CENTERPOINT ENERGY INC
Form 10-Q
November 02, 2006

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

FORM 10-Q

(Mark One)

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

FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2006

OR

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

FOR THE TRANSITION PERIOD FROM ______________ TO _______________.

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Commission file number 1-31447

CENTERPOINT ENERGY, INC.
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| TEXAS<br>(State or other jurisdiction of incorporation or organization) | 74-0694415<br>(I.R.S. Employer Identification No.) |
| 1111 LOUISIANA<br>HOUSTON, TEXAS 77002<br>(Address and zip code of principal executive offices) | (713) 207-1111<br>(Registrant's telephone number, including area code) |

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

Indicate by check mark 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 [X] Accelerated filer [ ] Non-accelerated filer [ ]

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

As of October 31, 2006, CenterPoint Energy, Inc. had 312,839,095 shares of common stock outstanding, excluding 166 shares held as treasury stock.

CENTERPOINT ENERGY, INC.
QUARTERLY REPORT ON FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2006

TABLE OF CONTENTS





CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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

The following are some of the factors that could cause actual results to differ materially from those expressed or implied in forward-looking statements:

- 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. (formerly named Reliant Resources, 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 a guarantor;

- the outcome of litigation brought by or against us;

- our ability to control costs;

- the investment performance of our employee benefit plans;

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

- other factors we discuss in "Risk Factors" in Item 1A of Part I of our Annual Report on Form 10-K for the year ended December 31, 2005, which is incorporated herein by reference and in "Risk Factors' in Item 1A of Part II of this Quarterly Report on Form 10-Q.

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. FINANCIAL INFORMATION

### ITEM 1. FINANCIAL STATEMENTS

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CONDENSED STATEMENTS OF CONSOLIDATED INCOME
(MILLIONS OF DOLLARS, EXCEPT PER SHARE AMOUNTS)
(UNAUDITED)

| | THREE MONTHS ENDED SEPTEMBER 30, | | NINE MONTHS ENDED SEPTEMBER 30 | |
|---|---|---|---|---|
| | 2005 | 2006 | 2005 | 200 |
| REVENUES | $2,073 | $1,935 | $6,510 | $6,8 |
| EXPENSES: | | | | |
| Natural gas | 1,277 | 1,058 | 4,161 | 4,2 |
| Operation and maintenance | 336 | 347 | 974 | 1,0 |
| Depreciation and amortization | 145 | 159 | 411 | 4 |
| Taxes other than income taxes | 90 | 87 | 277 | 2 |
| Total | 1,848 | 1,651 | 5,823 | 6,0 |
| OPERATING INCOME | 225 | 284 | 687 | 8 |
| OTHER INCOME (EXPENSE): | | | | |
| Gain (loss) on Time Warner investment | 30 | 20 | (29) | |
| Gain (loss) on indexed debt securities | (29) | (12) | 34 | ( |
| Interest and other finance charges | (168) | (120) | (521) | (3 |
| Interest on transition bonds | (9) | (32) | (27) | ( |
| Return on true-up balance | 35 | -- | 104 | |
| Other, net | 7 | 12 | 18 | |
| Total | (134) | (132) | (421) | (4 |
| INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES AND EXTRAORDINARY ITEM | 91 | 152 | 266 | 3 |
| Income tax expense | (41) | (69) | (122) | ( |

| | | | | |
|---|---|---|---|---|
| INCOME FROM CONTINUING OPERATIONS BEFORE EXTRAORDINARY ITEM | 50 | 83 | 144 | 3 |
| DISCONTINUED OPERATIONS: | | | | |
| Income from Texas Genco, net of tax | -- | -- | 11 | |
| Loss on Disposal of Texas Genco, net of tax | -- | -- | (14) | |
| Total | -- | -- | (3) | |
| INCOME BEFORE EXTRAORDINARY ITEM | 50 | 83 | 141 | 3 |
| EXTRAORDINARY ITEM, NET OF TAX | -- | -- | 30 | |
| NET INCOME | $ 50 | $ 83 | $ 171 | $ 3 |
| BASIC EARNINGS PER SHARE: | | | | |
| Income from Continuing Operations | $ 0.16 | $ 0.27 | $ 0.46 | $ 1. |
| Discontinued Operations, net of tax | -- | -- | (0.01) | |
| Extraordinary Item, net of tax | -- | -- | 0.10 | |
| Net Income | $ 0.16 | $ 0.27 | $ 0.55 | $ 1. |
| DILUTED EARNINGS PER SHARE: | | | | |
| Income from Continuing Operations | $ 0.15 | $ 0.26 | $ 0.43 | $ 1. |
| Discontinued Operations, net of tax | -- | -- | (0.01) | |
| Extraordinary Item, net of tax | -- | -- | 0.09 | |
| Net Income | $ 0.15 | $ 0.26 | $ 0.51 | $ 1. |

See Notes to the Company's Interim Condensed Financial Statements



CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(MILLIONS OF DOLLARS)
(UNAUDITED)

ASSETS

| | DECEMBER 31, 2005 | SEPTEMBER 30, 2006 |
|---|---|---|
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $ 74 | $ 285 |
| Investment in Time Warner common stock | 377 | 395 |
| Accounts receivable, net | 1,098 | 716 |
| Accrued unbilled revenues | 608 | 226 |
| Natural gas inventory | 294 | 286 |
| Materials and supplies | 88 | 96 |
| Non-trading derivative assets | 131 | 141 |
| Taxes receivable | 53 | -- |
| Prepaid expenses and other current assets | 168 | 421 |
| Total current assets | 2,891 | 2,566 |
| PROPERTY, PLANT AND EQUIPMENT: | | |

| | | |
|---|---|---|
| Property, plant and equipment | 11,558 | 12,106 |
| Less accumulated depreciation and amortization | (3,066) | (3,264) |
| Property, plant and equipment, net | 8,492 | 8,842 |
| OTHER ASSETS: | | |
| Goodwill | 1,709 | 1,709 |
| Other intangibles, net | 56 | 45 |
| Regulatory assets | 2,955 | 2,838 |
| Non-trading derivative assets | 104 | 47 |
| Other | 909 | 926 |
| Total other assets | 5,733 | 5,565 |
| TOTAL ASSETS | $17,116 | $16,973 |

See Notes to the Company's Interim Condensed Financial Statements

2

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS - (CONTINUED)
(MILLIONS OF DOLLARS)
(UNAUDITED)

LIABILITIES AND SHAREHOLDERS' EQUITY

| | DECEMBER 31, 2005 | SEPTEMBER 30, 2006 |
|---|---|---|
| CURRENT LIABILITIES: | | |
| Current portion of transition bond long-term debt | $ 73 | $ 147 |
| Current portion of other long-term debt | 266 | 1,093 |
| Indexed debt securities derivative | 292 | 305 |
| Accounts payable | 1,161 | 547 |
| Taxes accrued | 167 | 195 |
| Interest accrued | 122 | 127 |
| Non-trading derivative liabilities | 43 | 179 |
| Accumulated deferred income taxes, net | 385 | 401 |
| Other | 505 | 382 |
| Total current liabilities | 3,014 | 3,376 |
| OTHER LIABILITIES: | | |
| Accumulated deferred income taxes, net | 2,474 | 2,403 |
| Unamortized investment tax credits | 46 | 41 |
| Non-trading derivative liabilities | 35 | 110 |
| Benefit obligations | 475 | 455 |
| Regulatory liabilities | 728 | 826 |
| Other | 480 | 290 |
| Total other liabilities | 4,238 | 4,125 |
| LONG-TERM DEBT: | | |

| | | |
|---|---|---|
| Transition bonds | 2,407 | 2,260 |
| Other | 6,161 | 5,645 |
| Total long-term debt | 8,568 | 7,905 |
| COMMITMENTS AND CONTINGENCIES (NOTE 11) | | |
| SHAREHOLDERS' EQUITY: | | |
| Common stock (310,324,739 shares and 312,325,790 shares outstanding at December 31, 2005 and September 30, 2006, respectively) | 3 | 3 |
| Additional paid-in capital | 2,931 | 2,959 |
| Accumulated deficit | (1,600) | (1,375) |
| Accumulated other comprehensive loss | (38) | (20) |
| Total shareholders' equity | 1,296 | 1,567 |
| TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY | $17,116 | $16,973 |

See Notes to the Company's Interim Condensed Financial Statements



CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS
(MILLIONS OF DOLLARS)
(UNAUDITED)

| | NINE MONTHS ENDED SEPTEMBER 30, | |
|---|---|---|
| | 2005 | 2006 |
| CASH FLOWS FROM OPERATING ACTIVITIES: | | |
| Net income | $ 171 | $ 365 |
| Discontinued operations, net of tax | 3 | -- |
| Extraordinary item, net of tax | (30) | -- |
| Income from continuing operations | 144 | 365 |
| Adjustments to reconcile income from continuing operations to net cash provided by operating activities: | | |
| Depreciation and amortization | 411 | 452 |
| Amortization of deferred financing costs | 59 | 37 |
| Deferred income taxes | 162 | (81) |
| Tax and interest reserves reductions related to ZENS and ACES | -- | (119) |
| Investment tax credit | (6) | (6) |
| Unrealized loss (gain) on Time Warner investment | 29 | (17) |
| Unrealized loss (gain) on indexed debt securities | (34) | 13 |
| Write-down of natural gas inventory | -- | 56 |
| Changes in other assets and liabilities: | | |
| Accounts receivable and unbilled revenues, net | 316 | 788 |
| Inventory | (140) | (52) |
| Taxes receivable | -- | 53 |
| Accounts payable | (28) | (640) |

| | | |
|---|---|---|
| Fuel cost over (under) recovery/surcharge | (69) | 106 |
| Non-trading derivatives, net | 8 | (35) |
| Margin deposits, net | 78 | (176) |
| Short-term risk management activities, net | (19) | 3 |
| Interest and taxes accrued | (440) | 30 |
| Net regulatory assets | (166) | 65 |
| Other current assets | (39) | (87) |
| Other current liabilities | 8 | (48) |
| Other assets | (2) | 30 |
| Other liabilities | 37 | (16) |
| Other, net | 4 | 7 |
| Net cash provided by operating activities of continuing operations | 313 | 728 |
| Net cash used in operating activities of discontinued operations | (38) | -- |
| Net cash provided by operating activities | 275 | 728 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | |
| Capital expenditures | (506) | (641) |
| Proceeds from sale of Texas Genco | 700 | -- |
| Decrease in restricted cash of Texas Genco | 383 | -- |
| Purchase of minority interest in Texas Genco | (383) | -- |
| Decrease in cash of Texas Genco | 24 | -- |
| Increase in restricted cash of transition bond companies | -- | (6) |
| Other, net | -- | 21 |
| Net cash provided by (used in) investing activities | 218 | (626) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | |
| Increase in short-term borrowings, net | 75 | -- |
| Proceeds from issuance of long-term debt | -- | 324 |
| Commercial paper, net | 187 | (3) |
| Long-term revolving credit facilities, net | (239) | -- |
| Payments of long-term debt | (424) | (83) |
| Debt issuance costs | (7) | (4) |
| Payment of common stock dividends | (105) | (140) |
| Proceeds from issuance of common stock, net | 14 | 12 |
| Other | 3 | 3 |
| Net cash provided by (used in) financing activities | (496) | 109 |
| NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS | (3) | 211 |
| CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD | 165 | 74 |
| CASH AND CASH EQUIVALENTS AT END OF PERIOD | $ 162 | $ 285 |
| SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION: | | |
| Cash Payments: | | |
| Interest, net of capitalized interest | $ 515 | $ 423 |
| Income taxes | 464 | 150 |
| Non-cash transactions: | | |
| Increase in accounts payable related to capital expenditures | -- | 21 |

See Notes to the Company's Interim Condensed Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(1) BACKGROUND AND BASIS OF PRESENTATION

General. Included in this Quarterly Report on Form 10-Q (Form 10-Q) of CenterPoint Energy, Inc. are the condensed consolidated interim financial statements and notes (Interim Condensed Financial Statements) of CenterPoint Energy, Inc. and its subsidiaries (collectively, CenterPoint Energy, or the Company). The Interim Condensed Financial Statements are unaudited, omit certain financial statement disclosures and should be read with the Annual Report on Form 10-K of CenterPoint Energy for the year ended December 31, 2005 (CenterPoint Energy Form 10-K).

