(32)	(18)	(2)
Total Consolidated Operating Income	$ 864	$ 939	$ 1,045

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Electric Transmission & Distribution

The following tables provide summary data of our Electric Transmission & Distribution business segment, CenterPoint Houston, for 2004, 2005 and 2006 (in millions, except throughput and customer data):

	Year Ended December 31, 2004	2005	2006
Revenues:			
Electric transmission and distribution utility	$ 1,446	$ 1,538	$ 1,516
Transition bond companies	75	106	265
Total revenues	1,521	1,644	1,781
Expenses:			
Operation and maintenance	539	618	611
Depreciation and amortization	248	258	243
Taxes other than income taxes	203	214	212
Transition bond companies	37	67	139
Total expenses	1,027	1,157	1,205
Operating Income	$ 494	$ 487	$ 576
Operating Income Electric transmission and distribution utility	456	448	450
Operating Income Transition bond companies(1)	38	39	126
Total segment operating income	$ 494	$ 487	$ 576
Throughput (in gigawatt-hours (GWh)):			
Residential	23,748	24,924	23,955
Total	73,632	74,189	75,877
Average number of metered customers:			
Residential	1,639,488	1,683,100	1,732,656
Total	1,862,853	1,912,346	1,968,114

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

2006 Compared to 2005. Our Electric Transmission & Distribution business segment reported operating income of $576 million for 2006, consisting of $450 million for the regulated electric transmission and distribution utility (TDU) (including $55 million arising from the CTC) and $126 million related to the transition bonds. For 2005, operating income totaled $487 million, consisting of $448 million for the TDU (including $19 million arising from the CTC) and $39 million related to the transition bonds. Increases in operating income from customer growth ($34 million), a higher CTC amount collected in 2006 ($36 million), revenues from ancillary services ($11 million) and proceeds from land sales ($13 million) were partially offset by milder weather and reduced demand ($49 million), the implementation of reduced base rates ($13 million) and spending on low income assistance and energy efficiency programs ($5 million) resulting from the Settlement Agreement described in Business Our Business Regulation

State and Local Regulation Electric Transmission & Distribution CenterPoint Energy Rate Case in Item 1 of this report. In addition, the TDU s operating income for 2006 includes the $32 million adverse impact of the resolution of the remand of the 2001 UCOS order recorded in the second quarter.

2005 Compared to 2004. Our Electric Transmission & Distribution business segment reported operating income of $487 million for 2005, consisting of $448 million for the TDU and $39 million related to the transition bonds. For 2004, operating income totaled $494 million, consisting of $456 million for the TDU and $38 million for the transition bonds. Operating revenues increased primarily due to increased usage resulting from warmer weather ($13 million), continued customer growth ($33 million) with the addition of 61,000 metered customers in 2005, recovery of our 2004 true-up balance not covered by the transition bond financing order ($21 million) and higher transmission cost recovery ($13 million). The increase in operating revenues was more than offset by higher transmission costs ($24 million), the absence of a gain from a land sale recorded in 2004 ($11 million), the absence of a $15 million partial reversal of a reserve related to the final fuel reconciliation recorded in 2004, increased employee-related expenses ($20 million) and higher tree trimming expense ($6 million), partially offset by a decrease in pension expense ($14 million). Depreciation and amortization expense increased ($10 million) primarily as a result of higher plant balances. Taxes other than income taxes increased ($11 million) primarily due to higher franchise fees paid to the City of Houston.

In September 2005, CenterPoint Houston s service area in Texas was adversely affected by Hurricane Rita. Although damage to CenterPoint Houston s electric facilities was limited, over 700,000 customers lost power at the height of the storm. Power was restored to over a half million customers within 36 hours and all power was restored in less than five days. The Electric Transmission & Distribution business segment s revenues lost as a result of the storm were more than offset by warmer than normal weather during the third quarter of 2005. CenterPoint Houston deferred $28 million of restoration costs which are being amortized over a seven-year period that began in October 2006.

Natural Gas Distribution

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

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

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

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

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

Competitive Natural Gas Sales and Services

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

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

Pipeline	172	142	138
Total	6,245	6,608	6,730

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

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

Interstate Pipelines

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

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

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

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

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Field Services

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

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

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

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

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

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

Other Operations

The following table provides summary data for our Other Operations business segment for 2004, 2005 and 2006 (in millions):

	Year Ended December 31, 2004	2005	2006

Revenues	$ 8	$ 19	$ 15
Expenses	40	37	17
Operating Loss	$ (32)	$ (18)	$ (2)

2006 Compared to 2005. Our Other Operations business segment s operating loss in 2006 compared to 2005 decreased $16 million primarily due to increased rental revenues ($2 million), decreased insurance costs ($4 million), and decreased state franchise taxes ($8 million).

2005 Compared to 2004. Our Other Operations business segment s operating loss in 2005 compared to 2004 decreased $14 million primarily due to increased overhead allocated in 2005.

Discontinued Operations

In July 2004, we announced our agreement to sell our majority owned subsidiary, Texas Genco, to Texas Genco LLC. In December 2004, Texas Genco completed the sale of its fossil generation assets (coal, lignite and gas-fired plants) to Texas Genco LLC for $2.813 billion in cash. Following the sale, Texas Genco, whose principal remaining asset was its ownership interest in a nuclear generating facility, distributed $2.231 billion in cash to us. The final step of the transaction, the merger of Texas Genco with a subsidiary of Texas Genco LLC in exchange for an additional cash payment to us of $700 million, was completed in April 2005. We recorded an after-tax loss of $133 million and $3 million for the years ended December 31, 2004 and 2005, respectively, related to the operations of Texas Genco.

The consolidated financial statements report the businesses described above as discontinued operations for all periods presented in accordance with Statement of Financial Accounting Standards (SFAS) No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets (SFAS No. 144).

For further information regarding discontinued operations, please read Note 3 to our consolidated financial statements.

LIQUIDITY AND CAPITAL RESOURCES

Historical Cash Flow

The net cash provided by(used in) operating, investing and financing activities for 2004, 2005 and 2006 is as follows (in millions):

	Year Ended December 31,		
	2004	2005	2006
Cash provided by (used in):			
Operating activities	$ 736	$ 63	$ 991
Investing activities	1,466	17	(1,056)
Financing activities	(2,124)	(171)	118

Cash Provided by Operating Activities

Net cash provided by operating activities in 2006 increased $928 million compared to 2005 primarily due to decreased tax payments of $156 million, the majority of which related to the tax payment in the first quarter of 2005 associated with the sale of our former electric generation business (Texas Genco); increased fuel over-recovery ($240 million) primarily related to declining gas prices during 2006; decreases in net regulatory assets ($271 million), primarily due to the termination of excess mitigation credits effective April 2005 and recovery of regulatory assets through rates; increased net accounts receivable/payable ($128 million) primarily due to decreased gas prices as compared to 2005 partially offset by funding under CERC s receivables facility being accounted for as short-term borrowings instead of sales of receivables beginning in October 2006 and decreased cash used in the operations of Texas Genco ($38 million). Additionally, customer margin deposit requirements decreased ($155 million) primarily due to the decline in natural gas prices from December 2005 and our margin deposits increased ($52 million).

Net cash provided by operating activities in 2005 decreased $673 million compared to 2004 primarily due to increased tax payments of $475 million, the majority of which related to the tax payment in the second quarter of 2005 associated with the sale of Texas Genco, decreased cash provided by Texas Genco of $393 million, increased net accounts receivable/payable ($151 million), increased gas storage inventory ($105 million) and increased fuel under-recovery ($154 million), primarily due to higher gas prices in 2005 as compared to 2004. These decreases were partially offset by decreases in net regulatory assets/liabilities ($328 million), primarily due to the termination of excess mitigation credits effective April 29, 2005, and decreased pension contributions of $401 million in 2005 as compared to 2004.

Cash Provided by (Used in) Investing Activities

Net cash used in investing activities increased $1.1 billion in 2006 as compared to 2005 primarily due to increased capital expenditures of $314 million primarily related to our Electric Transmission & Distribution, Interstate Pipelines, and Field Services business segments, increased restricted cash of transition bond companies of $36 million primarily related to the $1.85 billion of transition bonds issued in December 2005 and the absence of $700 million in proceeds received in the second quarter of 2005 from the sale of our remaining interest in Texas Genco and cash of Texas Genco of $24 million.

Net cash provided by investing activities decreased $1.4 billion in 2005 as compared to 2004 primarily due to proceeds of $700 million received from the sale of our remaining interest in Texas Genco in April 2005 compared to proceeds of $2.947 billion received in 2004 from the sale of Texas Genco s fossil generation assets and increased capital expenditures of $89 million, partially offset by the purchase of the minority interest in Texas Genco in 2004 of $716 million and cash collateralization of letters of credit by Texas Genco in 2004 related to its anticipated purchase of an additional interest in the South Texas Project in the first half of 2005 of $191 million.

Cash Provided by (Used in) Financing Activities

Net cash provided by financing activities in 2006 increased $289 million compared to 2005 primarily due to net proceeds from the issuance of long-term debt of $324 million, decreased repayments of borrowings under our revolving credit facility ($236 million) and funding under CERC s receivables facility being accounted for as short-term borrowings ($187 million) in 2006, partially offset by the absence of borrowings under Texas Genco s revolving credit facility ($75 million) due to the sale of Texas Genco, payments of long-term debt ($229 million) and increased dividend payments of $63 million.

In 2005, debt payments exceeded net loan proceeds by $66 million. Proceeds from the December 2005 issuance of $1.85 billion in transition bonds were used to repay borrowings under our credit facility and CenterPoint Houston s $1.3 billion term loan.

Future Sources and Uses of Cash

Our liquidity and capital requirements are affected primarily by our results of operations, capital expenditures, debt service requirements, tax payments, working capital needs, various regulatory actions and appeals relating to such regulatory actions. Our principal cash requirements for 2007 include the following:

- approximately $1.1 billion of capital expenditures;

- cash settlement obligations in connection with possible conversions by holders of our 3.75% convertible senior notes, having an aggregate principal amount of $575 million;

- dividend payments on CenterPoint Energy common stock and debt service payments;

- settlement of our 2.875% convertible senior notes for $255 million and settlement of our 8.257% Junior Subordinated Deferrable Interest Debentures for $104 million, as discussed in Notes 8(b) and 15 to our consolidated financial statements; and

- $153 million of maturing long-term debt, including $147 million of transition bonds.

We expect that long-term debt securities issued in the first quarter of 2007 ($400 million), borrowings under our credit facilities and anticipated cash flows from operations will be sufficient to meet our cash needs for the next twelve months. Cash needs may also be met by issuing equity or debt securities in the capital markets.

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

	2006	2007	2008	2009	2010	2011
Electric Transmission & Distribution	$ 389	$ 408	$ 406	$ 402	$ 437	$ 435
Natural Gas Distribution	187	208	217	202	207	212
Competitive Natural Gas Sales and Services	18	18	12	12	12	12
Interstate Pipelines	437	272	269	45	54	62
Field Services	65	116	86	85	85	85
Other Operations	25	33	26	21	12	13
Total	$ 1,121	$ 1,055	$ 1,016	$ 767	$ 807	$ 819

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

Contractual Obligations	Total	2007	2008-2009	2010-2011	2012 and thereafter
Transition bond debt, including current portion	2,407	147	334	397	1,529
Other long-term debt, including current portion	6,593	476	513	781	4,823
Interest payments transition bond debt(1)	867	123	224	187	333
Interest payments other long-term debt(1)	4,702	419	798	745	2,740
Capital leases	1				1
Operating leases(2)	80	22	29	14	15
Benefit obligations(3)					
Purchase obligations(4)	181	181			
Non-trading derivative liabilities	221	141	44	36	
Other commodity commitments(5)	3,044	922	504	412	1,206
Total contractual cash obligations	18,096	2,431	2,446	2,572	10,647

(1) We calculated estimated interest payments for long-term debt as follows: for fixed-rate debt and term debt, we calculated interest based on the applicable rates and payment dates; for variable-rate debt and/or non-term debt, we used interest rates in place as of December 31, 2006. We typically expect to settle such interest payments with cash flows from operations and short-term borrowings.

(2) For a discussion of operating leases, please read Note 10(b) to our consolidated financial statements.

(3) Contributions to our qualified pension plan are not required in 2007. However, we expect to contribute approximately $7 million and $29 million, respectively, to our non-qualified pension and postretirement benefits plans in 2007.

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

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

Convertible Debt. As of December 31, 2006, the 3.75% convertible senior notes discussed in Note 8(b) to our consolidated financial statements have been included as current portion of long-term debt in our Consolidated Balance Sheets because the last reported sale price of CenterPoint Energy common stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the fourth quarter of 2006 was greater than or equal to 120% of the conversion price of the 3.75% convertible senior notes and therefore, during the first quarter of 2007, the 3.75% convertible senior notes meet the criteria that make them eligible for conversion at the option of the holders of these notes.

As of December 31, 2006, our 2.875% convertible senior notes discussed in Note 8(b) to our consolidated financial statements were included as current portion of long-term debt in our Consolidated Balance Sheets because in December 2006, we called our 2.875% convertible senior notes for redemption on January 22, 2007.

Junior Subordinated Debentures (Trust Preferred Securities). As of December 31, 2006, our 8.257% Junior Subordinated Deferrable Interest Debentures discussed in Note 8(b) to our consolidated financial statements have been included as current portion of long-term debt in our Consolidated Balance Sheets because in December 2006, we called our 8.257% Junior Subordinated Deferrable Interest Debentures for redemption in February 2007.

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

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

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

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

Prior to our distribution of our ownership in RRI to our shareholders, CERC had guaranteed certain contractual obligations of what became RRI s trading subsidiary. Under the terms of the separation agreement between the companies, RRI agreed to extinguish all such guaranty obligations prior to separation, but at the time of separation in September 2002, RRI had been unable to extinguish all obligations. To secure us and CERC against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for the benefit of CERC and us, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. CERC currently holds letters of credit in the amount of $33.3 million issued on behalf of RRI against guaranties that have not been released. Our current exposure under the guaranties relates to CERC s guaranty of the payment by RRI of demand charges related to transportation contracts with one counterparty. The demand charges are approximately $53 million per year through 2015, $49 million in 2016, $38 million in 2017 and $13 million in 2018. RRI continues to meet its obligations under the transportation contracts, and we believe current market conditions make those contracts valuable for transportation services in the near term. However, changes in market conditions could affect the value of those contracts. If RRI should fail to perform its obligations under the transportation contracts, our exposure to the counterparty under the guaranty could exceed the security provided by RRI. We have requested RRI to increase the amount of its existing letters of credit or, in the alternative, to obtain a release of CERC s obligations under the guaranty. In June 2006, the RRI trading subsidiary and CERC jointly filed a complaint at the FERC against the counterparty on the CERC guaranty. In the complaint, the RRI trading subsidiary seeks a determination by the FERC that the security demanded by the counterparty exceeds the level permitted by the FERC s policies. The complaint asks the FERC to require the counterparty to release CERC from its guaranty obligation and, in its place, accept (i) a guaranty from RRI of the obligations of the RRI trading subsidiary, and

(ii) letters of credit limited to (A) one year of demand charges for a transportation agreement related to a 2003 expansion of the counterparty s pipeline, and (B) three months of demand charges for three other transportation agreements held by the RRI trading subsidiary. The counterparty has argued that the amount of the guaranty does not violate the FERC s policies and that the proposed substitution of credit support is not authorized under the counterparty s financing documents or required by the FERC s policy. The parties have now completed their submissions to the FERC regarding the complaint. We cannot predict what action the FERC may take on the complaint or when the FERC may rule. In addition to the FERC proceeding, in February 2007 CenterPoint and CERC made a formal demand on RRI under procedures provided for by the Master Separation Agreement, dated as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc. That demand seeks to resolve the disagreement with RRI over the amount of security RRI is obligated to provide with respect to this guaranty. It is possible that this demand could lead to an arbitration proceeding between the companies, but when and on what terms the disagreement with RRI will ultimately be resolved cannot now be predicted.

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

In February 2007, we issued $250 million aggregate principal amount of senior notes due in February 2017 with an interest rate of 5.95%. The proceeds from the sale of the senior notes were used to repay debt incurred in satisfying our $255 million cash payment obligation in connection with the conversion and redemption of our 2.875% Convertible Notes.

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

Credit Facilities. In March 2006, we, CenterPoint Houston and CERC Corp., entered into amended and restated bank credit facilities. We replaced our $1 billion five-year revolving credit facility with a $1.2 billion five-year revolving credit facility. The facility has a first drawn cost of LIBOR plus 60 basis points based on our current credit ratings, as compared to LIBOR plus 87.5 basis points for borrowings under the facility it replaced. The facility contains covenants, including a debt (excluding transition bonds) to earnings before interest, taxes, depreciation and amortization (EBITDA) covenant.

CenterPoint Houston replaced its $200 million five-year revolving credit facility with a $300 million five-year revolving credit facility. The facility has a first drawn cost of LIBOR plus 45 basis points based on CenterPoint Houston s current credit ratings, as compared to LIBOR plus 75 basis points for borrowings under the facility it replaced. The facility contains covenants, including a debt (excluding transition bonds) to total capitalization covenant of 65%.

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

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

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

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

As of February 16, 2007, we had the following facilities (in millions):

Date Executed	Company	Type of Facility	Facility Size at February 16, 2007	Amount Utilized at February 16, 2007	Termination Date
March 31, 2006	CenterPoint Energy	Revolver	$ 1,200	$ 28(1)	March 31, 2011
March 31, 2006	CenterPoint Houston	Revolver	300	4(1)	March 31, 2011
March 31, 2006	CERC Corp.	Revolver	550	6(1)	March 31, 2011
October 31, 2006	CERC	Receivables	375	71	October 30, 2007

(1) Represents outstanding letters of credit.

The $1.2 billion CenterPoint Energy credit facility backstops a $1.0 billion commercial paper program under which CenterPoint Energy began issuing commercial paper in June 2005. As of December 31, 2006, there was no commercial paper outstanding. The commercial paper is rated Not Prime by Moody s Investors Service, Inc. (Moody s), A-3 by Standard & Poor s Rating Services (S&P), a division of The McGraw-Hill Companies, and F3 by Fitch, Inc. (Fitch) and, as a result, we do not expect to be able to rely on the sale of commercial paper to fund all of our short-term borrowing requirements. We cannot assure you that these ratings, or the credit ratings set forth below in Impact on Liquidity of a Downgrade in Credit Ratings, will remain in effect for any given period of time or that one or more of these ratings will not be lowered or withdrawn entirely by a rating agency. We note that these credit ratings are not recommendations to buy, sell or hold our securities and may be revised or withdrawn at any time by the rating agency. Each rating should be evaluated independently of any other rating. Any future reduction or withdrawal of one or more of our credit ratings could have a material adverse impact on our ability to obtain short- and long-term financing, the cost of such financings and the execution of our commercial strategies.

Securities Registered with the SEC. At December 31, 2006, CenterPoint Energy had a shelf registration statement covering senior debt securities, preferred stock and common stock aggregating $1 billion and CERC Corp. had a shelf registration statement covering $500 million principal amount of senior debt securities. Following February 2007 note issuances of $250 million and $150 million by CenterPoint Energy and CERC Corp., respectively, CenterPoint Energy s shelf registration statement covered securities aggregating $750 million and CERC Corp. s shelf registration covered $350 million principal amount of senior debt securities.

Temporary Investments. As of December 31, 2006, we had external temporary investments of less than $1 million. As of February 16, 2007, we had external temporary investments of $7 million.

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

Impact on Liquidity of a Downgrade in Credit Ratings. As of February 16, 2007, Moody s, S&P, and Fitch had assigned the following credit ratings to senior debt of CenterPoint Energy and certain subsidiaries:

	Moody s		**S&P**		**Fitch**	
Company/Instrument	**Rating**	**Outlook(1)**	**Rating**	**Outlook(2)**	**Rating**	**Outlook(3)**
CenterPoint Energy Senior Unsecured Debt	Ba1	Stable	BBB-	Stable	BBB-	Stable
CenterPoint Houston Senior Secured Debt (First Mortgage Bonds)	Baa2	Stable	BBB	Stable	A-	Stable
CERC Corp. Senior Unsecured Debt	Baa3	Stable	BBB	Stable	BBB	Stable

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

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

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

A decline in credit ratings could increase borrowing costs under our $1.2 billion credit facility, CenterPoint Houston s $300 million credit facility and CERC Corp. s $550 million credit facility. A decline in credit ratings would also increase the interest rate on long-term debt to be issued in the capital markets and could negatively impact our ability to complete capital market transactions. Additionally, a decline in credit ratings could increase cash collateral requirements and reduce margins of our Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments.

In September 1999, we issued 2.0% ZENS having an original principal amount of $1.0 billion of which $840 million remain outstanding. Each ZENS note is exchangeable at the holder s option at any time for an amount of cash equal to 95% of the market value of the reference shares of Time Warner Inc. common stock (TW Common) attributable to each ZENS note. If our creditworthiness were to drop such that ZENS note holders thought our liquidity was adversely affected or the market for the ZENS notes were to become illiquid, some ZENS note holders might decide to exchange their ZENS notes for cash. Funds for the payment of cash upon exchange could be obtained from the sale of the shares of TW Common that we own or from other sources. We own shares of TW Common equal to approximately 100% of the reference shares used to calculate our obligation to the holders of the ZENS notes. ZENS note exchanges result in a cash outflow because deferred tax liabilities related to the ZENS notes and TW Common shares become current tax obligations when ZENS notes are exchanged or otherwise retired and TW Common shares are sold. The ultimate tax obligation related to the ZENS notes continues to increase by the amount of the tax benefit realized each year and there could be a significant cash outflow when the taxes are paid as a result of ZENS notes maturing or being retired.

CenterPoint Energy Services, Inc. (CES), a wholly owned subsidiary of CERC Corp. operating in our Competitive Natural Gas Sales and Services business segment, provides comprehensive natural gas sales and services primarily to commercial and industrial customers and electric and gas utilities throughout the central and eastern United States. In order to economically hedge its exposure to natural gas prices, CES uses derivatives with provisions standard for the industry, including those pertaining to credit thresholds. Typically, the credit threshold negotiated with each counterparty defines the amount of unsecured credit that such counterparty will extend to CES. To the extent that the credit exposure that a counterparty has to CES at a particular time does not exceed that credit threshold, CES is not obligated to provide collateral. Mark-to-market exposure in excess of the credit threshold is routinely collateralized by CES. As of December 31, 2006, the amount posted as collateral amounted to $113 million. Should the credit ratings of CERC Corp. (the credit support provider for CES) fall below certain levels, CES would be required to provide additional collateral on two business days notice up to the amount of its previously unsecured credit limit. We estimate that as of December 31, 2006, unsecured credit limits extended to CES by counterparties aggregate $133 million; however, utilized credit capacity is significantly lower. In addition, CERC Corp. and its subsidiaries purchase natural gas under supply agreements that contain an aggregate credit threshold of $100 million based on CERC Corp. s S&P Senior Unsecured Long-Term Debt rating of BBB. Upgrades and downgrades from this BBB rating will increase and decrease the aggregate credit threshold accordingly.

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

Cross Defaults. Under our revolving credit facility, a payment default on, or a non-payment default that permits acceleration of, any indebtedness exceeding $50 million by us or any of our significant subsidiaries will

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cause a default. In addition, six outstanding series of our senior notes, aggregating $1.4 billion in principal amount as of February 16, 2007, provide that a payment default by us, CERC Corp. or CenterPoint Houston in respect of, or an acceleration of, borrowed money and certain other specified types of obligations, in the aggregate principal amount of $50 million, will cause a default. A default by CenterPoint Energy would not trigger a default under our subsidiaries debt instruments or bank credit facilities.

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

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

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

increased costs related to the acquisition of natural gas;

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

various regulatory actions;

the ability of RRI and its subsidiaries to satisfy their obligations as the principal customers of CenterPoint Houston and in respect of RRI s indemnity obligations to us and our subsidiaries or in connection with the contractual obligations to a third party pursuant to which CERC is a guarantor;

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

cash payments in connection with the exercise of contingent conversion rights of holders of convertible debt;

the outcome of litigation brought by and against us;

contributions to benefit plans;

restoration costs and revenue losses resulting from natural disasters such as hurricanes; and

various other risks identified in Risk Factors in Item 1A of this report.

Certain Contractual Limits on Our Ability to Issue Securities and Borrow Money. CenterPoint Houston s credit facility limits CenterPoint Houston s debt (excluding transition bonds) as a percentage of its total capitalization to 65 percent. CERC Corp. s bank facility and its receivables facility limit CERC s debt as a percentage of its total capitalization to 65 percent. Our $1.2 billion credit facility contains a debt to EBITDA covenant. Additionally, CenterPoint Houston is contractually prohibited, subject to certain exceptions, from issuing additional first mortgage bonds.

