CENTERPOINT ENERGY INC
Form 10-Q
November 02, 2007

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2007

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
FOR THE TRANSITION PERIOD FROM _________ TO _________.

Commission file number 1-31447
CENTERPOINT ENERGY, INC.
(Exact name of registrant as specified in its charter)

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

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

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

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

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

As of October 31, 2007, CenterPoint Energy, Inc. had 321,254,245 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, 2007
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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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, and changes in or application of laws or regulations applicable to the various aspects of our business;
- timely and appropriate rate actions and increases, allowing recovery of costs and a reasonable return on investment;
- industrial, commercial and residential growth in our service territory and changes in market demand and demographic patterns;
- the timing and extent of changes in commodity prices, particularly natural gas;
- the timing and extent of changes in the supply of natural gas;
- the timing and extent of changes in natural gas basis differentials;
- changes in interest rates or rates of inflation;
- weather variations and other natural phenomena;
- commercial bank and financial market conditions, our access to capital, the cost of such capital, and the results of our financing and refinancing efforts, including availability of funds in the debt capital markets;
- actions by rating agencies;
- effectiveness of our risk management activities;
- inability of various counterparties to meet their obligations to us;
- non-payment for our services due to financial distress of our customers, including Reliant Energy, Inc. (RRI);
- the ability of RRI and its subsidiaries to satisfy their other obligations to us, including indemnity obligations, or in connection with the contractual arrangements pursuant to which we are their guarantor;

the outcome of litigation brought by or against us;

our ability to control costs;

- the investment performance of our employee benefit plans;
- our potential business strategies, including acquisitions or dispositions of assets or businesses, which we cannot assure will be completed or will have the anticipated benefits to us;
- acquisition and merger activities involving us or our competitors; 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, 2006, which is incorporated herein by reference, in Risk Factors in Item 1A of Part II of this Quarterly Report on Form 10-Q, and in other reports we file from time to time with the Securities and Exchange Commission.

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

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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,	
	2006	2007	2006	2007
Revenues	$ 1,935	$ 1,882	$ 6,855	$ 7,021
Expenses:				
Natural gas	1,058	991	4,286	4,349
Operation and maintenance	347	349	1,018	1,031
Depreciation and amortization	159	170	452	475
Taxes other than income taxes	87	85	289	284
Total	1,651	1,595	6,045	6,139
Operating Income	284	287	810	882
Other Income (Expense):				
Gain (loss) on Time Warner investment	20	(58)	17	(74)
Gain (loss) on indexed debt securities	(12)	56	(13)	70
Interest and other finance charges	(120)	(126)	(353)	(368)
Interest on transition bonds	(32)	(30)	(98)	(93)
Distribution from AOL Time Warner litigation settlement		32		32
Additional distribution to ZENS holders		(27)		(27)
Other, net	12	11	27	23
Total	(132)	(142)	(420)	(437)
Income Before Income Taxes	152	145	390	445
Income tax expense	(69)	(54)	(25)	(154)
Net Income	$ 83	$ 91	$ 365	$ 291
Basic Earnings Per Share	$ 0.27	$ 0.29	$ 1.17	$ 0.91
Diluted Earnings Per Share	$ 0.26	$ 0.27	$ 1.14	$ 0.85

See Notes to the Company s Interim Condensed Consolidated Financial Statements

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Millions of Dollars)
(Unaudited)
ASSETS

	December 31, 2006	September 30, 2007
Current Assets:		
Cash and cash equivalents	$ 127	$ 54
Investment in Time Warner common stock	471	397
Accounts receivable, net	1,017	695
Accrued unbilled revenues	451	233
Natural gas inventory	305	451
Materials and supplies	94	97
Non-trading derivative assets	98	44
Prepaid expenses and other current assets	432	379
Total current assets	2,995	2,350
Property, Plant and Equipment:		
Property, plant and equipment	12,567	13,046
Less accumulated depreciation and amortization	(3,363)	(3,417)
Property, plant and equipment, net	9,204	9,629
Other Assets:		
Goodwill	1,705	1,705
Regulatory assets	3,290	3,139
Non-trading derivative assets	21	10
Notes receivable from unconsolidated affiliates		51
Other	418	419
Total other assets	5,434	5,324
Total Assets	$ 17,633	$ 17,303

See Notes to the Company s Interim Condensed Consolidated Financial Statements

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (continued)
(Millions of Dollars)
(Unaudited)
LIABILITIES AND SHAREHOLDERS EQUITY

	December 31, 2006	September 30, 2007
Current Liabilities:		
Short-term borrowings	$ 187	$ 150
Current portion of transition bond long-term debt	147	159
Current portion of other long-term debt	1,051	1,195
Indexed debt securities derivative	372	302
Accounts payable	1,010	455
Taxes accrued	364	252
Interest accrued	159	126
Non-trading derivative liabilities	141	81
Accumulated deferred income taxes, net	316	334
Other	474	331
Total current liabilities	4,221	3,385
Other Liabilities:		
Accumulated deferred income taxes, net	2,323	2,262
Unamortized investment tax credits	39	33
Non-trading derivative liabilities	80	42
Benefit obligations	545	522
Regulatory liabilities	792	825
Other	275	307
Total other liabilities	4,054	3,991
Long-term Debt:		
Transition bonds	2,260	2,101
Other	5,542	6,090
Total long-term debt	7,802	8,191
Commitments and Contingencies (Note 10)		
Shareholders Equity:		
Common stock (313,651,639 shares and 321,219,050 shares outstanding at December 31, 2006 and September 30, 2007, respectively)	3	3
Additional paid-in capital	2,977	3,025
Accumulated deficit	(1,355)	(1,225)

Accumulated other comprehensive loss		(69)		(67)
Total shareholders equity		1,556		1,736
Total Liabilities and Shareholders Equity	$	17,633	$	17,303

See Notes to the Company s Interim Condensed Consolidated Financial Statements

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS
(Millions of Dollars)
(Unaudited)

	Nine Months Ended September 30,	
	2006	**2007**
Cash Flows from Operating Activities:		
Net income	$ 365	$ 291
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	452	475
Amortization of deferred financing costs	37	44
Deferred income taxes	(81)	29
Tax and interest reserves reductions related to ZENS and ACES	(119)	
Investment tax credit	(6)	(6)
Unrealized loss (gain) on Time Warner investment	(17)	74
Unrealized loss (gain) on indexed debt securities	13	(70)
Write-down of natural gas inventory	56	11
Changes in other assets and liabilities:		
Accounts receivable and unbilled revenues, net	788	540
Inventory	(52)	(160)
Taxes receivable	53	
Accounts payable	(640)	(460)
Fuel cost over (under) recovery	106	(90)
Non-trading derivatives, net	(35)	13
Margin deposits, net	(176)	49
Short-term risk management activities, net	3	
Interest and taxes accrued	30	(150)
Net regulatory assets and liabilities	65	57
Other current assets	(87)	(29)
Other current liabilities	(48)	(49)
Other assets	30	(39)
Other liabilities	(16)	(50)
Other, net	7	12
Net cash provided by operating activities	728	492
Cash Flows from Investing Activities:		
Capital expenditures	(641)	(851)
Increase in restricted cash of transition bond companies	(6)	
Increase in notes receivable from unconsolidated affiliates		(51)
Investment in unconsolidated affiliates	(6)	(40)
Other, net	27	9
Net cash used in investing activities	(626)	(933)

Cash Flows from Financing Activities:		
Decrease in short-term borrowings, net		(37)
Long-term revolving credit facilities, net		580
Proceeds from commercial paper, net	(3)	76
Proceeds from issuance of long-term debt	324	400
Payments of long-term debt	(83)	(509)
Debt issuance costs	(4)	(4)
Payment of common stock dividends	(140)	(164)
Proceeds from issuance of common stock, net	12	20
Other	3	6
Net cash provided by financing activities	109	368
Net Increase (Decrease) in Cash and Cash Equivalents	211	(73)
Cash and Cash Equivalents at Beginning of Period	74	127
Cash and Cash Equivalents at End of Period	$ 285	$ 54
Supplemental Disclosure of Cash Flow Information:		
Cash Payments:		
Interest, net of capitalized interest	$ 423	$ 447
Income taxes	150	195
Non-cash transactions:		
Increase in accounts payable related to capital expenditures	21	

See Notes to the Company s Interim Condensed Consolidated Financial Statements

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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, 2006.

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).

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, 2007, the Company s indirect wholly owned subsidiaries included:

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

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

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) the timing of maintenance and other expenditures and (d) acquisitions and dispositions of businesses, assets and other interests. In addition, business segment information for the three and nine months ended September 30, 2006 has been recast to conform to the 2007 presentation due to the change in reportable business segments in the fourth quarter of 2006. The business segment detail revised as a result of the new reportable business segments did not affect consolidated operating income for any period presented.

For a description of the Company s reportable business segments, reference is made to Note 13.

(2) New Accounting Pronouncements

In July 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109 (FIN 48). FIN 48 clarifies the accounting for uncertain income tax positions and requires the Company to recognize management s best estimate of the impact of a tax position if it is considered more likely than not, as defined in Statement of Financial Accounting Standards (SFAS) No. 5, Accounting for Contingencies, of being sustained on audit based solely on the technical merits of the position. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The cumulative effect of adopting FIN 48 as of January 1, 2007 was an approximately $2 million credit to accumulated deficit. The Company recognizes interest and penalties as a component of income taxes.

The implementation of FIN 48 also affected other balance sheet accounts. The balance sheet as of January 1, 2007, upon adoption, would have reflected approximately $72 million of total unrecognized tax benefits in Other Liabilities. This amount includes $48 million reclassified from accumulated deferred income taxes to the liability for uncertain tax positions. The remaining $24 million represents amounts accrued for uncertain tax positions that, if recognized, would reduce the effective income tax rate. In addition to these amounts, the Company, at January 1, 2007, accrued approximately $4 million for the payment of interest for these uncertain tax positions.

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

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

(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,			
	2006		2007	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(in millions)			
Service cost	$ 9	$ 1	$ 9	$
Interest cost	26	6	25	7
Expected return on plan assets	(36)	(3)	(38)	(2)
Amortization of prior service cost	(2)	1	(1)	
Amortization of net loss	13		8	
Amortization of transition obligation		1		2
Net periodic cost	$ 10	$ 6	$ 3	$ 7

	Nine Months Ended September 30,			
	2006		2007	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(in millions)			
Service cost	$ 27	$ 2	$ 27	$ 1
Interest cost	76	19	75	20
Expected return on plan assets	(107)	(9)	(112)	(8)

Amortization of prior service cost		(6)		2		(5)		2
Amortization of net loss		38				26		
Amortization of transition obligation				5				5
Benefit enhancement		8		1				
Net periodic cost	$	36	$	20	$	11	$	20

The Company expects to contribute approximately $8 million in order to pay benefits under its nonqualified pension plan in 2007, of which $6 million had been contributed as of September 30, 2007.

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The Company expects to contribute approximately $27 million to its postretirement benefits plan in 2007, of which $20 million had been contributed as of September 30, 2007.

(4) 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 arguments before the Texas Third Court of Appeals were held in January 2007, but no prediction can be made as to when the court will issue a decision in this matter. No amounts related to the district court s judgment have been recorded in the Company s consolidated financial statements.