Background. CenterPoint Energy 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).

CenterPoint Energy was a registered public utility holding company under the Public Utility Holding Company Act of 1935, as amended (1935 Act). The Energy Policy Act of 2005 (Energy Act) repealed the 1935 Act effective February 8, 2006, and since that date the Company and its subsidiaries have no longer been subject to restrictions imposed under the 1935 Act. The Energy Act includes a new Public Utility Holding Company Act of 2005 (PUHCA 2005) which grants to the Federal Energy Regulatory Commission (FERC) authority to require holding companies and their subsidiaries to maintain certain books and records and make them available for review by the FERC and state regulatory authorities in certain circumstances. On December 8, 2005, the FERC issued rules implementing PUHCA 2005. Pursuant to those rules, on June 14, 2006, the Company filed with the FERC the required notification of its status as a public utility holding company. On October 19, 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 the Company provides services to its subsidiaries through a service company, its service company is not subject to the service company rules.

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 September 30, 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 gas distribution systems. The operations of its local distribution companies are conducted through two unincorporated divisions: Minnesota Gas and Southern Gas Operations. Through wholly owned subsidiaries, CERC Corp. owns two interstate natural gas pipelines and gas gathering systems and provides various ancillary services. Through a wholly owned subsidiary, CERC Corp. also offers variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities.

Basis of Presentation. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and 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.

The Company's Interim Condensed Financial Statements reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position, results of operations and cash flows for the respective periods. Amounts reported in the Company's Condensed Statements of Consolidated Income are not necessarily indicative of amounts expected for a full-year period due to the effects of, among other things, (a) seasonal fluctuations in demand for energy and energy services, (b) changes in energy commodity prices, (c)



timing of maintenance and other expenditures and (d) acquisitions and dispositions of businesses, assets and other interests. In addition, certain amounts from the prior year have been reclassified to conform to the Company's presentation of financial statements in the current year. These reclassifications relate to the establishment of the Competitive Natural Gas Sales and Services business segment as a new reportable business segment during the fourth quarter of 2005 as discussed in Note 13 and do not affect net income.

(2) DISCONTINUED OPERATIONS

In July 2004, the Company announced its agreement to sell its majority owned subsidiary, Texas Genco Holdings, Inc. (Texas Genco), to Texas Genco LLC. On December 15, 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. Following that sale, 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 on April 13, 2005, following receipt of approval from the Nuclear Regulatory Commission (NRC).

The Company recorded an after-tax loss of $3 million for the nine-month period ended September 30, 2005 related to the operations of Texas Genco. General corporate overhead, previously allocated to Texas Genco from the Company, was less than $1 million for the nine-month period ended September 30, 2005. These amounts were not eliminated by the sale of Texas Genco and have been excluded from income from discontinued operations and reflected as general corporate overhead of the Company in income from continuing operations in accordance with Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). The Interim Condensed Financial Statements present these operations as discontinued operations in accordance with SFAS No. 144.

Revenues related to Texas Genco included in discontinued operations for the nine months ended September 30, 2005 were $62 million. Income from these discontinued operations for the nine months ended September 30, 2005 is reported net of income tax expense of $4 million.

(3) EMPLOYEE BENEFIT PLANS

The Company's net periodic cost includes the following components relating to pension and postretirement benefits:

| | THREE MONTHS ENDED SEPTEMBER 30, | | | |
|---|---|---|---|---|
| | 2005 | | 2006 | |
| | PENSION BENEFITS | POSTRETIREMENT BENEFITS | PENSION BENEFITS | POSTRETIREMENT BENEFITS |
| | (IN MILLIONS) | | | |
| Service cost ........................... | $ 9 | $ 1 | $ 9 | $ 1 |
| Interest cost .......................... | 24 | 6 | 24 | 6 |
| Expected return on plan assets .......... | (34) | (3) | (36) | (3) |
| Amortization of prior service cost ...... | (2) | 1 | (1) | 1 |
| Amortization of net loss ................ | 11 | -- | 12 | -- |
| Amortization of transition obligation ... | -- | 1 | -- | 1 |
| Other ................................. | -- | 1 | -- | -- |
| Net periodic cost ...................... | $ 8 | $ 7 | $ 8 | $ 6 |

6

| | NINE MONTHS ENDED SEPTEMBER 30, | | | |
|---|---|---|---|---|
| | 2005 | | 2006 | |
| | PENSION BENEFITS | POSTRETIREMENT BENEFITS | PENSION BENEFITS | POSTRETIREMENT BENEFITS |
| | (IN MILLIONS) | | | |
| Service cost ........................... | $ 26 | $ 2 | $ 27 | $ 2 |
| Interest cost .......................... | 72 | 20 | 72 | 19 |
| Expected return on plan assets .......... | (103) | (9) | (107) | (9) |
| Amortization of prior service cost ...... | (5) | 2 | (5) | 2 |
| Amortization of net loss ................ | 33 | -- | 36 | -- |
| Amortization of transition obligation ... | -- | 5 | -- | 5 |
| Benefit enhancement ..................... | -- | -- | 8 | 1 |
| Other ................................. | -- | 1 | -- | -- |
| Net periodic cost ...................... | $ 23 | $21 | $ 31 | $20 |

The Company expects to contribute approximately $26 million to its postretirement benefits plan in 2006, of which $20 million had been contributed as of September 30, 2006.

Contributions to the pension plan are not required in 2006. In addition to the Company's non-contributory pension plan, the Company maintains a non-qualified benefit restoration plan. The net periodic cost associated with this plan was $2 million for each of the three-month periods ended September 30, 2005 and 2006 and $5 million for each of the nine-month periods ended September 30, 2005 and 2006.

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 was added to their qualified pension plan benefit and three years of service was added to their postretirement benefit. An additional pension and postretirement expense of approximately $9 million was recorded in the first quarter of 2006 and is reflected in the table above as a benefit enhancement.

(4) NEW ACCOUNTING PRONOUNCEMENTS

In September 2006, the Financial Accounting Standards Board (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 does not expect the adoption of this statement to have a material impact on its financial condition or results of operations.

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans - An Amendment of FASB Statements No. 87, 88, 106 and 132(R)" (SFAS No. 158). SFAS No. 158 requires the Company, as the sponsor of a single employer defined benefit plan, to (a) recognize on its Balance Sheets as an asset a pension plan's over-funded status or as a liability such plan's under-funded status, (b) measure a pension plan's assets and obligations that determine its funded status as of the end of the Company's fiscal year and (c) recognize changes in the funded status of a pension plan or postretirement plan in the year in which the changes occur through adjustments to other comprehensive income. SFAS No. 158 is effective for the Company for the year ended December 31, 2006.

SFAS No. 158 is expected to require a significant non-cash charge to the Company's equity to recognize previously unrecognized costs related to its pension and postretirement plans. The amount of the charge is unknown at this time due to possible changes in discount rates and investment returns through year-end. However, if SFAS No. 158 had been adopted as of December 31, 2005, the charge to comprehensive income would have been approximately $509 million (net of tax). The adoption of SFAS No. 158 will not impact the Company's compliance with debt covenants.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes - An Interpretation of FASB Statement No. 109" (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with 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 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 expects to adopt FIN 48 in the first quarter of 2007 and is currently evaluating the impact the adoption will have on the Company's financial position.



(5) REGULATORY MATTERS

(A) RECOVERY OF TRUE-UP BALANCE

In March 2004, CenterPoint Houston filed its true-up application with the Public Utility Commission of Texas (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 argument to the 3rd Court of Appeals in Austin is not expected to occur before late November 2006. No amounts related to the district court's judgment have been recorded in the 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 recent 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. The Company intends to seek a PLR asking the IRS whether the Texas Utility Commission's order reducing the Company's stranded cost recovery by $146 million for ADITC and EDFIT would cause a normalization violation. If the Company's PLR 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 an 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.

There are two ways for CenterPoint Houston to recover the true-up balance: by issuing transition bonds to securitize the amounts due and/or by implementing a competition transition charge (CTC). Pursuant to a financing order issued by the Texas Utility Commission in March 2005 and affirmed in August 2005 by the 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 (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. During the three and nine months ended September 30, 2006, CenterPoint Houston recognized approximately $14 million and $44 million, respectively, in operating income from the CTC. Additionally, during the three and nine months ended September 30, 2006, CenterPoint Houston recognized approximately $4 million and $10 million, respectively, of the allowed equity return not previously recorded. As of September 30, 2006, the Company had not recorded an allowed equity return of $237 million on its true-up balance because such return is being recognized as it is recovered in the future.

Certain parties appealed the CTC Order to the 98th 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 CTC 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 who have switched to new on-site generation. The Company and CenterPoint Houston disagree with the district court's conclusions and in May 2006 appealed the judgment to the court of appeals and, if required, plan to seek further review from the Texas Supreme Court. All briefs in the appeal have been filed. CenterPoint Houston has requested oral argument, but no date has been set. 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, reduces carrying costs 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 approximately $18 million per year for the first year with lesser impacts in subsequent years. On July 17, 2006, CenterPoint Houston made a compliance filing necessary to implement the rule changes effective August 1, 2006 per the settlement agreement discussed in Note 5(d) below.

(B) FINAL FUEL RECONCILIATION

The results of the Texas Utility Commission's final decision related to CenterPoint Houston's final fuel reconciliation are 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 court in May 2005 affirming the Texas Utility Commission's decision. CenterPoint Houston filed an appeal to the 3rd Court of Appeals in Austin in June 2005, and in April 2006, the 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. The Texas Supreme Court may grant 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.



(C) REMAND OF 2001 UNBUNDLED COST OF SERVICE (UCOS) ORDER

The 3rd Court of Appeals in Austin 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 its basis for its determination of certain projected transmission capital expenditures. The 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 its Staff to quantify the effect on CenterPoint Houston's rates. In the settlement of the CenterPoint Houston rate proceeding described in Note 5(d) 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 for $32 million in the second quarter of 2006 to reflect this obligation.

(D) RATE CASES

ELECTRIC TRANSMISSION & DISTRIBUTION

In October 2005, the Texas Utility Commission Staff filed a memorandum summarizing its review of the Earnings Reports filed by electric utilities for the calendar year ended December 31, 2004. Based on its review, the Staff concluded that continuation of CenterPoint Houston's rates could result in excess retail transmission and distribution revenues and excess wholesale transmission revenues and recommended that the Texas Utility Commission initiate a review of the reasonableness of existing rates.

In December 2005, the Texas Utility Commission agreed to order 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 current rates.

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 (the Agreement) with the Texas Utility Commission in August 2006 to seek approval of that settlement agreement. On September 5, 2006, the Texas Utility Commission issued its final order approving the Agreement. Revised base rates and other revised tariffs became effective as of October 10, 2006.

Under the terms of the Agreement, CenterPoint Houston's base rate revenues will be reduced by a net of approximately $58 million per year. Also, CenterPoint Houston will increase its energy efficiency expenditures by an additional $10 million per year over the $13 million included in existing 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 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.



The Agreement will permit CenterPoint Houston to amortize its expenditures of approximately $28 million related to Hurricane Rita over a seven-year period and to amortize regulatory expenses of approximately $7 million over a four-year period, both beginning in October 2006. Pursuant to the 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 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 5(c) above.

NATURAL GAS DISTRIBUTION

SOUTHERN GAS OPERATIONS

South Texas and Beaumont/East Texas. In April 2005, the Railroad Commission of Texas (Railroad Commission) established new gas tariffs that increased Southern Gas Operations' base rate and service revenues by a combined $2 million annually in the unincorporated environs of its Beaumont/East Texas and South Texas Divisions. In June and August 2005, Southern Gas Operations filed requests to implement these same rates within the incorporated cities located in the two divisions. During the second quarter of 2006, Southern Gas Operations reached settlement agreements with the last of the cities that had denied or appealed the rate change requests.