CRITICAL ACCOUNTING POLICIES

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

Accounting for Rate Regulation

SFAS No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS No. 71), provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. Our Electric Transmission & Distribution business applies SFAS No. 71, which results in our accounting for the regulatory effects of recovery of stranded costs and other regulatory assets resulting from the unbundling of the transmission and distribution business from our former electric generation operations in our consolidated financial statements. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Significant accounting estimates embedded within the application of SFAS No. 71 with respect to our Electric Transmission & Distribution business segment relate to $304 million of recoverable electric generation-related regulatory assets as of December 31, 2006. These costs are recoverable under the provisions of the 1999 Texas Electric Choice Plan. Based on our analysis of the final order issued by the Texas Utility Commission, we recorded an after-tax charge to earnings in 2004 of approximately $977 million to write down our electric generation-related regulatory assets to their realizable value, which was reflected as an extraordinary loss. Based on subsequent orders received from the Texas Utility Commission, we recorded an extraordinary gain of $30 million after-tax in the second quarter of 2005 related to the regulatory asset. Additionally, a district court in Travis County, Texas issued a judgment that would have the effect of restoring approximately $650 million, plus interest, of disallowed costs. CenterPoint Houston and other parties appealed the district court judgment. Oral arguments before the Texas 3rd Court of Appeals were held in January 2007, but a decision is not expected for several months. No amounts related to the district court s judgment have been recorded in our consolidated financial statements.

Impairment of Long-Lived Assets and Intangibles

We review the carrying value of our long-lived assets, including goodwill and identifiable intangibles, whenever events or changes in circumstances indicate that such carrying values may not be recoverable, and at least annually for goodwill as required by SFAS No. 142, *Goodwill and Other Intangible Assets.* No impairment of goodwill was indicated based on our annual analysis as of July 1, 2006. Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows, regulatory matters and operating costs could negatively affect the fair value of our assets and result in an impairment charge.

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

Asset Retirement Obligations

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

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

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

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

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

Changes in these factors could materially affect the obligation recorded to reflect the ultimate cost associated with retiring the assets under SFAS No. 143 and FIN 47. For example, if the inflation adjustment increased 25 basis points, this would increase the balance for asset retirement obligations by approximately 3.0%. Similarly, an increase in the discount rate by 25 basis points would decrease asset retirement obligations by approximately the same percentage. At December 31, 2006, our estimated cost of retiring these assets is approximately $84 million.

Unbilled Energy Revenues

Revenues related to the sale and/or delivery of electricity or natural gas (energy) are generally recorded when energy is delivered to customers. However, the determination of energy 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 energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. Unbilled electricity delivery revenue is estimated each month based on daily supply volumes, applicable rates and analyses reflecting significant historical trends and experience. Unbilled natural gas sales are estimated based on estimated purchased gas volumes, estimated lost and unaccounted for gas and tariffed rates in effect. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Pension and Other Retirement Plans

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

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impact to the amount of pension expense recorded. Please read Other Significant Matters Pension Plans for further discussion.

NEW ACCOUNTING PRONOUNCEMENTS

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

OTHER SIGNIFICANT MATTERS

Pension Plans. As discussed in Note 2(p) to our consolidated financial statements, we maintain a non-contributory qualified pension plan covering substantially all employees. Employer contributions for the qualified plan are based on actuarial computations that establish the minimum contribution required under the Employee Retirement Income Security Act of 1974 (ERISA) and the maximum deductible contribution for income tax purposes.

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

Although we were not required to make contributions to our qualified pension plan in 2005 or 2006, we made a voluntary contribution of $75 million in 2005.

Additionally, we maintain an unfunded non-qualified benefit restoration plan that allows participants to retain the benefits to which they would have been entitled under our non-contributory pension plan except for the federally mandated limits on qualified plan benefits or on the level of compensation on which qualified plan benefits may be calculated. Employer contributions for the non-qualified benefit restoration plan represent benefit payments made to participants and totaled $10 million and $7 million in 2005 and 2006, respectively.

In accordance with SFAS No. 87, Employers Accounting for Pensions, changes in pension obligations and assets may not be immediately recognized as pension costs in the income statement, but generally are recognized in future years over the remaining average service period of plan participants. As such, significant portions of pension costs recorded in any period may not reflect the actual level of benefit payments provided to plan participants.

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans An Amendment of FASB Statements No. 87, 88, 106 and 132(R) (SFAS No. 158). SFAS No. 158 requires us, as the sponsor of a plan, to (a) recognize on our balance sheets as an asset a plan s over-funded status or as a liability such plan s under-funded status, (b) measure a plan s assets and obligations as of the end of our fiscal year and (c) recognize changes in the funded status of our plans in the year that changes occur through adjustments to other comprehensive income.

As a result of the adoption of SFAS No. 158 as of December 31, 2006, we recorded a regulatory asset of $466 million and a charge to accumulated comprehensive income of $79 million, net of tax. For additional information regarding the implementation of SFAS No. 158, see Note 2(o).

At December 31, 2006, the projected benefit obligation of our pension plans exceeded the market value of plan assets by $30 million. Changes in interest rates and the market values of the securities held by the plan during 2007 could materially, positively or negatively, change our funded status and affect the level of pension expense and required contributions.

Pension costs were $86 million, $36 million and $46 million for 2004, 2005 and 2006, respectively. In addition, included in the costs for 2004 and 2005 are $11 million and less than $1 million, respectively, of expense related to Texas Genco participants. Pension expense for Texas Genco participants is reflected in our Statement of Consolidated Operations as discontinued operations.

The calculation of pension expense and related liabilities requires the use of assumptions. Changes in these assumptions can result in different expense and liability amounts, and future actual experience can differ from the

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assumptions. Two of the most critical assumptions are the expected long-term rate of return on plan assets and the assumed discount rate.

As of December 31, 2006, our qualified pension plan had an expected long-term rate of return on plan assets of 8.5%, which was unchanged from the rate assumed as of December 31, 2005. We believe that our actual asset allocation, on average, will approximate the targeted allocation and the estimated return on net assets. We regularly review our actual asset allocation and periodically rebalance plan assets as appropriate.

As of December 31, 2006, the projected benefit obligation was calculated assuming a discount rate of 5.85%, which is a 0.15% increase from the 5.70% discount rate assumed in 2005. The discount rate was determined by reviewing yields on high-quality bonds that receive one of the two highest ratings given by a recognized rating agency and the expected duration of pension obligations specific to the characteristics of our plan.

Pension expense for 2007, including the benefit restoration plan, is estimated to be $15 million based on an expected return on plan assets of 8.5% and a discount rate of 5.85% as of December 31, 2006. If the expected return assumption were lowered by 0.5% (from 8.5% to 8.0%), 2007 pension expense would increase by approximately $9 million.

Currently, pension plan assets (including the unfunded benefit restoration plan) exceed the accumulated benefit obligation by $30 million. However, if the discount rate were lowered by 0.5% (from 5.85% to 5.35%), the assumption change would increase our projected benefit obligation and 2007 pension expense by approximately $123 million and $11 million, respectively. In addition, the assumption change would impact our Consolidated Balance Sheet by increasing the regulatory asset recorded as of December 31, 2006 by $95 million and would result in a charge to comprehensive income in 2006 of $18 million, net of tax.

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

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

Impact of Changes in Interest Rates and Energy Commodity Prices

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

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

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

Interest Rate Risk

As of December 31, 2006, we had outstanding long-term debt, bank loans, mandatory redeemable preferred securities of a subsidiary trust holding solely our junior subordinated debentures (trust preferred securities), some lease obligations and our obligations under our 2.0% Zero-Premium Exchangeable Subordinated Notes due 2029 (ZENS) that subject us to the risk of loss associated with movements in market interest rates.

Our floating-rate obligations aggregated $3 million and $187 million at December 31, 2005 and 2006, respectively. If the floating interest rates were to increase by 10% from December 31, 2006 rates, our combined interest expense would increase by approximately $1 million.

At December 31, 2005 and 2006, we had outstanding fixed-rate debt (excluding indexed debt securities) and trust preferred securities aggregating $8.8 billion and $8.9 billion, respectively, in principal amount and having a fair value of $9.3 billion and $9.6 billion, respectively. These instruments are fixed-rate and, therefore, do not expose us to the risk of loss in earnings due to changes in market interest rates (please read Note 8 to our consolidated financial statements). However, the fair value of these instruments would increase by approximately $330 million if interest rates were to decline by 10% from their levels at December 31, 2006. In general, such an increase in fair value would impact earnings and cash flows only if we were to reacquire all or a portion of these instruments in the open market prior to their maturity.

As discussed in Note 6 to our consolidated financial statements, upon adoption of SFAS No. 133 effective January 1, 2001, the ZENS obligation was bifurcated into a debt component and a derivative component. The debt component of $111 million at December 31, 2006 was a fixed-rate obligation and, therefore, did not expose us to the risk of loss in earnings due to changes in market interest rates. However, the fair value of the debt component would increase by approximately $18 million if interest rates were to decline by 10% from levels at December 31, 2006. Changes in the fair value of the derivative component, a $372 million recorded liability at December 31, 2006, are recorded in our Statements of Consolidated Operations and, therefore, we are exposed to changes in the fair value of the derivative component as a result of changes in the underlying risk-free interest rate. If the risk-free interest rate were to increase by 10% from December 31, 2006 levels, the fair value of the derivative component liability would increase by approximately $6 million, which would be recorded as an unrealized loss in our Statements of Consolidated Operations.

Equity Market Value Risk

We are exposed to equity market value risk through our ownership of 21.6 million shares of TW Common, which we hold to facilitate our ability to meet our obligations under the ZENS. Please read Note 6 to our consolidated financial statements for a discussion of the effect of adoption of SFAS No. 133 on our ZENS obligation and our historical accounting treatment of our ZENS obligation. A decrease of 10% from the December 31, 2006 market value of TW Common would result in a net loss of approximately $4 million, which would be recorded as an unrealized loss in our Statements of Consolidated Operations.

Commodity Price Risk From Non-Trading Activities

We use derivative instruments as economic hedges to offset the commodity price exposure inherent in our businesses. The stand-alone commodity risk created by these instruments, without regard to the offsetting effect of the underlying exposure these instruments are intended to hedge, is described below. We measure the commodity risk of our non-trading energy derivatives using a sensitivity analysis. The sensitivity analysis performed on our non-trading energy derivatives measures the potential loss in fair value based on a hypothetical 10% movement in energy prices. At December 31, 2006, the recorded fair value of our non-trading energy derivatives was a net liability of $102 million. The net liability consisted of a $153 million net liability associated with Gas Operations price stabilization activities partially offset by a net asset of $51 million related to our Competitive Natural Gas Sales and Services business. Net assets or liabilities related to Gas Operations price stabilization activities correspond directly with net over/under recovered gas cost liabilities or assets on the balance sheet. A decrease of 10% in the market prices of energy commodities from their December 31, 2006 levels would have decreased the fair value of our non-trading energy derivatives by $80 million.

We have 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 our 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 our 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.

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Item 8. ***Financial Statements and Supplementary Data***

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of CenterPoint Energy, Inc. and subsidiaries (the Company) as of December 31, 2006 and 2005, and the related consolidated statements of operations, comprehensive income, shareholders equity, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of CenterPoint Energy, Inc. and subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans An Amendment of FASB Statements No. 87, 88, 106 and 132(R) , effective December 31, 2006. Also, 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.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2007 expressed an unqualified opinion on management s assessment of the effectiveness of the Company s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management s assessment, included in the accompanying Management s Annual Report on Internal Control Over Financial Reporting, that CenterPoint Energy, Inc. and subsidiaries (the Company) maintained effective internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, management s assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2006 of the Company and our report dated February 28, 2007 expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding the Company s adoption of new accounting standards related to defined benefit pension and other postretirement plans in 2006 and conditional asset retirement obligations in 2005.

DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2007

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MANAGEMENT S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

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

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

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

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control Integrated Framework, our management has concluded that our internal control over financial reporting was effective as of December 31, 2006.

Deloitte & Touche LLP, the Company s independent registered public accounting firm, has issued an attestation report on our management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 which is included herein on page 64.

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED OPERATIONS

	Year Ended December 31, 2004	2005	2006
	(In millions, except per share amounts)		
Revenues	$ 7,999	$ 9,722	$ 9,319
Expenses:			
Natural gas	5,013	6,509	5,909
Operation and maintenance	1,277	1,358	1,399
Depreciation and amortization	490	541	599
Taxes other than income taxes	355	375	367
Total	7,135	8,783	8,274
Operating Income	864	939	1,045
Other Income (Expense):			
Gain (loss) on Time Warner investment	31	(44)	94
Gain (loss) on indexed debt securities	(20)	49	(80)
Interest and other finance charges	(739)	(670)	(470)
Interest on transition bonds	(38)	(40)	(130)
Return on true-up balance	226	121	
Other, net	20	23	35
Total	(520)	(561)	(551)
Income From Continuing Operations Before Income Taxes and Extraordinary Item	344	378	494
Income tax expense	(139)	(153)	(62)
Income From Continuing Operations Before Extraordinary Item	205	225	432
Discontinued Operations:			
Income from Texas Genco, net of tax	294	11	
Minority interest on income from Texas Genco	(61)		
Loss on disposal of Texas Genco, net of tax	(366)	(14)	
Total	(133)	(3)	
Income Before Extraordinary Item	72	222	432
Extraordinary item, net of tax	(977)	30	
Net Income (Loss)	$ (905)	$ 252	$ 432

Basic Earnings (Loss) Per Share:			
Income From Continuing Operations Before Extraordinary Item	$ 0.67	$ 0.72	$ 1.39
Discontinued Operations, net of tax	(0.43)	(0.01)	
Extraordinary item, net of tax	(3.18)	0.10	
Net Income (Loss)	$ (2.94)	$ 0.81	$ 1.39
Diluted Earnings (Loss) Per Share:			
Income From Continuing Operations Before Extraordinary Item	$ 0.61	$ 0.67	$ 1.33
Discontinued Operations, net of tax	(0.37)	(0.01)	
Extraordinary item, net of tax	(2.72)	0.09	
Net Income (Loss)	$ (2.48)	$ 0.75	$ 1.33

See Notes to the Company s Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31,		
	2004	2005	2006
		(In millions)	
Net income (loss)	$ (905)	$ 252	$ 432
Other comprehensive income, net of tax:			
Minimum pension liability adjustment (net of tax of $197, ($5) and $6)	367	(9)	12
Net deferred gain from cash flow hedges (net of tax of $31, $9 and $11)	59	17	22
Reclassification of deferred loss (gain) from cash flow hedges realized in net income (net of tax of ($3), $6 and $8)	(7)	11	14
Reclassification of deferred gain from de-designation of cash flow hedges to over/under recovery of gas cost (net of tax of ($37))	(68)		
Other comprehensive income (loss) from discontinued operations (net of tax of ($2) and $2)	(4)	3	
Other comprehensive income	347	22	48
Comprehensive income (loss)	$ (558)	$ 274	$ 480

See Notes to the Company s Consolidated Financial Statements

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2005	December 31, 2006
	(In millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 74	$ 127
Investment in Time Warner common stock	377	471
Accounts receivable, net	1,098	1,017
Accrued unbilled revenues	608	451
Inventory	382	399
Non-trading derivative assets	131	98
Taxes receivable	53	
Prepaid expense and other current assets	168	432
Total current assets	2,891	2,995
Property, Plant and Equipment, net	8,492	9,204
Other Assets:		
Goodwill	1,709	1,709
Regulatory assets	2,955	3,290
Non-trading derivative assets	104	21
Other	965	414
Total other assets	5,733	5,434
Total Assets	$ 17,116	$ 17,633
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities:		
Short-term borrowings	$	$ 187
Current portion of long-term debt	339	1,198
Indexed debt securities derivative	292	372
Accounts payable	1,161	1,010
Taxes accrued	167	364
Interest accrued	122	159
Non-trading derivative liabilities	43	141
Accumulated deferred income taxes, net	385	316
Other	505	474
Total current liabilities	3,014	4,221

Other Liabilities:				
Accumulated deferred income taxes, net		2,474		2,323
Unamortized investment tax credits		46		39
Non-trading derivative liabilities		35		80
Benefit obligations		475		545
Regulatory liabilities		728		792
Other		480		275
Total other liabilities		4,238		4,054
Long-term Debt		8,568		7,802
Commitments and Contingencies (Note 10)				
Shareholders Equity		1,296		1,556
Total Liabilities and Shareholders Equity	$	17,116	$	17,633

See Notes to the Company s Consolidated Financial Statements

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED CASH FLOWS

	Year Ended December 31, 2004	2005	2006
		(In millions)	
Cash Flows from Operating Activities:			
Net income (loss)	$ (905)	$ 252	$ 432
Discontinued operations, net of tax	133	3	
Extraordinary item, net of tax	977	(30)	
Income from continuing operations and cumulative effect of accounting change	205	225	432
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:			
Depreciation and amortization	490	541	599
Amortization of deferred financing costs	92	77	56
Deferred income taxes	265	232	(234)
Tax and interest reserves reductions related to ZENS and ACES settlement			(107)
Investment tax credit	(7)	(8)	(7)
Unrealized loss (gain) on Time Warner investment	(32)	44	(94)
Unrealized loss (gain) on indexed debt securities	20	(49)	80
Write-down of natural gas inventory			66
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	(202)	(456)	262
Inventory	(10)	(115)	(82)
Taxes receivable	35	(53)	53
Accounts payable	218	321	(269)
Fuel cost over (under) recovery/surcharge	25	(129)	111
Non-trading derivatives, net	(40)	(12)	(18)
Margin deposits, net	12	51	(156)
Interest and taxes accrued	81	(471)	230
Net regulatory assets and liabilities	(520)	(192)	79
Clawback payment from RRI	177		
Pension contribution	(476)	(75)	
Other current assets	(34)	(14)	(76)
Other current liabilities	(22)	69	18
Other assets	80	30	43
Other liabilities	4	67	6
Other, net	20	18	(1)
Net cash provided by operating activities of continuing operations	381	101	991
Net cash provided by (used in) operating activities of discontinued operations	355	(38)	

Net cash provided by operating activities	736	63	991
Cash Flows from Investing Activities:			
Capital expenditures	(604)	(693)	(1,007)
Proceeds from sale of Texas Genco, including cash retained	2,947	700	
Purchase of minority interest of Texas Genco	(326)	(383)	
Decrease (increase) in restricted cash for purchase of minority interest of Texas Genco	(390)	383	
Funds held for purchase of additional shares in South Texas Project	(191)		
Increase in cash of Texas Genco		24	
Increase in restricted cash of transition bond companies		(12)	(32)
Other, net	30	(2)	(17)
Net cash provided by (used in) investing activities	1,466	17	(1,056)
Cash Flows from Financing Activities:			
Increase (decrease) in short-term borrowings, net	(63)	75	187
Long-term revolving credit facility, net	(1,206)	(236)	(3)
Proceeds from long-term debt	229	3,161	324
Payments of long-term debt	(943)	(3,045)	(229)
Debt issuance costs	(15)	(21)	(5)
Payment of common stock dividends	(123)	(124)	(187)
Payment of common stock dividends by subsidiary	(15)		
Proceeds from issuance of common stock, net	12	17	27
Other, net		2	4
Net cash provided by (used in) financing activities	(2,124)	(171)	118
Net Increase (Decrease) in Cash and Cash Equivalents	78	(91)	53
Cash and Cash Equivalents at Beginning of Year	87	165	74
Cash and Cash Equivalents at End of Year	$ 165	$ 74	$ 127
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 759	$ 667	$ 532
Income taxes (refunds), net	(124)	351	195
Non-cash transactions:			
Increase in accounts payable related to capital expenditures		35	113

See Notes to the Company s Consolidated Financial Statements

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

STATEMENTS OF CONSOLIDATED SHAREHOLDERS EQUITY

	2004		2005		2006	
	Shares	Amount	Shares	Amount	Shares	Amount
	(In millions of dollars and shares)					
Preference Stock, none outstanding		$		$		$
Cumulative Preferred Stock, $0.01 par value; authorized 20,000,000 shares, none outstanding						
Common Stock, $0.01 par value; authorized 1,000,000,000 shares						
Balance, beginning of year	306	3	308	3	310	3
Issuances related to benefit and investment plans	2		2		4	
Balance, end of year	308	3	310	3	314	3
Additional Paid-in-Capital						
Balance, beginning of year		2,868		2,891		2,931
Issuances related to benefit and investment plans		23		40		46
Balance, end of year		2,891		2,931		2,977
Unearned ESOP stock						
Balance, beginning of year	(1)	(3)				
Issuances related to benefit plan	1	3				
Balance, end of year						
Accumulated Deficit						
Balance, beginning of year		(700)		(1,728)		(1,600)
Net income (loss)		(905)		252		432
Common stock dividends $0.40 per share in 2004 and 2005, and $0.60 per share in 2006		(123)		(124)		(187)
Balance, end of year		(1,728)		(1,600)		(1,355)
Accumulated Other Comprehensive Loss						
Balance, end of year:						
SFAS No. 158 incremental effect						(79)
Minimum pension liability adjustment		(6)		(15)		(3)
Net deferred gain (loss) from cash flow hedges		(51)		(23)		13
Other comprehensive loss from discontinued operations		(3)				
Total accumulated other comprehensive loss, end of year		(60)		(38)		(69)

Total Shareholders Equity	$ 1,106	$ 1,296	$ 1,556

See Notes to the Company s Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Background and Basis of Presentation

(a) Background

CenterPoint Energy, Inc. is a public utility holding company, created on August 31, 2002 as part of a corporate restructuring of Reliant Energy, Incorporated (Reliant Energy) that implemented certain requirements of the Texas Electric Choice Plan (Texas electric restructuring law).

The Company s operating subsidiaries own and operate electric transmission and distribution facilities, natural gas distribution facilities, interstate pipelines and natural gas gathering, processing and treating facilities. As of December 31, 2006, the Company s indirect wholly owned subsidiaries included:

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

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

(b) Basis of Presentation

The Company sold the fossil generation assets of Texas Genco Holdings, Inc. (Texas Genco) in December 2004 and completed the sale of Texas Genco, which had continued to own an interest in a nuclear generating facility, in April 2005.

The consolidated financial statements report the businesses described above as discontinued operations for all periods presented in accordance with Statement of Financial Accounting Standards (SFAS) No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets (SFAS No. 144).

For a description of the Company s reportable business segments, see Note 14.

(2) Summary of Significant Accounting Policies

(a) Reclassifications and Use of Estimates

In addition to the items discussed in Note 3, segment information for 2004 and 2005 has been recast to conform to the 2006 presentation due to the change in reportable segments in the fourth quarter of 2006. The segment detail revised as a result of the new reportable business segments did not affect consolidated operating income for any year.

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

(b) ***Principles of Consolidation***

The accounts of CenterPoint Energy and its wholly owned and majority owned subsidiaries are included in the consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation. The Company uses the equity method of accounting for investments in entities in which the Company has an ownership interest between 20% and 50% and exercises significant influence. Such investments were $15 million and $32 million as of December 31, 2005 and 2006, respectively, and are included as part of other noncurrent assets in

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the Company s Consolidated Balance Sheets. Other investments, excluding marketable securities, are carried at cost.

(c) Revenues

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

(d) Long-lived Assets and Intangibles

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

	Weighted Average Useful Lives (Years)	December 31, 2005	December 31, 2006
		(In millions)	
Electric transmission & distribution	39	$ 6,463	$ 6,823
Natural gas distribution	30	2,740	2,875
Competitive natural gas sales and services	25	27	53
Interstate Pipelines	53	1,520	1,943
Field Services	52	367	429
Other property	30	441	444
Total		11,558	12,567
Accumulated depreciation and amortization:			
Electric transmission & distribution		(2,386)	(2,566)
Natural gas distribution		(391)	(462)
Competitive natural gas sales and services		(5)	(9)
Interstate Pipelines		(144)	(176)
Field Services		(23)	(31)
Other property		(117)	(119)
Total accumulated depreciation and amortization		(3,066)	(3,363)
Property, plant and equipment, net		$ 8,492	$ 9,204

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

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

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The Company performed the test at July 1, 2006, the Company s annual impairment testing date, and determined that no impairment charge for goodwill was required.

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

(e) Regulatory Assets and Liabilities

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

The following is a list of regulatory assets/liabilities reflected on the Company s Consolidated Balance Sheets as of December 31, 2005 and 2006:

	December 31, 2005	December 31, 2006
	(In millions)	
Recoverable electric generation-related regulatory assets(1)	$ 332	$ 304
Securitized regulatory asset	2,420	2,285
Unamortized loss on reacquired debt	91	85
Pension and postretirement related regulatory asset(2)		483
Other long-term regulatory assets/liabilities	46	38
Subtotal	2,889	3,195
Estimated removal costs	(662)	(697)

Total	$ 2,227	$ 2,498

(1) Excludes $248 million and $234 million of allowed equity return on the true-up balance as of December 31, 2005 and 2006, respectively.

(2) Upon adoption of SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans An Amendment of FASB Statements No. 87, 88, 106 and 132(R) (SFAS No. 158), the Company recorded a regulatory asset for its unrecognized costs associated with operations that have historically recovered and currently recover pension and postretirement expenses in rates. See Note 2(n).

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. During 2004, the Company wrote-off net regulatory assets of $1.5 billion ($977 million after-tax) as an extraordinary loss in response to the Texas Utility Commission s order on CenterPoint Houston s final true-up application. Based on subsequent orders received from the Texas Utility Commission, the Company recorded an extraordinary gain of $47 million ($30 million after-tax) in the second quarter of 2005 related to these regulatory assets. For further discussion of regulatory assets, see Note 4.