Among the issues raised in CenterPoint Houston s appeal of the True-Up Order is the Texas Utility Commission s reduction of CenterPoint Houston s stranded cost recovery by approximately $146 million for the present value of certain deferred tax benefits associated with its former electric generation assets. Such reduction was considered in the Company s recording of an after-tax extraordinary loss of $977 million in the last half of 2004. The Company believes that the Texas Utility Commission based its order on proposed regulations issued by the Internal Revenue Service (IRS) in March 2003 related to those tax benefits. Those proposed regulations would have allowed utilities owning assets that were deregulated before March 4, 2003 to make a retroactive election to pass the benefits of Accumulated Deferred Investment Tax Credits (ADITC) and Excess Deferred Federal Income Taxes (EDFIT) back to customers. However, in December 2005, the IRS withdrew those proposed normalization regulations and issued new proposed regulations that do not include the provision allowing a retroactive election to pass the tax benefits back to customers.

The Company subsequently requested a Private Letter Ruling (PLR) asking the IRS whether the Texas Utility Commission s order reducing CenterPoint Houston s stranded cost recovery by $146 million for ADITC and EDFIT would cause normalization violations. On August 2, 2007, the Company received the requested PLR. In that ruling the IRS concluded that such reductions would cause normalization violations with respect to the ADITC and EDFIT. As in a similar PLR issued in May 2006 to another Texas utility, the IRS did not reference its proposed regulations. If the Texas Utility Commission s order relating to the ADITC 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, 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. Such treatment, if required by the IRS, could have a material adverse impact on the Company s results of operations, financial condition and cash flows. However, the Company and CenterPoint Houston are vigorously pursuing the appeal of this issue and will seek other relief from the Texas Utility Commission to avoid a normalization violation. In September 2007, the Texas Utility Commission requested the Texas Third Court of Appeals to remand the normalization issue to the Texas Utility Commission in light of the position taken by the IRS in the PLR. Although the Texas Utility Commission has not previously required a company subject to its jurisdiction to take action that would result in a normalization violation, no prediction can be made as to the ultimate action the Texas Utility Commission may take on this issue.

Pursuant to a financing order issued by the Texas Utility Commission in March 2005 and affirmed in August 2005 by a Travis County district court, in December 2005, a subsidiary of CenterPoint Houston issued $1.85 billion in transition bonds with interest rates ranging from 4.84 percent to 5.30 percent and final maturity dates ranging

from February 2011 to August 2020. Through issuance of the transition bonds, CenterPoint Houston recovered approximately $1.7 billion of the true-up balance determined in the True-Up Order plus interest through the date on which the bonds were issued.

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

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

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

During the three months ended September 30, 2006 and 2007, CenterPoint Houston recognized approximately $14 million and $11 million, respectively, in operating income from the CTC. During the nine months ended September 30, 2006 and 2007, CenterPoint Houston recognized approximately $44 million and $32 million, respectively, in operating income from the CTC. Additionally, during each of the three months ended September 30, 2006 and 2007, CenterPoint Houston recognized approximately $5 million of the allowed equity return not previously recorded. During the nine months ended September 30, 2006 and 2007, CenterPoint Houston recognized approximately $10 million and $11 million, respectively, of the allowed equity return not previously recorded. As of September 30, 2007, the Company had not recorded an allowed equity return of $223 million on CenterPoint Houston s true-up balance because such return will be recognized as it is recovered in rates.

During the 2007 legislative session, the Texas legislature amended certain statutes authorizing amounts that can be securitized by utilities. In June 2007, CenterPoint Houston filed a request with the Texas Utility Commission for a financing order that would allow the securitization of more than $500 million, representing the remaining balance of the CTC, as well as the fuel reconciliation settlement amount discussed below. The request also included provisions for deduction of the environmental refund and provisions for settlement of any issues associated with the True-Up Order pending in the courts that might be resolved prior to issuance of the bonds. CenterPoint Houston reached substantial agreement with other parties to this proceeding, and a financing order was approved by the Texas Utility Commission in September 2007. The financing order allows for the netting of the fuel reconciliation settlement amount against the environmental refund. The financing order authorizes issuance of approximately $511 million of transition bonds by a new special purpose subsidiary of CenterPoint Houston.

(b) Final Fuel Reconciliation

The results of the Texas Utility Commission s final decision related to CenterPoint Houston s final fuel reconciliation were a component of the True-Up Order. CenterPoint Houston 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. A judgment was entered by a Travis County district court in May 2005 affirming the Texas Utility Commission s decision. CenterPoint Houston filed an appeal to the Texas Third Court of Appeals in June 2005, but in April 2006 that court issued a judgment affirming the Texas Utility Commission s decision. CenterPoint Houston filed an appeal with the Texas Supreme Court in August 2006, but in February 2007 CenterPoint Houston asked the Texas Supreme Court to hold that appeal in abeyance pending consideration by the Texas Utility Commission of a tentative settlement reached by the parties. The Texas Supreme Court granted the abatement of the appeal, and in June 2007 the Texas Utility Commission approved that settlement. The settlement allows CenterPoint Houston recovery of $12.5 million plus interest from January 2002. As a result of the settlement, CenterPoint Houston recorded a regulatory asset of $17 million in the second quarter of 2007. Following a request by CenterPoint Houston and the other parties to the appeal, the Texas Supreme Court vacated the lower court decisions and remanded the case to the Texas Utility Commission. In October 2007, the Texas Utility Commission issued a final order consistent with the terms of the approved settlement agreement.

(c) Refund of Environmental Retrofit Costs

The True-Up Order allowed recovery of approximately $699 million of environmental retrofit costs related to CenterPoint Houston s generation assets. The sale of CenterPoint Houston s interest in its generation assets was completed in early 2005. The True-Up Order required CenterPoint Houston to provide evidence by January 31, 2007 that the entire $699 million was actually spent by December 31, 2006 on environmental programs. In January 2007, the Company was notified by the successor in interest to CenterPoint Houston s generation assets that, as of December 31, 2006, it had only spent approximately $664 million. On January 31, 2007, CenterPoint Houston made the required filing with the Texas Utility Commission, identifying approximately $35 million in unspent funds to be refunded to customers along with approximately $7 million of interest and requesting permission to refund these amounts through a reduction of the CTC. Such amounts were recorded as regulatory liabilities as of December 31, 2006. In May 2007, all parties in the proceeding filed a letter with the Texas Utility Commission stipulating that the total amount of the refund, including all principal and interest, was $45 million as of May 31, 2007, and that interest would continue to accrue after May 31, 2007 on any unrefunded balance at a rate of 5.4519% per year. In July 2007, CenterPoint Houston, the Staff and the other parties filed a settlement agreement incorporating the May 2007 letter agreement and agreeing that the refund should be used to offset the principal amount proposed in CenterPoint Houston s application to securitize the CTC and other amounts. In August 2007, the Texas Utility Commission issued a final order consistent with the terms of the approved settlement agreement. As of September 30, 2007, CenterPoint Houston has recorded a regulatory liability of $46 million related to this matter.

(d) Rate Cases

Arkansas. In January 2007, CERC Corp. s natural gas distribution business (Gas Operations) filed an application with the Arkansas Public Service Commission (APSC) to change its natural gas distribution rates. This filing seeks approval to change the base rate portion of a customer s natural gas bill, which makes up about 30 percent of the total bill and covers the cost of distributing natural gas. The filing does not apply to the gas supply rate, which makes up the remaining approximately 70 percent of the bill.

The January filing requested an increase in annual base revenues of approximately $51 million. Gas Operations subsequently agreed to reduce its request to approximately $40 million. As part of the base rate filing, Gas Operations also proposed a revenue stabilization tariff (also known as decoupling) that would help stabilize revenues and eliminate the potential conflict between its efforts to earn a reasonable return on invested capital while promoting energy efficiency initiatives, because decoupling mitigates the negative effects of declining customer

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usage. As part of the revenue stabilization tariff, Gas Operations proposed to reduce the requested return on equity by 35 basis points which would reduce the base rate increase by $1 million.

In September 2007, the APSC staff and Gas Operations entered into and filed with the APSC a Stipulation and Settlement Agreement (Settlement Agreement) and a joint motion requesting APSC approval of the Settlement Agreement. Under the terms of the Settlement Agreement, the annual base revenues of Gas Operations would increase by approximately $20 million, and the revenue stabilization tariff would be allowed to go into effect upon approval of the Settlement Agreement, with an authorized rate of return on equity of 9.65% (which reflects a reduction of 10 basis points for the implementation of the revenue stabilization tariff). The other parties to the proceeding have agreed not to oppose the Settlement Agreement. In October 2007, an order approving the Settlement Agreement was issued by the APSC. The new rates became effective with bills rendered on and after November 1, 2007.

Texas. In September 2006, Gas Operations filed statements of intent with 47 cities in its Texas coast service territory to increase miscellaneous service charges and to allow recovery of the costs of financial hedging transactions through its purchased gas cost adjustment. In November 2006, these changes became effective as all 47 cities either approved the filings or took no action, thereby allowing rates to go into effect by operation of law. In December 2006, Gas Operations filed a statement of intent with the Railroad Commission of Texas (Railroad Commission) seeking to implement such changes in the environs of the Texas coast service territory. The Railroad Commission approved the filing in April 2007. The new service charges were implemented in the second quarter of 2007.

Minnesota. As of September 30, 2006, Gas Operations had recorded approximately $45 million as a regulatory asset related to prior years unrecovered purchased gas costs in its Minnesota service territory. Of the total, approximately $24 million related to the period from July 1, 2004 through June 30, 2006, and approximately $21 million related to the period from July 1, 2000 through June 30, 2004. The amounts related to periods prior to July 1, 2004 arose as a result of revisions to the calculation of unrecovered purchased gas costs previously approved by the Minnesota Public Utilities Commission (MPUC). Recovery of this regulatory asset was dependent upon obtaining a waiver from the MPUC rules. In November 2006, the MPUC considered the request and voted to deny the waiver. Accordingly, the Company recorded a $21 million adjustment to reduce pre-tax earnings in the fourth quarter of 2006 and reduced the regulatory asset by an equal amount. In February 2007, the MPUC denied reconsideration. In March 2007, the Company petitioned the Minnesota Court of Appeals for review of the MPUC s decision. No prediction can be made as to the ultimate outcome of this matter.

In November 2005, Gas Operations filed a request with the MPUC to increase annual base 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 as final rates was subject to refund to customers. In October 2006, the MPUC considered the request and indicated that it would grant a rate increase of approximately $21 million. In addition, the MPUC approved a $5 million affordability program to assist low-income customers, the actual cost of which will be recovered in rates in addition to the $21 million rate increase. A final order was issued in January 2007, and final rates were implemented beginning May 1, 2007. Gas Operations completed refunding the proportional share of the excess of the amounts collected in interim rates over the amount allowed by the final order to customers in the second quarter of 2007.