Settlement rates have now been implemented in all jurisdictions, including unincorporated areas. Southern Gas Operations' base rates and miscellaneous service charges are expected to increase by a total of $17 million annually over the pre-April 2005 levels. Approximately $4 million of this increase was reflected in the Company's 2005 revenues. The Company expects approximately $16 million will be reflected in revenues in 2006, and the total $17 million will be reflected in revenues in 2007. Approximately $3 million of expenditures related to these rate cases was charged to expense during the second quarter of 2006. The settlements also provide that these new rates will not change over the next three to five years.

MINNESOTA GAS

At September 30, 2006, Minnesota Gas had recorded approximately $45 million as a regulatory asset related to prior years' unrecovered purchased gas costs. Of the total, approximately $24 million relates to the period from July 1, 2004 through June 30, 2006, and approximately $21 million relates 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), and recovery of this regulatory asset is dependent upon obtaining a waiver from the MPUC rules. Minnesota Gas has requested to recover the amounts related to costs prior to July 1, 2004 over a three-year period beginning in 2007. The Minnesota Office of the Attorney General (OAG) and the Minnesota Department of Commerce have filed comments opposing recovery. Any amount not approved by the MPUC will be written off. There is no statutory time frame in which the MPUC must act.

In November 2005, Minnesota Gas filed a request with the MPUC to increase annual rates by approximately $41 million. In December 2005, the MPUC approved an interim rate increase of approximately $35 million that was implemented January 1, 2006. Any excess of amounts collected under the interim rates over the amounts approved in final rates is subject to refund to customers. On October 5, 2006, the MPUC considered the request and indicated that it will grant a rate increase of approximately $21 million, which is still subject to receipt of a final order. 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. Issuance of the formal written decision by the MPUC is expected in late 2006. The proportional share of the excess of the amounts collected in interim rates over the amount allowed by the final order of approximately $8 million has been accrued as of September 30, 2006, and will be refunded to customers in late 2006 or early 2007 after receipt of the formal decision.

In December 2004, the MPUC opened an investigation to determine whether Minnesota Gas' practices regarding restoring natural gas service during the period between October 15 and April 15 (Cold Weather Period) are in compliance with the MPUC's Cold Weather Rule (CWR), which governs disconnection and reconnection of customers during the Cold Weather Period. In June 2005, the OAG issued its report alleging Minnesota Gas had violated the CWR and recommended a $5 million penalty. In addition, in June 2005, CERC was named in a suit filed in the United States District Court, District of Minnesota on behalf of



a purported class of customers who allege that Minnesota Gas' conduct under the CWR was in violation of the law. On August 14, 2006 the court gave final approval to a $13.5 million settlement which resolves all but one small claim against Minnesota Gas 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. During the fourth quarter of 2005, CERC established a litigation reserve to cover the anticipated costs of this settlement.

(E) CITY OF TYLER, TEXAS DISPUTE

In July 2002, the City of Tyler, Texas, asserted that Southern Gas Operations had overcharged residential and small commercial customers in that city for gas costs under supply agreements in effect since 1992. That dispute was referred to the Railroad Commission by agreement of the parties for a determination of whether Southern Gas Operations has properly charged and collected for gas service to its residential and commercial customers in its Tyler distribution system in accordance with lawful filed tariffs during the period beginning November 1, 1992, and ending October 31, 2002. In May 2005, the Railroad Commission issued a final order finding that the Company had complied with its tariffs, acted prudently in entering into its gas supply contracts, and prudently managed those contracts. The City of Tyler appealed this order to a Travis County District Court, but in April 2006, Southern 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.

(6) DERIVATIVE INSTRUMENTS

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

Cash Flow Hedges. During each of the three-month and nine-month periods ended September 30, 2005 and 2006, hedge ineffectiveness resulted in a gain of less than $1 million from derivatives that qualify for and are designated as cash flow hedges. No component of the derivative instruments' gain or loss was excluded from the assessment of effectiveness. If it becomes probable that an anticipated transaction will not occur, the Company realizes in net income the deferred gains and losses previously recognized in accumulated other comprehensive loss. Once the anticipated transaction occurs, the accumulated deferred gain or loss recognized in accumulated other comprehensive loss is reclassified and included in the Company's Condensed Statements of Consolidated Income under the "Expenses" caption "Natural gas." Cash flows resulting from these transactions in non-trading energy derivatives are included in the Condensed Statements of Consolidated Cash Flows in the same category as the item being hedged. As of September 30, 2006, the Company expects $18 million ($12 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 ten years. The Company's policy is not to exceed ten years in hedging its exposure.

Other Derivative Financial Instruments. The Company enters into certain derivative financial 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 three months ended September 30, 2005 and 2006, the Company recognized unrealized net gains of $2 million and $23 million, respectively, on the derivative financial instruments that had not yet been settled. During the nine months ended September 30, 2005 and 2006, the Company recognized unrealized net gains of $3 million and $37 million, respectively. These derivative gains and losses are included in the Condensed Statements of Consolidated Income 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 each of the nine-month periods ended September 30, 2005 and 2006 was $23 million. Hedge ineffectiveness was not material during each of the nine-month periods ended September 30, 2005 and 2006. As of September 30, 2006, the Company expects $28 million ($19 million after-tax) in accumulated other comprehensive loss to be amortized during the next twelve months.



(7) GOODWILL AND INTANGIBLES

Goodwill as of December 31, 2005 and September 30, 2006 by reportable business segment is as follows (in millions):

| | |
|---|---|
| Natural Gas Distribution .................... | $ 746 |
| Pipelines and Field Services ................ | 604 |
| Competitive Natural Gas Sales and Services ... | 339 |
| Other Operations ........................... | 20 |
| Total .................................. | $1,709 |

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

The Company completed its annual evaluation of goodwill for impairment as of July 1, 2006 and no impairment was indicated.

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

| | DECEMBER 31, 2005 | | SEPTEMBER 30, 2006 | |
|---|---|---|---|---|
| | CARRYING AMOUNT | ACCUMULATED AMORTIZATION | CARRYING AMOUNT | ACCUMULATED AMORTIZATION |
| | (IN MILLIONS) | | | |
| Land Use Rights.... | $55 | $(14) | $55 | $(14) |
| Other.............. | 22 | (7) | 7 | (3) |
| Total........... | $77 | $(21) | $62 | $(17) |

Amortization expense for other intangibles during each of the three-month periods ended September 30, 2005 and 2006 was less than $1 million. Amortization expense for other intangibles during each of the nine-month periods ended September 30, 2005 and 2006 was $2 million. Estimated amortization expense is less than $1 million for the remainder of 2006 and approximately $1 million in each of the five succeeding fiscal years.

(8) COMPREHENSIVE INCOME

The following table summarizes the components of total comprehensive income (net of tax):

| | FOR THE THREE MONTHS ENDED SEPTEMBER 30, | | FOR THE NINE MONTHS ENDED SEPTEMBER 30, | |
|---|---|---|---|---|
| | 2005 | 2006 | 2005 | 2006 |
| | (IN MILLIONS) | | | |
| Net income | $50 | $ 83 | $171 | $365 |
| Other comprehensive income (loss): | | | | |
| Net deferred gain from cash flow hedges | 1 | 10 | 11 | 5 |
| Reclassification of deferred loss (gain) from cash flow hedges realized in net income | (2) | 7 | 6 | 13 |
| Other comprehensive income from discontinued operations | -- | -- | 3 | -- |
| Other comprehensive income (loss) | (1) | 17 | 20 | 18 |
| Comprehensive income | $49 | $100 | $191 | $383 |

The following table summarizes the components of accumulated other comprehensive loss:

| | DECEMBER 31, 2005 | SEPTEMBER 30, 2006 |
|---|---|---|
| | (IN MILLIONS) | |
| Minimum pension liability adjustment | $(15) | $(15) |
| Net deferred loss from cash flow hedges | (23) | (5) |
| Total accumulated other comprehensive loss | $(38) | $(20) |

13

(9) 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. At December 31, 2005, 310,324,905 shares of CenterPoint Energy common stock were issued and 310,324,739 shares of CenterPoint Energy common stock were outstanding. At September 30, 2006, 312,325,956 shares of CenterPoint Energy common stock were issued and 312,325,790 shares of CenterPoint Energy common stock were outstanding. Outstanding common shares exclude 166 treasury shares at both December 31, 2005 and September 30, 2006.

(10) LONG-TERM DEBT AND RECEIVABLES FACILITY

(A) 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 will be used for general corporate purposes, including repayment or refinancing of debt (including $145 million of CERC's 8.90% debentures due December 15, 2006), capital expenditures and working capital.

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 or CERC Corp. consider customary.

As of September 30, 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 under its $550 million credit facility. Additionally, the Company, CenterPoint Houston and CERC Corp. were in compliance with all covenants as of September 30, 2006.

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%. Holders may convert each of their notes into shares of CenterPoint Energy common stock at a conversion rate of 87.4094 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, the conversion rate increased to 87.4094 in accordance with the terms of the notes due to an increase in the amount of the dividend per common share paid by the Company in the first quarter of 2006.

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 September 30, 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 third 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 fourth quarter of 2006, 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%. Holders may convert each of their notes into shares of CenterPoint Energy common stock at a conversion rate of 79.0165 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% 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 and S&P 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 78.0640 shares of common stock per $1,000 principal amount of notes. However, effective February 16, 2006, the conversion rate increased to 79.0165 in accordance with the terms of the notes due to an increase in the amount of the dividend per common share paid by the Company in the first quarter of 2006.

Under the original terms of these convertible senior notes, CenterPoint Energy could elect to satisfy part or all of its conversion obligation by delivering cash in lieu of shares of CenterPoint Energy. On December 13, 2004, the



Company entered into a supplemental indenture with respect to these convertible senior notes in order to eliminate its right to settle the conversion of the notes solely in shares of its common stock. Holders have the right to require the Company to purchase all or any portion of the notes for cash on January 15, 2007, January 15, 2012 and January 15, 2017 for a purchase price equal to 100% of the principal amount of the notes. As of September 30, 2006, these notes were classified as current portion of other long-term debt in the Condensed Consolidated Balance Sheets. The convertible senior notes also have a contingent interest feature requiring contingent interest to be paid to holders of notes commencing on or after January 15, 2007, 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.

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 September 30, 2006.

The junior subordinated debentures are the trust's sole assets and their entire operations. CenterPoint Energy considers 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 are mandatorily redeemable upon the repayment of the related series of junior subordinated debentures at their stated maturity or earlier redemption. Subject to some limitations, CenterPoint Energy has the option of deferring payments of interest on the junior subordinated debentures. During any deferral or event of default, CenterPoint Energy may not pay dividends on its capital stock. As of September 30, 2006, no interest payments on the junior subordinated debentures had been deferred.

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 are as follows:

| TRUST | AGGREGATE LIQUIDATION AMOUNTS AS OF DECEMBER 31, 2005 | SEPTEMBER 30, 2006 | DISTRIBUTION RATE/ INTEREST RATE | MANDATORY REDEMPTION DATE/ MATURITY DATE | JUNIOR |
|---|---|---|---|---|---|
| | (IN MILLIONS) | | | | |
| HL&P Capital Trust II.... | $100 | $100 | 8.257% | February 2037 | 8.257% Deferra Series |

(B) RECEIVABLES FACILITY

In January 2006, CERC's $250 million receivables facility was extended to January 2007. The facility was temporarily increased to $375 million for the period from January 2006 to June 2006. As of September 30, 2006, no amounts were funded under CERC's receivables facility.

Funding under the receivables facility averaged $173 million and $85 million for the nine months ended September 30, 2005 and 2006, respectively. Sales of receivables were approximately $480 million and $-0- for the three months ended September 30, 2005 and 2006, respectively, and $1.4 billion and $555 million for the nine months ended September 30, 2005 and 2006, respectively. See Note 14(b) for a discussion of changes to the receivables facility during the fourth quarter of 2006.