The Company s rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of December 31, 2005 and 2006, these removal costs of $662 million and $697 million, respectively, are classified as regulatory liabilities in the Company s Consolidated Balance Sheets. A portion of the amount of removal costs that relate to asset retirement obligations have been reclassified from a regulated liability to an asset retirement liability in accordance with Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 47, Accounting for Conditional Asset Retirement Obligations (FIN 47).

(f) Depreciation and Amortization Expense

Depreciation is computed using the straight-line method based on economic lives or a regulatory-mandated recovery period. Amortization expense includes amortization of regulatory assets and other intangibles. See Notes 2(e) and 4(a) for additional discussion of these items.

The following table presents depreciation and amortization expense for 2004, 2005 and 2006.

	2004	2005	2006
Depreciation expense	$ 415	$ 432	$ 440
Amortization expense	75	109	159
Total depreciation and amortization expense	$ 490	$ 541	$ 599

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

Allowance for funds used during construction (AFUDC) represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases both utility plant and earnings, it is realized in cash through depreciation provisions included in rates for subsidiaries that apply SFAS No. 71. Interest and AFUDC for subsidiaries that apply SFAS No. 71 are capitalized as a component of projects under construction and will be amortized over the assets estimated useful lives. During 2004, 2005 and 2006, the Company capitalized interest and AFUDC of $4 million, $4 million and $10 million, respectively.

(h) Income Taxes

The Company files a consolidated federal income tax return and follows a policy of comprehensive interperiod income tax allocation. 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. Management evaluates uncertain tax positions and accrues for those which management believes are reasonably estimatable and probable of an unfavorable outcome. For additional information regarding income taxes, see Note 9.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(i) Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are net of an allowance for doubtful accounts of $43 million and $33 million at December 31, 2005 and 2006, respectively. The provision for doubtful accounts in the Company s Statements of Consolidated Operations for 2004, 2005 and 2006 was $27 million, $40 million and $35 million, respectively.

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

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

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

(j) Inventory

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

	December 31,	
	2005	2006
	(In millions)	
Materials and supplies	$ 88	$ 94
Natural gas	294	305
Total inventory	$ 382	$ 399

(k) Derivative Instruments

The Company utilizes derivative instruments such as physical forward contracts, swaps and options (energy derivatives) to mitigate the impact of changes in its natural gas business on its operating results and cash flows. Such contracts are recognized in the Company s Consolidated Balance Sheets at their fair value unless the Company elects the normal purchase and sales exemption for qualified physical transactions. A derivative contract may be designated as normal purchase or sale if the intent is to physically receive or deliver the product for use or sale in the normal course of business. If derivative contracts are designated as a cash flow hedge according to SFAS 133 Accounting for Derivative Instruments and Hedging Activities, the effective portions of the changes in their fair values are reflected initially as a separate component of shareholders equity and subsequently recognized in income at the same time as the hedged items. The ineffective portions of changes in fair values of derivatives designated as hedges are immediately recognized in income. Changes in other derivatives not designated as normal or as a cash flow hedge are recognized in income as they occur. The Company does not enter into or hold derivative financial instruments for trading purposes.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company has a Risk Oversight Committee composed of corporate and business segment officers that oversees all commodity price and credit risk activities, including the Company s trading, marketing, risk management services and hedging activities. The committee s duties are to establish the Company s commodity risk policies, allocate risk capital within limits established by the Company 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 the Company s board of directors.

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

(l) 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 shareholders equity and accumulated other comprehensive income. In accordance with SFAS No. 115, the Company reports trading securities at estimated fair value in the Company s Consolidated Balance Sheets, and any unrealized holding gains and losses are recorded as other income (expense) in the Company s Statements of Consolidated Operations.

As of December 31, 2005 and 2006, the Company held an investment in Time Warner Inc. (TW) common stock (TW Common), which was classified as a trading security. For information regarding this investment, see Note 6.

(m) Environmental Costs

The Company expenses or capitalizes environmental expenditures, as appropriate, depending on their future economic benefit. The Company expenses amounts that relate to an existing condition caused by past operations, 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.

(n) Statements of Consolidated Cash Flows

For purposes of reporting cash flows, the Company considers cash equivalents to be short-term, highly liquid investments with maturities of three months or less from the date of purchase. In connection with the issuance of transition bonds in October 2001 and December 2005, the Company was required to establish restricted cash accounts to collateralize the bonds that were issued in these financing transactions. These restricted cash accounts are not available for withdrawal until the maturity of the bonds. Cash and cash equivalents does not include restricted cash of $17 million and $49 million at December 31, 2005 and 2006, respectively. For additional information regarding the December 2005 securitization financing, see Notes 4(a) and 8(b). Cash and cash equivalents includes $40 million and $123 million at December 31, 2005 and 2006, respectively, that is held by the Company s transition bond subsidiaries for their operations related to servicing the transition bonds.

(o) New Accounting Pronouncements

In July 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109 (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, Accounting for Income Taxes. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006. The Company estimates the cumulative effect of adopting FIN 48 to be immaterial to the consolidated financial statements.

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

In September 2006, the FASB issued SFAS No. 158. SFAS No. 158 requires the Company, as the sponsor of a plan, to (a) recognize on its Balance Sheets as an asset a plan s over-funded status or as a liability such plan s under-funded status, (b) measure a plan s assets and obligations as of the end of the Company s fiscal year and (c) recognize changes in the funded status of its plans in the year in which changes occur through adjustments to other comprehensive income. Additional minimum liabilities are also derecognized upon adoption of the new standard. The Company adopted SFAS No. 158 as of December 31, 2006. The following table summarizes the effect of the adjustments to record the adoption of SFAS No. 158:

	Before Adoption of SFAS No. 158	Change due to SFAS No. 158	After Adoption of SFAS No. 158
Other Assets:			
Regulatory asset	$ 17	$ 466	$ 483
Other	616	(507)	109
Current Liabilities:			
Other		15	15
Other Liabilities:			
Accumulated deferred taxes, net	(2)	(64)	(66)
Benefit obligations	288	87	375
Shareholders Equity:			
Accumulated other comprehensive loss	(3)	(79)	(82)

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

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statements No. 115 (SFAS No. 159). SFAS No. 159 permits the Company to choose, at specified election dates, to measure eligible items at fair value (the fair value option). The Company would report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting period. This accounting standard is effective as of the beginning of the first fiscal year that begins after November 15, 2007. The Company is evaluating the effect of adoption of this new standard on its financial position, results of operations and cash flows.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Stock-Based Incentive Compensation Plans

The Company has long-term incentive compensation plans (LICPs) that provide for the issuance of stock-based incentives, including performance-based shares, performance-based units, restricted shares and stock options to officers and key employees. A maximum of approximately 36 million shares of CenterPoint Energy common stock is authorized to be issued under these plans.

Performance-based shares, performance-based units and restricted shares are granted to employees without cost to the participants. The performance shares and units are distributed based upon the performance of the Company over a three-year cycle. The restricted shares vest at various times ranging from one year to the end of a three-year period. Upon vesting, the shares are issued to the participants along with the value of common dividends declared during the vesting period. The restricted shares granted in 2005 and 2006 are subject to the performance condition that total common dividends declared during the three-year vesting period must be at least $1.20 and $1.80 per share, respectively.

Option awards are generally granted with an exercise price equal to the average of the high and low sales price of the Company s stock at the date of grant. These option awards generally become exercisable in one-third increments on each of the first through third anniversaries of the grant date and have 10-year contractual terms. No options were granted during 2005 and 2006.

Effective January 1, 2005, the Company adopted SFAS No. 123 (Revised 2004), Share-Based Payment (SFAS 123(R)), using the modified prospective transition method. Under this method, the Company records compensation expense at fair value for all awards it grants after the date it adopted the standard. In addition, the Company records compensation expense at fair value (as previous awards continue to vest) for the unvested portion of previously granted stock option awards that were outstanding as of the date of adoption. Pre-adoption awards of time-based restricted stock and performance-based restricted stock will continue to be expensed using the guidance contained in Accounting Principles Board Opinion No. 25. The adoption of SFAS 123(R) did not have a material impact on the Company s results of operations, financial condition or cash flows.

The Company recorded LICP compensation expense of $8 million, $13 million and $10 million in 2004, 2005 and 2006, respectively.

The total income tax benefit recognized related to such arrangements was $3 million, $5 million and $4 million in 2004, 2005 and 2006, respectively. No compensation cost related to such arrangements was capitalized as a part of inventory or fixed assets in 2004, 2005 or 2006.

Pro forma information for 2004 is provided to show the effect of amortizing stock-based compensation to expense on a straight-line basis over the vesting period. Had compensation costs been determined as prescribed by

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

SFAS No. 123, the Company s net income and earnings per share would have been as follows (in millions, except per share amounts):

	Year Ended December 31, 2004	
Net loss as reported	$	(905)
Add: Total stock-based employee compensation expense as recorded, net of related tax effects		5
Less: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects		(9)
Pro-forma net loss	$	(909)
Basic Loss Per Share:		
As reported	$	(2.94)
Pro-forma	$	(2.95)
Diluted Loss Per Share:		
As reported	$	(2.48)
Pro-forma	$	(2.49)

The following tables summarize the methods used to measure compensation cost for the various types of awards granted under the LICPs:

For awards granted before January 1, 2005

Award Type	Method Used to Determine Compensation Cost
Performance shares	Initially measured using fair value and expected achievement levels on the date of grant. Compensation cost is then periodically adjusted to reflect changes in market prices and achievement through the settlement date.
Performance units	Initially measured using the award s target unit value of $100 that reflects expected achievement levels on the date of grant. Compensation cost is then periodically adjusted to reflect changes in achievement through the settlement date.
Stock awards	Measured using fair value on the grant date.
Stock options	Estimated using the Black-Scholes option valuation method.

In 2004, the fair values of stock options were estimated using the Black-Scholes option valuation model with the following assumptions:

Expected life in years	5
Interest rate	3.02%
Volatility	27.23%
Expected common stock dividend	$ 0.40

For awards granted as of and after January 1, 2005

Award Type	Method Used to Determine Compensation Cost
Performance shares	Measured using fair value and expected achievement levels on the grant date.
Stock awards	Measured using fair value on the grant date and expected achievement.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For awards granted before January 1, 2005, forfeitures of awards were measured upon their occurrence. For awards granted as of and after January 1, 2005, forfeitures are estimated on the date of grant and are adjusted as required through the remaining vesting period.

The following tables summarize the Company s LICP activity for 2006:

Stock Options

	Outstanding Options Year Ended December 31, 2006				
	Shares (Thousands)	Weighted-Average Exercise Price	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (Millions)	
Outstanding at December 31, 2005	13,667	16.05			
Forfeited or expired	(2,306)	12.38			
Exercised	(1,788)	14.90			
Outstanding at December 31, 2006	9,573	17.15	3.7	$	35
Exercisable at December 31, 2006	9,007	17.54	3.5		32

	Non-Vested Options Year Ended December 31, 2006		
	Shares (Thousands)	Weighted-Average Grant Date Fair Value	
Outstanding at December 31, 2005	1,859	$	1.79
Vested	(1,244)		1.76
Forfeited or expired	(49)		1.81
Outstanding at December 31, 2006	566		1.86

Performance Shares

Outstanding and Non-Vested Shares

	Year Ended December 31, 2006			
	Shares (Thousands)	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (Millions)	Weighted-Average Grant Date Fair Value
Outstanding at December 31, 2005	1,560			$ 9.30
Granted	910			13.05
Forfeited	(78)			12.73
Vested and released to participants	(689)			5.72
Outstanding at December 31, 2006	1,703	1.5	$ 19	12.60

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

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Performance-Based Units

	Outstanding and Non-Vested Units Year Ended December 31, 2006			
	Units (Thousands)	Weighted-Average Grant Date Fair Value	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2005	34	$ 100.00		
Forfeited	(2)	100.00		
Vested and released to participants	(1)	100.00		
Outstanding at December 31, 2006	31	100.00		$ 2

The aggregate intrinsic value reflects the value of the performance units given current expectations of performance through the end of the cycle. Performance units outstanding at December 31, 2006 were settled in January 2007.

Stock Awards

	Outstanding and Non-Vested Shares Year Ended December 31, 2006			
	Shares (Thousands)	Weighted-Average Grant Date Fair Value	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2005	969	$ 8.88		
Granted	292	12.96		
Forfeited	(24)	12.09		
Vested and released to participants	(484)	6.11		
Outstanding at December 31, 2006	753	12.14	1.2	$ 12

The weighted-average grant-date fair values of awards granted were as follows for 2004, 2005 and 2006:

	Year Ended December 31, 2004	2005	2006
Options	$ 1.86	$	$
Performance units	100.00		
Performance shares		12.13	13.05
Stock awards	10.95	12.25	12.96

The total intrinsic value of awards received by participants were as follows for 2004, 2005 and 2006:

	Year Ended December 31, 2004	2005	2006
	(In millions)		
Options exercised	$ 3	$ 8	$ 10
Performance shares	7	5	10
Stock awards			7

As of December 31, 2006, there was $11 million of total unrecognized compensation cost related to non-vested LICP arrangements. That cost is expected to be recognized over a weighted-average period of 1.7 years.

Cash received from LICPs was $4 million, $9 million and $17 million for 2004, 2005 and 2006, respectively.

The actual tax benefit realized for tax deductions related to LICPs totaled $4 million, $5 million and $11 million, for 2004, 2005 and 2006, respectively.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company has a policy of issuing new shares in order to satisfy share-based payments related to LICPs.

Pension and Postretirement Benefits

The Company maintains a non-contributory qualified defined benefit plan covering substantially all employees, with benefits determined using a cash balance formula. Under the cash balance formula, participants accumulate a retirement benefit based upon 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. Certain employees participating in the plan as of December 31, 1998 automatically receive the greater of the accrued benefit calculated under the prior plan formula through 2008 or the cash balance formula. Participants are 100% vested in their benefit after completing five years of service. In addition to the non-contributory qualified defined benefit plan, the Company maintains a non-qualified benefit restoration plan which allows participants to receive the benefits to which they would have been entitled under the Company s non-contributory pension plan except for federally mandated limits on qualified plan benefits or on the level of compensation on which qualified plan benefits may be calculated.

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

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

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

In January 2005, the Department of Health and Human Services Centers for Medicare and Medicaid Services (CMS) released final regulations governing the Medicare prescription drug benefit and other key elements of the Medicare Modernization Act that went into effect January 1, 2006. Under the final regulations, a greater portion of benefits offered under the Company s plans meets the definition of actuarial equivalence and therefore qualifies for federal subsidies equal to 28% of allowable drug costs. As a result, the Company has remeasured its obligations and costs to take into account the new regulations. The Medicare subsidy reduced net periodic postretirement benefit costs by approximately $8 million and $17 million for 2005 and 2006, respectively.

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

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31,					
	2004		2005		2006	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(In millions)					
Service cost	$ 41	$ 4	$ 35	$ 2	$ 37	$ 2
Interest cost	106	31	99	27	101	26
Expected return on plan assets	(103)	(13)	(137)	(12)	(143)	(12)
Amortization of prior service cost	(9)	6	(7)	2	(7)	2
Amortization of net (gain) loss	47		46		50	
Amortization of transition obligation		7		7		7
Curtailment		17				
Benefit enhancement	4	2			8	1
Other				1		
Net periodic cost	$ 86	$ 54	$ 36	$ 27	$ 46	$ 26
Above amounts include the following net periodic cost related to discontinued operations	$ 11	$ 20	$	$	$	$

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

	December 31,					
	2004		2005		2006	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
Discount rate	6.25%	6.25%	5.75%	5.75%	5.70%	5.70%
	9.00	8.50	8.50	8.00	8.50	8.00

Expected return on plan assets			
Rate of increase in compensation levels	4.10	4.60	4.60

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

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes changes in the benefit obligation, plan assets, the amounts recognized in consolidated balance sheets and the key assumptions of our pension, including benefit restoration, and postretirement plans. The measurement dates for plan assets and obligations were December 31, 2005 and 2006.

	December 31,			
	2005		2006	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(In millions)			
Change in Benefit Obligation				
Benefit obligation, beginning of year	$ 1,791	$ 535	$ 1,830	$ 467
Service cost	35	2	37	2
Interest cost	99	27	101	26
Participant contributions		5		6
Benefits paid	(116)	(38)	(161)	(42)
Actuarial loss (gain)	21	(65)	(39)	(3)
Plan amendment				8
Medicare reimbursement				4
Benefit enhancement		1	8	1
Benefit obligation, end of year	1,830	467	1,776	469
Change in Plan Assets				
Plan assets, beginning of year	1,657	156	1,729	154
Employer contributions	85	24	7	27
Participant contributions		5		6
Benefits paid	(116)	(38)	(161)	(42)
Actual investment return	103	7	231	13
Plan assets, end of year	1,729	154	1,806	158
Funded status, end of year	(101)	(313)	30	(311)
Unrecognized actuarial loss	747	36		
Unrecognized prior service cost	(47)	12		
Unrecognized transition obligation		58		
Net amount recognized	$ 599	$ (207)	$ 30	$ (311)

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	December 31, 2005 Pension Benefits	December 31, 2005 Postretirement Benefits	December 31, 2006 Pension Benefits	December 31, 2006 Postretirement Benefits
	(In millions)			
Amounts Recognized in Balance Sheets				
Other assets-other	$ 655	$	$ 109	$
Current liabilities-other			(7)	(8)
Other liabilities-benefit obligations	(79)	(207)	(72)	(303)
Shareholders equity-accumulated other comprehensive loss	23			
Net asset (liability), end of year	$ 599	$ (207)	$ 30	$ (311)
Actuarial Assumptions				
Discount rate	5.70%	5.70%	5.85%	5.85%
Expected return on plan assets	8.50	8.00	8.50	7.60
Rate of increase in compensation levels	4.60		4.60	
Healthcare cost trend rate assumed for the next year		9.00		7.00
Prescription drug cost trend rate assumed for the next year				13.00
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)		5.50		5.50
Year that the rate reaches the ultimate trend rate		2011		2014

The accumulated benefit obligation for all defined benefit pension plans was $1,767 million and $1,719 million as of December 31, 2005 and 2006, respectively.

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

	December 31, 2005 Pension Benefits	December 31, 2005 Postretirement Benefits	December 31, 2006 Pension Benefits	December 31, 2006 Postretirement Benefits
	(In millions)			
Unrecognized actuarial loss	$ 26	$	$ 128	$ 8
Unrecognized prior service cost	(3)		(7)	16
Unrecognized transition obligation				4
Net amount recognized in other comprehensive income	$ 23	$	$ 121	$ 28

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

	Pension Benefits	Postretirement Benefits
Unrecognized actuarial loss	$ 9	$
Unrecognized prior service cost (credit)	(1)	2
Amounts in comprehensive income to be recognized in net periodic cost in 2007	$ 8	$ 2

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table displays pension benefits related to the Company s non-qualified benefits restoration plan that have accumulated benefit obligations in excess of plan assets:

	December 31, 2005	December 31, 2006
	(In millions)	
Accumulated benefit obligation	$ 79	$ 78
Projected benefit obligation	81	79
Plan assets		

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	$ 21	$ 18
Effect on total of service and interest cost	1	1

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

	December 31, 2005		December 31, 2006	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
Domestic equity securities	48%	27%	50%	28%
Global equity securities	10		11	
International equity securities	11	9	10	11
Debt securities	30	64	27	61
Real estate	1		1	
Cash			1	
Total	100%	100%	100%	100%

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

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

	Pension Benefits	**Postretirement Benefits**
Domestic equity securities	45-55%	22-32%
Global equity securities	7-13%	
International equity securities	7-13%	4-14%
Debt securities	24-34%	60-70%
Real estate	0-5%	
Cash	0-2%	0-2%

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 pension plan did not include any holdings of CenterPoint Energy common stock as of December 31, 2005 or 2006.

The Company contributed $7 million and $27 million to its pension and postretirement benefits plans in 2006, respectively. The Company expects to contribute approximately $7 million and $29 to its pension and postretirement benefits plans in 2007, respectively.

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

		Postretirement Benefit Plan	
	Pension Benefits	Benefit Payments	Medicare Subsidy Receipts
2007	$ 119	$ 33	$ (4)
2008	124	35	(4)
2009	129	36	(4)
2010	131	38	(5)
2011	132	40	(5)
2012-2016	691	216	(29)

Savings Plan

The Company has a qualified employee savings plan that includes a cash or deferred arrangement under Section 401(k) of the Internal Revenue Code of 1986, as amended (the Code), and an employee stock ownership plan (ESOP) under Section 4975(e)(7) of the Code. Under the plan, participating employees may contribute a portion of their compensation, on a pre-tax or after-tax basis, generally up to a maximum of 16% of compensation. The Company matches 75% of the first 6% of each employee s compensation contributed. The Company 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.

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

The savings plan has significant holdings of CenterPoint Energy common stock. As of December 31, 2006, an aggregate of 22,728,974 shares of CenterPoint Energy s common stock were held by the savings plan, which represented 27.5% of its investments. Given the concentration of the investments in CenterPoint Energy s common stock, the savings plan and its participants have market risk related to this investment.

The Company s savings plan benefit expense was $40 million, $35 million and $34 million in 2004, 2005 and 2006, respectively. Included in these amounts is $6 million and less than $1 million savings plan benefit expense for 2004 and 2005, respectively, related to Texas Genco participants. Amounts for Texas Genco s participants are reflected as discontinued operations in the Statements of Consolidated Operations.

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Postemployment Benefits

Net postemployment benefit costs for former or inactive employees, their beneficiaries and covered dependents, after employment but before retirement (primarily healthcare and life insurance benefits for participants in the long-term disability plan) were $8 million, $8 million and $6 million in 2004, 2005 and 2006, respectively.

Included in Benefit Obligations in the accompanying consolidated Balance Sheets at December 31, 2005 and 2006 was $42 million and $43 million, respectively, relating to postemployment obligations.

Other Non-Qualified Plans

The Company has non-qualified deferred compensation plans that provide benefits payable to directors, officers and certain key employees or their designated beneficiaries at specified future dates, upon termination, retirement or death. Benefit payments are made from the general assets of the Company. During 2004, 2005 and 2006, the Company recorded benefit expense relating to these programs of $9 million, $8 million and $6 million, respectively. Included in Benefit Obligations in the accompanying Consolidated Balance Sheets at December 31, 2005 and 2006 was $113 million and $105 million, respectively, relating to deferred compensation plans.

Change in Control Agreements and Other Employee Matters

Effective January 1, 2007, the Company entered into agreements with certain of its officers that generally provide, to the extent applicable, in the case of a change in control of the Company and termination of employment, for severance benefits of up to three times annual base salary plus bonus, and other benefits. By their terms, these agreements are for a one-year term with automatic renewal unless action is taken by the Board prior to the renewal.

As of December 31, 2006, approximately 31% of the Company s employees are subject to collective bargaining agreements. One agreement, covering approximately 3% of the Company s employees is covered by a collective bargaining unit agreement with the International Brotherhood of Electrical Workers Local 949 that expires in December 2007. We have a good relationship with this bargaining unit and expect to renegotiate new agreements in 2007.

(3) Discontinued Operations

In July 2004, the Company announced its agreement to sell Texas Genco to Texas Genco LLC. In December 2004, Texas Genco completed the sale of its fossil generation assets (coal, lignite and gas-fired plants) to Texas Genco LLC for $2.813 billion in cash. Following the sale, Texas Genco s principal remaining asset was its ownership interest in the South Texas Project Electric Generating Station, a nuclear generating facility (South Texas Project). The final step of the transaction, the merger of Texas Genco with a subsidiary of Texas Genco LLC in exchange for an additional cash payment to the Company of $700 million, was completed in April 2005.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes the components of the income (loss) from discontinued operations of Texas Genco for each of the years ended December 31, 2004 and 2005 (in millions):

	Year Ended December 31, 2004	Year Ended December 31, 2005
Texas Genco net income (loss) as reported	$ (99)	$ 10
Adjustment for Texas Genco loss on sale of fossil assets, net of tax(1)	426	
Texas Genco net income as adjusted for loss on sale of fossil assets	327	10
Adjustment for general corporate overhead reclassification, net of tax(2)	13	1
Adjustment for interest expense reclassification, net of tax(3)	(46)	
Adjusted income from discontinued operations of Texas Genco, net of tax	294	11
Minority interest in discontinued operations of Texas Genco	(61)	
Income from discontinued operations of Texas Genco, net of tax and minority interest	233	11
Loss on sale of Texas Genco, net of tax	(214)	(4)
Loss offsetting Texas Genco s earnings, net of tax	(152)	(10)
Loss on disposal of Texas Genco, net of tax	(366)	(14)
Total Discontinued Operations of Texas Genco	$ (133)	$ (3)

(1) In 2004, Texas Genco recorded an after-tax loss of $426 million related to the sale of its coal, lignite and gas-fired generation plants which occurred in the first step of the transaction pursuant to which Texas Genco was sold. This loss was reversed by CenterPoint Energy to reflect its estimated loss on the sale of Texas Genco.