(e) APSC Affiliate Transaction Rulemaking Proceeding

In December 2006, the APSC adopted new rules governing affiliate transactions involving public utilities operating in Arkansas. In February 2007, in response to requests by CERC and other gas and electric utilities operating in Arkansas, the APSC granted reconsideration of the rules and stayed their operation in order to permit additional consideration. In May 2007, the APSC adopted revised rules, which incorporated many revisions proposed by the utilities, the Arkansas Attorney General and the APSC staff. The revised rules prohibit affiliated financing transactions for purposes not related to utility operations, but permit the continuation of existing money pool and multi-jurisdictional financing arrangements such as those currently in place at CERC. Non-financial affiliate transactions generally have to be priced under an asymmetrical pricing formula under which utilities would benefit from any difference between the cost of providing goods and services to or from the utility operations and the market value of those goods or services. However, corporate services provided at fully allocated cost such as

those provided by service companies are exempt. The rules also restrict utilities from engaging in businesses other than utility and utility-related businesses if the total book value of non-utility businesses exceeds 10 percent of the book value of the utility and its affiliates. However, existing businesses are grandfathered under the revised rules. The revised rules also permit utilities to petition for waivers of financing and non-financial rules that would otherwise be applicable to their transactions.

The APSC s revised rules impose record keeping, record access, employee training and reporting requirements related to affiliate transactions, including notification to the APSC of the formation of new affiliates that will engage in transactions with the utility and annual certification by the utility s president or chief executive officer and its chief financial officer of compliance with the rules. In addition, the revised rules require a report to the APSC in the event the utility s bond rating is downgraded in certain circumstances. Although the revised rules impose new requirements on CERC s operations in Arkansas, at this time neither CERC nor the Company anticipates that the revised rules will have an adverse effect on existing operations in Arkansas. In September 2007, Gas Operations made a filing with the APSC in accordance with the revised rules to document existing practices that would be covered by grandfathering provisions of those rules.

(5) Derivative Instruments

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

Non-Trading Activities

Cash Flow Hedges. The Company enters into certain derivative instruments that qualify as cash flow hedges under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133). The objective of these derivative instruments is to hedge the price risk associated with natural gas purchases and sales to reduce cash flow variability related to meeting the Company s wholesale and retail customer obligations. During the nine months ended September 30, 2006 and 2007, hedge ineffectiveness resulted in a gain of less than $1 million and a loss of less than $1 million, respectively, from derivatives that qualify for and are designated as cash flow hedges. No component of the derivative instruments gain or loss was excluded from the assessment of effectiveness. If it becomes probable that an anticipated transaction being hedged will not occur, the Company realizes in net income the deferred gains and losses previously recognized in accumulated other comprehensive loss. When an anticipated transaction being hedged affects earnings, the accumulated deferred gain or loss recognized in accumulated other comprehensive loss is reclassified and included in the 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, 2007, the Company expects $15 million ($10 million after-tax) in accumulated other comprehensive income to be reclassified as a decrease in natural gas expense during the next twelve months.

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

Other Derivative Instruments. The Company enters into certain derivative instruments to manage physical commodity price risks that do not qualify or are not designated as cash flow or fair value hedges under SFAS No. 133. The Company utilizes these financial instruments to manage physical commodity price risks and does not engage in proprietary or speculative commodity trading. During the three months ended September 30, 2006 and 2007, the Company recognized unrealized net gains of $20 million and $2 million, respectively. During the nine months ended September 30, 2006 and 2007, the Company recognized unrealized net gains of $33 million and net losses of $12 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 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 the nine months ended September 30, 2006 and 2007 was $23 million and $20 million, respectively. During the third quarter of 2007, the remaining $5 million ($3 million after-tax) in accumulated other comprehensive loss related to interest rate swaps was amortized into interest expense.

Embedded Derivative. The Company s 3.75% convertible senior notes contain contingent interest provisions. The contingent interest component is an embedded derivative as defined by SFAS No. 133, and accordingly must be split from the host instrument and recorded at fair value on the balance sheet. The value of the contingent interest component was not material at issuance or at September 30, 2007.

(6) Goodwill

Goodwill by reportable business segment as of both December 31, 2006 and September 30, 2007 is as follows (in millions):

Natural Gas Distribution	$ 746
Interstate Pipelines	579
Competitive Natural Gas Sales and Services	335
Field Services	25
Other Operations	20
Total	$ 1,705

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

The Company performed the test at July 1, 2007, the Company s annual impairment testing date, and determined that no impairment charge for goodwill was required.

(7) 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,	
	2006	2007	2006	2007
	(in millions)			
Net income	$ 83	$ 91	$ 365	$ 291
Other comprehensive income (loss):				
Adjustment to pension and other postretirement plans (net of tax of $1 and $4)		1		5
Net deferred gain (loss) from cash flow hedges (net of tax of $7, $3, $5 and $6)	10	6	5	11
	7	3	13	(14)

Reclassification of deferred loss (gain) from cash flow hedges realized in net income (net of tax of $4, $1, $4 and $(10))				
Total	17	10	18	2
Comprehensive income	$ 100	$ 101	$ 383	$ 293

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

	December 31, 2006	September 30, 2007
	(in millions)	
SFAS No. 158 incremental effect	$ (79)	$ (74)
Minimum pension liability adjustment	(3)	(3)
Net deferred gain from cash flow hedges	13	10
Total accumulated other comprehensive loss	$ (69)	$ (67)

(8) 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, 2006, 313,651,805 shares of CenterPoint Energy common stock were issued and 313,651,639 shares of CenterPoint Energy common stock were outstanding. At September 30, 2007, 321,219,216 shares of CenterPoint Energy common stock were issued and 321,219,050 shares of CenterPoint Energy common stock were outstanding. See Note 9(b) describing the conversion of the 2.875% Convertible Senior Notes in January 2007. Outstanding common shares exclude 166 treasury shares at both December 31, 2006 and September 30, 2007.

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

(a) Short-term Borrowings

In October 2007, CERC amended its receivables facility and extended the termination date to October 28, 2008. The facility size will range from $150 million to $375 million during the period from September 30, 2007 to the October 28, 2008 termination date. The variable size of the facility was designed to track the seasonal pattern of receivables in CERC s natural gas businesses. At September 30, 2007, the facility size was $150 million. Commencing with an October 2006 amendment to the receivables facility, the provisions for sale accounting under SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, were no longer met. Accordingly, advances received by CERC upon the sale of receivables are accounted for as short-term borrowings as of December 31, 2006 and September 30, 2007. As of December 31, 2006 and September 30, 2007, $187 million and $150 million, respectively, was advanced for the purchase of receivables under CERC s receivables facility.

(b) Long-term Debt

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

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

In October 2007, CERC Corp. issued $250 million aggregate principal amount of 6.125% senior notes due in November 2017 and $250 million aggregate principal amount of 6.625% senior notes due in November 2037. The proceeds from the sale of the senior notes will be used for general corporate purposes, including repayment or refinancing of debt, including $300 million of CERC Corp. s 6.5% senior notes due February 1, 2008, capital expenditures, working capital and loans to or investments in affiliates. Pending application of the proceeds for these purposes, CERC Corp. repaid borrowings under its revolving credit and receivables facilities.

Revolving Credit Facilities. In June 2007, the Company, CenterPoint Houston and CERC Corp. entered into amended and restated bank credit facilities. The Company s amended credit facility is a $1.2 billion five-year senior unsecured revolving credit facility. The facility has a first drawn cost of London Interbank Offered Rate (LIBOR)

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plus 55 basis points based on the Company s current credit ratings, versus the previous rate of LIBOR plus 60 basis points.

The amended facility at CenterPoint Houston is a $300 million five-year senior unsecured revolving credit facility. The facility s first drawn cost remains at LIBOR plus 45 basis points based on CenterPoint Houston s current credit ratings.

The amended facility at CERC Corp. is a $950 million five-year senior unsecured revolving credit facility versus a $550 million facility prior to the amendment. The facility s first drawn cost remains at LIBOR plus 45 basis points based on CERC Corp. s current credit ratings.

Under each of the credit facilities, an additional utilization fee of 5 basis points applies to borrowings any time more than 50% of the facility is utilized. The spread to LIBOR and the utilization fee fluctuate based on the borrower s credit rating.

As of September 30, 2007, the Company had $220 million of borrowings and approximately $27 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 $360 million of borrowings and approximately $19 million of outstanding letters of credit under its $950 million credit facility. The Company also had approximately $76 million of commercial paper outstanding at September 30, 2007, which is supported by its $1.2 billion credit facility. The Company, CenterPoint Houston and CERC Corp. were in compliance with all covenants as of September 30, 2007.

Convertible Debt. On May 19, 2003, the Company issued $575 million aggregate principal amount of convertible senior notes due May 15, 2023 with an interest rate of 3.75%. As of September 30, 2007, holders could convert each of their notes into shares of CenterPoint Energy common stock at a conversion rate of 89.4381 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, the conversion rate has increased to 89.4381, in accordance with the terms of the notes, due to quarterly common stock dividends in excess of $0.10 per share.

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

In August 2005, the Company accepted for exchange approximately $572 million aggregate principal amount of its 3.75% convertible senior notes due 2023 (Old Notes) for an equal amount of its new 3.75% convertible senior notes due 2023 (New Notes). Old Notes of approximately $3 million remain outstanding. Under the terms of the

New Notes, which are substantially similar to the Old Notes, settlement of the principal portion will be made in cash rather than stock.

As of December 31, 2006 and September 30, 2007, the 3.75% convertible senior notes are 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 quarter was greater than or equal to 120% of the conversion price of the 3.75% convertible senior notes and therefore, the 3.75% convertible senior notes meet the criteria that make them eligible for conversion at the option of the holders of these notes.

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

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

(10) Commitments and Contingencies

(a) Natural Gas Supply Commitments

Natural gas supply commitments include natural gas contracts related to the Company s Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments, which have various quantity requirements and durations, that are not classified as non-trading derivative assets and liabilities in the Company s Consolidated Balance Sheets as of December 31, 2006 and September 30, 2007 as these contracts meet the SFAS No. 133 exception to be classified as normal purchases contracts or do not meet the definition of a derivative. Natural gas supply commitments also include natural gas transportation contracts that do not meet the definition of a derivative. As of September 30, 2007, minimum payment obligations for natural gas supply commitments are approximately $436 million for the remaining three months in 2007, $734 million in 2008, $283 million in 2009, $276 million in 2010, $274 million in 2011 and $1.3 billion in 2012 and thereafter.

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

The Company and/or Reliant Energy have been named in approximately 35 of these lawsuits, which were instituted between 2001 and 2007 and are pending in California state court in San Diego County, in Nevada state court in Clark County, in federal district court in Nevada and before the Ninth Circuit Court of Appeals. However, the Company, CenterPoint Houston and Reliant Energy were not participants in the electricity or natural gas markets in California. The Company and Reliant Energy have been dismissed from certain of the lawsuits, either voluntarily by the plaintiffs or by order of the court, and the Company believes it is not a proper defendant in the remaining cases and will continue to seek dismissal from such remaining cases.

To date, several of the electricity complaints have been dismissed, and several of the dismissals have been affirmed by appellate courts. Others have been resolved by the settlement described in the following paragraph. Three of the gas complaints were dismissed based on defendants claims of the filed rate doctrine, but the Ninth Circuit Court of Appeals recently reversed two of those dismissals and remanded the cases back to the district court for further proceedings. In June 2005, a San Diego state court refused to dismiss other gas complaints on the same basis. In October 2006, RRI reached a tentative settlement of 11 class action natural gas cases pending in state court in California. The court approved this settlement in June 2007. The other gas cases remain in the early procedural stages.