(11) 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 September 30, 2006 as these contracts meet the SFAS No. 133 exception to be classified as "normal purchases contracts" or do not meet the definition of a derivative. Natural gas supply commitments also include natural gas transportation contracts which do not meet the definition of a derivative. As of September 30, 2006, minimum payment obligations for natural gas supply commitments are approximately $302 million for the remaining three months in 2006, $724 million in 2007, $230 million in 2008, $131 million in 2009, $130 million in 2010 and $733 million in 2011 and thereafter.

(B) CAPITAL COMMITMENTS

In October 2005, CenterPoint Energy Gas Transmission Company (CEGT), a wholly owned subsidiary of CERC Corp., 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 billion cubic feet (Bcf) per day. CEGT has signed firm contracts for the full capacity of the pipeline.

On October 2, 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 first quarter 2007 at a cost of approximately $455 million.

Based on strong interest expressed during an open season held earlier this year, and subject to FERC approval, CEGT expects to expand capacity of the pipeline to 1.5 Bcf per day, which would bring the total estimated capital cost of the project to approximately $510 million. 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.

Earlier this year, CenterPoint Energy Southeast Pipelines Holding, L.L.C., a wholly owned subsidiary of CERC Corp., signed a joint venture agreement with a subsidiary of Duke Energy Gas Transmission (DEGT) to construct, own and operate a 270-mile pipeline (Southeast Supply Header) 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 DEGT. In August 2006, the joint venture signed an agreement with Florida Power & Light Company (FPL) for firm transportation services, which subscribes approximately half of the planned 1 Bcf per day capacity of the pipeline. FPL's commitment is contingent on the approval of the FPL contract by the Florida Public Service Commission in December 2006. Subject to the venture receiving a certificate from the FERC to construct, own and operate the pipeline, subsidiaries of DEGT and CERC Corp. have committed to build the pipeline, for which total costs are estimated to be $700 to $800 million. The pre-filing process with the FERC has been initiated, and an application is expected to be filed in December 2006. Once the project is approved by the FERC, construction is anticipated to begin in the fourth quarter of 2007, with an expected in-service date of June 2008.

(C) 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 California, Colorado and Nevada and in state court in California and Nevada in connection with the operation of the electricity and natural gas markets in California and certain other western 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, attorneys' fees and divestiture of assets. 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 30 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 federal district court in Colorado, Nevada and the Northern District of California 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. Four 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. The other gas cases remain in the early procedural stages.

On August 12, 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 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 suit filed in 1997 under the Federal False Claims Act alleging mismeasurement of natural gas produced from federal and Indian lands. The suit seeks undisclosed damages, along with statutory penalties, interest, costs, and fees. The complaint is part of a larger series of complaints filed against 77 natural gas pipelines and their subsidiaries and affiliates. An earlier single action making substantially similar allegations against the pipelines was dismissed by the federal district court for the District of Columbia on grounds of improper joinder and lack of jurisdiction. As a result, the various individual complaints were filed in numerous courts throughout the country. This case has been consolidated, together with the other similar False Claims Act cases, in the federal district court in Cheyenne, Wyoming. On October 20, 2006, the judge considering this matter granted defendants' motion to dismiss the suit on the ground that the court lacked subject matter jurisdiction over the claims asserted.

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 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 suits are without merit. CERC does not expect the ultimate outcome 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 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 suit 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 Southern Gas Operations to a purported class of certain consumers of natural gas and gas service without advance approval by the Louisiana Public Service Commission (LPSC). In October 2004, a similar case was filed in district court in Miller County, Arkansas against the Company, CERC, Entex Gas Marketing Company, CEGT, CenterPoint Energy Field Services, CenterPoint Energy Pipeline Services, Inc., CenterPoint Energy - Mississippi River Transmission Corp. (CEMRT) 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 CEMRT. 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 5(e). 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.

Pipeline Safety Compliance. Pursuant to an order from the Minnesota Office of Pipeline Safety, CERC substantially completed removal of certain non-code-compliant components from a portion of its distribution system by December 2, 2005. The components were installed by a predecessor company, which was not affiliated with CERC during the period in which the components were installed. In November 2005, Minnesota Gas filed a request with the MPUC to recover the capitalized expenditures (approximately $39 million) and related expenses, together with a return on the capitalized portion through rates as part of its existing rate case as further discussed in Note 5(d). Based on the MPUC deliberations held in October 2006 in the Minnesota Gas rate case, the capitalized expenditures, plus approximately $2 million previously expensed in 2005, are expected to be allowed 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 5(d) 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 approvals 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 September 30, 2006, CERC had accrued $14 million for remediation of these Minnesota sites. At September 30, 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 September 30, 2006, CERC has collected $13 million from insurance companies and rate payers to be used for future environmental remediation.

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



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.

TAX CONTINGENCIES

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

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 Company's 2.0% Zero Premium Exchangeable Subordinated Notes (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 Time Warner Inc. (TW Common), constituted a straddle under Sections 1092 and 246 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 reached agreement with the IRS on terms of a settlement regarding the tax treatment of the Company's ZENS and its former ACES. On July 17, 2006, the Company signed a Closing Agreement prepared by the IRS and the Company for the tax years 1999 through 2029 with respect to the ZENS issue. The agreement reached with the IRS and the Closing Agreement are subject to approval by the Joint Committee on Taxation of the U.S. Congress. Under the terms of the agreement reached with the IRS, the Company will pay approximately $64 million in previously accrued taxes associated with the ACES and the ZENS and will reduce its future interest deductions associated with the ZENS. As a result of the agreement reached with the IRS, the Company reduced its previously accrued tax and related interest reserves by approximately $119 million in the second quarter of 2006, and will no longer accrue a quarterly reserve related to this tax contingency.

The Company has also established reserves for other significant tax items including issues relating to prior acquisitions and dispositions of business operations, certain positions taken with respect to state tax filings and certain items related to employee benefits. The total amount reserved for the other tax items was approximately $60 million and $50 million as of December 31, 2005 and September 30, 2006, respectively.

GUARANTEES

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 guarantee obligations prior to separation, but when separation occurred in September 2002, RRI had been unable to extinguish all obligations. To secure the Company and CERC against obligations under the remaining guarantees, RRI agreed to provide cash or letters of credit for the benefit of CERC and the Company, and agreed to use commercially reasonable efforts to extinguish the remaining guarantees. The Company's current exposure under the remaining guarantees relates to CERC's guarantee of the payment by RRI of demand charges related to transportation contracts with one counterparty. The demand charges are approximately $53 million per year in 2006 through 2015, $49 million in 2016, $38 million in 2017 and $13 million in 2018. As a result of changes in market conditions, the Company's potential exposure under that guarantee currently exceeds the security provided by RRI. The Company has requested RRI to increase the amount of its existing letters of credit or, in the alternative, to obtain a release of CERC's obligations under the guarantee. On June 30, 2006, the RRI trading subsidiary and CERC jointly filed a complaint at the FERC against the counterparty on the CERC guarantee. In the complaint, the RRI trading subsidiary seeks a determination by the FERC that the security held 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 guarantee obligation and, in its place accept (i) a guarantee from RRI of the obligations of the RRI trading subsidiary, and (ii) letters of credit equal 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. On July 20, 2006, the counterparty filed its answer to the complaint, arguing that CERC is contractually bound to continue the guarantee, that the amount of the guarantee does not violate the FERC's policies and that the proposed substitution of credit support is not authorized under the counterparty's financing documents. The Company and the RRI trading subsidiary have filed a reply to that answer and, in response to a FERC order, the counterparty has submitted financing documents for FERC review. It is presently unknown what action the FERC may take on the complaint. The RRI trading subsidiary continues to meet its obligations under the transportation contracts.

NUCLEAR DECOMMISSIONING FUND COLLECTIONS

Pursuant to regulatory requirements and its tariff, CenterPoint Houston, as collection agent, collects from its transmission and distribution customers the nuclear decommissioning charge assessed with respect to the 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 2003 and 2004, $2.9 million was transferred each year and $3.2 million was transferred in 2005. There are various investment restrictions imposed on owners of nuclear generating stations by the Texas Utility Commission and the NRC 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.

(12) EARNINGS PER SHARE

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

| | FOR THE THREE MONTHS ENDED SEPTEMBER 30, | | FOR THE NINE MONTHS SEPTEMBER 30, | |
|---|---|---|---|---|
| | 2005 | 2006 | 2005 | 20 |
| | (IN MILLIONS, EXCEPT SHARE AND PER SHARE AMOUNT | | | |
| Basic earnings per share calculation: | | | | |
| Income from continuing operations before extraordinary item ................. | $ 50 | $ 83 | $ 144 | $ |
| Discontinued operations, net of tax .... | -- | -- | (3) | |
| Extraordinary item, net of tax ......... | -- | -- | 30 | |
| Net income ........................... | $ 50 | $ 83 | $ 171 | $ |
| Weighted average shares outstanding ....... | 309,657,000 | 311,945,000 | 309,080,000 | 311,4 |
| Basic earnings per share: | | | | |

| | | | | |
|---|---|---|---|---|
| Income from continuing operations before extraordinary item .................. | $ 0.16 | $ 0.27 | $ 0.46 | $ |
| Discontinued operations, net of tax .... | -- | -- | (0.01) | |
| Extraordinary item, net of tax ......... | -- | -- | 0.10 | |
| Net income ............................ | $ 0.16 | $ 0.27 | $ 0.55 | $ |



| | FOR THE THREE MONTHS ENDED SEPTEMBER 30, | | FOR THE NINE MONTHS SEPTEMBER 30, | |
|---|---|---|---|---|
| | 2005 | 2006 | 2005 | 20 |
| | (IN MILLIONS, EXCEPT SHARE AND PER SHARE AMOUNT | | | |
| Diluted earnings per share calculation: | | | | |
| Net income ............................ | $ 50 | $ 83 | $ 171 | $ |
| Plus: Income impact of assumed conversions: | | | | |
| Interest on 3.75% convertible senior notes ........................... | 2 | -- | 9 | |
| Total earnings effect assuming dilution ........................... | $ 52 | $ 83 | $ 180 | $ |
| Weighted average shares outstanding ....... | 309,657,000 | 311,945,000 | 309,080,000 | 311,4 |
| Plus: Incremental shares from assumed conversions: | | | | |
| Stock options (1) .................. | 1,457,000 | 1,161,000 | 1,259,000 | 1,0 |
| Restricted stock ................... | 1,500,000 | 1,292,000 | 1,500,000 | 1,2 |
| 2.875% convertible senior notes ..... | 1,620,000 | 1,613,000 | -- | 3 |
| 3.75% convertible senior notes ...... | 32,269,000 | 8,705,000 | 43,183,000 | 5,8 |
| Weighted average shares assuming dilution ........................... | 346,503,000 | 324,716,000 | 355,022,000 | 319,9 |
| Diluted earnings per share: | | | | |
| Income from continuing operations before extraordinary item .................. | $ 0.15 | $ 0.26 | $ 0.43 | $ |
| Discontinued operations, net of tax .... | -- | -- | (0.01) | |
| Extraordinary item, net of tax ......... | -- | -- | 0.09 | |
| Net income ............................ | $ 0.15 | $ 0.26 | $ 0.51 | $ |

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(1) Options to purchase 8,940,201 shares were outstanding for both the three months and nine months ended September 30, 2005, and options to purchase 6,539,344 shares were outstanding for both the three months and nine months ended September 30, 2006, but were not included in the computation of

diluted earnings per share because the options' exercise price was greater than the average market price of the common shares for the respective periods.

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 10) 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 $12.66 and $11.44, respectively, at September 30, 2006.