(2) General corporate overhead previously allocated to Texas Genco from CenterPoint Energy, which will not be eliminated by the sale of Texas Genco, was excluded from income from discontinued operations and is reflected as general corporate overhead of CenterPoint Energy in income from continuing operations in accordance with SFAS No. 144.

(3) Interest expense was reclassified to discontinued operations of Texas Genco related to the applicable amounts of CenterPoint Energy s term loan and revolving credit facility debt that would have been assumed to be paid off with any proceeds from the sale of Texas Genco during those respective periods in accordance with SFAS No. 144.

Revenues related to Texas Genco included in discontinued operations for the years ended December 31, 2004 and 2005 were $2.1 billion and $62 million, respectively. Income from these discontinued operations for the years ended December 31, 2004 and 2005 is reported net of income tax expense of $166 million and $4 million, respectively.

(4) Regulatory Matters

(a) Recovery of True-Up Balance

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

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

County, Texas. In August 2005, the court issued its final judgment on the various appeals. In its judgment, the court affirmed most aspects of the True-Up Order, but reversed two of the Texas Utility Commission s rulings. The judgment would have the effect of restoring approximately $650 million, plus interest, of the $1.7 billion the Texas Utility Commission had disallowed from CenterPoint Houston s initial request. CenterPoint Houston and other parties appealed the district court s judgment. Oral arguments before the Texas 3rd Court of Appeals were held in January 2007, but a decision is not expected for several months. No amounts related to the district court s judgment have been recorded in the Company s consolidated financial statements.

Among the issues raised in CenterPoint Houston s appeal of the True-Up Order is the Texas Utility Commission s reduction of CenterPoint Houston s stranded cost recovery by approximately $146 million for the present value of certain deferred tax benefits associated with its former electric generation assets. Such reduction was considered in the Company s recording of an after-tax extraordinary loss of $977 million in the last half of 2004. The Company believes that the Texas Utility Commission based its order on proposed regulations issued by the Internal Revenue Service (IRS) in March 2003 related to those tax benefits. Those proposed regulations would have allowed utilities owning assets that were deregulated before March 4, 2003 to make a retroactive election to pass the benefits of Accumulated Deferred Investment Tax Credits (ADITC) and Excess Deferred Federal Income Taxes (EDFIT) back to customers. However, in December 2005, the IRS withdrew those proposed normalization regulations and issued new proposed regulations that do not include the provision allowing a retroactive election to pass the tax benefits back to customers. In a May 2006 Private Letter Ruling (PLR) issued to a Texas utility on facts similar to CenterPoint Houston s, the IRS, without referencing its proposed regulations, ruled that a normalization violation would occur if ADITC and EDFIT were required to be returned to customers. CenterPoint Houston has requested a PLR asking the IRS whether the Texas Utility Commission s order reducing CenterPoint Houston s stranded cost recovery by $146 million for ADITC and EDFIT would cause a normalization violation. If the IRS determines that such reduction would cause a normalization violation with respect to the ADITC and the Texas Utility Commission s order relating to such reduction is not reversed or otherwise modified, the IRS could require the Company to pay an amount equal to CenterPoint Houston s unamortized ADITC balance as of the date that the normalization violation is deemed to have occurred. In addition, if a normalization violation with respect to EDFIT is deemed to have occurred and the Texas Utility Commission s order relating to such reduction is not reversed or otherwise modified, the IRS could deny CenterPoint Houston the ability to elect accelerated tax depreciation benefits beginning in the taxable year that the normalization violation is deemed to have occurred. If a normalization violation should ultimately be found to exist, it could have a material adverse impact on the Company s results of operations, financial condition and cash flows. However, the Company and CenterPoint Houston are vigorously pursuing the appeal of this issue and will seek other relief from the Texas Utility Commission to avoid a normalization violation. The Texas Utility Commission has not previously required a company subject to its jurisdiction to take action that would result in a normalization violation.

Pursuant to a financing order issued by the Texas Utility Commission in March 2005 and affirmed in August 2005 by a Travis County district court, in December 2005, a subsidiary of CenterPoint Houston issued $1.85 billion in transition bonds with interest rates ranging from 4.84 percent to 5.30 percent and final maturity dates ranging from February 2011 to August 2020. Through issuance of the transition bonds, CenterPoint Houston recovered approximately $1.7 billion of the true-up balance determined in the True-Up Order plus interest through the date on which the bonds were issued.

In July 2005, CenterPoint Houston received an order from the Texas Utility Commission allowing it to implement a CTC designed to collect approximately $596 million over 14 years plus interest at an annual rate of 11.075 percent (CTC Order). The CTC Order authorizes CenterPoint Houston to impose a charge on retail electric providers to recover the portion of the true-up balance not covered by the financing order. The CTC Order also allows CenterPoint Houston to collect approximately $24 million of rate case expenses over three years without a return through a separate tariff rider (Rider RCE). CenterPoint Houston implemented the CTC and Rider RCE effective September 13, 2005 and began recovering approximately $620 million. Effective September 13, 2005, the return on the CTC portion of the true-up balance is included in CenterPoint Houston s tariff-based revenues.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Certain parties appealed the CTC Order to a district court in Travis County. In May 2006, the district court issued a judgment reversing the CTC Order in three respects. First, the court ruled that the Texas Utility Commission had improperly relied on provisions of its rule dealing with the interest rate applicable to CTC amounts. The district court reached that conclusion on the grounds that the Texas Supreme Court had previously invalidated that entire section of the rule. Second, the district court reversed the Texas Utility Commission s ruling that allows CenterPoint Houston to recover through the Rider RCE the costs (approximately $5 million) for a panel appointed by the Texas Utility Commission in connection with the valuation of the Company s electric generation assets. Finally, the district court accepted the contention of one party that the CTC should not be allocated to retail customers that have switched to new on-site generation. The Texas Utility Commission and CenterPoint Houston disagree with the district court s conclusions and, in May 2006, appealed the judgment to the Texas 3rd Court of Appeals, and if required, plan to seek further review from the Texas Supreme Court. All briefs in the appeal have been filed. Oral arguments were held in December 2006. Pending completion of judicial review and any action required by the Texas Utility Commission following a remand from the courts, the CTC remains in effect. The 11.075 percent interest rate in question was applicable from the implementation of the CTC Order on September 13, 2005 until August 1, 2006, the effective date of the implementation of a new CTC in compliance with the new rule discussed below. The ultimate outcome of this matter cannot be predicted at this time. However, the Company does not expect the disposition of this matter to have a material adverse effect on the Company s or CenterPoint Houston s financial condition, results of operations or cash flows.

In June 2006, the Texas Utility Commission adopted the revised rule governing the carrying charges on unrecovered true-up balances as recommended by its staff (Staff). The rule, which applies to CenterPoint Houston, reduced the allowed interest rate on the unrecovered CTC balance prospectively from 11.075 percent to a weighted average cost of capital of 8.06 percent. The annualized impact on operating income is a reduction of approximately $18 million per year for the first year with lesser impacts in subsequent years. In July 2006, CenterPoint Houston made a compliance filing necessary to implement the rule changes effective August 1, 2006 per the settlement agreement discussed in Note 4(d) below under Rate Case Electric Transmission & Distribution .

During the years ended December 31, 2005 and 2006, CenterPoint Houston recognized approximately $19 million and $55 million, respectively, in operating income from the CTC. Additionally, during the years ended December 31, 2005 and 2006, CenterPoint Houston recognized approximately $1 million and $13 million, respectively, of the allowed equity return not previously recorded. As of December 31, 2006, the Company had not recorded an allowed equity return of $234 million on CenterPoint Houston s true-up balance because such return will be recognized as it is recovered in rates.

(b) Final Fuel Reconciliation

The results of the Texas Utility Commission s final decision related to CenterPoint Houston s final fuel reconciliation were a component of the True-Up Order. CenterPoint Houston has appealed certain portions of the True-Up Order involving a disallowance of approximately $67 million relating to the final fuel reconciliation in 2003 plus interest of $10 million. CenterPoint Houston has fully reserved for the disallowance and related interest accrual. A judgment was entered by a Travis County district court in May 2005 affirming the Texas Utility Commission s decision. CenterPoint Houston filed an appeal to the Texas 3rd Court of Appeals in June 2005, and in April 2006, the Texas 3rd Court of Appeals issued a judgment affirming the Texas Utility Commission s decision. CenterPoint Houston filed an appeal with the Texas Supreme Court in August 2006, and in October 2006, the Texas Supreme Court requested that the Texas Utility Commission and the City of Houston file written responses to CenterPoint Houston s petition for review. Those responses were filed in January 2007. In February 2007, CenterPoint Houston filed an agreement with the Texas Supreme Court indicating that the parties had reached a tentative settlement of the appeal. In order for the settlement to become final, the Texas Supreme Court must abate the pending appeal, and the Texas Utility Commission must issue a final order approving the settlement. If the Texas Utility Commission does not approve the agreement or modifies the agreement in a manner unacceptable to CenterPoint Houston, CenterPoint Houston would be entitled to ask the Texas Supreme Court to reinstate the

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

appeal. If the Texas Utility Commission approves the agreement, the parties will request the Texas Supreme Court to set aside the lower court decisions and remand the case for entry of an order approving that settlement. The Texas Supreme Court is not required to abate the appeal. If the Texas Supreme Court does not abate the appeal, it may request full briefing or deny the petition for review. If the petition is denied, the Court of Appeals judgment would become final. If the petition is granted, the Texas Supreme Court would address the merits of CenterPoint Houston s appeal. There is no deadline for the Texas Supreme Court s decisions. As of December 31, 2006, the Company has not recorded any amounts related to this decision.

(c) Remand of 2001 Unbundled Cost of Service (UCOS) Order

The Texas 3rd Court of Appeals remanded to the Texas Utility Commission an issue that was decided by the Texas Utility Commission in CenterPoint Houston s 2001 UCOS proceeding. In its remand order, the court ruled that the Texas Utility Commission had failed to adequately explain the basis for its determination of certain projected transmission capital expenditures. The Texas 3rd Court of Appeals ordered the Texas Utility Commission to reconsider that determination on the basis of the record that existed at the time of the Texas Utility Commission s original order. In April 2006, the Texas Utility Commission opined orally that the rate base should be reduced by $57 million and instructed the Staff to quantify the effect on CenterPoint Houston s rates. In the settlement of the CenterPoint Houston rate case described in Note 4(e) below under Rate Cases Electric Transmission & Distribution , the parties to the remand proceeding agreed to settle all issues that could be raised in the remand. Under the terms of that settlement, CenterPoint Houston implemented riders to its tariff rates under which it will provide rate credits to retail and wholesale customers for a total of approximately $8 million per year until a total of $32 million has been credited to customers under those tariff riders. Those riders became effective October 10, 2006. CenterPoint Houston reduced revenues and established a corresponding regulatory liability of $32 million in the second quarter of 2006 to reflect this obligation.

(d) Refund of Environmental Retrofit Costs

The True-Up Order allowed recovery of approximately $699 million of environmental retrofit costs related to CenterPoint Houston s generation assets. The sale of CenterPoint Houston s interest in its generation assets was completed in early 2005. The True-Up Order required CenterPoint Houston to provide evidence by January 31, 2007 that the entire $699 million was actually spent by December 31, 2006 on environmental programs. The Texas Utility Commission will determine the appropriate manner to return to customers any unused portion of these funds, including interest on the funds and on stranded costs attributable to the environmental costs portion of the stranded costs recovery. In January 2007, the Company was notified by the successor in interest to CenterPoint Houston s generation assets that, as of December 31, 2006, it had only spent approximately $664 million. On January 31, 2007, CenterPoint Houston made the required filing with the Texas Utility Commission identifying approximately $35 million in unspent funds to be refunded to customers along with approximately $7 million of interest and requesting permission to refund these amounts through a reduction to the CTC, effective March 1, 2007. Such amounts are recorded in regulatory liabilities as of December 31, 2006. In February 2007, the Texas Utility Commission adopted the Staff s recommendation for a slower procedural schedule than that requested by CenterPoint Houston. The procedural schedule as proposed by the Staff would make it unlikely that the proposed refund would be effective before May 1, 2007. At this time, the Company cannot predict whether any party will oppose CenterPoint Houston s filing or whether the Texas Utility Commission will approve CenterPoint Houston s request.

(e) Rate Cases

Electric Transmission & Distribution

In December 2005, the Texas Utility Commission ordered the commencement of a rate proceeding concerning the reasonableness of CenterPoint Houston s existing rates for transmission and distribution service and required

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CenterPoint Houston to make a filing by April 15, 2006 to justify or change those rates. In April 2006, CenterPoint Houston filed cost data and other information that supported the rates then in effect.

In July 2006, CenterPoint Houston entered into a settlement agreement with the parties to the proceeding that resolved the issues raised in this matter. CenterPoint Houston filed a Stipulation and Agreement (Settlement Agreement) with the Texas Utility Commission in August 2006 to seek approval of the Settlement Agreement. In September 2006, the Texas Utility Commission issued its final order approving the Settlement Agreement. Revised base rates and other revised tariffs became effective in October 2006.

Under the terms of the Settlement Agreement, CenterPoint Houston s base rate revenues were reduced by a net of approximately $58 million per year. Also, CenterPoint Houston agreed to increase its energy efficiency expenditures by an additional $10 million per year over the $13 million then included in rates. The expenditures will be made to benefit both residential and commercial customers. CenterPoint Houston also will fund $10 million per year for programs providing financial assistance to qualified low-income customers in its service territory.

The Settlement Agreement provides that until June 30, 2010 CenterPoint Houston will not seek to increase its base rates and the other parties will not petition to decrease those rates. This rate freeze is subject to adjustments for changes related to certain transmission costs, implementation of the Texas Utility Commission s recently-adopted change to its CTC rule and certain other changes. The rate freeze does not apply to changes required to reflect the result of currently pending appeals of the True-Up Order, the pending appeal of the Texas Utility Commission s order regarding CenterPoint Houston s final fuel reconciliation, the appeal of the order implementing CenterPoint Houston s CTC or the implementation of transition charges associated with current and future securitizations. In addition, CenterPoint Houston is not required to file annual earnings reports for the calendar years 2006 through 2008, but is required to file an earnings report for 2009 no later than March 1, 2010. CenterPoint Houston must make a new base rate filing not later than June 30, 2010, based on a test year ended December 31, 2009, unless the Texas Utility Commission staff and certain cities with original jurisdiction notify CenterPoint Houston that such a filing is unnecessary.

Pursuant to the Settlement Agreement, in October 2006 CenterPoint Houston began amortizing expenditures of approximately $28 million related to Hurricane Rita over a seven-year period and regulatory expenses of approximately $7 million over a four-year period. Pursuant to the Settlement Agreement, the Texas Utility Commission determined that franchise fees payable by CenterPoint Houston under new franchise agreements with the City of Houston and certain other municipalities in CenterPoint Houston s service area are deemed reasonable and necessary, along with the revised base rates.

The Settlement Agreement also resolves all issues that could be raised in the Texas Utility Commission s proceeding to review its decision in CenterPoint Houston s 2001 UCOS case. See Note 4(c) above.

Natural Gas Distribution

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

The filing seeks approval by the APSC of the new rates that would go into effect later this year and would generate approximately $51 million in additional revenue on an annual basis. The effect on individual monthly bills would vary depending on natural gas use and customer class. As part of the base rate filing, Gas Operations is also proposing a mechanism that, if approved, would help stabilize revenues, eliminate the potential conflict between its

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

efforts to earn a reasonable return on invested capital while promoting energy efficiency initiatives, and minimize the need for future rate cases. As part of the revenue stabilization mechanism, we proposed to reduce the requested return on equity by 35 basis points which would reduce the base rate increase by $1 million. The mechanism would be in place through December 31, 2010.

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

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

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

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

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

In November 2005, the Company filed a request with the MPUC to increase annual rates by approximately $41 million. In December 2005, the MPUC approved an interim rate increase of approximately $35 million that was implemented January 1, 2006. Any excess of amounts collected under the interim rates over the amounts approved

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

(f) City of Tyler, Texas Dispute

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

(5) Derivative Instruments

The Company is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. The Company utilizes derivative instruments such as physical forward contracts, swaps and options (energy derivatives) to mitigate the impact of changes in its natural gas businesses on its operating results and cash flows.

(a) Non-Trading Activities

Cash Flow Hedges. The Company enters into certain derivative instruments that qualify as cash flow hedges under SFAS No. 133. The objective of these derivative instruments is to hedge the price risk associated with natural gas purchases and sales to reduce cash flow variability related to meeting its wholesale and retail customer obligations. During the years ended December 31, 2004, 2005 and 2006, hedge ineffectiveness resulted in a loss of less than $1 million, a loss of $2 million and a gain of $2 million, respectively, from derivatives that qualify for and are designated as cash flow hedges. No component of the derivative instruments gain or loss was excluded from the assessment of effectiveness. If it becomes probable that an anticipated transaction will not occur, the Company realizes in net income the deferred gains and losses previously recognized in accumulated other comprehensive

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

loss. Once the anticipated transaction affects earnings, the accumulated deferred gain or loss recognized in accumulated other comprehensive loss is reclassified and included in the Company s Statements of Consolidated Operations under the Expenses caption Natural gas. Cash flows resulting from these transactions in non-trading energy derivatives are included in the Condensed Statements of Consolidated Cash Flows in the same category as the item being hedged. As of December 31, 2006, the Company expects $42 million ($26 million after-tax) in accumulated other comprehensive income to be reclassified as a decrease in Natural gas expense during the next twelve months.

The maximum length of time the Company is hedging its exposure to the variability in future cash flows using financial instruments is primarily two years with a limited amount up to four years. The Company s policy is not to exceed ten years in hedging its exposure.

Other Derivative Instruments. The Company enters into certain derivative instruments to manage physical commodity price risks that do not qualify or are not designated as cash flow or fair value hedges under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133). While the Company utilizes these financial instruments to manage physical commodity price risks, it does not engage in proprietary or speculative commodity trading. During the years ended December 31, 2004, 2005 and 2006, the Company recognized unrealized net gains of $2 million, $2 million and $34 million, respectively. These derivative gains are included in the Statements of Consolidated Operations under the Expenses caption Natural gas.

Interest Rate Swaps. During 2002, the Company settled forward-starting interest rate swaps having an aggregate notional amount of $1.5 billion at a cost of $156 million, which was recorded in other comprehensive loss and is being amortized into interest expense over the five-year life of the designated fixed-rate debt. Amortization of amounts deferred in accumulated other comprehensive loss for 2004, 2005 and 2006 was $25 million, $31 million and $31 million, respectively. Hedge ineffectiveness was not material during each of the years ended December 31, 2004, 2005 and 2006. As of December 31, 2006, the Company expects $20 million ($13 million after-tax) in accumulated other comprehensive loss to be amortized during the next twelve months.

Embedded Derivative. The Company s 3.75% and 2.875% convertible senior notes contain contingent interest provisions. The contingent interest component is an embedded derivative as defined by SFAS No. 133, and accordingly, must be split from the host instrument and recorded at fair value on the balance sheet. The value of the contingent interest components was not material at issuance or at December 31, 2006. All of the Company s 2.875% convertible senior notes were either redeemed or surrendered for conversion in January 2007, as described in Note 8(b), Long-term Debt Convertible Debt.

(b) Credit Risks

In addition to the risk associated with price movements, credit risk is also inherent in the Company s non-trading derivative activities. Credit risk relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. The following table shows the composition of the non-trading derivative assets of the Company as of December 31, 2005 and 2006 (in millions):

	December 31, 2005	December 31, 2006

	Investment Grade(1)	Total	Investment Grade(1)	Total
Energy marketers	$ 24	$ 25	$ 22	$ 27
Financial institutions	208	208	51	51
Other		2	45	41
Total	$ 232	$ 235	$ 118	$ 119

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

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

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

(a) Original Investment in Time Warner Securities

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

(b) ZENS

In September 1999, the Company issued its 2.0% Zero-Premium Exchangeable Subordinated Notes due 2029 (ZENS) having an original principal amount of $1.0 billion. ZENS are exchangeable for cash equal to the market value of a specified number of shares of TW common. The Company pays interest on the ZENS at an annual rate of 2% plus the amount of any quarterly cash dividends paid in respect of the shares of TW Common attributable to the ZENS. The principal amount of ZENS is subject to being increased or decreased to the extent that the annual yield from interest and cash dividends on the reference shares of TW Common is less than or more than 2.309%. At December 31, 2006, ZENS having an original principal amount of $840 million and a contingent principal amount of $849 million were outstanding and were exchangeable, at the option of the holders, for cash equal to 95% of the market value of 21.6 million shares of TW Common deemed to be attributable to the ZENS. At December 31, 2006, the market value of such shares was approximately $471 million, which would provide an exchange amount of $533 for each $1,000 original principal amount of ZENS. At maturity, the holders of the ZENS will receive in cash the higher of the original principal amount of the ZENS (subject to adjustment as discussed above) or an amount based on the then-current market value of TW Common, or other securities distributed with respect to TW Common.

Upon adoption of SFAS No. 133 effective January 1, 2001, the ZENS obligation was bifurcated into a debt component and a derivative component (the holder s option to receive the appreciated value of TW Common at maturity). The derivative component was valued at fair value and determined the initial carrying value assigned to the debt component ($121 million) as the difference between the original principal amount of the ZENS ($1 billion) and the fair value of the derivative component at issuance ($879 million). Effective January 1, 2001 the debt component was recorded at its accreted amount of $122 million and the derivative component was recorded at its fair value of $788 million, as a current liability. Subsequently, the debt component accretes through interest charges at 17.5% annually up to the minimum amount payable upon maturity of the ZENS in 2029 (approximately $908 million assuming no dividends are paid on the TW Common subsequent to 2006) which reflects exchanges and adjustments to maintain a 2.309% annual yield, as discussed above. Changes in the fair value of the derivative component are recorded in the Company s Statements of Consolidated Operations. During 2004, 2005 and 2006, the Company recorded a gain (loss) of $31 million, $(44) million and $94 million, respectively, on the Company s investment in TW Common. During 2004, 2005 and 2006, the Company recorded a gain (loss) of $(20) million, $49 million and $(80) million, respectively, associated with the fair value of the derivative component of the ZENS obligation. Changes in the fair value of the TW Common held by the Company are expected to substantially offset changes in the fair value of the derivative component of the ZENS.

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

	TW Investment	Debt Component of ZENS	Derivative Component of ZENS
Balance at December 31, 2003	$ 390	$ 105	$ 321
Accretion of debt component of ZENS		2	
Loss on indexed debt securities			20
Gain on TW Common	31		
Balance at December 31, 2004	421	107	341
Accretion of debt component of ZENS		2	
Gain on indexed debt securities			(49)
Loss on TW Common	(44)		
Balance at December 31, 2005	377	109	292
Accretion of debt component of ZENS		2	
Loss on indexed debt securities			80
Gain on TW Common	94		
Balance at December 31, 2006	$ 471	$ 111	$ 372

(7) Equity

(a) Capital Stock

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

(b) Shareholder Rights Plan

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

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

	December 31, 2005		December 31, 2006	
	Long-Term	Current(1)	Long-Term	Current(1)
	(In millions)			
Short-term borrowings:				
CERC Corp. receivables facility	$	$	$	$ 187
Long-term debt:				
CenterPoint Energy:				
ZENS(2)	$	$ 109	$	$ 111
Senior notes 5.875% to 7.25% due 2008 to 2015	600		600	
Convertible senior notes 2.875% to 3.75% due 2023 to 2024(3)	830			830
Pollution control bonds 5.60% to 6.70% due 2012 to 2027(4)	151		151	
Pollution control bonds 4.70% to 8.00% due 2011 to 2030(5)	1,046		1,046	
Bank loans and commercial paper due 2006 to 2010(6)	3			
Junior subordinated debentures payable to affiliate 8.257% due 2037(7)	103			103
CenterPoint Houston:				
First mortgage bonds 9.15% due 2021	102		102	
General mortgage bonds 5.60% to 6.95% due 2013 to 2033	1,262		1,262	
Pollution control bonds 3.625% to 5.60% due 2012 to 2027(8)	229		229	
Transition Bonds 3.84% to 5.63% due 2006 to 2019	2,407	73	2,260	147
CERC Corp.:				
Convertible subordinated debentures 6.00% due 2012	63	6	56	7
Senior notes 5.95% to 7.875% due 2007 to 2014	1,772	148	2,097	
Other	2	3	1	
Unamortized discount and premium(9)	(2)		(2)	
Total long-term debt	8,568	339	7,802	1,198
Total debt	$ 8,568	$ 339	$ 7,802	$ 1,385

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

(2) Upon adoption of SFAS No. 133 effective January 1, 2001, the Company s ZENS obligation was bifurcated into a debt component and an embedded derivative component. For additional information regarding ZENS, see Note 6(b). As ZENS are exchangeable for cash at any time at the option of the holders, these notes are classified as a current portion of long-term debt.

(3) All of the Company s 2.875% convertible senior notes were either redeemed or surrendered for conversion in January 2007, as described in Note 8(b), Long-term Debt Convertible Debt.