In August 2005, RRI reached a settlement with the Federal Energy Regulatory Commission (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, which heard oral arguments from the parties in October 2007. The Company believes that this lawsuit is without merit and will continue to vigorously defend the case. However, the ultimate outcome of this matter cannot be predicted at this time.

Other Legal Matters

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

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

Gas Cost Recovery Litigation. In October 2002, CERC ratepayers filed suit in state district court in Wharton County, Texas against the Company, CERC, Entex Gas Marketing Company (EGMC), and certain non-affiliated companies alleging fraud, violations of the Texas Deceptive Trade Practices Act, violations of the Texas Utilities Code, civil conspiracy and violations of the Texas Free Enterprise and Antitrust Act with respect to rates charged to certain consumers of natural gas in the State of Texas. The plaintiffs initially sought certification of a class of Texas ratepayers, but subsequently dropped their request for class certification. The plaintiffs later added as defendants CenterPoint Energy Marketing Inc., CenterPoint Energy Gas Transmission Company (CEGT), United Gas, Inc., Louisiana Unit Gas Transmission Company, CenterPoint Energy Pipeline Services, Inc. (CEPS), and CenterPoint Energy Trading and Transportation Group, Inc., all of which are subsidiaries of the Company, and other non-affiliated companies. In February 2005, the case was removed to federal district court in Houston, Texas, and in March 2005, the plaintiffs voluntarily dismissed the case and agreed not to refile the claims asserted unless the Miller County case described below is not certified as a class action or is later decertified.

In October 2004, CERC ratepayers in Texas and Arkansas filed suit in circuit court in Miller County, Arkansas against the Company, CERC, EGMC, CEGT, CenterPoint Energy Field Services (CEFS), CEPS, Mississippi River Transmission Corp. (MRT) and other non-affiliated companies alleging fraud, unjust enrichment and civil conspiracy with respect to rates charged to certain consumers of natural gas in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas. Subsequently, the plaintiffs dropped as defendants CEGT and MRT. The plaintiffs seek class certification, but the proposed class has not been certified. In June 2007, the Arkansas Supreme Court determined that the Arkansas claims are within the sole and exclusive jurisdiction of the APSC. Also in June 2007, the Company, CERC, EGMC and other defendants in the Miller County case filed a petition in a district court in Travis County, Texas seeking a determination that the Railroad Commission has original exclusive jurisdiction over the Texas claims asserted in the Miller County case. In August 2007 the Miller County court stayed but refused to dismiss the Arkansas claims. Also in August 2007, the Arkansas plaintiff initiated a complaint at the APSC seeking a decision concerning the extent of the APSC s jurisdiction over the Miller County case and an investigation into the merits of the allegations asserted in his complaint with respect to CERC. In September 2007, the Company, CERC, EGMC and other defendants in the Miller County case initiated proceedings in the Arkansas

Supreme Court to direct the Miller County court to dismiss the entire case on the grounds that the plaintiffs claims are within the exclusive jurisdiction of the APSC or Railroad Commission, as applicable.

In February 2003, a lawsuit was filed in state court in Caddo Parish, Louisiana against CERC with respect to rates charged to a purported class of certain consumers of natural gas and gas service in the State of Louisiana. In February 2004, another suit was filed in state court in Calcasieu Parish, Louisiana against CERC seeking to recover alleged overcharges for gas or gas services allegedly provided by CERC to a purported class of certain consumers of natural gas and gas service without advance approval by the Louisiana Public Service Commission (LPSC). 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 proceedings by the LPSC. In August 2007, the LPSC issued an order approving a Stipulated Settlement in the review initiated by the plaintiffs in the Calcasieu Parish litigation. In that proceeding, CERC s gas purchases were reviewed back to 1971. The review concluded that CERC s gas costs were reasonable and prudent , but CERC agreed to credit to jurisdictional customers approximately $920,000 related to certain off-system sales, including interest. A regulatory liability was established and the Company began refunding that amount to jurisdictional customers in September 2007. A similar review related to the Caddo Parish litigation remains pending at the LPSC.

The range of relief sought by the plaintiffs in the Caddo Parish case includes injunctive and declaratory relief, restitution for the alleged overcharges, exemplary damages or trebling of actual damages, civil penalties and attorney s fees. In this case, 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 Company and CERC do not expect the outcome of this matter to have a material impact on the financial condition, results of operations or cash flows of either the Company or CERC.

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

Environmental Matters

Hydrocarbon Contamination. CERC Corp. and certain of its subsidiaries were among the defendants in lawsuits filed beginning in August 2001 in Caddo Parish and Bossier Parish, Louisiana. The suits alleged 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 was 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.

In July 2007, pursuant to the terms of a previously agreed settlement in principle, the parties implemented the terms of their settlement and resolved this matter. Pursuant to the agreed terms, a CERC Corp. subsidiary had entered into a cooperative agreement with the Louisiana Department of Environmental Quality (LDEQ), pursuant to which CERC Corp. s subsidiary will work with the LDEQ to develop a remediation plan that could be implemented by the CERC Corp. subsidiary. Pursuant to the settlement terms, CERC made a settlement payment within the amounts previously reserved for this matter. The Company and CERC do not expect the costs associated with the resolution of 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, 2007, CERC had accrued $14 million for remediation of these Minnesota sites and the estimated range of possible remediation costs for these sites was $4 million to $35 million based on remediation continuing for 30 to 50 years. The cost estimates are based on studies of a site or industry average costs for remediation of sites of similar size. The actual remediation costs will be dependent upon the number of sites to be remediated, the participation of other potentially responsible parties (PRP), if any, and the remediation methods used. 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, 2007, CERC had collected $13 million from insurance companies and rate payers to be used for future environmental remediation.

In addition to the Minnesota sites, the United States Environmental Protection Agency and other regulators have investigated MGP sites that were owned or operated by CERC or may have been owned by one of its former affiliates. CERC has been named as a defendant in a lawsuit filed in the United States District Court, District of Maine, under which contribution is sought by private parties for the cost to remediate former MGP sites based on the previous ownership of such sites by former affiliates of 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 the lawsuit. In June 2006, the federal district court in Maine ruled that the current owner of the site is responsible for site remediation but that an additional evidentiary hearing is required to determine if other potentially responsible parties, including CERC, would have to contribute to that remediation. The Company is investigating details regarding the site and the range of environmental expenditures for potential remediation. However, CERC believes it is not liable as a former owner or operator of the site under the Comprehensive Environmental, Response, Compensation and Liability Act of 1980, as amended, and applicable state statutes, and is vigorously contesting 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.

In July 2007, the Company was notified of acceptance of its claim in connection with the 2002 AOL Time Warner, Inc. securities and ERISA class action litigation by receipt of approximately $32 million from the independent settlement administrator appointed by the United States District Court, Southern District of New York. Pursuant to the terms of the Indenture governing the Company s 2% Zero Premium Exchangeable Subordinated Notes (ZENS), in August 2007, the Company distributed to current ZENS holders approximately $27 million, which amount represented the portion of the payment received which was attributable to the reference shares of Time Warner Common stock corresponding to each ZENS. This distribution reduced the contingent principal amount of the ZENS from $848 million to $821 million. The litigation settlement was recorded as other income and the distribution to ZENS holders was recorded as other expense during the third quarter of 2007.

Guaranties

Prior to the Company s distribution of its ownership in RRI to its shareholders, CERC had guaranteed certain contractual obligations of what became RRI s trading subsidiary. Under the terms of the separation agreement between the companies, RRI agreed to extinguish all such guaranty obligations prior to separation, but at the time of separation in September 2002, RRI had been unable to extinguish all obligations. To secure the Company and CERC against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for the benefit of CERC and the Company, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. In February 2007, the Company and CERC made a formal demand on RRI under procedures provided by the Master Separation Agreement, dated as of December 31, 2000, between Reliant Energy and RRI. That demand sought to resolve a disagreement with RRI over the amount of security RRI is obligated to provide with respect to this guaranty. In conjunction with discussion of that demand, the Company and RRI entered into an agreement to delay further proceedings regarding this dispute in order to permit further discussions. CERC currently holds letters of credit in the amount of $29.3 million issued on behalf of RRI against guaranties that have not been released. The Company s current exposure under the guaranties relates to CERC s guaranty of the payment by RRI of demand charges related to transportation contracts with one counterparty. RRI has advised the Company and CERC that it has permanently released a portion of the capacity its trading subsidiary holds under those transportation contracts, and CERC has been released from its guaranty with respect to the capacity released.

In June 2006, the RRI trading subsidiary and CERC jointly filed a complaint with the FERC against the counterparty on the CERC guaranty. In response to the FERC s July 2007 order regarding that complaint, the counterparty accepted, with respect to one of the four transportation contracts, the replacement of the CERC guaranty with a letter of credit provided by RRI in the amount of three months of demand charges. The three remaining transportation contracts continue to be covered by the CERC guaranty. After giving effect to the assignments and the substitution of the RRI letter of credit, the reduced level of demand charges is now approximately $19 million per year in 2008, $18 million in 2009 through 2015, $17 million in 2016, $10 million in 2017 and $3 million in 2018. RRI continues to meet its obligations under the transportation contracts, and the Company believes current market conditions make those contracts valuable for transportation services in the near

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term and that additional security is not needed at this time. However, changes in market conditions could affect the value of those contracts. If RRI should fail to perform its obligations under the transportation contracts, the Company s exposure to the counterparty under the guaranty could exceed the security provided by RRI.

(11) Income Taxes

During the three months and nine months ended September 30, 2007, the Company s effective tax rate was 37% and 35%, respectively. During the three months and nine months ended September 30, 2006, the Company s effective tax rate was 45% and 6%, respectively. The most significant items affecting the effective tax rate for the nine months ended September 30, 2006 were a decrease to the tax reserve of approximately $119 million during 2006 relating to the ZENS and Automatic Common Exchange Securities issues as a result of an agreement reached with the IRS in July 2006 and a decrease in the tax reserve for other tax issues. The most significant items affecting the effective tax rate during the three months ended September 30, 2006 were an increase in deferred state taxes and an increase in the tax reserve.