(13) 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, Pipelines and 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. The Company reorganized the oversight of its Natural Gas Distribution business segment and, as a result, beginning in the fourth quarter of 2005, the Company established a new reportable business segment, Competitive Natural Gas Sales and Services. Competitive Natural Gas Sales and Services represents the Company's non-rate regulated gas



sales and services operations, which consist of three operational functions: wholesale, retail and intrastate pipelines. Pipelines and Field Services includes the interstate natural gas pipeline operations and the natural gas gathering and pipeline services businesses. Other Operations consists primarily of other corporate operations which support all of the Company's business operations. All prior period segment information has been reclassified to conform to the 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):

| | FOR THE THREE MONTHS ENDED SEPTEMBER 30, 2005 | | |
|---|---|---|---|
| | REVENUES FROM EXTERNAL CUSTOMERS | NET INTERSEGMENT REVENUES | OPERATING INCOME (LOSS) |
| Electric Transmission & Distribution ......... | $ 484(1) | $ -- | $183 |
| Natural Gas Distribution ..................... | 532 | 3 | (16) |
| Competitive Natural Gas Sales and Services ... | 974 | 39 | 4 |
| Pipelines and Field Services ................. | 81 | 35 | 52 |
| Other Operations ............................. | 2 | 2 | 2 |
| Eliminations ................................. | -- | (79) | -- |
| Consolidated ................................. | $2,073 | $ -- | $225 |

| | FOR THE THREE MONTHS ENDED SEPTEMBER 30, 2006 | | |
|---|---|---|---|
| | REVENUES FROM EXTERNAL CUSTOMERS | NET INTERSEGMENT REVENUES | OPERATING INCOME (LOSS) |
| Electric Transmission & Distribution ......... | $ 533(1) | $ -- | $219 |
| Natural Gas Distribution ..................... | 483 | 2 | (11) |
| Competitive Natural Gas Sales and Services ... | 813 | 17 | 12 |
| Pipelines and Field Services ................. | 104 | 37 | 69 |
| Other Operations ............................. | 2 | 1 | (5) |
| Eliminations ................................. | -- | (57) | -- |
| Consolidated ................................. | $1,935 | $ -- | $284 |

| | FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2005 | | | |
|---|---|---|---|---|
| | REVENUES FROM EXTERNAL CUSTOMERS | NET INTERSEGMENT REVENUES | OPERATING INCOME (LOSS) | A |
| Electric Transmission & Distribution ......... | $1,243(1) | $ -- | $385 | |
| Natural Gas Distribution ..................... | 2,399 | 6 | 116 | |
| Competitive Natural Gas Sales and Services ... | 2,607 | 176 | 30 | |
| Pipelines and Field Services ................. | 252 | 110 | 168 | |
| Other Operations ............................. | 9 | 6 | (12) | |
| Eliminations ................................. | -- | (298) | -- | |
| Consolidated ................................. | $6,510 | $ -- | $687 | |

| | FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2006 | | |
|---|---|---|---|
| | REVENUES FROM EXTERNAL CUSTOMERS | NET INTERSEGMENT REVENUES | OPERATING INCOME (LOSS) |
| Electric Transmission & Distribution ......... | $1,374(1) | $ -- | $480 |
| Natural Gas Distribution ..................... | 2,506 | 8 | 90 |
| Competitive Natural Gas Sales and Services ... | 2,681 | 62 | 44 |
| Pipelines and Field Services ................. | 287 | 114 | 203 |
| Other Operations ............................. | 7 | 5 | (7) |
| Eliminations ................................. | -- | (189) | -- |
| Consolidated ................................. | $6,855 | $ -- | $810 |

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(1) Sales to subsidiaries of RRI in the three months ended September 30, 2005 and 2006 represented approximately $249 million and $225 million, respectively. Sales to subsidiaries of RRI in the nine months ended September 30, 2005 and 2006 represented approximately $615 million and $569 million, respectively.

(2) Included in total assets of Other Operations as of December 31, 2005 and September 30, 2006 is a pension asset of $654 million and $624 million, respectively.

(14) SUBSEQUENT EVENTS

(A) DIVIDEND DECLARATION

On October 26, 2006, the Company's board of directors declared a regular quarterly cash dividend of $0.15 per share of common stock payable on December 8, 2006, to shareholders of record as of the close of business on November 16, 2006. The conversion rates related to the Company's 3.75% convertible senior notes and 2.875% convertible senior notes are expected to increase as a result of such dividend.

(B) RECEIVABLES FACILITY

In October 2006, CERC extended the termination date of its receivables facility to October 30, 2007. The facility size is $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 termination date of the facility.

26

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS OF CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

The following discussion and analysis should be read in combination with our Interim Condensed Financial Statements contained in this Form 10-Q.

## EXECUTIVE SUMMARY

### RECENT EVENTS

Carthage to Perryville Pipeline. In October 2005, CenterPoint Energy Gas Transmission Company (CEGT), a wholly owned subsidiary of CenterPoint Energy Resources Corp. (CERC Corp.), 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.

On October 2, 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 first quarter 2007 at a cost of approximately $455 million.

Based on strong interest expressed during an open season held earlier this year, and subject to FERC approval, CEGT expects to expand capacity of the pipeline to 1.5 Bcf per day, which would bring the total estimated capital cost of the project to approximately $510 million. 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.

Pipeline Joint Venture with Duke Energy Subsidiary. Earlier this year, CenterPoint Energy Southeast Pipelines Holding, L.L.C., a wholly owned subsidiary of CERC Corp., signed a joint venture agreement with a subsidiary of Duke Energy Gas Transmission (DEGT) to construct, own and operate a 270-mile pipeline (Southeast Supply Header) 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 DEGT. In August 2006, the joint venture signed an agreement with Florida Power & Light Company (FPL) for firm transportation services, which subscribes approximately half of the planned 1 Bcf per day capacity of the pipeline. FPL's commitment is contingent on the approval of the FPL contract by the Florida Public Service Commission in December 2006. Subject to the venture receiving a certificate from the FERC to construct, own and operate the pipeline, subsidiaries of DEGT and CERC Corp. have committed to build the pipeline, for which total costs are estimated to be $700 to $800 million. The pre-filing process with the FERC has been initiated, and an application is expected to be filed in December 2006. Once the project is approved by the FERC, construction is anticipated to begin in the fourth quarter of 2007, with an expected in-service date of June 2008.



## CONSOLIDATED RESULTS OF OPERATIONS

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

| | THREE MONTHS ENDED SEPTEMBER 30, 2005 | THREE MONTHS ENDED SEPTEMBER 30, 2006 | NINE MONTHS ENDED SEPTEMBER 30, 2005 | NINE MONTHS ENDED SEPTEMBER 30, 2006 |
|---|---|---|---|---|
| Revenues | $2,073 | $1,935 | $6,510 | $6,855 |
| Expenses | 1,848 | 1,651 | 5,823 | 6,045 |
| Operating Income | 225 | 284 | 687 | 810 |
| Interest and Other Finance Charges | (177) | (152) | (548) | (451) |
| Other Income, net | 43 | 20 | 127 | 31 |
| Income From Continuing Operations Before Income Taxes and Extraordinary Item | 91 | 152 | 266 | 390 |
| Income Tax Expense | (41) | (69) | (122) | (25) |
| Income From Continuing Operations Before Extraordinary Item | 50 | 83 | 144 | 365 |
| Discontinued Operations, net of tax | -- | -- | (3) | -- |
| Income Before Extraordinary Item | 50 | 83 | 141 | 365 |
| Extraordinary Item, net of tax | -- | -- | 30 | -- |
| Net Income | $ 50 | $ 83 | $ 171 | $ 365 |
| BASIC EARNINGS PER SHARE: | | | | |
| Income From Continuing Operations | $ 0.16 | $ 0.27 | $ 0.46 | $ 1.17 |
| Discontinued Operations, net of tax | -- | -- | (0.01) | -- |
| Extraordinary Item, net of tax | -- | -- | 0.10 | -- |
| Net Income | $ 0.16 | $ 0.27 | $ 0.55 | $ 1.17 |
| DILUTED EARNINGS PER SHARE: | | | | |
| Income From Continuing Operations | $ 0.15 | $ 0.26 | $ 0.43 | $ 1.14 |
| Discontinued Operations, net of tax | -- | -- | (0.01) | -- |
| Extraordinary Item, net of tax | -- | -- | 0.09 | -- |
| Net Income | $ 0.15 | $ 0.26 | $ 0.51 | $ 1.14 |

THREE MONTHS ENDED SEPTEMBER 30, 2006 COMPARED TO THREE MONTHS ENDED SEPTEMBER 30, 2005

Income from Continuing Operations. We reported income from continuing operations before extraordinary item of $83 million ($0.26 per diluted share) for the three months ended September 30, 2006 as compared to $50 million ($0.15 per diluted share) for the same period in 2005. As discussed below, the increase in income from continuing operations of $33 million was primarily due to:

- a $48 million decrease in interest expense, excluding transition bond-related interest expense, due to lower borrowing costs and borrowing levels;

- a $17 million increase in operating income from our Pipelines and Field Services business segment;

- a $13 million increase in operating income from the regulated utility operations of our Electric Transmission & Distribution business segment, including a $12 million increase for the competitive transition charge (CTC); and

- an $8 million increase in operating income from our Competitive Natural Gas Sales and Services business segment.

These increases in income from continuing operations were partially offset by:

- a $35 million decrease in other income related to a return on the true-up balance of our Electric Transmission & Distribution business segment recorded in the third quarter of 2005; and

- a $28 million increase in income taxes resulting from higher income.



NINE MONTHS ENDED SEPTEMBER 30, 2006 COMPARED TO NINE MONTHS ENDED SEPTEMBER 30, 2005

Income from Continuing Operations. We reported income from continuing operations before extraordinary item of $365 million ($1.14 per diluted share) for the nine months ended September 30, 2006 as compared to $144 million ($0.43 per diluted share) for the same period in 2005. As discussed below, the increase in income from continuing operations of $221 million was primarily due to:

- a $168 million decrease in interest expense, excluding transition bond-related interest expense, due to lower borrowing costs and borrowing levels;

- a $119 million decrease in income tax expense from the reduction to previously accrued tax and related interest reserves related to our ZENS and ACES recorded in the second quarter of 2006;

- a $35 million increase in operating income from our Pipelines and Field Services business segment;

- a $26 million increase in operating income from the regulated utility operations of our Electric Transmission & Distribution business segment, including a $42 million increase for the CTC partially offset by the $32 million adverse impact of the resolution of the 2001 Unbundled Cost of Service (UCOS) order recorded in the second quarter of 2006; and

- a $14 million increase in operating income from our Competitive Natural Gas Sales and Services business segment.

These increases in income from continuing operations were partially offset by:

- a $104 million decrease in other income related to a return on the true-up balance of our Electric Transmission & Distribution business segment recorded in the first nine months of 2005; and

- a $26 million decrease in operating income from our Natural Gas Distribution business segment.

INCOME TAX EXPENSE

During the three months and nine months ended September 30, 2006, our effective tax rate was 45% and 6%, respectively. We reached an agreement with the IRS in July 2006 and have reduced our previously accrued tax and related interest reserves related to the ZENS and ACES by approximately $119 million in the second quarter of 2006. The most significant items affecting the tax rate during the three months ended September 30, 2006, were an increase in deferred state taxes and an increase in the tax reserve. During the three months and nine months ended September 30, 2005, our effective tax rate was 45% and 46%, respectively. During the three months and nine months ended September 30, 2005, the most significant item affecting our effective tax rates was an addition to the tax reserve relating to the ZENS and ACES of approximately $10 million and $32 million, respectively.

EXTRAORDINARY ITEM AND LOSS ON DISPOSAL OF TEXAS GENCO

Net income for the nine months ended September 30, 2005 included an after-tax extraordinary gain of $30 million ($0.09 per diluted share) 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. Net income for the nine months ended September 30, 2005 included a net after-tax loss from discontinued operations of Texas Genco of $3 million ($0.01 per diluted share).