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

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

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

(7) 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

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pursuant to the adoption of FIN 46. All of the junior subordinated debentures issued to the Company s subsidiary trust were redeemed in February 2007, as described in Note 15.

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

(9) Debt acquired in business acquisitions is adjusted to fair market value as of the acquisition date. Included in long-term debt is additional unamortized premium related to fair value adjustments of long-term debt of $5 million and $4 million at December 31, 2005 and 2006, respectively, which is being amortized over the respective remaining term of the related long-term debt.

(a) Short-term Borrowings.

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

(b) Long-term Debt

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

Revolving Credit Facilities. In March 2006, the Company, CenterPoint Houston and CERC Corp., entered into amended and restated bank credit facilities. The Company replaced its $1 billion five-year revolving credit facility with a $1.2 billion five-year revolving credit facility. The facility has a first drawn cost of London Interbank Offered Rate (LIBOR) plus 60 basis points based on the Company s current credit ratings, as compared to LIBOR plus 87.5 basis points for borrowings under the facility it replaced. The facility contains covenants, including a debt (excluding transition bonds) to earnings before interest, taxes, depreciation and amortization covenant.

CenterPoint Houston replaced its $200 million five-year revolving credit facility with a $300 million five-year revolving credit facility. The facility has a first drawn cost of LIBOR plus 45 basis points based on CenterPoint Houston s current credit ratings, as compared to LIBOR plus 75 basis points for borrowings under the facility it replaced. The facility contains covenants, including a debt (excluding transition bonds) to total capitalization covenant of 65%.

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2006, the Company had no borrowings and approximately $28 million of outstanding letters of credit under its $1.2 billion credit facility, CenterPoint Houston had no borrowings and approximately $4 million of outstanding letters of credit under its $300 million credit facility and CERC Corp. had no borrowings and approximately $4 million of outstanding letters of credit under its $550 million credit facility. Additionally, the Company, CenterPoint Houston and CERC Corp. were in compliance with all covenants as of December 31, 2006.

Transition Bonds. Pursuant to a financing order issued by the Texas Utility Commission in March 2005 and affirmed in all respects in August 2005 by the same Travis County District Court considering the appeal of the True-Up Order, in December 2005 a subsidiary of CenterPoint Houston issued $1.85 billion in transition bonds with interest rates ranging from 4.84 percent to 5.30 percent and final maturity dates ranging from February 2011 to August 2020. Scheduled payment dates range from August 2006 to August 2019. Through issuance of the transition bonds, CenterPoint Houston recovered approximately $1.7 billion of the true-up balance determined in the True-Up Order plus interest through the date on which the bonds were issued. The proceeds received from the issuance of the transition bonds were used to repay CenterPoint Houston s $1.3 billion credit facility, which was utilized in November 2005 to repay CenterPoint Houston s $1.3 billion term loan upon its maturity.

Convertible Debt. On May 19, 2003, the Company issued $575 million aggregate principal amount of convertible senior notes due May 15, 2023 with an interest rate of 3.75%. As of December 31, 2006, holders could convert each of their notes into shares of CenterPoint Energy common stock at a conversion rate of 88.3833 shares of common stock per $1,000 principal amount of notes at any time prior to maturity under the following circumstances: (1) if the last reported sale price of CenterPoint Energy common stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the previous calendar quarter is greater than or equal to 120% or, following May 15, 2008, 110% of the conversion price per share of CenterPoint Energy common stock on such last trading day, (2) if the notes have been called for redemption, (3) during any period in which the credit ratings assigned to the notes by both Moody s Investors Service, Inc. (Moody s) and Standard & Poor s Ratings Services (S&P), a division of The McGraw-Hill Companies, are lower than Ba2 and BB, respectively, or the notes are no longer rated by at least one of these ratings services or their successors, or (4) upon the occurrence of specified corporate transactions, including the distribution to all holders of CenterPoint Energy common stock of certain rights entitling them to purchase shares of CenterPoint Energy common stock at less than the last reported sale price of a share of CenterPoint Energy common stock on the trading day prior to the declaration date of the distribution or the distribution to all holders of CenterPoint Energy common stock of the Company s assets, debt securities or certain rights to purchase the Company s securities, which distribution has a per share value exceeding 15% of the last reported sale price of a share of CenterPoint Energy common stock on the trading day immediately preceding the declaration date for such distribution. The notes originally had a conversion rate of 86.3558 shares of common stock per $1,000 principal amount of notes. However, effective February 16, 2006 and November 17, 2006, the conversion rate increased to 87.4094 and 88.3833, respectively, in accordance with the terms of the notes due to quarterly common stock dividends in excess of $0.10 per share.

Holders have the right to require the Company to purchase all or any portion of the notes for cash on May 15, 2008, May 15, 2013 and May 15, 2018 for a purchase price equal to 100% of the principal amount of the notes. The convertible senior notes also have a contingent interest feature requiring contingent interest to be paid to holders of notes commencing on or after May 15, 2008, in the event that the average trading price of a note for the applicable five-trading-day period equals or exceeds 120% of the principal amount of the note as of the day immediately preceding the first day of the applicable six-month interest period. For any six-month period, contingent interest will be equal to 0.25% of the average trading price of the note for the applicable five-trading-day period.

In August 2005, the Company accepted for exchange approximately $572 million aggregate principal amount of its 3.75% convertible senior notes due 2023 (Old Notes) for an equal amount of its new 3.75% convertible senior notes due 2023 (New Notes). Old Notes of approximately $3 million remain outstanding. Under the terms of the New Notes, which are substantially similar to the Old Notes, settlement of the principal portion will be made in cash rather than stock.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Additionally, as of December 31, 2006, the 3.75% convertible senior notes have been included as current portion of long-term debt in the Consolidated Balance Sheets because the last reported sale price of CenterPoint Energy common stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the fourth quarter of 2006 was greater than or equal to 120% of the conversion price of the 3.75% convertible senior notes and therefore, during the first quarter of 2007, the 3.75% convertible senior notes meet the criteria that make them eligible for conversion at the option of the holders of these notes.

On December 17, 2003, the Company issued $255 million aggregate principal amount of convertible senior notes due January 15, 2024 with an interest rate of 2.875%. As of December 31, 2006, holders could convert each of their notes into shares of CenterPoint Energy common stock at a conversion rate of 79.8969 shares of common stock per $1,000 principal amount of notes. The notes originally had a conversion rate of 78.0640 shares of common stock per $1,000 principal amount of notes. However, effective February 16, 2006 and November 17, 2006, the conversion rate increased to 79.0165 and 79.8969, respectively, in accordance with the terms of the notes due to quarterly common stock dividends in excess of $0.10 per share. As of December 31, 2006, these notes were classified as current portion of other long-term debt in the Company s Consolidated Balance Sheets.

In December 2006, the Company called its 2.875% Convertible Senior Notes due 2024 (2.875% Convertible Notes) for redemption on January 22, 2007 at 100% of their principal amount. The 2.875% Convertible Notes became immediately convertible at the option of the holders upon the call for redemption and were convertible through the close of business on the redemption date. Substantially all the $255 million aggregate principal amount of the 2.875% Convertible Notes were converted. The $255 million principal amount of the 2.875% Convertible Notes was settled in cash and the excess value due converting holders of $97 million was settled by delivering approximately 5.6 million shares of the Company s common stock.

Junior Subordinated Debentures (Trust Preferred Securities). In February 1997, a Delaware statutory business trust created by CenterPoint Energy (HL&P Capital Trust II) issued to the public $100 million aggregate amount of capital securities. The trust used the proceeds of the offering to purchase junior subordinated debentures issued by CenterPoint Energy having an interest rate and maturity date that correspond to the distribution rate and the mandatory redemption date of the capital securities. The amount of outstanding junior subordinated debentures discussed above was included in long-term debt as of December 31, 2005 and in current portion of long-term debt as of December 31, 2006.

The junior subordinated debentures are the trust s sole assets and their entire operations. CenterPoint Energy considered its obligations under the Amended and Restated Declaration of Trust, Indenture, Guaranty Agreement and, where applicable, Agreement as to Expenses and Liabilities, relating to the capital securities, taken together, to constitute a full and unconditional guarantee by CenterPoint Energy of the trust s obligations with respect to the capital securities.

The capital securities were mandatorily redeemable upon the repayment of the related series of junior subordinated debentures at their stated maturity or earlier redemption.

The outstanding aggregate liquidation amount, distribution rate and mandatory redemption date of the capital securities of the trust described above and the identity and similar terms of the related series of junior subordinated debentures were as follows:

Trust	Aggregate Liquidation Amounts as of December 31, 2005	2006	Distribution Rate/ Interest Rate	Mandatory Redemption Date/ Maturity Date	Junior Subordinated Debentures
	(In millions)				
HL&P Capital Trust II	$ 100	$ 100	8.257%	February 2037	8.257% Junior Subordinated Deferrable Interest Debentures Series B

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For information regarding the redemption of the Trust Preferred Securities in February 2007, see Note 15.

Maturities. The Company s maturities of long-term debt, capital leases and sinking fund requirements, excluding the ZENS obligation, are $508 million in 2007, $666 million in 2008, $181 million in 2009, $397 million in 2010 and $782 million in 2011.

Liens. As of December 31, 2006, CenterPoint Houston s assets were subject to liens securing approximately $253 million of first mortgage bonds. Sinking or improvement fund and replacement fund requirements on the first mortgage bonds may be satisfied by certification of property additions. Sinking fund and replacement fund requirements for 2004, 2005 and 2006 have been satisfied by certification of property additions. The replacement fund requirement to be satisfied in 2007 is approximately $160 million, and the sinking fund requirement to be satisfied in 2007 is approximately $3 million. The Company expects CenterPoint Houston to meet these 2007 obligations by certification of property additions. As of December 31, 2006, CenterPoint Houston s assets were also subject to liens securing approximately $2.0 billion of general mortgage bonds which are junior to the liens of the first mortgage bonds.

(9) Income Taxes

The Company s current and deferred components of income tax expense (benefit) were as follows:

	Year Ended December 31,		
	2004	2005	2006
	(In millions)		
Current:			
Federal	$ (130)	$ (74)	$ 373
State	11	2	37
Total current	(119)	(72)	410
Deferred:			
Federal	264	208	(362)
State	(6)	17	14
Total deferred	258	225	(348)
Income tax expense	$ 139	$ 153	$ 62

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31,		
	2004	2005	2006
		(In millions)	
Income from continuing operations before income taxes and extraordinary loss	$ 344	$ 378	$ 494
Federal statutory rate	35%	35%	35%
Income taxes at statutory rate	120	132	173
Net addition (reduction) in taxes resulting from:			
State income taxes, net of valuation allowances and federal income tax benefit	3	13	33
Amortization of investment tax credit	(8)	(8)	(8)
Excess deferred taxes	(4)	(3)	(3)
Deferred tax asset write-off	19		
Increase (decrease) in tax reserve	7	32	(118)
Other, net	2	(13)	(15)
Total	19	21	(111)
Income tax expense	$ 139	$ 153	$ 62
Effective rate	40.4%	40.6%	12.6%

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31, 2005	December 31, 2006
	(In millions)	
Deferred tax assets:		
Current:		
Allowance for doubtful accounts	$ 20	$ 17
Non-trading derivative assets, net	16	
Total current deferred tax assets	36	17
Non-current:		
Loss carryforwards	26	27
Deferred gas costs	59	60
Employee benefits		186
Other	102	56
Total non-current deferred tax assets before valuation allowance	187	329
Valuation allowance	(21)	(22)
Total non-current deferred tax assets	166	307
Total deferred tax assets, net	202	324
Deferred tax liabilities:		
Current:		
Unrealized gain on indexed debt securities	348	217
Unrealized gain on TW Common	73	109
Non-trading derivative liabilities, net		7
Total current deferred tax liabilities	421	333
Non-current:		
Depreciation	1,432	1,370
Regulatory assets, net	1,076	1,173
Employee benefits	52	
Other	80	87
Total non-current deferred tax liabilities	2,640	2,630

Total deferred tax liabilities	3,061	2,963
Accumulated deferred income taxes, net	$ 2,859	$ 2,639

Tax Attribute Carryforwards. At December 31, 2006 the Company has approximately $257 million of state net operating loss carryforwards. The losses are available to offset future state taxable income through the year 2026. Substantially all of the state loss carryforwards will expire between 2010 and 2021. A valuation allowance has been established against approximately $111 million of the state net operating loss carryforwards.

Tax Contingencies. CenterPoint Energy s consolidated federal income tax returns have been audited and settled through the 1996 tax year.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In the audits of the 1997 through 2003 tax years, the IRS proposed to disallow all deductions for original issue discount (OID), including interest paid, relating to the ZENS, and the interest paid on the 7% Automatic Common Exchange Securities (ACES) redeemed in 1999. The IRS contended that (1) those instruments, in combination with the Company s long position in shares of TW Common, constituted a straddle under Sections 1092 and 263(g) of the Internal Revenue Code of 1986, as amended and (2) the indebtedness underlying those instruments was incurred to carry the TW Common.

The Company and the IRS reached a final settlement on the ACES and ZENS issues and executed a closing agreement on the ZENS, approved by the Joint Committee on Taxation of the U.S. Congress. As a result of the settlement reached with the IRS, the Company reduced its previously accrued tax and related interest reserves by approximately $107 million, for a net reduction of $92 million in 2006, and will no longer accrue quarterly reserves related to the tax treatment of the ACES and ZENS.

The Company also reached tentative settlements with the IRS for a number of other tax matters in the fourth quarter of 2006; including issues associated with prior acquisitions and dispositions. Those tentative settlements have allowed the Company to reduce its total tax and related interest reserve for other tax items from $60 million at December 31, 2005 to $34 million at December 31, 2006. Most of the remaining reserve is related to certain tax positions taken with respect to state tax filings and certain items related to employee benefits.

(10) Commitments and Contingencies

(a) Natural Gas Supply Commitments

Natural gas supply commitments include natural gas contracts related to the Company s natural gas distribution and competitive natural gas sales and services operations, which have various quantity requirements and durations, that are not classified as non-trading derivative assets and liabilities in the Company s Consolidated Balance Sheets as of December 31, 2005 and 2006 as these contracts meet the SFAS No. 133 exemption to be classified as normal purchases contracts. Natural gas supply commitments also include natural gas transportation and storage contracts that do not meet the definition of a derivative. As of December 31, 2006, minimum payment obligations for natural gas supply commitments are approximately $921 million in 2007, $294 million in 2008, $210 million in 2009, $207 million in 2010 and $1.4 billion in 2011 and thereafter.

(b) Lease Commitments

The following table sets forth information concerning the Company s obligations under non-cancelable long-term operating leases at December 31, 2006, which primarily consist of rental agreements for building space, data processing equipment and vehicles (in millions):

2007	$ 22
2008	18
2009	11
2010	8

2011	6
2012 and beyond	15
Total	$ 80

Total lease expense for all operating leases was $32 million, $37 million and $56 million during 2004, 2005 and 2006, respectively.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(c) Capital Commitments

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

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

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(d) Legal, Environmental and Other Regulatory Matters

Legal Matters

RRI Indemnified Litigation

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

Electricity and Gas Market Manipulation Cases. A large number of lawsuits have been filed against numerous market participants and remain pending in federal court in Colorado and Nevada and in state court in California, Wisconsin and Nevada in connection with the operation of the electricity and natural gas markets in California and certain other states in 2000-2001, a time of power shortages and significant increases in prices. These lawsuits, many of which have been filed as class actions, are based on a number of legal theories, including violation of state and federal antitrust laws, laws against unfair and unlawful business practices, the federal Racketeer Influenced Corrupt Organization Act, false claims statutes and similar theories and breaches of contracts to supply power to governmental entities. Plaintiffs in these lawsuits, which include state officials and governmental entities as well as private litigants, are seeking a variety of forms of relief, including recovery of compensatory damages (in some cases in excess of $1 billion), a trebling of compensatory damages and punitive damages, injunctive relief, restitution, interest due, disgorgement, civil penalties and fines, costs of suit and attorneys fees. The Company s former subsidiary, RRI, was a participant in the California markets, owning generating plants in the state and participating in both electricity and natural gas trading in that state and in western power markets generally.

The Company and/or Reliant Energy have been named in approximately 35 of these lawsuits, which were instituted between 2001 and 2006 and are pending in California state court in San Diego County, in Nevada state court in Clark County, in Wisconsin state court in Dane County, in federal district court in Colorado and Nevada and before the Ninth Circuit Court of Appeals. However, the Company, CenterPoint Houston and Reliant Energy were not participants in the electricity or natural gas markets in California. The Company and Reliant Energy have been dismissed from certain of the lawsuits, either voluntarily by the plaintiffs or by order of the court, and the Company believes it is not a proper defendant in the remaining cases and will continue to seek dismissal from such remaining cases.

To date, several of the electricity complaints have been dismissed, and several of the dismissals have been affirmed by appellate courts. Others have been resolved by the settlement described in the following paragraph. Five of the gas complaints have also been dismissed based on defendants claims of federal preemption and the filed rate doctrine, and these dismissals have been appealed. In June 2005, a San Diego state court refused to dismiss other gas complaints on the same basis. In October 2006, RRI reached a tentative settlement of the 12 class action natural gas cases pending in state court in California. This settlement remains subject to final court approval. The other gas cases remain in the early procedural stages.

In August 2005, RRI reached a settlement with the FERC enforcement staff, the states of California, Washington and Oregon, California s three largest investor-owned utilities, classes of consumers from California and other western states, and a number of California city and county government entities that resolves their claims against RRI related to the operation of the electricity markets in California and certain other western states in 2000-2001. The settlement also resolves the claims of the three states and the investor-owned utilities related to the 2000-2001 natural gas markets. The settlement has been approved by the FERC, by the California Public Utilities Commission, and by the courts in which the electricity class action cases are pending. Two parties have appealed the courts approval of the settlement to the California Court of Appeals. A party in the FERC proceedings filed a

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

motion for rehearing of the FERC s order approving the settlement, which the FERC denied on May 30, 2006. That party has filed for review of the FERC s orders in the Ninth Circuit Court of Appeals. The Company is not a party to the settlement, but may rely on the settlement as a defense to any claims brought against it related to the time when the Company was an affiliate of RRI. The terms of the settlement do not require payment by the Company.

Other Class Action Lawsuits. In May 2002, three class action lawsuits were filed in federal district court in Houston on behalf of participants in various employee benefits plans sponsored by the Company. Two of the lawsuits were dismissed without prejudice. In the remaining lawsuit, the Company and certain current and former members of its benefits committee are defendants. That lawsuit alleged that the defendants breached their fiduciary duties to various employee benefits plans, directly or indirectly sponsored by the Company, in violation of the Employee Retirement Income Security Act of 1974 by permitting the plans to purchase or hold securities issued by the Company when it was imprudent to do so, including after the prices for such securities became artificially inflated because of alleged securities fraud engaged in by the defendants. The complaint sought monetary damages for losses suffered on behalf of the plans and a putative class of plan participants whose accounts held CenterPoint Energy or RRI securities, as well as restitution. In January 2006, the federal district judge granted a motion for summary judgment filed by the Company and the individual defendants. The plaintiffs appealed the ruling to the Fifth Circuit Court of Appeals. The Company believes that this lawsuit is without merit and will continue to vigorously defend the case. However, the ultimate outcome of this matter cannot be predicted at this time.

Other Legal Matters

Natural Gas Measurement Lawsuits. CERC Corp. and certain of its subsidiaries are defendants in a lawsuit filed in 1997 under the Federal False Claims Act alleging mismeasurement of natural gas produced from federal and Indian lands. The suit seeks undisclosed damages, along with statutory penalties, interest, costs and fees. The complaint is part of a larger series of complaints filed against 77 natural gas pipelines and their subsidiaries and affiliates. An earlier single action making substantially similar allegations against the pipelines was dismissed by the federal district court for the District of Columbia on grounds of improper joinder and lack of jurisdiction. As a result, the various individual complaints were filed in numerous courts throughout the country. This case has been consolidated, together with the other similar False Claims Act cases, in the federal district court in Cheyenne, Wyoming. On October 20, 2006, the judge considering this matter granted the defendants motion to dismiss the suit on the ground that the court lacked subject matter jurisdiction over the claims asserted, but the plaintiff has sought review of that dismissal from the Court of Appeals for the 10th Circuit.

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

Gas Cost Recovery Litigation. In October 2002, a suit was filed in state district court in Wharton County, Texas against the Company, CERC, Entex Gas Marketing Company, and certain non-affiliated companies alleging

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

fraud, violations of the Texas Deceptive Trade Practices Act, violations of the Texas Utilities Code, civil conspiracy and violations of the Texas Free Enterprise and Antitrust Act with respect to rates charged to certain consumers of natural gas in the State of Texas. Subsequently, the plaintiffs added as defendants CenterPoint Energy Marketing Inc., CEGT, United Gas, Inc., Louisiana Unit Gas Transmission Company, CenterPoint Energy Pipeline Services, Inc., and CenterPoint Energy Trading and Transportation Group, Inc., all of which are subsidiaries of the Company. The plaintiffs alleged that defendants inflated the prices charged to certain consumers of natural gas. In February 2003, a similar lawsuit was filed in state court in Caddo Parish, Louisiana against CERC with respect to rates charged to a purported class of certain consumers of natural gas and gas service in the State of Louisiana. In February 2004, another suit was filed in state court in Calcasieu Parish, Louisiana against CERC seeking to recover alleged overcharges for gas or gas services allegedly provided by CERC to a purported class of certain consumers of natural gas and gas service without advance approval by the Louisiana Public Service Commission (LPSC). In October 2004, a similar case was filed in district court in Miller County, Arkansas against the Company, CERC, Entex Gas Marketing Company, CEGT, CenterPoint Energy Field Services, CenterPoint Energy Pipeline Services, Inc., Mississippi River Transmission Corp. (MRT) and other non-affiliated companies alleging fraud, unjust enrichment and civil conspiracy with respect to rates charged to certain consumers of natural gas in at least the states of Arkansas, Louisiana, Mississippi, Oklahoma and Texas. Subsequently, the plaintiffs dropped as defendants CEGT and MRT. At the time of the filing of each of the Caddo and Calcasieu Parish cases, the plaintiffs in those cases filed petitions with the LPSC relating to the same alleged rate overcharges. The Caddo and Calcasieu Parish cases have been stayed pending the resolution of the respective proceedings by the LPSC. The plaintiffs in the Miller County case seek class certification, but the proposed class has not been certified. In February 2005, the Wharton County case was removed to federal district court in Houston, Texas, and in March 2005, the plaintiffs voluntarily moved to dismiss the case and agreed not to refile the claims asserted unless the Miller County case is not certified as a class action or is later decertified. The range of relief sought by the plaintiffs in these cases includes injunctive and declaratory relief, restitution for the alleged overcharges, exemplary damages or trebling of actual damages, civil penalties and attorney s fees. In these cases, the Company, CERC and their affiliates deny that they have overcharged any of their customers for natural gas and believe that the amounts recovered for purchased gas have been in accordance with what is permitted by state and municipal regulatory authorities. The allegations in these cases are similar to those asserted in the City of Tyler proceeding, as described in Note 4(f). The Company and CERC 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 CERC.

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

Pipeline Safety Compliance. Pursuant to an order from the Minnesota Office of Pipeline Safety, CERC substantially completed removal of certain non-code-compliant components from a portion of its distribution

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Minnesota Cold Weather Rule. For a discussion of this matter, see Note 4(e) above.

Environmental Matters

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

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

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

At December 31, 2006, CERC had accrued $14 million for remediation of these Minnesota sites. At December 31, 2006, the estimated range of possible remediation costs for these sites was $4 million to $35 million based on remediation continuing for 30 to 50 years. The cost estimates are based on studies of a site or industry average costs for remediation of sites of similar size. The actual remediation costs will be dependent upon the number of sites to be remediated, the participation of other potentially responsible parties (PRP), if any, and the remediation methods used.

CERC has utilized an environmental expense tracker mechanism in its rates in Minnesota to recover estimated costs in excess of insurance recovery. As of December 31, 2006, CERC had collected $13 million from insurance companies and rate payers to be used for future environmental remediation.

In addition to the Minnesota sites, the United States Environmental Protection Agency and other regulators have investigated MGP sites that were owned or operated by CERC or may have been owned by one of its former affiliates. CERC has been named as a defendant in two lawsuits, one filed in the United States District Court,

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

District of Maine and the other filed in the Middle District of Florida, Jacksonville Division, under which contribution is sought by private parties for the cost to remediate former MGP sites based on the previous ownership of such sites by former affiliates of CERC or its divisions. CERC has also been identified as a PRP by the State of Maine for a site that is the subject of one of the lawsuits. In March 2005, the federal district court considering the suit for contribution in Florida granted CERC s motion to dismiss on the grounds that CERC was not an operator of the site as had been alleged. In October 2006, the 11th Circuit Court of Appeals affirmed the district court s dismissal. In June 2006, the federal district court in Maine that is considering the other suit ruled that the current owner of the site is responsible for site remediation but that an additional evidentiary hearing is required to determine if other potentially responsible parties, including CERC, would have to contribute to that remediation. The Company is investigating details regarding these sites and the range of environmental expenditures for potential remediation. However, CERC believes it is not liable as a former owner or operator of those sites under the Comprehensive Environmental, Response, Compensation and Liability Act of 1980, as amended, and applicable state statutes, and is vigorously contesting those suits and its designation as a PRP.