The following table summarizes the Company s liability for uncertain tax positions in accordance with FIN 48 at January 1 and September 30, 2007 (in millions):

	January 1, 2007	**September 30, 2007**
Liability for uncertain tax positions	$ 72	$ 85
Portion of liability for uncertain tax positions that, if recognized, would reduce the effective income tax rate	24	19
Interest accrued on uncertain tax positions	4	5

(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, 2006	**2007**	**For the Nine Months Ended September 30, 2006**	**2007**
	(in millions, except share and per share amounts)			
Basic earnings per share calculation:				
Net income	$ 83	$ 91	$ 365	$ 291
Weighted average shares outstanding	311,945,000	321,192,000	311,414,000	320,071,000
Basic earnings per share	$ 0.27	$ 0.29	$ 1.17	$ 0.91
Diluted earnings per share calculation:				
Net income	$ 83	$ 91	$ 365	$ 291
Weighted average shares outstanding	311,945,000	321,192,000	311,414,000	320,071,000
Plus: Incremental shares from assumed conversions:				
Stock options (1)	1,161,000	1,027,000	1,050,000	1,104,000
Restricted stock	1,292,000	1,713,000	1,292,000	1,713,000

2.875% convertible senior notes	1,613,000		349,000	389,000
3.75% convertible senior notes	8,705,000	17,042,000	5,869,000	18,945,000
Weighted average shares assuming dilution	324,716,000	340,974,000	319,974,000	342,222,000
Diluted earnings per share	$ 0.26	$ 0.27	$ 1.14	$ 0.85

(1) Options to purchase 6,539,344 shares were outstanding for both the three and nine months ended September 30, 2006, and options to purchase 3,474,562 shares were outstanding for both the three and nine months ended

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September 30, 2007, 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 Emerging Issues Task Force Issue No. 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 9) 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 price for the 3.75% contingently convertible senior notes at September 30, 2007 was $11.18 and the conversion price of the 2.875% convertible senior notes at the time of their extinguishment was $12.52.

(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, Interstate Pipelines, Field Services and Other Operations. The electric transmission and distribution function (CenterPoint Houston) is reported in the Electric Transmission & Distribution business segment. Natural Gas Distribution consists of intrastate natural gas sales to, and natural gas transportation and distribution for residential, commercial, industrial and institutional customers. Competitive Natural Gas Sales and Services represents the Company s non-rate regulated gas sales and services operations, which consist of three operational functions: wholesale, retail and intrastate pipelines. Beginning in the fourth quarter of 2006, the Company began reporting its interstate pipelines and field services businesses as two separate business segments, the Interstate Pipelines business segment and the Field Services business segment. These business segments were previously aggregated and reported as the Pipelines and Field Services business segment. The Interstate Pipelines business segment includes the interstate natural gas pipeline operations. The Field Services business segment includes the natural gas gathering and processing operations. Other Operations consists primarily of other corporate operations which support all of the Company s business operations. All prior periods have been recast to conform to the 2007 presentation.

Long-lived assets include net property, plant and equipment, net goodwill 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, 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
Interstate Pipelines	73	33	48
Field Services	31	8	21
Other Operations	2	1	(5)
Eliminations		(61)	

Consolidated	$	1,935	$	$	284

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	For the Three Months ended September 30, 2007		
	Revenues from External Customers	Net Intersegment Revenues	Operating Income (Loss)
Electric Transmission & Distribution	$ 528(1)	$	$ 196
Natural Gas Distribution	457	1	(8)
Competitive Natural Gas Sales and Services	758	12	4
Interstate Pipelines	100	37	70
Field Services	36	8	26
Other Operations	3		(1)
Eliminations		(58)	
Consolidated	$ 1,882	$	$ 287

	For the Nine Months Ended September 30, 2006			
	Revenues from External Customers	Net Intersegment Revenues	Operating Income (Loss)	Total Assets as of December 31, 2006
Electric Transmission & Distribution	$ 1,374(1)	$	$ 480	$ 8,463
Natural Gas Distribution	2,506	8	90	4,463
Competitive Natural Gas Sales and Services	2,681	62	44	1,501
Interstate Pipelines	198	101	137	2,738
Field Services	89	25	66	608
Other Operations	7	5	(7)	2,047(2)
Eliminations		(201)		(2,187)
Consolidated	$ 6,855	$	$ 810	$ 17,633

	For the Nine Months Ended September 30, 2007			
	Revenues from External Customers	Net Intersegment Revenues	Operating Income (Loss)	Total Assets as of September 30, 2007
Electric Transmission & Distribution	$ 1,399(1)	$	$ 457	$ 8,341
Natural Gas Distribution	2,594	7	129	4,199
Competitive Natural Gas Sales and Services	2,679	36	56	1,154
Interstate Pipelines	247	101	166	2,934

Field Services	94	31	75	642
Other Operations	8		(1)	1,806(2)
Eliminations		(175)		(1,773)
Consolidated	$ 7,021	$	$ 882	$ 17,303

(1) Sales to subsidiaries of RRI in the three months ended September 30, 2006 and 2007 represented approximately $225 million and $196 million, respectively, of CenterPoint Houston s transmission and distribution revenues. Sales to subsidiaries of RRI in the nine months ended September 30, 2006 and 2007 represented approximately $569 million and $496 million, respectively.

(2) Included in total assets of Other Operations as of December 31, 2006 and September 30, 2007 is a pension asset of $109 million and $122 million, respectively. Also included in total assets of

Other Operations as of December 31, 2006 and September 30, 2007, is a pension-related regulatory asset of $420 million and $406 million, respectively, that resulted from the Company s adoption of SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans An Amendment of FASB Statements No. 87, 88, 106 and 132(R).

(14) Subsequent Event

On October 25, 2007, the Company s board of directors declared a regular quarterly cash dividend of $0.17 per share of common stock payable on December 10, 2007, to shareholders of record as of the close of business on November 16, 2007.

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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

Debt Financing Transactions

In October 2007, CenterPoint Energy Resources Corp. (CERC Corp., together with its subsidiaries, CERC) issued $250 million aggregate principal amount of 6.125% senior notes due in November 2017 and $250 million aggregate principal amount of 6.625% senior notes due in November 2037. The proceeds from the sale of the senior notes will be used for general corporate purposes, including repayment or refinancing of debt, including $300 million of CERC Corp. s 6.5% senior notes due February 1, 2008, capital expenditures, working capital and loans to or investments in affiliates. Pending application of the proceeds for these purposes, CERC Corp. repaid borrowings under its revolving credit and receivables facilities.

In October 2007, CERC amended its receivables facility and extended the termination date to October 28, 2008. The facility size will range from $150 million to $375 million during the period from September 30, 2007 to the October 28, 2008 termination date. The variable size of the facility was designed to track the seasonal pattern of receivables in CERC s natural gas businesses.

Interstate Pipeline Expansion

Carthage to Perryville. In April 2007, CenterPoint Energy Gas Transmission (CEGT), a wholly owned subsidiary of CERC Corp., completed phase one construction of a 172-mile, 42-inch diameter pipeline and related compression facilities for the transportation of gas from Carthage, Texas to CEGT s Perryville hub in Northeast Louisiana. On May 1, 2007, CEGT began service under its firm transportation agreements with shippers of approximately 960 million cubic feet per day. CEGT s second phase of the project, which involved adding compression that increased the total capacity of the pipeline to approximately 1.25 billion cubic feet (Bcf) per day, was placed into service in August 2007. CEGT has signed firm contracts for the full capacity of phases one and two.

Based on interest expressed during an open season held in 2006, CEGT will add a phase three which will expand capacity of the pipeline to 1.5 Bcf per day by adding additional compression and operating at higher pressures. In May 2007, CEGT received Federal Energy Regulatory Commission (FERC) approval for the third phase of the project to expand capacity of the pipeline, and in July 2007, CEGT received U.S. Department of Transportation approval to increase the maximum allowable operating pressure. The third phase is projected to be in-service in the first quarter of 2008.

Southeast Supply Header. In June 2006, CenterPoint Energy Southeast Pipelines Holding, L.L.C., a wholly owned subsidiary of CERC Corp., and a subsidiary of Spectra Energy Corp. (Spectra) formed a joint venture (Southeast Supply Header or SESH) to construct, own and operate a 270-mile pipeline with a capacity of approximately 1 Bcf per day that will extend from CEGT s Perryville hub in northeast Louisiana to a point interconnecting with Gulfstream Natural Gas System, which is 50 percent owned by an affiliate of Spectra. We account for our 50 percent interest in SESH as an equity investment. In 2006, SESH signed agreements with shippers for firm transportation services, which subscribed capacity of 945 million cubic feet per day.

An application to construct, own and operate the pipeline was filed with the FERC in December 2006. In September 2007, the FERC issued the certificate authorizing the construction of the pipeline. SESH is currently in the preliminary construction stage and is updating its projection for capital costs for the pipeline. Based on a preliminary analysis, SESH is currently projecting the capital costs for its interest in the pipeline may exceed $900 million. SESH expects to complete construction in the summer of 2008.

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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,		Nine Months Ended September 30,	
	2006	2007	2006	2007
Revenues	$ 1,935	$ 1,882	$ 6,855	$ 7,021
Expenses	1,651	1,595	6,045	6,139
Operating Income	284	287	810	882
Interest and Other Finance Charges	(120)	(126)	(353)	(368)
Interest on Transition Bonds	(32)	(30)	(98)	(93)
Other Income, net	20	14	31	24
Income Before Income Taxes	152	145	390	445
Income Tax Expense	(69)	(54)	(25)	(154)
Net Income	$ 83	$ 91	$ 365	$ 291
Basic Earnings Per Share	$ 0.27	$ 0.29	$ 1.17	$ 0.91
Diluted Earnings Per Share	$ 0.26	$ 0.27	$ 1.14	$ 0.85

Three months ended September 30, 2007 compared to three months ended September 30, 2006

We reported consolidated net income of $91 million ($0.27 per diluted share) for the three months ended September 30, 2007 as compared to $83 million ($0.26 per diluted share) for the same period in 2006. The increase in net income of $8 million was primarily due to:

§ increased operating income of $22 million in our Interstate Pipelines business segment;

§ decreased income tax expense of $15 million as discussed below;

§ increased operating income of $5 million in our Field Services business segment;

§ decreased operating loss of $4 million in our Other Operations business segment; and

§ decreased operating loss of $3 million in our Natural Gas Distribution business segment.

These increases in consolidated net income were partially offset by:

§ decreased operating income of $21 million from our Electric Transmission & Distribution utility;

§ decreased operating income of $8 million in our Competitive Natural Gas Sales and Services business segment; and

§ increased interest expense, excluding interest on transition bonds, of $6 million due to higher borrowing levels.

Nine months ended September 30, 2007 compared to nine months ended September 30, 2006

We reported consolidated net income of $291 million ($0.85 per diluted share) for the nine months ended September 30, 2007 as compared to $365 million ($1.14 per diluted share) for the same period in 2006. The decrease in net income of $74 million was primarily due to:

- increased income tax expense of $129 million as discussed below;
- decreased operating income of $17 million from our Electric Transmission & Distribution utility; and
- increased interest expense, excluding interest on transition bonds, of $15 million due to higher borrowing levels.

These decreases in consolidated net income were partially offset by:

§ increased operating income of $39 million in our Natural Gas Distribution business segment;

§ increased operating income of $29 million in our Interstate Pipelines business segment;

§ increased operating income of $12 million in our Competitive Natural Gas Sales and Services business segment;

§ increased operating income of $9 million in our Field Services business segment; and

§ decreased operating loss of $6 million in our Other Operations business segment.

AOL Time Warner Litigation Settlement

In July 2007, we were notified of acceptance of our claim in connection with the 2002 AOL Time Warner, Inc. securities and ERISA class action litigation by receipt of approximately $32 million from the independent settlement administrator appointed by the United States District Court, Southern District of New York. Pursuant to the terms of the Indenture governing our 2% Zero Premium Exchangeable Subordinated Notes (ZENS), in August 2007, we distributed to current ZENS holders approximately $27 million, which amount represented the portion of the payment received which was attributable to the reference shares of Time Warner Common stock corresponding to each ZENS. The litigation settlement was recorded as other income and the distribution to ZENS holders was recorded as other expense during the third quarter of 2007.