29

## RESULTS OF OPERATIONS BY BUSINESS SEGMENT

The following table presents operating income (loss) for each of our business segments for the three and nine months ended September 30, 2005 and 2006. Some amounts from the previous year have been reclassified to conform to the 2006 presentation of the financial statements. These reclassifications do not affect consolidated net income.

| | THREE MONTHS ENDED SEPTEMBER 30, | | NINE MONTHS ENDED SEPTEMBER 30, | |
|---|---|---|---|---|
| | 2005 | 2006 | 2005 | 2006 |
| | (IN MILLIONS) | | | |
| Electric Transmission & Distribution ......... | $183 | $219 | $385 | $480 |
| Natural Gas Distribution ..................... | (16) | (11) | 116 | 90 |
| Competitive Natural Gas Sales and Services ... | 4 | 12 | 30 | 44 |
| Pipelines and Field Services ................ | 52 | 69 | 168 | 203 |
| Other Operations ............................ | 2 | (5) | (12) | (7) |
| Total Consolidated Operating Income ....... | $225 | $284 | $687 | $810 |

ELECTRIC TRANSMISSION & DISTRIBUTION

For information regarding factors that may affect the future results of operations of our Electric Transmission & Distribution business segment, please read "Risk Factors -- Risk Factors Affecting Our Electric Transmission & Distribution Business," " -- Risk Factors Associated with Our Consolidated Financial Condition" and "-- Risks Common to Our Business and Other Risks" in Item 1A of Part I of our Annual Report on Form 10-K for the year ended December 31, 2005 (2005 Form 10-K).

The following tables provide summary data of our Electric Transmission & Distribution business segment for the three and nine months ended September 30, 2005 and 2006 (in millions, except throughput and customer data):

| | THREE MONTHS ENDED SEPTEMBER 30, | | NINE MONTHS SEPTEMBER | |
|---|---|---|---|---|
| | 2005 | 2006 | 2005 | |
| Revenues: | | | | |
| Electric transmission and distribution utility ... | $ 453 | $ 453 | $ 1,164 | $ |
| Transition bond companies ...................... | 31 | 80 | 79 | |
| Total revenues .............................. | 484 | 533 | 1,243 | |
| Expenses: | | | | |
| Operation and maintenance ...................... | 155 | 155 | 446 | |
| Depreciation and amortization .................. | 69 | 58 | 197 | |
| Taxes other than income taxes .................. | 55 | 53 | 163 | |
| Transition bond companies ...................... | 22 | 48 | 52 | |
| Total expenses .............................. | 301 | 314 | 858 | |
| Operating Income ................................. | $ 183 | $ 219 | $ 385 | $ |
| Operating Income - Electric transmission and distribution utility ............................ | $ 174 | $ 187 | $ 358 | $ |
| Operating Income - Transition bond companies (1) ................................. | 9 | 32 | 27 | |
| Total segment operating income ............ | $ 183 | $ 219 | $ 385 | $ |
| Throughput (in gigawatt-hours (GWh)): | | | | |
| Residential .................................... | 8,871 | 8,523 | 19,607 | |
| Total .......................................... | 22,351 | 22,830 | 57,134 | |
| Average number of metered customers: | | | | |
| Residential .................................... | 1,690,819 | 1,740,079 | 1,675,904 | 1 |
| Total .......................................... | 1,921,594 | 1,976,559 | 1,904,235 | 1 |

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



THREE MONTHS ENDED SEPTEMBER 30, 2006 COMPARED TO THREE MONTHS ENDED SEPTEMBER 30, 2005

Our Electric Transmission & Distribution business segment reported operating income of $219 million for the three months ended September 30, 2006, consisting of $187 million for the regulated electric transmission and distribution utility (TDU) (including $14 million for the CTC) and $32 million related to the transition bonds. For the three months ended September 30, 2005, operating income totaled $183 million, consisting of $174 million for the TDU (including $2 million for the CTC) and $9 million related to the transition bonds. Revenues for the TDU continue to benefit from solid customer growth, with nearly 49,000 metered customers added since September 2005 ($10 million), higher transmission cost recovery ($3 million) and recovery of our 2004 true-up balance ($2 million). Houston experienced normal weather during the third quarter of 2006, which created an unfavorable weather variance ($14 million) when compared to the abnormally warm weather in 2005, that substantially offset the increases in revenues discussed above. Operation and maintenance expense remained flat primarily due to higher tree trimming expenses ($3 million) and higher transmission costs ($3 million) offset by lower employee benefit expenses ($4 million) and decreased corporate support services ($4 million). Depreciation and amortization expense decreased ($11 million) primarily as a result of amortization of regulatory liabilities related to the 2004 true-up balance ($13 million), partially offset by an increase in depreciation expense due to higher plant balances ($3 million).

NINE MONTHS ENDED SEPTEMBER 30, 2006 COMPARED TO NINE MONTHS ENDED SEPTEMBER 30, 2005

Our Electric Transmission & Distribution business segment reported operating income of $480 million for the nine months ended September 30, 2006, consisting of $384 million for the TDU (including $44 million for the CTC) and $96 million related to the transition bonds. For the nine months ended September 30, 2005, operating income totaled $385 million, consisting of $358 million for the TDU (including $2 million for the CTC) and $27 million related to the transition bonds. Revenues for the TDU increased due to continued customer growth, with nearly 49,000 metered customers added since September 2005 ($28 million), recovery of our 2004 true-up balance ($28 million) and higher transmission recovery ($8 million), partially offset by the unfavorable weather discussed above and decreased usage ($28 million) and the impact related to the resolution of the 2001 UCOS order ($32 million). Operation and maintenance expense decreased primarily due to a gain on the sale of land in 2006 ($14 million) and lower employee benefit and payroll-related expenses ($6 million), which was partially offset by higher transmission costs ($8 million) and severance costs associated with staff reductions ($4 million). Depreciation and amortization expense decreased ($15 million) primarily as a result of amortization of regulatory liabilities related to the 2004 true-up balance ($26 million), partially offset by an increase in depreciation expense due to higher plant balances ($8 million). Additionally, taxes other than income taxes increased primarily due to higher franchise fees ($13 million) partially offset by decreased property and state franchise tax ($6 million).

NATURAL GAS DISTRIBUTION

For information regarding factors that may affect the future results of operations of our Natural Gas Distribution business segment, please read "Risk Factors -- Risk Factors Affecting Our Natural Gas Distribution, Competitive Natural Gas Sales and Services and Pipelines and Field Services Businesses," " -- Risk Factors Associated with Our Consolidated Financial Condition" and "-- Risks Common to Our Business and Other Risks" in Item 1A of Part I of our 2005 Form 10-K.

31

The following table provides summary data of our Natural Gas Distribution business segment for the three and nine months ended September 30, 2005 and 2006 (in millions, except throughput and customer data):

| | THREE MONTHS ENDED SEPTEMBER 30, | | NINE MONTHS ENDED SEPTEMBER 30, | |
|---|---|---|---|---|
| | 2005 | 2006 | 2005 | 2006 |
| Revenues | $ 535 | $ 485 | $ 2,405 | $ 2,514 |
| Expenses: | | | | |
| Natural gas | 355 | 298 | 1,693 | 1,787 |
| Operation and maintenance | 132 | 137 | 393 | 429 |
| Depreciation and amortization | 39 | 38 | 115 | 113 |
| Taxes other than income taxes | 25 | 23 | 88 | 95 |
| Total expenses | 551 | 496 | 2,289 | 2,424 |
| Operating Income (Loss) | $ (16) | $ (11) | $ 116 | $ 90 |
| Throughput (in billion cubic feet (Bcf)): | | | | |
| Residential | 9 | 14 | 107 | 98 |
| Commercial and industrial | 38 | 44 | 158 | 160 |
| Total Throughput | 47 | 58 | 265 | 258 |
| Average number of customers: | | | | |
| Residential | 2,820,629 | 2,849,040 | 2,835,306 | 2,864,999 |
| Commercial and industrial | 244,249 | 253,063 | 246,370 | 253,357 |
| Total | 3,064,878 | 3,102,103 | 3,081,676 | 3,118,356 |

THREE MONTHS ENDED SEPTEMBER 30, 2006 COMPARED TO THREE MONTHS ENDED SEPTEMBER 30, 2005

Our Natural Gas Distribution business segment reported an operating loss of $11 million for the three months ended September 30, 2006 as compared to an operating loss of $16 million for the three months ended September 30, 2005. Due to seasonal impacts, the third quarter for this business segment is typically one of the weakest of the year. Higher operating margins (revenues less natural gas costs) from rate increases and rate design changes, along with the addition of nearly 43,000 customers since September 2005 ($7 million) were partially offset by increased operation and maintenance expenses driven primarily by higher bad debt expense due to high natural gas prices ($5 million).

NINE MONTHS ENDED SEPTEMBER 30, 2006 COMPARED TO NINE MONTHS ENDED SEPTEMBER 30, 2005

Our Natural Gas Distribution business segment reported operating income of $90 million for the nine months ended September 30, 2006 as compared to $116 million for the nine months ended September 30, 2005. Increased operating margins from rate increases and rate design changes, along with the addition of nearly 43,000 customers since September 2005 ($26 million) and increased gross receipts taxes resulting from higher revenues ($6 million), were partially offset by decreased customer usage and unfavorable weather ($20 million). Operation and maintenance expenses increased primarily due to costs associated with staff reductions ($12 million), increased bad debt expense due to high natural gas prices ($11 million), increased contracts and services expenses and corporate services ($8 million) and a write-off of certain rate case expenses ($3 million). Additionally, taxes other than income taxes increased ($7 million) primarily due to higher gross receipts taxes ($6 million), which offset the corresponding increase in revenues discussed above.

COMPETITIVE NATURAL GAS SALES AND SERVICES

For information regarding factors that may affect the future results of operations of our Competitive Natural Gas Sales and Services business segment, please read "Risk Factors -- Risk Factors Affecting Our Natural Gas Distribution, Competitive Natural Gas Sales and Services and Pipelines and Field Services Business," " -- Risk Factors Associated with Our Consolidated Financial Condition" and "-- Risks Common to Our Business and Other Risks" in Item 1A of Part I of our 2005 Form 10-K.



The following table provides summary data of our Competitive Natural Gas Sales and Services business segment for the three and nine months ended September 30, 2005 and 2006 (in millions, except throughput and customer data):

| | THREE MONTHS ENDED SEPTEMBER 30, | | NINE MONTHS ENDED SEPTEMBER 30, | |
|---|---|---|---|---|
| | 2005 | 2006 | 2005 | 2006 |
| Revenues | $1,013 | $ 830 | $ 2,783 | $2,743 |
| Expenses: | | | | |
| Natural gas | 998 | 809 | 2,728 | 2,673 |
| Operation and maintenance | 9 | 8 | 21 | 23 |
| Depreciation and amortization | -- | -- | 1 | 1 |
| Taxes other than income taxes | 2 | 1 | 3 | 2 |
| Total expenses | 1,009 | 818 | 2,753 | 2,699 |
| Operating Income | $ 4 | $ 12 | $ 30 | $ 44 |
| Throughput (in Bcf): | | | | |
| Wholesale - third parties | 81 | 90 | 235 | 251 |
| Wholesale - affiliates | 11 | 8 | 46 | 27 |
| Retail | 31 | 31 | 112 | 110 |
| Pipeline | 10 | 9 | 41 | 28 |
| Total Throughput | 133 | 138 | 434 | 416 |
| Average number of customers: | | | | |
| Wholesale | 144 | 140 | 143 | 140 |
| Retail | 6,225 | 6,213 | 6,203 | 6,416 |
| Pipeline | 147 | 138 | 154 | 138 |
| Total | 6,516 | 6,491 | 6,500 | 6,694 |

THREE MONTHS ENDED SEPTEMBER 30, 2006 COMPARED TO THREE MONTHS ENDED SEPTEMBER 30, 2005

Our Competitive Natural Gas Sales and Services business segment reported operating income of $12 million for the three months ended September 30, 2006 as compared to $4 million for the three months ended September 30, 2005. The increase was primarily driven by increased sales of gas from inventory ($9 million), reduced bad debt expenses ($2 million) and a favorable variance related to mark-to-market accounting for non-trading financial derivatives used to lock in the economic value associated with basis differentials ($21 million). These positive variances were partially offset by a write-down of natural gas inventory to the lower of average cost or market ($26 million). Our Competitive Natural Gas Sales and Services business segment purchases and stores natural gas to meet certain future sales requirements and enters into derivative contracts to hedge the economic value of the future sales. Due to the inventory write-downs, operating income in the future periods, when these sales of inventory occur, is expected to be higher.