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

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

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.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other Proceedings

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

Guaranties

Prior to the Company s distribution of its ownership in RRI to its shareholders, CERC had guaranteed certain contractual obligations of what became RRI s trading subsidiary. Under the terms of the separation agreement between the companies, RRI agreed to extinguish all such guaranty obligations prior to separation, but at the time of separation in September 2002, RRI had been unable to extinguish all obligations. To secure the Company and CERC against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for the benefit of CERC and the Company, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. CERC currently holds letters of credit in the amount of $33.3 million issued on behalf of RRI against guaranties that have not been released. The Company s current exposure under the guaranties relates to CERC s guaranty of the payment by RRI of demand charges related to transportation contracts with one counterparty. The demand charges are approximately $53 million per year through 2015, $49 million in 2016, $38 million in 2017 and $13 million in 2018. RRI continues to meet its obligations under the transportation contracts, and the Company believes current market conditions make those contracts valuable for transportation services in the near term. However, changes in market conditions could affect the value of those contracts. If RRI should fail to perform its obligations under the transportation contracts, the Company s exposure to the counterparty under the guaranty could exceed the security provided by RRI. The Company has requested RRI to increase the amount of its existing letters of credit or, in the alternative, to obtain a release of CERC s obligations under the guaranty. In June 2006, the RRI trading subsidiary and CERC jointly filed a complaint at the FERC against the counterparty on the CERC guaranty. In the complaint, the RRI trading subsidiary seeks a determination by the FERC that the security demanded by the counterparty exceeds the level permitted by the FERC s policies. The complaint asks the FERC to require the counterparty to release CERC from its guaranty obligation and, in its place, accept (i) a guaranty from RRI of the obligations of the RRI trading subsidiary, and (ii) letters of credit limited to (A) one year of demand charges for a transportation agreement related to a 2003 expansion of the counterparty s pipeline, and (B) three months of demand charges for three other transportation agreements held by the RRI trading subsidiary. The counterparty has argued that the amount of the guaranty does not violate the FERC s policies and that the proposed substitution of credit support is not authorized under the counterparty s financing documents or required by FERC s policy. The parties have now completed their submissions to FERC regarding the complaint. The Company cannot predict what action the FERC may take on the complaint or when the FERC may rule. In addition to the FERC proceeding, in February 2007 the Company and CERC made a formal demand on RRI under procedures provided for by the Master Separation Agreement, dated as of December 31, 2000, between Reliant Energy and RRI. That demand seeks to resolve the disagreement with RRI over the amount of security RRI is obligated to provide with respect to this guaranty. It is possible that this demand could lead to an arbitration proceeding between the companies, but when and on what terms the disagreement with RRI will ultimately be resolved cannot be predicted.

Nuclear Decommissioning Fund Collections

Pursuant to regulatory requirements and its tariff, CenterPoint Houston, as collection agent, collects from its transmission and distribution customers a nuclear decommissioning charge assessed with respect to its former 30.8% ownership interest in the South Texas Project, which it owned when it was part of an integrated electric utility. Amounts collected are transferred to nuclear decommissioning trusts maintained by the current owner of that

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

interest in the South Texas Project. During 2004, 2005 and 2006, $2.9 million, $3.2 million and $3.1 million, respectively, was transferred. There are various investment restrictions imposed on owners of nuclear generating stations by the Texas Utility Commission and the U.S. Nuclear Regulatory Commission relating to nuclear decommissioning trusts. Pursuant to the provisions of both a separation agreement and a final order of the Texas Utility Commission relating to the 2005 transfer of ownership to Texas Genco LLC, now NRG, CenterPoint Houston and a subsidiary of NRG were, until July 1, 2006, jointly administering the decommissioning funds through the Nuclear Decommissioning Trust Investment Committee. In June 2006, the Texas Utility Commission approved an application by CenterPoint Houston and an NRG subsidiary to name the NRG subsidiary as the sole fund administrator. As a result, CenterPoint Houston is no longer responsible for administration of decommissioning funds it collects as collection agent.

(11) Estimated Fair Value of Financial Instruments

The fair values of cash and cash equivalents, investments in debt and equity securities classified as available-for-sale and trading in accordance with SFAS No. 115, and short-term borrowings are estimated to be approximately equivalent to carrying amounts and have been excluded from the table below. The fair values of non-trading derivative assets and liabilities are equivalent to their carrying amounts in the Consolidated Balance Sheets at December 31, 2005 and 2006 and have been determined using quoted market prices for the same or similar instruments when available or other estimation techniques (see Note 5). Therefore, these financial instruments are stated at fair value and are excluded from the table below.

	December 31, 2005		December 31, 2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Financial liabilities:				
Long-term debt (excluding capital leases)	$ 8,794	$ 9,277	$ 8,889	$ 9,573

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(12) Earnings Per Share

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

	For the Year Ended December 31,		
	2004	2005	2006
	(In millions, except per share and share amounts)		
Basic earnings (loss) per share calculation:			
Income from continuing operations before extraordinary item	$ 205	$ 225	$ 432
Loss from discontinued operations, net of tax	(133)	(3)	
Extraordinary item, net of tax	(977)	30	
Net income (loss)	$ (905)	$ 252	$ 432
Weighted average shares outstanding	307,185,000	309,349,000	311,826,000
Basic earnings (loss) per share:			
Income from continuing operations before extraordinary item	$ 0.67	$ 0.72	$ 1.39
Loss from discontinued operations, net of tax	(0.43)	(0.01)	
Extraordinary item, net of tax	(3.18)	0.10	
Net income (loss)	$ (2.94)	$ 0.81	$ 1.39
Diluted earnings (loss) per share calculation:			
Net income (loss)	$ (905)	$ 252	$ 432
Plus: Income impact of assumed conversions:			
Interest on 3.75% contingently convertible senior notes	14	9	
Interest on 6.25% convertible trust preferred securities			
Total earnings effect assuming dilution	$ (891)	$ 261	$ 432
Weighted average shares outstanding	307,185,000	309,349,000	311,826,000
Plus: Incremental shares from assumed conversions:			
Stock options(1)	1,203,000	1,241,000	974,000
Restricted stock	1,447,000	1,851,000	1,553,000
2.875% convertible senior notes			1,625,000
3.75% convertible senior notes	49,655,000	33,587,000	8,800,000
6.25% convertible trust preferred securities	16,000		
Weighted average shares assuming dilution	359,506,000	346,028,000	324,778,000

Diluted earnings (loss) per share:			
Income from continuing operations before extraordinary item	$ 0.61	$ 0.67	$ 1.33
Loss from discontinued operations, net of tax	(0.37)	(0.01)	
Extraordinary item, net of tax	(2.72)	0.09	
Net income (loss)	$ (2.48)	$ 0.75	$ 1.33

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(1) Options to purchase 11,892,508, 8,677,660 and 5,863,907 shares were outstanding for the years ended December 31, 2004, 2005 and 2006, respectively, but were not included in the computation of diluted earnings (loss) per share because the options exercise price was greater than the average market price of the common shares for the respective years.

In accordance with EITF 04-8, because all of the 2.875% contingently convertible senior notes and approximately $572 million of the 3.75% contingently convertible senior notes (subsequent to the August 2005 exchange discussed in Note 8) provide for settlement of the principal portion in cash rather than stock, the Company excludes the portion of the conversion value of these notes attributable to their principal amount from its computation of diluted earnings per share from continuing operations. The Company includes the conversion spread in the calculation of diluted earnings per share when the average market price of the Company s common stock in the respective reporting period exceeds the conversion price. The conversion prices for the 2.875% and the 3.75% contingently convertible senior notes were $12.52 and $11.31, respectively, at December 31, 2006. All of the Company s 2.875% convertible senior notes were either redeemed or surrendered for conversion in January 2007, as described in Note 8(b), Long-term Debt Convertible Debt.

(13) Unaudited Quarterly Information

The consolidated financial statements have been prepared to reflect the sale of Texas Genco as described in Note 3. Accordingly, the consolidated financial statements present the Texas Genco business as discontinued operations, in accordance with SFAS No. 144. Summarized quarterly financial data is as follows:

	Year Ended December 31, 2005			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share amounts)			
Revenues	$ 2,595	$ 1,842	$ 2,073	$ 3,212
Operating income	276	186	225	252
Income from continuing operations	67	27	50	81
Discontinued operations, net of tax		(3)		
Extraordinary item, net of tax		30		
Net income	$ 67	$ 54	$ 50	$ 81
Basic earnings per share:(1)				
Income from continuing operations	$ 0.22	$ 0.09	$ 0.16	$ 0.26
Discontinued operations, net of tax		(0.01)		
Extraordinary item, net of tax		0.10		
Net income	$ 0.22	$ 0.18	$ 0.16	$ 0.26

Diluted earnings per share:(1)				
Income from continuing operations	$ 0.20	$ 0.09	$ 0.15	$ 0.25
Discontinued operations, net of tax		(0.01)		
Extraordinary item, net of tax		0.08		
Net income	$ 0.20	$ 0.16	$ 0.15	$ 0.25

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31, 2006			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share amounts)			
Revenues	$ 3,077	$ 1,843	$ 1,935	$ 2,464
Operating income	306	220	284	235
Net income	88	194	83	67
Basic earnings per share:(1)				
Net income	$ 0.28	$ 0.62	$ 0.27	$ 0.21
Diluted earnings per share:(1)				
Net income	$ 0.28	$ 0.61	$ 0.26	$ 0.20

(1) Quarterly earnings per common share are based on the weighted average number of shares outstanding during the quarter, and the sum of the quarters may not equal annual earnings per common share. The Company s 3.75% contingently convertible notes are included in the calculation of diluted earnings per share for first and second quarters of 2005, as they are dilutive. In the third quarter of 2005, the Company modified approximately $572 million of the 3.75% contingently convertible senior notes to provide for settlement of the principal portion in cash rather than stock. Accordingly, the Company excludes the portion of the conversion value of these notes and the 2.875% contingently convertible notes attributable to their principal amount from its computation of diluted earnings per share from continuing operations. The Company includes the conversion spread in the calculation of diluted earnings per share when the average market price of the Company s common stock in the respective reporting period exceeds the conversion price. All of the Company s 2.875% convertible senior notes were either redeemed or surrendered for conversion in January 2007, as described in Note 8(b), Long-term Debt Convertible Debt.

(14) Reportable Business Segments

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

The Company s reportable business segments include the following: Electric Transmission & Distribution, Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines, Field Services and Other Operations. The electric transmission and distribution function (CenterPoint Houston) is reported in the Electric Transmission & Distribution business segment. Natural Gas Distribution consists of intrastate natural gas sales to, and natural gas transportation and distribution for, residential, commercial, industrial and institutional customers. Competitive Natural Gas Sales and Services represents the Company s non-rate regulated gas sales and services operations, which consist of three operational functions: wholesale, retail and intrastate pipelines. Beginning in the fourth quarter of 2006, the Company is reporting its interstate pipelines and field services businesses as two separate business segments, the

Interstate Pipelines business segment and the Field Services business segment. These business segments were previously aggregated and reported as the Pipelines and Field Services business segment. The Interstate Pipelines includes the interstate natural gas pipeline operations. The Field Services business segment includes the natural gas gathering operations. Other Operations consists primarily of other corporate operations which support all of the Company s business operations. The Company s generation operations, which were previously reported in the Electric Generation business segment, are presented as

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

discontinued operations within these consolidated financial statements. All prior periods have been recast to conform to the 2006 presentation.

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

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

	Revenues from External Customers	Intersegment Revenues	Depreciation and Amortization	Operating Income (Loss)	Extraordinary Item, net of tax	Total Assets	Expenditures for Long-Lived Assets
As of and for the year ended December 31, 2004:							
Electric Transmission and Distribution	$ 1,521(1)	$	$ 284	$ 494	$ 977	$ 8,783	$ 235
Natural Gas Distribution	3,577	2	141	178		4,083	196
Competitive Natural Gas Sales and Services	2,593(2)	255	2	44		964	1
Interstate Pipelines	239	129	36	129		2,164	39
Field Services	67	25	8	51		451	34
Other	2	6	19	(32)		2,794(3)	25
Discontinued Operations						1,565	74
Reconciling Eliminations		(417)				(2,708)	
Consolidated	$ 7,999	$	$ 490	$ 864	$ 977	$ 18,096	$ 604
As of and for the year ended December 31, 2005:							
Electric Transmission and Distribution	$ 1,644(1)	$	$ 322	$ 487	$ (30)	$ 8,227	$ 281
Natural Gas Distribution	3,837	9	152	175		4,612	249
Competitive Natural Gas Sales and Services	3,884(2)	245	2	60		1,849	12
Interstate Pipelines	255	131	36	165		2,400	118
Field Services	91	29	9	70		529	38
Other	11	8	20	(18)		2,202(3)	21
Discontinued Operations							9
Reconciling Eliminations		(422)				(2,703)	

Consolidated	$ 9,722	$	$ 541	$ 939	$ (30)	$ 17,116	$ 728
As of and for the year ended December 31, 2006:							
Electric Transmission and Distribution	$ 1,781(1)	$	$ 379	$ 576	$	$ 8,463	$ 389
Natural Gas Distribution	3,582	11	152	124		4,463	187
Competitive Natural Gas Sales and Services	3,572(2)	79	1	77		1,501	18
Interstate Pipelines	255	133	37	181		2,738	437
Field Services	119	31	10	89		608	65
Other	10	5	20	(2)		2,047(3)	25
Reconciling Eliminations		(259)				(2,187)	
Consolidated	$ 9,319	$	$ 599	$ 1,045	$	$ 17,633	$ 1,121

(1) Sales to subsidiaries of RRI in 2004, 2005 and 2006 represented approximately $882 million, $812 million and $737 million, respectively, of CenterPoint Houston s transmission and distribution revenues.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) Sales to Texas Genco in 2004 represented approximately $20 million of the Competitive Natural Gas Sales and Services business segment s revenues from external customers. Texas Genco has been presented as discontinued operations in these consolidated financial statements.

(3) Included in total assets of Other Operations as of December 31, 2004, 2005 and 2006 is a pension asset of $610 million, $654 million and $109 million, respectively. Also included in total assets of Other Operations as of December 31, 2006, is a pension related regulatory asset of $420 million that resulted from the Company s adoption of SFAS No. 158.

	Year Ended December 31,		
	2004	2005	2006
		(In millions)	
Revenues by Products and Services:			
Electric delivery sales	$ 1,521	$ 1,644	$ 1,781
Retail gas sales	4,239	4,871	4,546
Wholesale gas sales	1,526	2,410	2,331
Gas transport	613	684	550
Energy products and services	100	113	111
Total	$ 7,999	$ 9,722	$ 9,319

(15) Subsequent Events

On February 1, 2007, the Company s board of directors declared a regular quarterly cash dividend of $0.17 per share of common stock payable on March 6, 2007, to shareholders of record as of the close of business on February 16, 2007.

In February 2007, the Company s 8.257% Junior Subordinated Deferrable Interest Debentures having an aggregate principal amount of $103 million were redeemed at 104.1285% of their principal amount and the related 8.257% capital securities issued by HL&P Capital Trust II were redeemed at 104.1285% of their aggregate liquidation value of $100 million.

In February 2007, the Company issued $250 million aggregate principal amount of senior notes due in February 2017 with an interest rate of 5.95%. The proceeds from the sale of the senior notes were used to repay debt incurred in satisfying its $255 million cash payment obligation in connection with the conversion and redemption of its 2.875% Convertible Notes.

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

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

None.

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

Disclosure Controls And Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2006 to provide assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding disclosure.

There has been no change in our internal controls over financial reporting that occurred during the three months ended December 31, 2006 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

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

None.

PART III

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

The information called for by Item 10, to the extent not set forth in Executive Officers in Item 1, is or will be set forth in the definitive proxy statement relating to CenterPoint Energy s 2007 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 10 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Item 11. ***Executive Compensation***

The information called for by Item 11 is or will be set forth in the definitive proxy statement relating to CenterPoint Energy s 2007 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 11 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

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

The information called for by Item 12 is or will be set forth in the definitive proxy statement relating to CenterPoint Energy s 2007 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 12 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

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

The information called for by Item 13 is or will be set forth in the definitive proxy statement relating to CenterPoint Energy s 2007 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 13 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

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

The information called for by Item 14 is or will be set forth in the definitive proxy statement relating to CenterPoint Energy s 2007 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 14 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a)(1) Financial Statements.

(a)(2) Financial Statement Schedules for the Three Years Ended December 31, 2006.

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

III, IV and V.

(a)(3) Exhibits.

See Index of Exhibits beginning on page 132, which index also includes the management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(b)(10)(iii) of Regulation S-K.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the consolidated financial statements of CenterPoint Energy, Inc. and subsidiaries (the Company) as of December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, and have issued our report thereon dated February 28, 2007 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the Company s adoption of new accounting standards for defined benefit pension and other postretirement plans in 2006 and conditional asset retirement obligations in 2005), and management s assessment of the effectiveness of the Company s internal control over financial reporting as of December 31, 2006 and the effectiveness of the Company s internal control over financial reporting as of December 31, 2006, and have issued our report thereon dated February 28, 2007; such reports are included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedules the Company listed in the index at Item 15 (a)(2). These consolidated financial statement schedules are the responsibility of the Company s management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2007

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CENTERPOINT ENERGY, INC.

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

STATEMENTS OF OPERATIONS

	For the Year Ended December 31,		
	2004	2005	2006
		(In millions)	
Equity Income of Subsidiaries	$ 707	$ 425	$ 560
Interest Income from Subsidiaries	21	15	18
Other Income			6
Loss on Disposal of Subsidiary	(366)	(14)	
Gain (Loss) on Indexed Debt Securities	(20)	49	(80)
Operation and Maintenance Expenses	(21)	(29)	(19)
Depreciation and Amortization			
Taxes Other than Income			(2)
Interest Expense to Subsidiaries	(80)	(61)	(69)
Interest Expense	(303)	(204)	(196)
Income Tax Benefit	134	41	214
Extraordinary Item, net of tax	(977)	30	
Net Income (Loss)	$ (905)	$ 252	$ 432

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

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CENTERPOINT ENERGY, INC.

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

BALANCE SHEETS

	December 31, 2005	December 31, 2006
	(In millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1	$
Notes receivable subsidiaries	460	391
Accounts receivable subsidiaries	22	271
Other assets	3	2
Total current assets	486	664
Property, Plant and Equipment, net		
Other Assets:		
Investment in subsidiaries	5,225	5,568
Notes receivable subsidiaries	172	151
Other assets	714	573
Total other assets	6,111	6,292
Total Assets	$ 6,597	$ 6,956
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities:		
Notes payable subsidiaries	$ 5	$ 158
Current portion of long-term debt	109	941
Indexed debt securities derivative	292	372
Accounts payable:		
Subsidiaries	30	312
Other	4	(8)
Taxes accrued	698	726
Interest accrued	26	26
Other	22	21
Total current liabilities	1,186	2,548
Other Liabilities:		

Accumulated deferred tax liabilities	328	223
Benefit obligations	78	71
Notes payable subsidiaries	923	750
Other	157	12
Total non-current liabilities	1,486	1,056
Long-Term Debt	2,629	1,796
Shareholders Equity:		
Common stock	3	3
Additional paid-in capital	2,931	2,977
Accumulated deficit	(1,600)	(1,355)
Accumulated other comprehensive loss	(38)	(69)
Total shareholders equity	1,296	1,556
Total Liabilities and Shareholders Equity	$ 6,597	$ 6,956

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

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CENTERPOINT ENERGY, INC.

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

STATEMENTS OF CASH FLOWS

	For the Year Ended December 31,		
	2004	**2005**	**2006**
		(In millions)	
Operating Activities:			
Net income (loss)	$ (905)	$ 252	$ 432
Loss on disposal of subsidiary	366	14	
Extraordinary item, net of tax	977	(30)	
Adjusted income	438	236	432
Non-cash items included in net income (loss):			
Equity income of subsidiaries	(707)	(425)	(560)
Deferred income tax expense	155	106	(169)
Tax and interest reserves reductions related to ZENS and ACES settlement			(107)
Amortization of debt issuance costs	70	37	36
Loss (gain) on indexed debt securities	20	(49)	80
Changes in working capital:			
Accounts receivable/(payable) from subsidiaries, net	(6)	1	33
Accounts payable	(1)	(1)	(13)
Other current assets	(5)	(1)	(1)
Other current liabilities	(290)	(73)	117
Common stock dividends received from subsidiaries	177	508	227
Pension contribution	(476)	(75)	
Other	54	77	18
Net cash provided by (used in) operating activities	(571)	341	93
Investing Activities:			
Proceeds from sale of Texas Genco	2,231	700	
Investments in (distributions from) subsidiaries	19	(144)	
Short-term notes receivable from subsidiaries	76	(335)	69
Long-term notes receivable from subsidiaries	192	154	21
Capital expenditures, net	(6)		
Net cash provided by investing activities	2,512	375	90
Financing Activities:			
Long-term revolving credit facility, net	(1,205)	(236)	
Commercial paper, net			(3)
Payments on long-term debt	(889)		

Debt issuance costs	(1)	(5)	(3)
Common stock dividends paid	(123)	(124)	(187)
Proceeds from issuance of common stock, net		17	27
Short-term notes payable to subsidiaries	121	(122)	153
Long-term notes payable to subsidiaries	134	(245)	(171)
Net cash used in financing activities	(1,963)	(715)	(184)
Net Increase (Decrease) in Cash and Cash Equivalents	(22)	1	(1)
Cash and Cash Equivalents at Beginning of Year	22		1
Cash and Cash Equivalents at End of Year	$	$ 1	$

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

CENTERPOINT ENERGY, INC.

SCHEDULE I NOTES TO CONDENSED FINANCIAL INFORMATION (PARENT COMPANY)

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

(2) Prior to repeal of the Public Utility Holding Company Act of 1935, effective February 8, 2006, CenterPoint Energy was a registered public utility holding company under that act.

(3) In July 2004, the Company announced its agreement to sell its majority owned subsidiary, Texas Genco, to Texas Genco LLC. In December 2004, Texas Genco completed the sale of its fossil generation assets (coal, lignite and gas-fired plants) to Texas Genco LLC for $2.813 billion in cash. Following the sale, Texas Genco distributed $2.231 billion in cash to the Company. Texas Genco s principal remaining asset was its ownership interest in a nuclear generating facility. The final step of the transaction, the merger of Texas Genco with a subsidiary of Texas Genco LLC in exchange for an additional cash payment to the Company of $700 million, was completed in April 2005. The Company recorded after tax losses of $366 million and $14 million in 2004 and 2005, respectively, related to the sale of Texas Genco.

(4) In March 2006, the Company replaced its $1 billion five-year revolving credit facility with a $1.2 billion five-year revolving credit facility. The facility has a first drawn cost of London Interbank Offered Rate (LIBOR) plus 60 basis points based on the Company s current credit ratings, as compared to LIBOR plus 87.5 basis points for borrowings under the facility it replaced. The facility contains covenants, including a debt (excluding transition bonds) to earnings before interest, taxes, depreciation and amortization covenant.

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

As of December 31, 2006, the Company had no borrowings and approximately $28 million of outstanding letters of credit under its $1.2 billion credit facility. Additionally, the Company was in compliance with all covenants as of December 31, 2006.

On May 19, 2003, the Company issued $575 million aggregate principal amount of convertible senior notes due May 15, 2023 with an interest rate of 3.75%. As of December 31, 2006, holders could convert each of their notes into shares of CenterPoint Energy common stock at a conversion rate of 88.3833 shares of common stock per $1,000 principal amount of notes at any time prior to maturity under the following circumstances: (1) if the last reported sale price of CenterPoint Energy common stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the previous calendar quarter is greater than or equal to 120% or, following May 15, 2008, 110% of the conversion price per share of CenterPoint Energy common stock on such last trading day, (2) if the notes have been called for redemption, (3) during any period in which the credit ratings assigned to the notes by both Moody s Investors Service, Inc. (Moody s) and Standard & Poor s Ratings Services (S&P), a division of The

McGraw-Hill Companies, are lower than Ba2 and BB, respectively, or the notes are no longer rated by at least one of these ratings services or their successors, or (4) upon the occurrence of specified corporate transactions, including the distribution to all holders of CenterPoint Energy common stock of certain rights entitling them to purchase shares of CenterPoint Energy common stock at less than the last reported sale price of a share of CenterPoint Energy common stock on the trading day prior to the declaration date of the distribution or the distribution to all holders of CenterPoint Energy common stock of the Company s assets, debt securities or certain rights to purchase the Company s securities, which distribution has a per share value exceeding 15% of the last reported sale price of a share of CenterPoint Energy common stock on the trading day immediately preceding the declaration date for such distribution. The notes originally had a conversion rate of 86.3558 shares of common stock per $1,000 principal amount of notes. However, effective February 16, 2006 and November 17, 2006, the conversion rate increased to 87.4094 and 88.3833, respectively, in accordance with the terms of the notes due to quarterly common stock dividends in excess of $0.10 per share.