Income Tax Expense

During the three months and nine months ended September 30, 2007, our effective tax rate was 37% and 35%, respectively. During the three months and nine months ended September 30, 2006, our effective tax rate was 45% and 6%, respectively. The most significant items affecting our effective tax rate for the nine months ended September 30, 2006 were a decrease to the tax reserve of approximately $119 million during 2006 relating to the ZENS and Automatic Common Exchange Securities issues as a result of an agreement reached with the Internal Revenue Service in July 2006 and a decrease in the tax reserve for other tax issues. The most significant items affecting the effective tax rate during the three months ended September 30, 2006 were an increase in deferred state taxes and an increase in the tax reserve.

RESULTS OF OPERATIONS BY BUSINESS SEGMENT

The following table presents operating income (in millions) for each of our business segments for the three and nine months ended September 30, 2006 and 2007. Due to the change in reportable segments in the fourth quarter of 2006, we have recast our segment information for 2006, as discussed in Note 13 to our Interim Condensed Financial Statements, to conform to the new presentation. The segment detail revised as a result of the new reportable business segments did not affect consolidated operating income for any period.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2007	2006	2007
	(in millions)			
Electric Transmission & Distribution:				
Electric Transmission and Distribution Operations	$ 173	$ 155	$ 340	$ 335
Competition Transition Charge	14	11	44	32
Total Electric Transmission and Distribution Utility	187	166	384	367
Transition Bond Companies	32	30	96	90
Total Electric Transmission & Distribution	219	196	480	457
Natural Gas Distribution	(11)	(8)	90	129
Competitive Natural Gas Sales and Services	12	4	44	56

Interstate Pipelines	48	70	137	166
Field Services	21	26	66	75
Other Operations	(5)	(1)	(7)	(1)
Total Consolidated Operating Income	$ 284	$ 287	$ 810	$ 882

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, 2006 (2006 Form 10-K) and Risk Factors in Item 1A of Part II of this Quarterly Report on Form 10-Q.

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The following tables provide summary data of our Electric Transmission & Distribution business segment for the three and nine months ended September 30, 2006 and 2007 (in millions, except throughput and customer data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2007	2006	2007
Revenues:				
Electric transmission and distribution utility	$ 453	$ 445	$ 1,170	$ 1,187
Transition bond companies	80	83	204	212
Total revenues	533	528	1,374	1,399
Expenses:				
Operation and maintenance, excluding transition bond companies	155	163	436	467
Depreciation and amortization, excluding transition bond companies	58	58	182	182
Taxes other than income taxes	53	58	168	171
Transition bond companies	48	53	108	122
Total expenses	314	332	894	942
Operating Income	$ 219	$ 196	$ 480	$ 457
Operating Income:				
Electric transmission and distribution operations	$ 173	$ 155	$ 340	$ 335
Competition transition charge	14	11	44	32
Transition bond companies (1)	32	30	96	90
Total segment operating income	$ 219	$ 196	$ 480	$ 457
Throughput (in gigawatt-hours (GWh)):				
Residential	8,523	8,381	19,317	19,060
Total	22,830	22,726	59,239	58,561
Average number of metered customers:				
Residential	1,740,079	1,782,281	1,729,348	1,767,431
Total	1,976,559	2,022,448	1,964,189	2,006,344

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

Three months ended September 30, 2007 compared to three months ended September 30, 2006

Our Electric Transmission & Distribution business segment reported operating income of $196 million for the three months ended September 30, 2007, consisting of $155 million from the regulated electric transmission and distribution utility operations (TDU), $11 million from the competition transition charge (CTC), and $30 million related to transition bond companies. For the three months ended September 30, 2006, operating income totaled $219 million, consisting of $173 million from the TDU, $14 million from the CTC, and $32 million related to transition bond companies. Revenues for the TDU decreased due to lower usage due primarily to milder weather ($7 million), the rate reduction resulting from the 2006 rate case settlement that was implemented in October 2006 ($21 million), and lower CTC return resulting from the August 2006 reduction in our allowed rate of return ($3 million). The decreases were partially offset by higher transmission revenues ($12 million), customer growth, with over 47,000 metered customers added since September 30, 2006 ($9 million) and increased miscellaneous service charges ($3 million). Operation and maintenance expense increased primarily due to higher transmission costs ($5 million) and increased expenses related to low income and energy efficiency programs as required by the 2006 rate case settlement ($2 million).

Nine months ended September 30, 2007 compared to nine months ended September 30, 2006

Our Electric Transmission & Distribution business segment reported operating income of $457 million for the nine months ended September 30, 2007, consisting of $335 million from the TDU, $32 million from the CTC, and $90 million related to transition bond companies. For the nine months ended September 30, 2006, operating income totaled $480 million, consisting of $340 million from the TDU, $44 million from the CTC, and $96 million related to transition bond companies. Revenues for the TDU increased due to customer growth, with over 47,000 metered customers added since September 30, 2006 ($19 million), higher transmission revenues ($13 million), increased miscellaneous service charges ($10 million), settlement of the final fuel reconciliation ($4 million) and a one-time charge in the second quarter of 2006 related to the resolution of the unbundled cost of service order ($32 million). These increases were partially offset by the rate reduction resulting from the 2006 rate case settlement that was implemented in October 2006 ($40 million), lower CTC return resulting from the August 2006 reduction in our allowed rate of return ($12 million) and lower usage due primarily to milder weather ($4 million). Operation and maintenance expense increased primarily due to a gain on the sale of property in 2006 ($13 million), higher transmission costs ($19 million), and increased expenses related to low income and energy efficiency programs as required by the 2006 rate case settlement ($7 million), partially offset by settlement of the final fuel reconciliation ($13 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, Interstate 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 2006 Form 10-K and Risk Factors in Item 1A of Part II of this Quarterly Report on Form 10-Q.

The following table provides summary data of our Natural Gas Distribution business segment for the three and nine months ended September 30, 2006 and 2007 (in millions, except throughput and customer data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2007	2006	2007
Revenues	$ 485	$ 458	$ 2,514	$ 2,601
Expenses:				
Natural gas	298	267	1,787	1,845
Operation and maintenance	137	139	429	421
Depreciation and amortization	38	38	113	114
Taxes other than income taxes	23	22	95	92
Total expenses	496	466	2,424	2,472
Operating Income (Loss)	$ (11)	$ (8)	$ 90	$ 129
Throughput (in Bcf):				
Residential	14	12	98	118
Commercial and industrial	44	42	160	168
Total Throughput	58	54	258	286
Average number of customers:				
Residential	2,862,020	2,910,041	2,875,345	2,927,122
Commercial and industrial	240,083	246,021	243,011	246,382
Total	3,102,103	3,156,062	3,118,356	3,173,504

Three months ended September 30, 2007 compared to three months ended September 30, 2006

Our Natural Gas Distribution business segment reported an operating loss of $8 million for the three months ended September 30, 2007 compared to an operating loss of $11 million for the three months ended September 30, 2006. Operating income improved as a result of customer growth ($2 million) from the addition of nearly 48,000 customers since September 30, 2006.

Nine months ended September 30, 2007 compared to nine months ended September 30, 2006

Our Natural Gas Distribution business segment reported operating income of $129 million for the nine months ended September 30, 2007 compared to operating income of $90 million for the nine months ended September 30, 2006. Operating income improved as a result of increased usage primarily due to unusually mild weather in 2006 ($14 million) and growth from the addition of nearly 48,000 customers since September 30, 2006 ($7 million) and reduced operation and maintenance expenses, primarily as a result of costs associated with staff reductions incurred

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in 2006 ($15 million), reduced employee benefit costs ($9 million) and the 2006 write-off of certain rate case expenses ($3 million). The increase in operating income was partially offset by higher expenses associated with initiatives undertaken to improve customer service ($4 million) and the recognition in 2006 of certain favorable regulatory orders ($4 million).

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, Interstate 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 2006 Form 10-K and Risk Factors in Item 1A of Part II of this Quarterly Report on Form 10-Q.

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, 2006 and 2007 (in millions, except throughput and customer data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2007	2006	2007
Revenues	$ 830	$ 770	$ 2,743	$ 2,715
Expenses:				
Natural gas	809	756	2,673	2,631
Operation and maintenance	8	7	23	23
Depreciation and amortization		3	1	4
Taxes other than income taxes	1		2	1
Total expenses	818	766	2,699	2,659
Operating Income	$ 12	$ 4	$ 44	$ 56
Throughput (in Bcf):				
Wholesale third parties	90	74	251	241
Wholesale affiliates	8	2	27	7
Retail and Pipeline	40	43	138	145
Total Throughput	138	119	416	393
Average number of customers:				
Wholesale	140	233	140	235
Retail and Pipeline	6,351	6,743	6,554	6,779
Total	6,491	6,976	6,694	7,014

Three months ended September 30, 2007 compared to three months ended September 30, 2006

Our Competitive Natural Gas Sales and Services business segment reported operating income of $4 million for the three months ended September 30, 2007 compared to operating income of $12 million for the three months ended September 30, 2006. The decrease in operating income of $8 million was primarily due to a reduction in locational and seasonal natural gas price differentials ($4 million). In addition, the third quarter of 2007 included a gain from mark-to-market accounting for non-trading financial derivatives ($2 million) and a write-down of natural gas inventory to the lower of average cost or market ($5 million), compared to a gain from mark-to-market accounting ($21 million) and a natural gas inventory write-down ($26 million) for the same period of 2006. Natural gas that is purchased for inventory is accounted for at the lower of average cost or market price at each balance sheet date.

Nine months ended September 30, 2007 compared to nine months ended September 30, 2006

Our Competitive Natural Gas Sales and Services business segment reported operating income of $56 million for the nine months ended September 30, 2007 compared to $44 million for the nine months ended September 30, 2006. The increase in operating income of $12 million was primarily due to increased operating margins (revenues less

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natural gas costs) related to sales of gas from inventory and asset utilization. In addition, the first nine months of 2007 included a charge from mark-to-market accounting for non-trading financial derivatives ($12 million) and a write-down of natural gas inventory to the lower of average cost or market ($11 million), compared to a gain from mark-to-market accounting ($34 million) and an inventory write-down ($56 million) for the same period of 2006.

Interstate Pipelines

For information regarding factors that may affect the future results of operations of our Interstate Pipelines business segment, please read Risk Factors Risk Factors Affecting Our Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate 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 2006 Form 10-K and Risk Factors in Item 1A of Part II of this Quarterly Report on Form 10-Q.