NINE MONTHS ENDED SEPTEMBER 30, 2006 COMPARED TO NINE MONTHS ENDED SEPTEMBER 30, 2005

Our Competitive Natural Gas Sales and Services business segment reported operating income of $44 million for the nine months ended September 30, 2006 as compared to $30 million for the nine months ended September 30, 2005. The increase included improved margins ($38 million) and a favorable variance related to mark-to-market accounting ($34 million), which was partially offset by a write-down of natural gas inventory ($56 million).

PIPELINES AND FIELD SERVICES

For information regarding factors that may affect the future results of operations of our Pipelines and Field Services business segment, please read "Risk Factors -- Risk Factors Affecting Our Natural Gas Distribution, Competitive Natural Gas Sales and Services and Pipelines and Field Services Businesses," " -- Risk Factors Associated with Our Consolidated Financial Condition" and "-- Risks Common to Our Business and Other Risks" in Item 1A of Part I of our 2005 Form 10-K.



The following table provides summary data of our Pipelines and Field Services business segment for the three and nine months ended September 30, 2005 and 2006 (in millions, except throughput data):

| | THREE MONTHS ENDED SEPTEMBER 30, | | NINE MONTHS ENDED SEPTEMBER 30, | |
|---|---|---|---|---|
| | 2005 | 2006 | 2005 | 2006 |
| Revenues | $116 | $141 | $362 | $401 |
| Expenses: | | | | |
| Natural gas | -- | 7 | 25 | 10 |
| Operation and maintenance | 47 | 47 | 121 | 136 |
| Depreciation and amortization | 12 | 12 | 34 | 36 |
| Taxes other than income taxes | 5 | 6 | 14 | 16 |
| Total expenses | 64 | 72 | 194 | 198 |
| Operating Income | $ 52 | $ 69 | $168 | $203 |

| | | | | |
|---|---|---|---|---|
| Operating Income - Pipeline business ........ | $ 36 | $ 48 | $119 | $137 |
| Operating Income - Field Services business .. | 16 | 21 | 49 | 66 |
| Total segment operating income ........ | $ 52 | $ 69 | $168 | $203 |
| Throughput (in Bcf): | | | | |
| Natural Gas Sales ....................... | -- | 1 | 4 | 3 |
| Transportation .......................... | 199 | 204 | 700 | 718 |
| Gathering ............................... | 92 | 97 | 262 | 279 |
| Elimination (1) ......................... | (1) | (1) | (4) | (2) |
| Total Throughput ..................... | 290 | 301 | 962 | 998 |

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(1) Elimination of volumes both transported and sold.

THREE MONTHS ENDED SEPTEMBER 30, 2006 COMPARED TO THREE MONTHS ENDED SEPTEMBER 30, 2005

Our Pipelines and Field Services business segment reported operating income of $69 million for the three months ended September 30, 2006 as compared to $52 million for the three months ended September 30, 2005. This segment's businesses continue to benefit from favorable dynamics in the markets for natural gas gathering and transportation services in the Gulf Coast and Mid-Continent regions. Within this segment, the pipeline business achieved higher operating income of $48 million for the three months ended September 30, 2006 as compared to $36 million for the same period in 2005. This $12 million increase was largely attributable to a pre-tax gain of $13 million associated with the FERC authorized sale of cushion gas which is no longer required for operational purposes as the result of certain capital improvements to enhance working gas capacity and deliverability at one of our storage facilities. The field services business achieved higher operating income of $21 million for the three months ended September 30, 2006 as compared to $16 million for the same period in 2005 primarily driven by increased throughput ($7 million).

In addition, this business segment recorded equity income of $1 million and $2 million for the three months ended September 30, 2005 and 2006, respectively, from its 50 percent interest in a jointly-owned gas processing plant. These amounts are included in Other - net under the Other Income (Expense) caption in our Condensed Statements of Consolidated Income.

NINE MONTHS ENDED SEPTEMBER 30, 2006 COMPARED TO NINE MONTHS ENDED SEPTEMBER 30, 2005

Our Pipelines and Field Services business segment reported operating income of $203 million for the nine months ended September 30, 2006 as compared to $168 million for the nine months ended September 30, 2005. The pipeline business achieved operating income of $137 million for the nine months ended September 30, 2006 as compared to $119 million for the same period in 2005. This $18 million increase is attributable to the gain on the sale of cushion gas ($13 million) discussed above, increased demand for transportation due to favorable basis differentials across the system ($9 million), higher demand for ancillary services ($6 million) and increased project-related revenues ($5 million). These favorable variances were partially offset by increased operating expenses related to increased project-related expenses ($4 million), increased labor-related costs ($3 million) and increased costs associated with normal pipeline maintenance, compliance with pipeline integrity regulations and normal price level increases ($8 million). The field services business achieved operating income of $66 million for the nine months ended September 30, 2006 as compared to $49 million for the same period in 2005 driven by increased throughput ($14 million), higher commodity prices ($7 million) and higher demand for ancillary services ($2 million), partially offset by increased operation and maintenance expenses ($6 million).

Equity income from the jointly-owned gas processing plant discussed above was $4 million and $7 million for the nine months ended September 30, 2005 and 2006, respectively.

OTHER OPERATIONS

The following table shows the operating loss of our Other Operations business segment for the three and nine months ended September 30, 2005 and 2006 (in millions):

| | THREE MONTHS ENDED SEPTEMBER 30, | | NINE MONTHS ENDED SEPTEMBER 30, | |
|---|---|---|---|---|
| | 2005 | 2006 | 2005 | 2006 |
| Revenues | $4 | $ 3 | $ 15 | $12 |
| Expenses | 2 | 8 | 27 | 19 |
| Operating Income (Loss) | $2 | $(5) | $(12) | $(7) |

## CERTAIN FACTORS AFFECTING FUTURE EARNINGS

For information on other developments, factors and trends that may have an impact on our future earnings, please read Note 5(d) to the Interim Condensed Financial Statements for a discussion of CenterPoint Houston's rate case settlement, "Management's Discussion and Analysis of Financial Condition and Results of Operations -- Certain Factors Affecting Future Earnings" in Item 7 of Part II and "Risk Factors" in Item 1A of Part I of our 2005 Form 10-K and "Risk Factors" in Item 1A of Part II of this Quarterly Report on Form 10-Q.

## LIQUIDITY AND CAPITAL RESOURCES

HISTORICAL CASH FLOWS

The following table summarizes the net cash provided by (used in) operating, investing and financing activities for the nine months ended September 30, 2005 and 2006 (in millions):

| | NINE MONTHS ENDED SEPTEMBER 30, | |
|---|---|---|
| | 2005 | 2006 |

| | | |
|---|---|---|
| Cash provided by (used in): | | |
| Operating activities............ | $ 275 | $ 728 |
| Investing activities............ | 218 | (626) |
| Financing activities............ | (496) | 109 |

CASH PROVIDED BY OPERATING ACTIVITIES

Net cash provided by operating activities in the first nine months of 2006 increased $453 million compared to the same period in 2005 primarily due to decreased tax payments of $314 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 ($175 million) primarily related to declining gas prices during the first nine months of 2006, decreases in net regulatory assets ($231 million), primarily due to the termination of excess mitigation credits effective April 29, 2005, decreased gas storage inventory purchases ($96 million) and decreased cash used in the operations of Texas Genco ($38 million). These increases in cash provided by operating activities were partially offset by decreased net accounts receivable/payable ($140 million) primarily due to decreased gas prices in the first nine months of 2006 as compared to the same period in 2005 and decreases in funding of purchases of receivables under CERC Corp.'s receivables facility. Additionally, customer margin deposit requirements decreased ($203 million) primarily due to the decline in natural gas prices from December 2005 to September 2006 and our margin deposits increased ($51 million).

35

CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES

Net cash used in investing activities increased $844 million in the first nine months of 2006 as compared to the same period in 2005 primarily due to increased capital expenditures of $135 million primarily related to our Electric Transmission & Distribution and Pipelines and Field Services business segments 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.

CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES

Net cash provided by financing activities in the first nine months of 2006 increased $605 million compared to the same period in 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 ($239 million) and decreased payments of long-term debt ($341 million), partially offset by the absence of commercial paper borrowings ($190 million) and borrowings under Texas Genco's revolving credit facility ($75 million) due to the sale of Texas Genco and increased dividend payments of $35 million.

FUTURE SOURCES AND USES OF CASH

Our liquidity and capital requirements are affected primarily by our results of operations, capital expenditures, debt service requirements, tax payments, working capital needs, various regulatory actions and appeals relating to such regulatory actions. Our principal cash requirements for the remaining three months of 2006 include the following:

- approximately $420 million of capital expenditures, including approximately $200 million related to our Carthage to Perryville pipeline project discussed above;

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

- long-term debt payments of $145 million.

We expect that borrowings under our credit facilities, liquidation of temporary investments 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 securities in the capital markets.

Commodity Commitments. We negotiated new natural gas transportation contracts during 2006 which was the primary reason for a $933 million increase in the amount of other commodity commitments from the contractual obligations reported in our 2005 Form 10-K. Minimum payment obligations for natural gas supply and related transportation commitments are approximately $302 million for the remaining three months of 2006, $724 million in 2007, $230 million in 2008, $131 million in 2009, $130 million in 2010 and $733 million in 2011 and thereafter.

Convertible Debt. As of September 30, 2006, the 3.75% convertible senior notes discussed in Note 10 to our Interim Condensed Financial Statements 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 third 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 fourth quarter of 2006, the 3.75% convertible senior notes meet the criteria that make them eligible for conversion at the option of the holders of these notes.

Arkansas Public Service Commission, Affiliate Transaction Rulemaking Proceeding. On August 10, 2006, the Arkansas Public Service Commission (APSC) instituted a rulemaking proceeding to promulgate rules governing affiliate transactions involving public utilities operating in Arkansas.

The proposed rules would treat as affiliate transactions all transactions between CERC Corp.'s Arkansas utility operations and other divisions of CERC Corp., as well as transactions between the Arkansas utility operations and affiliates of CERC Corp. All such affiliate transactions would have 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. The Arkansas utility operations could not participate in any financing other than to finance retail utility operations in Arkansas, which would preclude continuation of existing financing arrangements in which CERC Corp. finances its divisions and subsidiaries, including its Arkansas utility operations. Currently, CERC Corp. provides financing for all regulated gas distribution divisions in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas and for CERC's pipeline, field services, gas services and other unregulated businesses.

Under the proposed rules, utilities operating in Arkansas would be required to provide annual certifications from the utility's chief executive and chief financial officers that the rules have been complied with during the previous year, and the utility would be required to fund, without recovery through rates or otherwise, the cost of an annual audit of the utility's compliance with the requirements of the affiliated transactions rules. The utility would be restricted in the level of its non-utility activities and could be required to terminate relationships with affiliates (including its parent) if the APSC were to find that a downgrade of the utility's bond ratings below investment grade would not have occurred but for its relationship with that affiliate. The utility or its parent utility holding company would also be required to file an annual report, signed by its president, certifying that the utility is in compliance with the rules regarding non-utility ownership and providing financial information necessary to demonstrate compliance.

No prediction can be made at this time as to whether, or in what form, the proposed Arkansas affiliate transaction rules will be adopted. However, if the rules are adopted as proposed, the rules would have significant adverse effects on CERC's ability to operate its utility operations in Arkansas. At a minimum, a restructuring of CERC Corp. would be required to create a legal separation of the Arkansas utility operations from CERC Corp.'s other utility and non-utility activities. Financing separate from the financing currently provided by CERC for its utility and non-utility operations would be required for the Arkansas utility operations.

Further, it is still unclear whether CERC would be able to restructure its organization and financing arrangements in order to comply with the proposed rules. It is also unclear whether, even after such a restructuring, the Arkansas utility operations could provide cost-effective utility service in Arkansas.

Under the procedural schedule established by the APSC, comments on the proposed rules were filed with the APSC by CERC and other interested persons on October 6, 2006 and reply comments were filed October 27, 2006. A hearing on the adoption of the proposed rules is scheduled for November 8, 2006. CERC is vigorously contesting the adoption of the proposed rules by the APSC in their current form on the grounds that (i) the proposed rules exceed the statutory authority granted to APSC on the matters covered by the proposed rules, (ii) their implementation would violate the Interstate Commerce Clause of the U.S. Constitution, and (iii) the rules would adversely affect service provided to Arkansas consumers.