Holders have the right to require the Company to purchase all or any portion of the notes for cash on May 15, 2008, May 15, 2013 and May 15, 2018 for a purchase price equal to 100% of the principal amount of the notes. The convertible senior notes also have a contingent interest feature requiring contingent interest to be paid to holders of notes commencing on or after May 15, 2008, in the event that the average trading price of a note for the applicable five-trading-day period equals or exceeds 120% of the principal amount of the note as of the day immediately preceding the first day of the applicable six-month interest period. For any six-month period, contingent interest will be equal to 0.25% of the average trading price of the note for the applicable five-trading-day period.

In August 2005, the Company accepted for exchange approximately $572 million aggregate principal amount of its 3.75% convertible senior notes due 2023 (Old Notes) for an equal amount of its new 3.75% convertible senior notes due 2023 (New Notes). Old Notes of approximately $3 million remain outstanding. Under the terms of the New Notes, which are substantially similar to the Old Notes, settlement of the principal portion will be made in cash rather than stock.

Additionally, as of December 31, 2006, the 3.75% convertible senior notes have been included as current portion of long-term debt in the Condensed Balance Sheets because the last reported sale price of CenterPoint Energy common stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the fourth quarter of 2006 was greater than or equal to 120% of the conversion price of the 3.75% convertible senior notes and therefore, during the first quarter of 2007, the 3.75% convertible senior notes meet the criteria that make them eligible for conversion at the option of the holders of these notes.

On December 17, 2003, the Company issued $255 million aggregate principal amount of convertible senior notes due January 15, 2024 with an interest rate of 2.875%. As of December 31, 2006, holders could convert each of their notes into shares of CenterPoint Energy common stock at a conversion rate of 79.8969 shares of common stock per $1,000 principal amount of notes. The notes originally had a conversion rate of 78.0640 shares of common stock per $1,000 principal amount of notes. However, effective February 16, 2006 and November 17, 2006, the conversion rate increased to 79.0165 and 79.8969, respectively, in accordance with the terms of the notes due to quarterly common stock dividends in excess of $0.10 per share. As of December 31, 2006, these notes were classified as current portion of other long-term debt in the Condensed Balance Sheets.

In December 2006, the Company called the 2.875% Convertible Senior Notes due 2024 (2.875% Convertible Notes) for redemption on January 22, 2007 at 100% of their principal amount. The 2.875% Convertible Notes became immediately convertible at the option of the holders upon the call for redemption and were convertible through the close of business on the redemption date. Substantially all the $255 million aggregate principal amount of the 2.875% Convertible Notes were converted. The $255 million principal amount of the 2.875% Convertible Notes was settled in cash and the excess value due converting holders of $97 million was settled by delivering approximately 5.6 million shares of the Company s common stock.

(6) CenterPoint Energy Intrastate Pipelines, Inc., CenterPoint Energy Services, Inc. and other wholly owned subsidiaries of CERC Corp. provide comprehensive natural gas sales and services to industrial and commercial customers which are primarily located within or near the territories served by the Company s pipelines and distribution subsidiaries. In order to hedge their exposure to natural gas prices, these CERC Corp. subsidiaries have entered standard purchase and sale agreements with various counterparties. CenterPoint Energy has guaranteed the payment obligations of these subsidiaries under certain of these agreements, typically for one-year terms. As of December 31,

2006, CenterPoint Energy had guaranteed $128 million under these agreements.

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CENTERPOINT ENERGY, INC.

SCHEDULE II QUALIFYING VALUATION ACCOUNTS
For the Three Years Ended December 31, 2006

Column A	Column B	Column C Additions		Column D	Column E
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts(1)	Deductions From Reserves(2)	Balance at End of Period
			(In millions)		
Year Ended December 31, 2006:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 43	$ 35	$	$ 45	$ 33
Deferred tax asset valuation allowance	21	1			22
Year Ended December 31, 2005:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 30	$ 40	$	$ 27	$ 43
Deferred tax asset valuation allowance	20	1			21
Year Ended December 31, 2004:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 31	$ 27	$	$ 28	$ 30
Deferred tax asset valuation allowance	73	(67)	14		20

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

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

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, the State of Texas, on the 28th day of February, 2007.

CENTERPOINT ENERGY, INC.
(Registrant)

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 28, 2007.

Signature	Title
/s/ DAVID M. MCCLANAHAN David M. McClanahan	President, Chief Executive Officer and Director (Principal Executive Officer and Director)
/s/ GARY L. WHITLOCK Gary L. Whitlock	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ JAMES S. BRIAN JAMES S. BRIAN	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
/s/ MILTON CARROLL Milton Carroll	Chairman of the Board of Directors
/s/ DONALD R. CAMPBELL Donald R. Campbell	Director
/s/ JOHN T. CATER John T. Cater	Director
/s/ DERRILL CODY Derrill Cody	Director
/s/ O. HOLCOMBE CROSSWELL	Director

O. Holcombe Crosswell

/s/ JANIECE M. LONGORIA	Director
Janiece M. Longoria	
/s/ THOMAS F. MADISON	Director
Thomas F. Madison	

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Signature	Title
/s/ ROBERT T. O CONNELL	Director
Robert T. O Connell	
/s/ MICHAEL E. SHANNON	Director
Michael E. Shannon	
/s/ PETER S. WAREING	Director
Peter S. Wareing	

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CENTERPOINT ENERGY, INC.

EXHIBITS TO THE ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2006

INDEX OF EXHIBITS

Exhibits included with this report are designated by a cross ( ); all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated by an asterisk (*) are management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(b)(10)(iii) of Regulation S-K. CenterPoint Energy has not filed the exhibits and schedules to Exhibit 2. CenterPoint Energy hereby agrees to furnish supplementally a copy of any schedule omitted from Exhibit 2 to the SEC upon request.

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
2	Transaction Agreement dated July 21, 2004 among CenterPoint Energy, Utility Holding, LLC, NN Houston Sub, Inc., Texas Genco Holdings, Inc. (Texas Genco), HPC Merger Sub, Inc. and GC Power Acquisition LLC	CenterPoint Energy s Form 8-K dated July 21, 2004	1-31447	10.1
3(a)(1)	Amended and Restated Articles of Incorporation of CenterPoint Energy	CenterPoint Energy s Registration Statement on Form S-4	3-69502	3.1
3(a)(2)	Articles of Amendment to Amended and Restated Articles of Incorporation of CenterPoint Energy	CenterPoint Energy s Form 10-K for the year ended December 31, 2001	1-31447	3.1.1
3(b)	Amended and Restated Bylaws of CenterPoint Energy	CenterPoint Energy s Form 10-K for the year ended December 31, 2001	1-31447	3.2
3(c)	Statement of Resolution Establishing Series of Shares designated Series A Preferred Stock of CenterPoint Energy	CenterPoint Energy s Form 10-K for the year ended December 31, 2001	1-31447	3.3
4(a)	Form of CenterPoint Energy Stock Certificate	CenterPoint Energy s Registration Statement on Form S-4	3-69502	4.1
4(b)	Rights Agreement dated January 1, 2002, between CenterPoint	CenterPoint Energy s Form 10-K for the year ended December 31, 2001	1-31447	4.2

	Energy and JPMorgan Chase Bank, as Rights Agent			
4(c)	Contribution and Registration Agreement dated December 18, 2001 among Reliant Energy, CenterPoint Energy and the Northern Trust Company, trustee under the Reliant Energy, Incorporated Master Retirement Trust	CenterPoint Energy s Form 10-K for the year ended December 31, 2001	1-31447	4.3

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Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(d)(1)	Mortgage and Deed of Trust, dated November 1, 1944 between Houston Lighting and Power Company (HL&P) and Chase Bank of Texas, National Association (formerly, South Texas Commercial National Bank of Houston), as Trustee, as amended and supplemented by 20 Supplemental Indentures thereto	HL&P s Form S-7 filed on August 25, 1977	2-59748	2(b)
4(d)(2)	Twenty-First through Fiftieth Supplemental Indentures to Exhibit 4(d)(1)	HL&P s Form 10-K for the year ended December 31, 1989	1-3187	4(a)(2)
4(d)(3)	Fifty-First Supplemental Indenture to Exhibit 4(d)(1) dated as of March 25, 1991	HL&P s Form 10-Q for the quarter ended June 30, 1991	1-3187	4(a)
4(d)(4)	Fifty-Second through Fifty-Fifth Supplemental Indentures to Exhibit 4(d)(1) each dated as of March 1, 1992	HL&P s Form 10-Q for the quarter ended March 31, 1992	1-3187	4
4(d)(5)	Fifty-Sixth and Fifty-Seventh Supplemental Indentures to Exhibit 4(d)(1) each dated as of October 1, 1992	HL&P s Form 10-Q for the quarter ended September 30, 1992	1-3187	4
4(d)(6)	Fifty-Eighth and Fifty-Ninth Supplemental Indentures to Exhibit 4(d)(1) each dated as of March 1, 1993	HL&P s Form 10-Q for the quarter ended March 31, 1993	1-3187	4
4(d)(7)	Sixtieth Supplemental Indenture to Exhibit 4(d)(1) dated as of	HL&P s Form 10-Q for the quarter ended June 30, 1993	1-3187	4

	July 1, 1993			
4(d)(8)	Sixty-First through Sixty-Third Supplemental Indentures to Exhibit 4(d)(1) each dated as of December 1, 1993	HL&P s Form 10-K for the year ended December 31, 1993	1-3187	4(a)(8)
4(d)(9)	Sixty-Fourth and Sixty-Fifth Supplemental Indentures to Exhibit 4(d)(1) each dated as of July 1, 1995	HL&P s Form 10-K for the year ended December 31, 1995	1-3187	4(a)(9)
4(e)(1)	General Mortgage Indenture, dated as of October 10, 2002, between CenterPoint Energy Houston Electric, LLC and JPMorgan Chase Bank, as Trustee	CenterPoint Houston s Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(1)

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(e)(2)	Second Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston s Form 10- Q for the quarter ended September 30, 2002	1-3187	4(j)(3)
4(e)(3)	Third Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston s Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(4)
4(e)(4)	Fourth Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston s Form 10- Q for the quarter ended September 30, 2002	1-3187	4(j)(5)
4(e)(5)	Fifth Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston s Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(6)
4(e)(6)	Sixth Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston s Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(7)
4(e)(7)	Seventh Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston s Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(8)
4(e)(8)	Eighth Supplemental Indenture to Exhibit 4(e)(1), dated as of October 10, 2002	CenterPoint Houston s Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(9)
4(e)(9)	Officer s Certificates dated October 10, 2002 setting forth the form, terms and provisions of the First through Eighth Series of General Mortgage Bonds	CenterPoint Energy s Form 10-K for the year ended December 31, 2003	1-31447	4(e)(10)
4(e)(10)	Ninth Supplemental Indenture to Exhibit 4(e)(1), dated as of November 12, 2002	CenterPoint Energy s Form 10-K for the year ended December 31, 2002	1-31447	4(e)(10)
4(e)(11)	Officer s Certificate dated November 12, 2003 setting forth the form, terms and provisions of the Ninth	CenterPoint Energy s Form 10-K for the year ended December 31, 2003	1-31447	4(e)(12)

	Series of General Mortgage Bonds			
4(e)(12)	Tenth Supplemental Indenture to Exhibit 4(e)(1), dated as of March 18, 2003	CenterPoint Energy s Form 8-K dated March 13, 2003	1-31447	4.1
4(e)(13)	Officer s Certificate dated March 18, 2003 setting forth the form, terms and provisions of the Tenth Series and Eleventh Series of General Mortgage Bonds	CenterPoint Energy s Form 8-K dated March 13, 2003	1-31447	4.2
4(e)(14)	Eleventh Supplemental Indenture to Exhibit 4(e)(1), dated as of May 23, 2003	CenterPoint Energy s Form 8-K dated May 16, 2003	1-31447	4.2

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Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(e)(15)	Officer s Certificate dated May 23, 2003 setting forth the form, terms and provisions of the Twelfth Series of General Mortgage Bonds	CenterPoint Energy s Form 8-K dated May 16, 2003	1-31447	4.1
4(e)(16)	Twelfth Supplemental Indenture to Exhibit 4(e)(1), dated as of September 9, 2003	CenterPoint Energy s Form 8-K dated September 9, 2003	1-31447	4.2
4(e)(17)	Officer s Certificate dated September 9, 2003 setting forth the form, terms and provisions of the Thirteenth Series of General Mortgage Bonds	CenterPoint Energy s Form 8-K dated September 9, 2003	1-31447	4.3
4(e)(18)	Thirteenth Supplemental Indenture to Exhibit 4(e)(1), dated as of February 6, 2004	CenterPoint Energy s Form 10-K for the year ended December 31, 2005	1-31447	4(e)(16)
4(e)(19)	Officer s Certificate dated February 6, 2004 setting forth the form, terms and provisions of the Fourteenth Series of General Mortgage Bonds	CenterPoint Energy s Form 10-K for the year ended December 31, 2005	1-31447	4(e)(17)
4(e)(20)	Fourteenth Supplemental Indenture to Exhibit 4(e)(1), dated as of February 11, 2004	CenterPoint Energy s Form 10-K for the year ended December 31, 2005	1-31447	4(e)(18)
4(e)(21)	Officer s Certificate dated February 11, 2004 setting forth the form, terms and provisions of the Fifteenth Series of General Mortgage Bonds	CenterPoint Energy s Form 10-K for the year ended December 31, 2005	1-31447	4(e)(19)
4(e)(22)	Fifteenth Supplemental Indenture to Exhibit 4(e)(1), dated as of	CenterPoint Energy s Form 10-K for the year ended December 31, 2005	1-31447	4(e)(20)

	March 31, 2004			
4(e)(23)	Officer s Certificate dated March 31, 2004 setting forth the form, terms and provisions of the Sixteenth Series of General Mortgage Bonds	CenterPoint Energy s Form 10-K for the year ended December 31, 2005	1-31447	4(e)(21)
4(e)(24)	Sixteenth Supplemental Indenture to Exhibit 4(e)(1), dated as of March 31, 2004	CenterPoint Energy s Form 10-K for the year ended December 31, 2005	1-31447	4(e)(22)

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Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(e)(25)	Officer s Certificate dated March 31, 2004 setting forth the form, terms and provisions of the Seventeenth Series of General Mortgage Bonds	CenterPoint Energy s Form 10-K for the year ended December 31, 2005	1-31447	4(e)(23)
4(e)(26)	Seventeenth Supplemental Indenture to Exhibit 4(e)(1), dated as of March 31, 2004	CenterPoint Energy s Form 10-K for the year ended December 31, 2005	1-31447	4(e)(24)
4(e)(27)	Officer s Certificate dated March 31, 2004 setting forth the form, terms and provisions of the Eighteenth Series of General Mortgage Bonds	CenterPoint Energy s Form 10-K for the year ended December 31, 2005	1-31447	4(e)(25)
4(f)(1)	Indenture, dated as of February 1, 1998, between Reliant Energy Resources Corp. (RERC Corp.) and Chase Bank of Texas, National Association, as Trustee	CERC Corp. s Form 8-K dated February 5, 1998	1-13265	4.1
4(f)(2)	Supplemental Indenture No. 1 to Exhibit 4(f)(1), dated as of February 1, 1998, providing for the issuance of RERC Corp. s 61/2% Debentures due February 1, 2008	CERC Corp. s Form 8-K dated November 9, 1998	1-13265	4.2
4(f)(3)	Supplemental Indenture No. 2 to Exhibit 4(f)(1), dated as of November 1, 1998, providing for the issuance of RERC Corp. s 63/8% Term Enhanced ReMarketable Securities	CERC Corp. s Form 8-K dated November 9, 1998	1-13265	4.1
4(f)(4)	Supplemental Indenture No. 3 to Exhibit 4(f)(1), dated as of July 1, 2000,	CERC Corp. s Registration Statement on Form S-4	333-49162	4.2

	providing for the issuance of RERC Corp. s 8.125% Notes due 2005			
4(f)(5)	Supplemental Indenture No. 4 to Exhibit 4(f)(1), dated as of February 15, 2001, providing for the issuance of RERC Corp. s 7.75% Notes due 2011	CERC Corp. s Form 8-K dated February 21, 2001	1-13265	4.1

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Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(f)(6)	Supplemental Indenture No. 5 to Exhibit 4(f)(1), dated as of March 25, 2003, providing for the issuance of CenterPoint Energy Resources Corp. s (CERC Corp. s) 7.875% Senior Notes due 2013	CenterPoint Energy s Form 8-K dated March 18, 2003	1-31447	4.1
4(f)(7)	Supplemental Indenture No. 6 to Exhibit 4(f)(1), dated as of April 14, 2003, providing for the issuance of CERC Corp. s 7.875% Senior Notes due 2013	CenterPoint Energy s Form 8-K dated April 7, 2003	1-31447	4.2
4(f)(8)	Supplemental Indenture No. 7 to Exhibit 4(f)(1), dated as of November 3, 2003, providing for the issuance of CERC Corp. s 5.95% Senior Notes due 2014	CenterPoint Energy s Form 8-K dated October 29, 2003	1-31447	4.2
4(f)(9)	Supplemental Indenture No. 8 to Exhibit 4(f)(1), dated as of December 28, 2005, providing for a modification of CERC Corp. s 61/2% Debentures due 2008	CenterPoint Energy s Form 10-K for the year ended December 31, 2005	1-31447	4(f)(9)
4(f)(10)	Supplemental Indenture No. 9 to Exhibit 4(f)(1), dated as of May 18, 2006, providing for the issuance of CERC Corp. s 6.15% Senior Notes due 2016	CenterPoint Energy s Form 10-Q for the quarter ended June 30, 2006	1-31447	4.7
4(f)(11)	Supplemental Indenture No. 10 to Exhibit 4(f)(1), dated as of February 6, 2007, providing for the issuance of CERC Corp. s 6.25% Senior			

	Notes due 2037				
4(g)(1)	Indenture, dated as of May 19, 2003, between CenterPoint Energy and JPMorgan Chase Bank, as Trustee	CenterPoint Energy s Form 8-K dated May 19, 2003		1-31447	4.1
4(g)(2)	Supplemental Indenture No. 1 to Exhibit 4(g)(1), dated as of May 19, 2003, providing for the issuance of CenterPoint Energy s 3.75% Convertible Senior Notes due 2023	CenterPoint Energy s Form 8-K dated May 19, 2003		1-31447	4.2

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(g)(3)	Supplemental Indenture No. 2 to Exhibit 4(g)(1), dated as of May 27, 2003, providing for the issuance of CenterPoint Energy s 5.875% Senior Notes due 2008 and 6.85% Senior Notes due 2015	CenterPoint Energy s Form 8-K dated May 19, 2003	1-31447	4.3
4(g)(4)	Supplemental Indenture No. 3 to Exhibit 4(g)(1), dated as of September 9, 2003, providing for the issuance of CenterPoint Energy s 7.25% Senior Notes due 2010	CenterPoint Energy s Form 8-K dated September 9, 2003	1-31447	4.2
4(g)(5)	Supplemental Indenture No. 4 to Exhibit 4(g)(1), dated as of December 17, 2003, providing for the issuance of CenterPoint Energy s 2.875% Convertible Senior Notes due 2024	CenterPoint Energy s Form 8-K dated December 10, 2003	1-31447	4.2
4(g)(6)	Supplemental Indenture No. 5 to Exhibit 4(g)(1), dated as of December 13, 2004, as supplemented by Exhibit 4(g)(5), relating to the issuance of CenterPoint Energy s 2.875% Convertible Senior Notes dues 2024	CenterPoint Energy s Form 8-K dated December 9, 2004	1-31447	4.1
4(g)(7)	Supplemental Indenture No. 6 to Exhibit 4(g)(1), dated as of August 23, 2005, providing for the issuance of CenterPoint Energy s 3.75% Convertible Senior Notes, Series B Due 2023	CenterPoint Energy s Form 10-K for the year ended December 31, 2005	1-31447	4(g)(7)
4(g)(8)	Supplemental Indenture No. 7 to Exhibit 4(g)(1), dated as of February 6, 2007, providing for the			

	issuance of CenterPoint Energy s 5.95% Senior Notes due 2017			
4(h)(1)	Subordinated Indenture dated as of September 1, 1999	Reliant Energy s Form 8-K dated September 1, 1999	1-3187	4.1

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Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(h)(2)	Supplemental Indenture No. 1 dated as of September 1, 1999, between Reliant Energy and Chase Bank of Texas (supplementing Exhibit 4(h)(1) and providing for the issuance Reliant Energy s 2% Zero-Premium Exchangeable Subordinated Notes Due 2029)	Reliant Energy s Form 8-K dated September 15, 1999	1-3187	4.2
4(h)(3)	Supplemental Indenture No. 2 dated as of August 31, 2002, between CenterPoint Energy, Reliant Energy and JPMorgan Chase Bank (supplementing Exhibit 4(h)(1))	CenterPoint Energy s Form 8-K12B dated August 31, 2002	1-31447	4(e)
4(h)(4)	Supplemental Indenture No. 3 dated as of December 28, 2005, between CenterPoint Energy, Reliant Energy and JPMorgan Chase Bank (supplementing Exhibit 4(h)(1))	CenterPoint Energy s Form 10-K for the year ended December 31, 2005	1-31447	4(h)(4)
4(i)	$1,200,000,000 Amended and Restated Credit Agreement dated as of March 31, 2006, CenterPoint Energy, as Borrower, and the banks named therein	CenterPoint Energy s Form 8-K dated March 31, 2006	1-31447	4.1
4(j)	$300,000,000 Amended and Restated Credit Agreement dated as of March 31, 2006, among CenterPoint Houston, as Borrower, and the Initial Lenders named therein, as Initial Lenders	CenterPoint Energy s Form 8-K dated March 31, 2006	1-31447	4.2

4(k)	$550,000,000 Amended and Restated Credit Agreement dated as of March 31, 2006 among CERC Corp., as Borrower, and the banks named therein	CenterPoint Energy s Form 8-K dated March 31, 2006	1-31447	4.1

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Pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K, CenterPoint Energy has not filed as exhibits to this Form 10-K certain long-term debt instruments, including indentures, under which the total amount of securities authorized does not exceed 10% of the total assets of CenterPoint Energy and its subsidiaries on a consolidated basis. CenterPoint Energy 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)(1)	Executive Benefit Plan of Houston Industries Incorporated (HI) and First and Second Amendments thereto effective as of June 1, 1982, July 1, 1984, and May 7, 1986, respectively	HI s Form 10-Q for the quarter ended March 31, 1987	1-7629	10(a)(1), 10(a)(2), and 10(a)(3)
*10(a)(2)	Third Amendment dated September 17, 1999 to Exhibit 10(a)(1)	Reliant Energy s Form 10-K for the year ended December 31, 2000	1-3187	10(a)(2)
*10(a)(3)	CenterPoint Energy Executive Benefits Plan, as amended and restated effective June 18, 2003	CenterPoint Energy s Form 10-Q for the quarter ended September 30, 2003	1-31447	10.4
*10(b)(1)	Executive Incentive Compensation Plan of HI effective as of January 1, 1982	HI s Form 10-K for the year ended December 31, 1991	1-7629	10(b)
*10(b)(2)	First Amendment to Exhibit 10(b)(1) effective as of March 30, 1992	HI s Form 10-Q for the quarter ended March 31, 1992	1-7629	10(a)
*10(b)(3)	Second Amendment to Exhibit 10(b)(1) effective as of November 4, 1992	HI s Form 10-K for the year ended December 31, 1992	1-7629	10(b)
*10(b)(4)	Third Amendment to Exhibit 10(b)(1) effective as of September 7, 1994	HI s Form 10-K for the year ended December 31, 1994	1-7629	10(b)(4)
*10(b)(5)	Fourth Amendment to Exhibit 10(b)(1) effective as of August 6, 1997	HI s Form 10-K for the year ended December 31, 1997	1-3187	10(b)(5)
*10(c)(1)	Executive Incentive Compensation Plan of HI effective as of January 1, 1985	HI s Form 10-Q for the quarter ended March 31, 1987	1-7629	10(b)(1)
*10(c)(2)	First Amendment to Exhibit 10(c)(1) effective as of January 1, 1985	HI s Form 10-K for the year ended December 31, 1988	1-7629	10(b)(3)
*10(c)(3)			1-7629	10(c)(3)

	Second Amendment to Exhibit 10(c)(1) effective as of January 1, 1985	HI s Form 10-K for the year ended December 31, 1991		
*10(c)(4)	Third Amendment to Exhibit 10(c)(1) effective as of March 30, 1992	HI s Form 10-Q for the quarter ended March 31, 1992	1-7629	10(b)
*10(c)(5)	Fourth Amendment to Exhibit 10(c)(1) effective as of November 4, 1992	HI s Form 10-K for the year ended December 31, 1992	1-7629	10(c)(5)
*10(c)(6)	Fifth Amendment to Exhibit 10(c)(1) effective as of September 7, 1994	HI s Form 10-K for the year ended December 31, 1994	1-7629	10(c)(6)
*10(c)(7)	Sixth Amendment to Exhibit 10(c)(1) effective as of August 6, 1997	HI s Form 10-K for the year ended December 31, 1997	1-3187	10(c)(7)
*10(d)	Executive Incentive Compensation Plan of HL&P effective as of January 1, 1985	HI s Form 10-Q for the quarter ended March 31, 1987	1-7629	10(b)(2)
*10(e)(1)	Executive Incentive Compensation Plan of HI as amended and restated on January 1, 1989	HI s Form 10-Q for the quarter ended June 30, 1989	1-7629	10(b)