The following table provides summary data of our Interstate Pipelines business segment for the three and nine months ended September 30, 2006 and 2007 (in millions, except throughput data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2007	2006	2007
Revenues	$ 106	$ 137	$ 299	$ 348
Expenses:				
Natural gas	10	27	22	55
Operation and maintenance	33	29	98	85
Depreciation and amortization	10	11	28	32
Taxes other than income taxes	5		14	10
Total expenses	58	67	162	182
Operating Income	$ 48	$ 70	$ 137	$ 166
Throughput (in Bcf):				
Transportation	204	312	718	880

Three months ended September 30, 2007 compared to three months ended September 30, 2006

Our Interstate Pipeline business segment reported operating income of $70 million for the three months ended September 30, 2007 compared to $48 million for the three months ended September 30, 2006. The increase in operating income was primarily due to the new Carthage to Perryville pipeline ($16 million) and other transportation and ancillary services ($11 million). Additionally, taxes other than income were lower than 2006 primarily due to tax refunds ($4 million) related to the settlement of certain state tax issues. These favorable variances were partially offset by the FERC-authorized sale of excess gas associated with our storage enhancement projects ($13 million) in the third quarter of 2006.

Nine months ended September 30, 2007 compared to nine months ended September 30, 2006

Our Interstate Pipeline business segment reported operating income of $166 million for the nine months ended September 30, 2007 compared to $137 million for the nine months ended September 30, 2006. The increase in operating income was primarily due to the new Carthage to Perryville pipeline, which went into commercial service in May 2007 ($25 million), other transportation and ancillary services ($17 million) and lower taxes other than income ($4 million) as discussed previously. These favorable variances were partially offset by higher sales in 2006 of excess gas associated with storage enhancement projects ($10 million) and the absence of a favorable storage adjustment recorded in the first quarter of 2006 ($3 million).

Field Services

For information regarding factors that may affect the future results of operations of our Field Services business segment, please read Risk Factors Risk Factors Affecting Our Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines and Field Services Businesses, Risk Factors Associated with Our

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Consolidated Financial Condition and Risks Common to Our Business and Other Risks in Item 1A of Part I of our 2006 Form 10-K and Risk Factors in Item 1A of Part II of this Quarterly Report on Form 10-Q.

The following table provides summary data of our Field Services business segment for the three and nine months ended September 30, 2006 and 2007 (in millions, except throughput data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2007	2006	2007
Revenues	$ 39	$ 44	$ 114	$ 125
Expenses:				
Natural gas	(1)	(2)	(4)	(9)
Operation and maintenance	15	17	42	49
Depreciation and amortization	3	2	8	8
Taxes other than income taxes	1	1	2	2
Total expenses	18	18	48	50
Operating Income	$ 21	$ 26	$ 66	$ 75
Throughput (in Bcf):				
Gathering	97	104	279	297

Three months ended September 30, 2007 compared to three months ended September 30, 2006

Our Field Services business segment reported operating income of $26 million for the three months ended September 30, 2007 compared to $21 million for the three months ended September 30, 2006. Increased revenues due to higher throughput and ancillary services ($9 million) was partially offset by lower commodity prices ($2 million) and increased operation and maintenance expenses related to cost increases and expanded operations ($2 million).

In addition, this business segment recorded equity income of $2 million in each of the three months ended September 30, 2006 and 2007 from its 50 percent interest in the Waskom plant. These amounts are included in Other net under the Other Income (Expense) caption.

Nine months ended September 30, 2007 compared to nine months ended September 30, 2006

Our Field Services business segment reported operating income of $75 million for the nine months ended September 30, 2007 compared to $66 million for the nine months ended September 30, 2006. Continued increased demand for gas gathering and ancillary services ($25 million) was partially offset by lower commodity prices ($9 million) and increased operation and maintenance expenses related to cost increases and expanded operations ($7 million).

In addition, this business segment recorded equity income of $7 million and $6 million in the nine months ended September 30, 2006 and 2007, respectively, from its 50 percent interest in the Waskom plant. These amounts are included in Other net under the Other Income (Expense) caption.

Other Operations

The following table shows the operating income (loss) of our Other Operations business segment for the three and nine months ended September 30, 2006 and 2007 (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2007	2006	2007
Revenues	$ 3	$ 3	$ 12	$ 8
Expenses	8	4	19	9

Operating Income (Loss)	$	(5)	$	(1)	$	(7)	$	(1)

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CERTAIN FACTORS AFFECTING FUTURE EARNINGS

For information on other developments, factors and trends that may have an impact on our future earnings, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Certain Factors Affecting Future Earnings in Item 7 of Part II; Risk Factors in Item 1A of Part I of our 2006 Form 10-K, Risk Factors in Item 1A of Part II of this Quarterly Report on Form 10-Q and Cautionary Statement Regarding Forward-Looking Information.

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, 2006 and 2007:

	Nine Months Ended September 30,	
	2006	2007
	(in millions)	
Cash provided by (used in):		
Operating activities	$ 728	$ 492
Investing activities	(626)	(933)
Financing activities	109	368

Cash Provided by Operating Activities

Net cash provided by operating activities in the first nine months of 2007 decreased $236 million compared to the same period in 2006 primarily due to fuel under-recovery ($196 million), increased tax payments ($45 million), increased interest payments ($24 million), increased gas storage inventory ($105 million) and decreased net accounts receivable/payable ($68 million). These decreases were partially offset by decreased reductions in customer margin deposit requirements ($78 million) and decreases in our margin deposit requirements ($147 million).

Cash Used in Investing Activities

Net cash used in investing activities increased $307 million in the first nine months of 2007 as compared to the same period in 2006 primarily due to increased capital expenditures of $210 million primarily related to pipeline projects for our Interstate Pipelines business segment, increased notes receivable from unconsolidated affiliates of $51 million related to the SESH pipeline project and increased investment in unconsolidated affiliates of $34 million.

Cash Provided by Financing Activities

Net cash provided by financing activities in the first nine months of 2007 increased $259 million compared to the same period in 2006 primarily due to increased borrowings under revolving credit facilities ($580 million), increased net proceeds from commercial paper ($79 million) and increased proceeds from long-term debt ($76 million), which were partially offset by increased repayments of long-term debt ($426 million) and decreased short-term borrowings ($37 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 2007 include the following:

- approximately $365 million of capital requirements;

- investment in and advances to SESH of approximately $120 million; and dividend payments on CenterPoint Energy common stock and debt service payments.

We expect that borrowings under our credit facilities and anticipated cash flows from operations will be sufficient to meet our cash needs for the remaining three months of 2007. Cash needs or discretionary financing or refinancing may also result in the issuance of equity or debt securities in the capital markets.

Securitization Bonds. During the 2007 legislative session, the Texas legislature amended certain statutes authorizing amounts that can be securitized by utilities. In June 2007, CenterPoint Houston filed a request with the Texas Utility Commission for a financing order that would allow the securitization of more than $500 million, representing the remaining balance of the CTC, as well as the fuel reconciliation settlement amount. The request also included provisions for deduction of the environmental refund and provisions for settlement of any issues associated with the True-Up Order pending in the courts that might be resolved prior to issuance of the bonds. CenterPoint Houston reached substantial agreement with other parties to this proceeding, and a financing order was approved by the Texas Utility Commission in September 2007. The financing order allows for the netting of the fuel reconciliation settlement amount against the environmental refund. The financing order authorizes issuance of approximately $511 million of transition bonds by a new special purpose subsidiary of CenterPoint Houston.

Convertible Debt. As of September 30, 2007, the 3.75% convertible senior notes discussed in Note 9(b) to our consolidated financial statements have been included as current portion of long-term debt in our Condensed Consolidated Balance Sheets because the last reported sale price of our common stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the second quarter of 2007 was greater than or equal to 120% of the conversion price of the 3.75% convertible senior notes and therefore, during the third quarter of 2007, the 3.75% convertible senior notes meet the criteria that make them eligible for conversion at the option of the holders of these notes.

Arkansas Public Service Commission (APSC), Affiliate Transaction Rulemaking Proceeding. In December 2006, the APSC adopted new rules governing affiliate transactions involving public utilities operating in Arkansas. In February 2007, in response to requests by CERC and other gas and electric utilities operating in Arkansas, the APSC granted reconsideration of the rules and stayed their operation in order to permit additional consideration. In May 2007, the APSC adopted revised rules, which incorporated many revisions proposed by the utilities, the Arkansas Attorney General and the APSC staff. The revised rules prohibit affiliated financing transactions for purposes not related to utility operations, but permit the continuation of existing money pool and multi-jurisdictional financing arrangements such as those currently in place at CERC. Non-financial affiliate transactions generally have to be priced under an asymmetrical pricing formula under which utilities would benefit from any difference between the cost of providing goods and services to or from the utility operations and the market value of those goods or services. However, corporate services provided at fully allocated cost such as those provided by service companies are exempt. The rules also restrict utilities from engaging in businesses other than utility and utility-related businesses if the total book value of non-utility businesses exceeds 10 percent of the book value of the utility and its affiliates. However, existing businesses are grandfathered under the revised rules. The revised rules also permit utilities to petition for waivers of financing and non-financial rules that would otherwise be applicable to their transactions.

The APSC s revised rules impose record keeping, record access, employee training and reporting requirements related to affiliate transactions, including notification to the APSC of the formation of new affiliates that will engage in transactions with the utility and annual certification by the utility s president or chief executive officer and its chief financial officer of compliance with the rules. In addition, the revised rules require a report to the APSC in the event the utility s bond rating is downgraded in certain circumstances. Although the revised rules impose new requirements on CERC s operations in Arkansas, at this time neither we nor CERC anticipate that the revised rules will have an adverse effect on existing operations in Arkansas. In September 2007, Gas Operations made a filing with the APSC in accordance with the revised rules to document existing practices that would be covered by grandfathering provisions of those rules.

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

Prior to the distribution of our ownership in Reliant Energy, Inc. (RRI) to our shareholders, CERC had guaranteed certain contractual obligations of what became RRI s trading subsidiary. Under the terms of the

separation agreement between the companies, RRI agreed to extinguish all such guaranty obligations prior to separation, but at the time of separation in September 2002, RRI had been unable to extinguish all obligations. To secure us and CERC against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for the benefit of CERC and us, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. In February 2007, we and CERC made a formal demand on RRI under procedures provided by the Master Separation Agreement, dated as of December 31, 2000, between Reliant Energy, Incorporated (Reliant Energy) and RRI. That demand sought to resolve a disagreement with RRI over the amount of security RRI is obligated to provide with respect to this guaranty. In conjunction with discussion of that demand, we and RRI entered into an agreement to delay further proceedings regarding this dispute in order to permit further discussions. CERC currently holds letters of credit in the amount of $29.3 million issued on behalf of RRI against guaranties that have not been released. Our current exposure under the guaranties relates to CERC s guaranty of the payment by RRI of demand charges related to transportation contracts with one counterparty. RRI has advised us and CERC that it has permanently released a portion of the capacity its trading subsidiary holds under those transportation contracts, and CERC has been released from its guaranty with respect to the capacity released.

In June 2006, the RRI trading subsidiary and CERC jointly filed a complaint with the FERC against the counterparty on the CERC guaranty. In response to the FERC s July 2007 order regarding that complaint, the counterparty accepted, with respect to one of the four transportation contracts, the replacement of the CERC guaranty with a letter of credit provided by RRI in the amount of three months of demand charges. The three remaining transportation contracts continue to be covered by the CERC guaranty. After giving effect to the assignments and the substitution of the RRI letter of credit, the reduced level of demand charges is now approximately $19 million per year in 2008, $18 million in 2009 through 2015, $17 million in 2016, $10 million in 2017 and $3 million in 2018. RRI continues to meet its obligations under the transportation contracts, and we believe current market conditions make those contracts valuable for transportation services in the near term and that additional security is not needed at this time. However, changes in market conditions could affect the value of those contracts. If RRI should fail to perform its obligations under the transportation contracts, our exposure to the counterparty under the guaranty could exceed the security provided by RRI.