Off-Balance Sheet Arrangements. Other than operating leases and the guarantees described below, we have no off-balance sheet arrangements. However, we do participate in a receivables factoring arrangement. CERC Corp. has a bankruptcy remote subsidiary, which we consolidate, that was formed for the sole purpose of buying receivables created by CERC and selling those receivables to an unrelated third-party. This transaction is accounted for as a sale of receivables under the provisions of Statement of Financial Accounting Standards (SFAS) No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," and, as a result, the related receivables are excluded from the Condensed Consolidated Balance Sheet. In October 2006, the termination date of CERC's receivables facility was extended to October 2007. As of September 30, 2006, no amounts were funded under such facility. The facility size is $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 termination date of the facility.

Prior to CenterPoint Energy'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 guarantee obligations prior to separation, but when separation occurred in September 2002, RRI had been unable to extinguish all obligations. To secure CenterPoint Energy and CERC against obligations under the remaining guarantees, RRI agreed to provide cash or



letters of credit for the benefit of CERC and CenterPoint Energy, and agreed to use commercially reasonable efforts to extinguish the remaining guarantees. CenterPoint Energy's current exposure under the remaining guarantees relates to CERC's guarantee of the payment by RRI of demand charges related to transportation contracts with one counterparty. The demand charges are approximately $53 million per year in 2006 through 2015, $49 million in 2016, $38 million in 2017 and $13 million in 2018. As a result of changes in market conditions, the Company's potential exposure under that guarantee currently exceeds the security provided by RRI. CenterPoint Energy has requested RRI to increase the amount of its existing letters of credit or, in the alternative, to obtain a release of CERC's obligations under the guarantee. On June 30, 2006, the RRI trading subsidiary and CERC jointly filed a complaint at the FERC against the counterparty on the CERC guarantee. In the complaint, the RRI trading subsidiary seeks a determination by the FERC that the security held 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 guarantee obligation and, in its place accept (i) a guarantee from RRI of the obligations of the RRI trading subsidiary, and (ii) letters of credit equal 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. On July 20, 2006, the counterparty filed its answer to the complaint, arguing that CERC is contractually bound to continue the guarantee, that the amount of the guarantee does not violate the FERC's policies and that the proposed substitution of credit support is not authorized under the counterparty's financing documents. CenterPoint Energy and the RRI trading subsidiary have filed a reply to that answer and in response to a FERC order, the counterparty has submitted financing documents for FERC review. It is presently unknown what action the FERC may take on the complaint. The RRI trading subsidiary continues to meet its obligations under the transportation contracts.

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 will be used for general corporate purposes, including repayment or refinancing of debt (including $145 million of CERC's 8.90% debentures due December 15, 2006), capital expenditures and working capital.

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.

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



As of October 31, 2006, we had the following credit facilities (in millions):

| DATE EXECUTED | COMPANY | SIZE OF FACILITY | AMOUNT UTILIZED AT OCTOBER 31, 2006 | TERMINATION DATE |
|---|---|---|---|---|
| March 31, 2006 | CenterPoint Energy | $1,200 | $28(1) | March 31, 2011 |
| March 31, 2006 | CenterPoint Houston | 300 | 4(1) | March 31, 2011 |
| March 31, 2006 | CERC Corp. | 550 | 4(1) | March 31, 2011 |

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(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 September 30, 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 September 30, 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 debt securities.

Temporary Investments. As of September 30, 2006, we had external temporary investments of $230 million. As of October 31, 2006, we had external temporary investments of $279 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 commercial paper.

Impact on Liquidity of a Downgrade in Credit Ratings. As of October 31, 2006, 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 | OUTLOO |
| CenterPoint Energy Senior Unsecured Debt........................... | Ba1 | Stable | BBB- | Stable | BBB- | Stab |
| CenterPoint Houston Senior Secured Debt (First Mortgage Bonds)..... | Baa2 | Stable | BBB | Stable | A- | Stab |
| CERC Corp. Senior Unsecured Debt... | Baa3 | Stable | BBB | Stable | BBB | Stab |

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

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

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

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's $550 million revolving credit facility. A decline in credit ratings would also increase the interest rate on long-term debt to be issued in the capital markets and could negatively impact our ability to complete capital market transactions. Additionally, a decline in credit ratings could increase



cash collateral requirements and reduce margins of our Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments.

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 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 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 and TW Common shares are sold.

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 hedge its exposure to natural gas prices, CES uses financial 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 mark-to-market 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. 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 September 30, 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 after November 30, 2006 and 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 cause a default. Pursuant to the indenture governing our senior notes, 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. As of October 31, 2006, we had issued six series of senior notes aggregating $1.4 billion in principal amount under this indenture. A default by CenterPoint Energy would not trigger a default under our 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 arrangement 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 Part I of our 2005 Form 10-K and in "Risk Factors" in Item 1A of Part II of this Quarterly Report on Form 10-Q.

Certain Contractual Limits on Our Ability to Issue Securities, Borrow Money and Pay Dividends on Our Common Stock. 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, in connection with the issuance of a certain series of general mortgage bonds, CenterPoint Houston agreed not to issue, subject to certain limited exceptions, 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 the consolidated financial statements in our 2005 Form 10-K. 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 $308 million of recoverable electric generation-related regulatory assets as of September 30, 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 argument to the 3rd Court of Appeals in Austin is not expected to occur before late November 2006. 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.

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 September 30, 2006, our estimated cost of retiring these assets is approximately $79 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 impact to the amount of pension expense recorded. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations-- Other Significant Matters -- Pension Plan" in Item 7 of our 2005 Form 10-K.

## NEW ACCOUNTING PRONOUNCEMENTS

See Note 4 to the Interim Condensed Financial Statements for a discussion of new accounting pronouncements that affect us.

## ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

COMMODITY PRICE RISK FROM NON-TRADING ACTIVITIES

We measure the commodity risk of our non-trading derivatives (Non-Trading Energy Derivatives) using a sensitivity analysis.

The sensitivity analysis performed on our Non-Trading Energy Derivatives measures the potential loss based on a hypothetical 10% movement in energy prices. At September 30, 2006, the recorded fair value of our Non-Trading Energy Derivatives was a net liability of $101 million. A decrease of 10% in the market prices of energy commodities from their September 30, 2006 levels would have decreased the fair value of our Non-Trading Energy Derivatives from their levels on that date by $98 million.

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

INTEREST RATE RISK

We have outstanding long-term debt, bank loans, mandatory redeemable preferred securities of subsidiary trusts holding solely our junior subordinated debentures (trust preferred securities), some lease obligations and our obligations under the ZENS that subject us to the risk of loss associated with movements in market interest rates.

We had no floating-rate obligations at September 30, 2006.

At September 30, 2006, we had outstanding fixed-rate debt (excluding indexed debt securities) and trust preferred securities aggregating $9.1 billion in principal amount and having a fair value of $9.6 billion. 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. However, the fair value of these instruments would increase by approximately $394 million if interest rates were to decline by 10% from their levels at September 30, 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.

Upon adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (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 September 30, 2006 is a fixed-rate obligation and, therefore, does 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 $17 million if interest rates were to decline by 10% from levels at September 30, 2006. Changes in the fair value of the derivative component will be recorded in our Condensed Statements of Consolidated Income and, therefore, we are exposed to changes in the fair value of the derivative component as a result of changes in the underlying risk-free interest rate. If the risk-free interest rate were to increase by 10% from September 30, 2006 levels, the fair value of the derivative component would increase by approximately $6 million, which would be recorded as a loss in our Condensed Statements of Consolidated Income.

EQUITY MARKET VALUE RISK

We are exposed to equity market value risk through our ownership of 21.6 million shares of TW Common, which we hold to facilitate our ability to meet our obligations under the ZENS. A decrease of 10% from the September 30, 2006 market value of TW Common would result in a net loss of approximately $4 million, which would be recorded as a loss in our Condensed Statements of Consolidated Income.

ITEM 4. 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 September 30, 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 September 30, 2006 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For a description of certain legal and regulatory proceedings affecting CenterPoint Energy, please read Notes 5 and 11 to our Interim Condensed Financial Statements, each of which is incorporated herein by reference. See also "Business -- Regulation" and " -- Environmental Matters" in Item 1 and "Legal Proceedings" in Item 3 of our 2005 Form 10-K.



ITEM 1A. RISK FACTORS

Other than with respect to the risk factor related to our Pipelines and Field Services business segment set forth below, there have been no material changes from the risk factors disclosed in our 2005 Form 10-K.

THE ACTUAL CONSTRUCTION COSTS OF OUR PROPOSED PIPELINES AND RELATED COMPRESSION FACILITIES MAY BE SIGNIFICANTLY HIGHER THAN OUR CURRENT ESTIMATES.

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

ITEM 5. OTHER INFORMATION

The ratio of earnings to fixed charges for the nine months ended September 30, 2005 and 2006 was 1.47 and 1.82, respectively. We do not believe that the ratios for these nine-month periods are necessarily indicators of the ratios for the twelve-month periods due to the seasonal nature of our business. The ratios were calculated pursuant to applicable rules of the Securities and Exchange Commission.

ITEM 6. EXHIBITS

The following exhibits are filed herewith:

Exhibits not incorporated by reference to a prior filing are designated by a cross (+); all exhibits not so designated are incorporated by reference to a prior filing of CenterPoint Energy, Inc.

| EXHIBIT NUMBER | | DESCRIPTION | REPORT OR REGISTRATION STATEMENT | SEC F OR REGISTR NUMBE |
|---|---|---|---|---|
| 3.1.1 | -- | Amended and Restated Articles of Incorporation of CenterPoint Energy | CenterPoint Energy's Registration Statement on Form S-4 | 3-69 |
| 3.1.2 | -- | 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 | 1-31 |
| 3.2 | -- | Amended and Restated Bylaws of CenterPoint Energy | CenterPoint Energy's Form 10-K for the year ended December 31, 2001 | 1-31 |
| 3.3 | -- | 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 | 1-31 |
| 4.1 | -- | Form of CenterPoint Energy Stock Certificate | CenterPoint Energy's Registration Statement on Form S-4 | 3-69 |
| 4.2 | -- | Rights Agreement dated January 1, 2002, between CenterPoint Energy and JPMorgan Chase Bank, as Rights Agent | CenterPoint Energy's Form 10-K for the year ended December 31, 2001 | 1-31 |
| 4.3 | -- | $1,200,000,000 Amended and Restated Credit Agreement dated as of March 31, 2006, among CenterPoint Energy, | CenterPoint Energy's Form 8-K dated March 31, 2006 | 1-31 |



| EXHIBIT NUMBER | | DESCRIPTION | REPORT OR REGISTRATION STATEMENT | SEC F OR REGISTR NUMBE |
|---|---|---|---|---|
| | | as Borrower, and the banks named therein | | |
| 4.4 | -- | $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 | CenterPoint Energy's Form 8-K dated March 31, 2006 | 1-31 |

| | | | | |
|---|---|---|---|---|
| | | Initial Lenders | | |
| 4.5 | -- | $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 | 1-31 |
| +12 | -- | Computation of Ratios of Earnings to Fixed Charges | | |
| +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 | | |
| +99.1 | -- | Items incorporated by reference from the CenterPoint Energy Form 10-K. Item 1A "Risk Factors" | | |

45

SIGNATURES

Pursuant to the requirements 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.

CENTERPOINT ENERGY, INC.

By: /s/ James S. Brian
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James S. Brian
Senior Vice President and Chief
Accounting Officer

Date: November 2, 2006

46

Index to Exhibits

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| 3.1.1 | -- | Amended and Restated Articles of Incorporation of CenterPoint Energy | CenterPoint Energy's Registration Statement on Form S-4 | 3-6 |
| 3.1.2 | -- | 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 | 1-3 |
| 3.2 | -- | Amended and Restated Bylaws of CenterPoint Energy | CenterPoint Energy's Form 10-K for the year ended December 31, 2001 | 1-3 |
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