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Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
*10(e)(2)	First Amendment to Exhibit 10(e)(1) effective as of January 1, 1989	HI s Form 10-K for the year ended December 31, 1991	1-7629	10(e)(2)
*10(e)(3)	Second Amendment to Exhibit 10(e)(1) effective as of March 30, 1992	HI s Form 10-Q for the quarter ended March 31, 1992	1-7629	10(c)
*10(e)(4)	Third Amendment to Exhibit 10(e)(1) effective as of November 4, 1992	HI s Form 10-K for the year ended December 31, 1992	1-7629	10(c)(4)
*10(e)(5)	Fourth Amendment to Exhibit 10(e)(1) effective as of September 7, 1994	HI s Form 10-K for the year ended December 31, 1994	1-7629	10(e)(5)
*10(f)(1)	Executive Incentive Compensation Plan of HI as amended and restated on January 1, 1991	HI s Form 10-K for the year ended December 31, 1990	1-7629	10(b)
*10(f)(2)	First Amendment to Exhibit 10(f)(1) effective as of January 1, 1991	HI s Form 10-K for the year ended December 31, 1991	1-7629	10(f)(2)
*10(f)(3)	Second Amendment to Exhibit 10(f)(1) effective as of March 30, 1992	HI s Form 10-Q for the quarter ended March 31, 1992	1-7629	10(d)
*10(f)(4)	Third Amendment to Exhibit 10(f)(1) effective as of November 4, 1992	HI s Form 10-K for the year ended December 31, 1992	1-7629	10(f)(4)
*10(f)(5)	Fourth Amendment to Exhibit 10(f)(1) effective as of January 1, 1993	HI s Form 10-K for the year ended December 31, 1992	1-7629	10(f)(5)
*10(f)(6)	Fifth Amendment to Exhibit 10(f)(1) effective in part, January 1, 1995, and in part, September 7, 1994	HI s Form 10-K for the year ended December 31, 1994	1-7629	10(f)(6)
*10(f)(7)	Sixth Amendment to Exhibit 10(f)(1) effective as of August 1, 1995	HI s Form 10-Q for the quarter ended June 30, 1995	1-7629	10(a)
*10(f)(8)	Seventh Amendment to Exhibit 10(f)(1) effective as of January 1, 1996	HI s Form 10-Q for the quarter ended June 30, 1996	1-7629	10(a)
*10(f)(9)	Eighth Amendment to Exhibit 10(f)(1) effective as of January 1, 1997	HI s Form 10-Q for the quarter ended June 30, 1997	1-7629	10(a)
*10(f)(10)	Ninth Amendment to Exhibit 10(f)(1) effective in part, January 1, 1997, and	HI s Form 10-K for the year ended December 31, 1997	1-3187	10(f)(10)

	in part, January 1, 1998			
*10(g)	Benefit Restoration Plan of HI effective as of June 1, 1985	HI s Form 10-Q for the quarter ended March 31, 1987	1-7629	10(c)
*10(h)	Benefit Restoration Plan of HI as amended and restated effective as of January 1, 1988	HI s Form 10-K for the year ended December 31, 1991	1-7629	10(g)(2)
*10(i)(1)	Benefit Restoration Plan of HI, as amended and restated effective as of July 1, 1991	HI s Form 10-K for the year ended December 31, 1991	1-7629	10(g)(3)
*10(i)(2)	First Amendment to Exhibit 10(i)(1) effective in part, August 6, 1997, in part, September 3, 1997, and in part, October 1, 1997	HI s Form 10-K for the year ended December 31, 1997	1-3187	10(i)(2)
*10(j)(1)	Deferred Compensation Plan of HI effective as of September 1, 1985	HI s Form 10-Q for the quarter ended March 31, 1987	1-7629	10(d)
*10(j)(2)	First Amendment to Exhibit 10(j)(1) effective as of September 1, 1985	HI s Form 10-K for the year ended December 31, 1990	1-7629	10(d)(2)

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
*10(j)(3)	Second Amendment to Exhibit 10(j)(1) effective as of March 30, 1992	HI s Form 10-Q for the quarter ended March 31, 1992	1-7629	10(e)
*10(j)(4)	Third Amendment to Exhibit 10(j)(1) effective as of June 2, 1993	HI s Form 10-K for the year ended December 31, 1993	1-7629	10(h)(4)
*10(j)(5)	Fourth Amendment to Exhibit 10(j)(1) effective as of September 7, 1994	HI s Form 10-K for the year ended December 31, 1994	1-7629	10(h)(5)
*10(j)(6)	Fifth Amendment to Exhibit 10(j)(1) effective as of August 1, 1995	HI s Form 10-Q for the quarter ended June 30, 1995	1-7629	10(d)
*10(j)(7)	Sixth Amendment to Exhibit 10(j)(1) effective as of December 1, 1995	HI s Form 10-Q for the quarter ended June 30, 1995	1-7629	10(b)
*10(j)(8)	Seventh Amendment to Exhibit 10(j)(1) effective as of January 1, 1997	HI s Form 10-Q for the quarter ended June 30, 1997	1-7629	10(b)
*10(j)(9)	Eighth Amendment to Exhibit 10(j)(1) effective as of October 1, 1997	HI s Form 10-K for the year ended December 31, 1997	1-3187	10(j)(9)
*10(j)(10)	Ninth Amendment to Exhibit 10(j)(1) effective as of September 3, 1997	HI s Form 10-K for the year ended December 31, 1997	1-3187	10(j)(10)
*10(j)(11)	Tenth Amendment to Exhibit 10(j)(1) effective as of January 1, 2001	CenterPoint Energy s Form 10-K for the year ended December 31, 2002	1-31447	10(j)(11)
*10(j)(12)	Eleventh Amendment to Exhibit 10(j)(1) effective as of August 31, 2002	CenterPoint Energy s Form 10-K for the year ended December 31, 2002	1-31447	10(j)(12)
*10(j)(13)	CenterPoint Energy 1985 Deferred Compensation Plan, as amended and restated effective January 1, 2003	CenterPoint Energy s Form 10-Q for the quarter ended September 30, 2003	1-31447	10.1
*10(k)(1)	Deferred Compensation Plan of HI effective as of January 1, 1989	HI s Form 10-Q for the quarter ended June 30, 1989	1-7629	10(a)
*10(k)(2)	First Amendment to Exhibit 10(k)(1) effective as of January 1, 1989	HI s Form 10-K for the year ended December 31, 1989	1-7629	10(e)(3)
*10(k)(3)	Second Amendment to Exhibit 10(k)(1) effective as of March 30, 1992	HI s Form 10-Q for the quarter ended March 31, 1992	1-7629	10(f)

*10(k)(4)	Third Amendment to Exhibit 10(k)(1) effective as of June 2, 1993	HI s Form 10-K for the year ended December 31, 1993	1-7629	10(i)(4)
*10(k)(5)	Fourth Amendment to Exhibit 10(k)(1) effective as of September 7, 1994	HI s Form 10-K for the year ended December 31, 1994	1-7629	10(i)(5)
*10(k)(6)	Fifth Amendment to Exhibit 10(k)(1) effective as of August 1, 1995	HI s Form 10-Q for the quarter ended June 30, 1995	1-7629	10(c)
*10(k)(7)	Sixth Amendment to Exhibit 10(k)(1) effective December 1, 1995	HI s Form 10-Q for the quarter ended June 30, 1995	1-7629	10(c)
*10(k)(8)	Seventh Amendment to Exhibit 10(k)(1) effective as of January 1, 1997	HI s Form 10-Q for the quarter ended June 30, 1997	1-7629	10(c)

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
*10(k)(9)	Eighth Amendment to Exhibit 10(k)(1) effective in part October 1, 1997 and in part January 1, 1998	HI s Form 10-K for the year ended December 31, 1997	1-3187	10(k)(9)
*10(k)(10)	Ninth Amendment to Exhibit 10(k)(1) effective as of September 3, 1997	HI s Form 10-K for the year ended December 31, 1997	1-3187	10(k)(10)
*10(k)(11)	Tenth Amendment to Exhibit 10(k)(1) effective as of January 1, 2001	CenterPoint Energy s Form 10-K for the year ended December 31, 2002	1-31447	10(k)(11)
*10(k)(12)	Eleventh Amendment to Exhibit 10(k)(1) effective as of August 31, 2002	CenterPoint Energy s Form 10-K for the year ended December 31, 2002	1-31447	10(k)(12)
*10(l)(1)	Deferred Compensation Plan of HI effective as of January 1, 1991	HI s Form 10-K for the year ended December 31, 1990	1-7629	10(d)(3)
*10(l)(2)	First Amendment to Exhibit 10(l)(1) effective as of January 1, 1991	HI s Form 10-K for the year ended December 31, 1991	1-7629	10(j)(2)
*10(l)(3)	Second Amendment to Exhibit 10(l)(1) effective as of March 30, 1992	HI s Form 10-Q for the quarter ended March 31, 1992	1-7629	10(g)
*10(l)(4)	Third Amendment to Exhibit 10(l)(1) effective as of June 2, 1993	HI s Form 10-K for the year ended December 31, 1993	1-7629	10(j)(4)
*10(l)(5)	Fourth Amendment to Exhibit 10(l)(1) effective as of December 1, 1993	HI s Form 10-K for the year ended December 31, 1993	1-7629	10(j)(5)
*10(l)(6)	Fifth Amendment to Exhibit 10(l)(1) effective as of September 7, 1994	HI s Form 10-K for the year ended December 31, 1994	1-7629	10(j)(6)
*10(l)(7)	Sixth Amendment to Exhibit 10(l)(1) effective as of August 1, 1995	HI s Form 10-Q for the quarter ended June 30, 1995	1-7629	10(b)
*10(l)(8)	Seventh Amendment to Exhibit 10(l)(1) effective as of December 1, 1995	HI s Form 10-Q for the quarter ended June 30, 1996	1-7629	10(d)
*10(l)(9)	Eighth Amendment to Exhibit 10(l)(1) effective as of January 1, 1997	HI s Form 10-Q for the quarter ended June 30, 1997	1-7629	10(d)
*10(l)(10)	Ninth Amendment to Exhibit 10(l)(1) effective in part August 6, 1997, in part October 1, 1997, and in	HI s Form 10-K for the year ended December 31, 1997	1-3187	10(l)(10)

	part January 1, 1998			
*10(l)(11)	Tenth Amendment to Exhibit 10(l)(1) effective as of September 3, 1997	HI s Form 10-K for the year ended December 31, 1997	1-3187	10(i)(11)
*10(l)(12)	Eleventh Amendment to Exhibit 10(l)(1) effective as of January 1, 2001	CenterPoint Energy s Form 10-K for the year ended December 31, 2002	1-31447	10(l)(12)
*10(l)(13)	Twelfth Amendment to Exhibit 10(l)(1) effective as of August 31, 2002	CenterPoint Energy s Form 10-K for the year ended December 31, 2002	1-31447	10(l)(13)
*10(m)(1)	Long-Term Incentive Compensation Plan of HI effective as of January 1, 1989	HI s Form 10-Q for the quarter ended June 30, 1989	1-7629	10(c)
*10(m)(2)	First Amendment to Exhibit 10(m)(1) effective as of January 1, 1990	HI s Form 10-K for the year ended December 31, 1989	1-7629	10(f)(2)

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Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
*10(m)(3)	Second Amendment to Exhibit 10(m)(1) effective as of December 22, 1992	HI s Form 10-K for the year ended December 31, 1992	1-7629	10(k)(3)
*10(m)(4)	Third Amendment to Exhibit 10(m)(1) effective as of August 6, 1997	HI s Form 10-K for the year ended December 31, 1997	1-3187	10(m)(4)
*10(m)(5)	Fourth Amendment to Exhibit 10(m)(1) effective as of January 1, 2001	Reliant Energy s Form 10-Q for the quarter ended June 30, 2002	1-3187	10.4
*10(n)(1)	Form of stock option agreement for non-qualified stock options granted under Exhibit 10(m)(1)	HI s Form 10-Q for the quarter ended March 31, 1992	1-7629	10(h)
*10(n)(2)	Forms of restricted stock agreement for restricted stock granted under Exhibit 10(m)(1)	HI s Form 10-Q for the quarter ended March 31, 1992	1-7629	10(i)
*10(o)(1)	1994 Long-Term Incentive Compensation Plan of HI effective as of January 1, 1994	HI s Form 10-K for the year ended December 31, 1993	1-7629	10(n)(1)
*10(o)(2)	Form of stock option agreement for non-qualified stock options granted under Exhibit 10(o)(1)	HI s Form 10-K for the year ended December 31, 1993	1-7629	10(n)(2)
*10(o)(3)	First Amendment to Exhibit 10(o)(1) effective as of May 9, 1997	HI s Form 10-Q for the quarter ended June 30, 1997	1-7629	10(e)
*10(o)(4)	Second Amendment to Exhibit 10(o)(1) effective as of August 6, 1997	HI s Form 10-K for the year ended December 31, 1997	1-3187	10(p)(4)
*10(o)(5)	Third Amendment to Exhibit 10(o)(1) effective as of January 1, 1998	HI s Form 10-K for the year ended December 31, 1998	1-3187	10(p)(5)
*10(o)(6)	Reliant Energy 1994 Long-Term Incentive Compensation Plan, as amended and restated effective January 1, 2001	Reliant Energy s Form 10-Q for the quarter ended June 30, 2002	1-3187	10.6
*10(o)(7)	First Amendment to Exhibit 10(o)(6), effective December 1, 2003	CenterPoint Energy s Form 10-K for the year ended December 31, 2003	1-31447	10(p)(7)
*10(o)(8)	Form of Non-Qualified Stock Option Award Notice	CenterPoint Energy s Form 8-K dated January 25, 2005	1-31447	10.6

	under Exhibit 10(o)(6)			
*10(p)(1)	Savings Restoration Plan of HI effective as of January 1, 1991	HI s Form 10-K for the year ended December 31, 1990	1-7629	10(f)
*10(p)(2)	First Amendment to Exhibit 10(p)(1) effective as of January 1, 1992	HI s Form 10-K for the year ended December 31, 1991	1-7629	10(l)(2)
*10(p)(3)	Second Amendment to Exhibit 10(p)(1) effective in part, August 6, 1997, and in part, October 1, 1997	HI s Form 10-K for the year ended December 31, 1997	1-3187	10(q)(3)
*10(q)(1)	Director Benefits Plan effective as of January 1, 1992	HI s Form 10-K for the year ended December 31, 1991	1-7629	10(m)
*10(q)(2)	First Amendment to Exhibit 10(q)(1) effective as of August 6, 1997	HI s Form 10-K for the year ended December 31, 1998	1-7629	10(m)(1)
*10(q)(3)	CenterPoint Energy Outside Director Benefits Plan, as amended and restated effective June 18, 2003	CenterPoint Energy s Form 10-Q for the quarter ended September 30, 2003	1-31447	10.6

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
*10(q)(4)	First Amendment to Exhibit 10(q)(3) effective as of January 1, 2004	CenterPoint Energy s Form 10-Q for the quarter ended June 30, 2004	1-31447	10.6
*10(r)(1)	Executive Life Insurance Plan of HI effective as of January 1, 1994	HI s Form 10-K for the year ended December 31, 1993	1-7629	10(q)
*10(r)(2)	First Amendment to Exhibit 10(r)(1) effective as of January 1, 1994	HI s Form 10-Q for the quarter ended June 30, 1995	1-7629	10
*10(r)(3)	Second Amendment to Exhibit 10(r)(1) effective as of August 6, 1997	HI s Form 10-K for the year ended December 31, 1997	1-3187	10(s)(3)
*10(r)(4)	CenterPoint Energy Executive Life Insurance Plan, as amended and restated effective June 18, 2003	CenterPoint Energy s Form 10-Q for the quarter ended September 30, 2003	1-31447	10.5
*10(s)	Employment and Supplemental Benefits Agreement between HL&P and Hugh Rice Kelly	HI s Form 10-Q for the quarter ended March 31, 1987	1-7629	10(f)
10(t)(1)	Stockholder s Agreement dated as of July 6, 1995 between Houston Industries Incorporated and Time Warner Inc.	Schedule 13-D dated July 6, 1995	5-19351	2
10(t)(2)	Amendment to Exhibit 10(t)(1) dated November 18, 1996	HI s Form 10-K for the year ended December 31, 1996	1-7629	10(x)(4)
*10(u)(1)	Houston Industries Incorporated Executive Deferred Compensation Trust effective as of December 19, 1995	HI s Form 10-K for the year ended December 31, 1995	1-7629	10(7)
*10(u)(2)	First Amendment to Exhibit 10(u)(1) effective as of August 6, 1997	HI s Form 10-Q for the quarter ended June 30, 1998	1-3187	10
*10(v)	Letter Agreement dated December 9, 2004 between CenterPoint Energy and Milton Carroll	CenterPoint Energy s Form 8-K dated December 9, 2004	1-31447	10.1
*10(w)(1)	Reliant Energy, Incorporated and Subsidiaries Common	Reliant Energy s Form 10-K for the year ended December 31, 2000	1-3187	10(y)

	Stock Participation Plan for Designated New Employees and Non-Officer Employees effective as of March 4, 1998			
*10(w)(2)	Reliant Energy, Incorporated and Subsidiaries Common Stock Participation Plan for Designated New Employees and Non-Officer Employees, as amended and restated effective January 1, 2001	CenterPoint Energy s Form 10-K for the year ended December 31, 2002	1-31447	10(y)(2)
*10(x)	Reliant Energy, Incorporated Annual Incentive Compensation Plan, as amended and restated effective January 1, 1999	Reliant Energy s Definitive Proxy Statement for 2000 Annual Meeting of Shareholders	1-3187	Exhibit A
*10(y)(1)	Long-Term Incentive Plan of Reliant Energy, Incorporated effective as of January 1, 2001	Reliant Energy s Registration Statement on Form S-8 dated May 4, 2001	333-60260	4.6
*10(y)(2)	First Amendment to Exhibit 10(y)(1) effective as of January 1, 2001	Reliant Energy s Registration Statement on Form S-8 dated May 4, 2001	333-60260	4.7
*10(y)(3)	Second Amendment to Exhibit 10(y)(1) effective November 5, 2003	CenterPoint Energy s Form 10-K for the year ended December 31, 2003	1-31447	10(aa)(3)

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
*10(y)(4)	Long-Term Incentive Plan of CenterPoint Energy, Inc. (amended and restated effective as of May 1, 2004)	CenterPoint Energy s Form 10-Q for the quarter ended June 30, 2004	1-31447	10.5
*10(y)(5)	Form of Non-Qualified Stock Option Award Agreement under Exhibit 10(y)(4)	CenterPoint Energy s Form 8-K dated January 25, 2005	1-31447	10.1
*10(y)(6)	Form of Restricted Stock Award Agreement under Exhibit 10(y)(4)	CenterPoint Energy s Form 8-K dated January 25, 2005	1-31447	10.2
*10(y)(7)	Form of Performance Share Award under Exhibit 10(y)(4)	CenterPoint Energy s Form 8-K dated January 25, 2005	1-31447	10.3
*10(y)(8)	Form of Performance Unit Award under Exhibit 10(y)(4)	CenterPoint Energy s Form 8-K dated January 25, 2005	1-31447	10.4
*10(y)(9)	Form of Restricted Stock Award Agreement (With Performance Vesting Requirement) under Exhibit 10(y)(4)	CenterPoint Energy s Form 8-K dated February 21, 2005	1-31447	10.2
*10(y)(10)	Summary of Performance Objectives for Awards under Exhibit 10(y)(4)	CenterPoint Energy s Form 8-K dated January 25, 2005	1-31447	10.5
*10(y)(11)	Form of Performance Share Award Agreement for 20XX 20XX Performance Cycle under Exhibit 10(y)(4)	CenterPoint Energy s Form 8-K dated February 21, 2007	1-31447	10.1
*10(y)(12)	Form of Stock Award Agreement (With Performance Goal) under Exhibit 10(y)(4)	CenterPoint Energy s Form 8-K dated February 21, 2007	1-31447	10.2
*10(y)(13)	Form of Stock Award Agreement (Without Performance Goal) under Exhibit 10(y)(4)	CenterPoint Energy s Form 8-K dated February 21, 2007	1-31447	10.3
10(z)(1)	Master Separation Agreement entered into as of December 31, 2000 between Reliant Energy, Incorporated and Reliant	Reliant Energy s Form 10-Q for the quarter ended March 31, 2001	1-3187	10.1

	Resources, Inc.			
10(z)(2)	First Amendment to Exhibit 10(z)(1) effective as of February 1, 2003	CenterPoint Energy s Form 10-K for the year ended December 31, 2002	1-31447	10(bb)(5)
10(z)(3)	Employee Matters Agreement, entered into as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy s Form 10-Q for the quarter ended March 31, 2001	1-3187	10.5
10(z)(4)	Retail Agreement, entered into as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy s Form 10-Q for the quarter ended March 31, 2001	1-3187	10.6
10(z)(5)	Tax Allocation Agreement, entered into as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy s Form 10-Q for the quarter ended March 31, 2001	1-3187	10.8
10(aa)(1)	Separation Agreement entered into as of August 31, 2002 between CenterPoint Energy and Texas Genco	CenterPoint Energy s Form 10-K for the year ended December 31, 2002	1-31447	10(cc)(1)

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
10(aa)(2)	Transition Services Agreement, dated as of August 31, 2002, between CenterPoint Energy and Texas Genco	CenterPoint Energy s Form 10-K for the year ended December 31, 2002	1-31447	10(cc)(2)
10(aa)(3)	Tax Allocation Agreement, dated as of August 31, 2002, between CenterPoint Energy and Texas Genco	CenterPoint Energy s Form 10-K for the year ended December 31, 2002	1-31447	10(cc)(3)
*10(bb)	Retention Agreement effective October 15, 2001 between Reliant Energy and David G. Tees	Reliant Energy s Form 10-K for the year ended December 31, 2001	1-3187	10(jj)
*10(cc)	Retention Agreement effective October 15, 2001 between Reliant Energy and Michael A. Reed	Reliant Energy s Form 10-K for the year ended December 31, 2001	1-3187	10(kk)
*10(dd)(1)	Non-Qualified Executive Disability Income Plan of Arkla, Inc. effective as of August 1, 1983	CenterPoint Energy s Form 10-K for the year ended December 31, 2002	1-31447	10(ff)(1)
*10(dd)(2)	Executive Disability Income Agreement effective July 1, 1984 between Arkla, Inc. and T. Milton Honea	CenterPoint Energy s Form 10-K for the year ended December 31, 2002	1-31447	10(ff)(2)
*10(ee)	Non-Qualified Unfunded Executive Supplemental Income Retirement Plan of Arkla, Inc. effective as of August 1, 1983	CenterPoint Energy s Form 10-K for the year ended December 31, 2002	1-31447	10(gg)
*10(ff)(1)	Deferred Compensation Plan for Directors of Arkla, Inc. effective as of November 10, 1988	CenterPoint Energy s Form 10-K for the year ended December 31, 2002	1-31447	10(hh)(1)
*10(ff)(2)	First Amendment to Exhibit 10(ff)(1) effective as of August 6, 1997	CenterPoint Energy s Form 10-K for the year ended December 31, 2002	1-31447	10(hh)(2)
10(gg)	Pledge Agreement dated as of May 28, 2003 by Utility Holding, LLC in favor of JP Morgan Chase Bank, as administrative agent	CenterPoint Energy s Form 10-Q for the quarter ended June 30, 2003	1-31447	10.1
*10(hh)			1-31447	10.2

	CenterPoint Energy Deferred Compensation Plan, as amended and restated effective January 1, 2003	CenterPoint Energy s Form 10-Q for the quarter ended June 30, 2003		
*10(ii)	CenterPoint Energy Short Term Incentive Plan, as amended and restated effective January 1, 2003	CenterPoint Energy s Form 10-Q for the quarter ended September 30, 2003	1-31447	10.3
*10(jj)	CenterPoint Energy Stock Plan for Outside Directors, as amended and restated effective May 7, 2003	CenterPoint Energy s Form 10-K for the year ended December 31, 2003	1-31447	10(ll)
10(kk)	City of Houston Franchise Ordinance	CenterPoint Energy s Form 10-Q for the quarter ended June 30, 2005	1-31447	10.1
10(ll)	Letter Agreement dated March 16, 2006 between CenterPoint Energy and John T. Cater	CenterPoint Energy s Form 10-Q for the quarter ended March 30, 2006	1-31447	10
10(mm)	Summary of non-employee director compensation			
10(nn)	Summary of named executive officer compensation			
*10(oo)	Form of Change in Control Agreement	CenterPoint Energy s Form 8-K dated February 21, 2007	1-31447	10.4
12	Computation of Ratios of Earnings to Fixed Charges			

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Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
21	Subsidiaries of CenterPoint Energy			
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			