Credit and Receivables Facilities. In June 2007, we, CenterPoint Houston and CERC Corp. entered into amended and restated bank credit facilities. Our amended credit facility is a $1.2 billion five-year senior unsecured revolving credit facility. The facility has a first drawn cost of London Interbank Offered Rate (LIBOR) plus 55 basis points based on our current credit ratings, versus the previous rate of LIBOR plus 60 basis points. The facility contains covenants, including a debt (excluding transition bonds) to earnings before interest, taxes, depreciation and amortization covenant.

The amended facility at CenterPoint Houston is a $300 million five-year senior unsecured revolving credit facility. The facility first drawn cost remains at LIBOR plus 45 basis points based on CenterPoint Houston s current credit ratings. The facility contains covenants, including a debt (excluding transition bonds) to total capitalization covenant.

The amended facility at CERC Corp. is a $950 million five-year senior unsecured revolving credit facility versus a $550 million facility prior to the amendment. The facility s first drawn cost remains at LIBOR plus 45 basis points based on CERC Corp. s current credit ratings. The facility contains covenants, including a debt to total capitalization covenant.

As of October 31, 2007, we had the following facilities (in millions):

Date Executed	Company	Type of Facility	Size of Facility	Amount Utilized at October 31, 2007	Termination Date
June 29, 2007	CenterPoint Energy	Revolver	$1,200	$122(1)	June 29, 2012
June 29, 2007	CenterPoint Houston	Revolver	300	4(2)	June 29, 2012
June 29, 2007	CERC Corp.	Revolver	950	19(2)	June 29, 2012

October 31, 2006	CERC	Receivables	200	156	October 28, 2008

(1) Includes $95 million of borrowings under the credit facility and $27 million of outstanding letters of credit.

(2) Represents outstanding letters of credit.

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Under each of the credit facilities, an additional utilization fee of 5 basis points applies to borrowings any time more than 50% of the facility is utilized. The spread to LIBOR and the utilization fee fluctuate based on the 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.

CERC s receivables facility terminates in October 2008. The facility size will range from $150 million to $375 million during the period from September 30, 2007 to the October 28, 2008 termination date of the facility. At September 30, 2007, the $150 million facility was fully utilized.

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

The $1.2 billion CenterPoint Energy credit facility backstops a $1.0 billion commercial paper program under which we began issuing commercial paper in June 2005. As of September 30, 2007, there was approximately $76 million of commercial paper outstanding. The commercial paper is rated Not Prime by Moody s Investors Service, Inc. (Moody s), A-2 by Standard & Poor s Rating Services (S&P), a division of The McGraw-Hill Companies, and 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. As of September 30, 2007, CenterPoint Energy had a shelf registration statement covering senior debt securities, preferred stock and common stock aggregating $750 million and CERC Corp. had a shelf registration statement covering $900 million principal amount of senior debt securities. In October 2007, CERC Corp. issued $500 million aggregate principal amount of senior debt securities, resulting in $400 million of capacity remaining on the shelf registration statement.

Temporary Investments. As of October 31, 2007, we had external temporary investments of $7 million.

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

Impact on Liquidity of a Downgrade in Credit Ratings. As of October 31, 2007, Moody s, S&P, and Fitch had assigned the following credit ratings to senior debt of CenterPoint Energy and certain subsidiaries:

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

(1) A stable outlook from Moody s

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

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

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

A decline in credit ratings could increase borrowing costs under our $1.2 billion credit facility, CenterPoint Houston s $300 million credit facility and CERC Corp. s $950 million credit facility. A decline in credit ratings would also increase the interest rate on long-term debt to be issued in the capital markets and could negatively impact our ability to complete capital market transactions. Additionally, a decline in credit ratings could increase cash collateral requirements and reduce earnings of our Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments.

In September 1999, we issued 2.0% ZENS having an original principal amount of $1.0 billion of which $840 million remain outstanding. Each ZENS note is exchangeable at the holder s option at any time for an amount of cash equal to 95% of the market value of the reference shares of Time Warner Inc. common stock (TW Common) attributable to each ZENS note. If our creditworthiness were to drop such that ZENS note holders thought our liquidity was adversely affected or the market for the ZENS notes were to become illiquid, some ZENS note holders might decide to exchange their ZENS notes for cash. Funds for the payment of cash upon exchange could be obtained from the sale of the shares of TW Common that we own or from other sources. We own shares of TW Common equal to approximately 100% of the reference shares used to calculate our obligation to the holders of the ZENS notes. ZENS note exchanges result in a cash outflow because deferred tax liabilities related to the ZENS notes and TW Common shares become current tax obligations when ZENS notes are exchanged or otherwise retired and TW Common shares are sold. A tax obligation of approximately $145 million relating to our original issue discount deductions on the ZENS would have been payable if all of the ZENS had been exchanged for cash on September 30, 2007. The ultimate tax obligation related to the ZENS notes continues to increase by the amount of the tax benefit realized each year and there could be a significant cash outflow when the taxes are paid as a result of the retirement of the ZENS notes.

CenterPoint Energy Services, Inc. (CES), a wholly owned subsidiary of CERC Corp. operating in our Competitive Natural Gas Sales and Services business segment, provides comprehensive natural gas sales and services primarily to commercial and industrial customers and electric and gas utilities throughout the central and eastern United States. In order to economically hedge its exposure to natural gas prices, CES uses derivatives with provisions standard for the industry, including those pertaining to credit thresholds. Typically, the credit threshold negotiated with each counterparty defines the amount of unsecured credit that such counterparty will extend to CES. To the extent that the credit exposure that a counterparty has to CES at a particular time does not exceed that credit threshold, CES is not obligated to provide collateral. Mark-to-market exposure in excess of the credit threshold is routinely collateralized by CES. As of September 30, 2007, the amount posted as collateral amounted to approximately $64 million. Should the credit ratings of CERC Corp. (as the credit support provider for CES) fall below certain levels, CES would be required to provide additional collateral on two business days notice up to the amount of its previously unsecured credit limit. We estimate that as of September 30, 2007, unsecured credit limits extended to CES by counterparties aggregate $149 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 SESH s 270-mile pipeline project, CERC Corp. has committed that it will advance funds to the joint venture or cause funds to be advanced for its 50 percent share of the cost to construct the pipeline. CERC Corp. also agreed to provide a letter of credit in an amount up to $400 million for its share of funds that have not been advanced in the event S&P reduces CERC Corp. s bond rating below investment grade before CERC Corp. has advanced the required construction funds. However, CERC Corp. is relieved of these commitments

(i) to the extent of 50 percent of any borrowing agreements that the joint venture has obtained and maintains for funding the construction of the pipeline and (ii) to the extent CERC Corp. or its subsidiary participating in the joint venture obtains committed borrowing agreements pursuant to which funds may be borrowed and used for the construction of the pipeline. A similar commitment has been provided by the other party to the joint venture. As of September 30, 2007, subsidiaries of CERC Corp. have advanced approximately $103 million to SESH, of which $52 million was equity and $51 million was debt.

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. In addition, six outstanding series of our senior notes, aggregating $1.4 billion in principal amount as of September 30, 2007, provide that a payment default by us, CERC Corp. or CenterPoint Houston in respect of, or an acceleration of, borrowed money and certain other specified types of obligations, in the aggregate principal amount of $50 million, will cause a default. A default by CenterPoint Energy would not trigger a default under our subsidiaries debt instruments or bank credit facilities.

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

- cash collateral requirements that could exist in connection with certain contracts, including gas purchases, gas price hedging and gas storage activities of our Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments, particularly given gas price levels and volatility;
- acceleration of payment dates on certain gas supply contracts under certain circumstances, as a result of increased gas prices and concentration of natural gas suppliers;
- increased costs related to the acquisition of natural gas;
- increases in interest expense in connection with debt refinancings and borrowings under credit facilities;
- various regulatory actions;
- the ability of RRI and its subsidiaries to satisfy their obligations as the principal customers of CenterPoint Houston and in respect of RRI s indemnity obligations to us and our subsidiaries or in connection with the contractual obligations to a third party pursuant to which CERC is a guarantor;
- slower customer payments and increased write-offs of receivables due to higher gas prices or changing economic conditions;
- 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 our 2006 Form 10-K and 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 and Borrow Money. CenterPoint Houston s credit facility limits CenterPoint Houston s debt (excluding transition bonds) as a percentage of its total capitalization to 65 percent. CERC Corp. s bank facility and its receivables facility limit CERC s debt as a percentage of its total capitalization to 65 percent. Our $1.2 billion credit facility contains a debt, excluding transition bonds, to EBITDA covenant. Additionally, CenterPoint Houston is contractually prohibited, subject to certain exceptions, from issuing additional first mortgage bonds.

CRITICAL ACCOUNTING POLICIES

A critical accounting policy is one that is both important to the presentation of our financial condition and results of operations and requires management to make difficult, subjective or complex accounting estimates. An accounting estimate is an approximation made by management of a financial statement element, item or account in the financial statements. Accounting estimates in our historical consolidated financial statements measure the effects of past business transactions or events, or the present status of an asset or liability. The accounting estimates described below require us to make assumptions about matters that are highly uncertain at the time the estimate is made. Additionally, different estimates that we could have used or changes in an accounting estimate that are reasonably likely to occur could have a material impact on the presentation of our financial condition or results of operations. The circumstances that make these judgments difficult, subjective and/or complex have to do with the need to make estimates about the effect of matters that are inherently uncertain. Estimates and assumptions about future events and their effects cannot be predicted with certainty. We base our estimates on historical experience and on various other assumptions that we believe to be reasonable under the circumstances, the results of which form the basis for making judgments. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. Our significant accounting policies are discussed in Note 2 to our consolidated financial statements in our 2006 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 $290 million of recoverable electric generation-related regulatory assets as of September 30, 2007. 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 Public Utility Commission of Texas (Texas Utility Commission), we recorded an after-tax charge to earnings in 2004 of approximately $977 million to write down our electric generation-related regulatory assets to their realizable value, which was reflected as an extraordinary loss. Based on subsequent orders received from the Texas Utility Commission, we recorded an extraordinary gain of $30 million after-tax in the second quarter of 2005 related to the regulatory asset. Additionally, a district court in Travis County, Texas issued a judgment that would have the effect of restoring approximately $650 million, plus interest, of disallowed costs. CenterPoint Houston and other parties appealed the district court judgment. Oral arguments before the Texas Third Court of Appeals were held in January 2007, but no prediction can be made as to when the court will issue a decision in this matter. 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, 2007. 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 which 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, 2007, our estimated cost of retiring these assets is approximately $89 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 2006 Form 10-K for further discussion.

NEW ACCOUNTING PRONOUNCEMENTS

See Note 2 to our 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 in fair value based on a hypothetical 10% movement in energy prices. At September 30, 2007, the recorded fair value of our non-trading energy derivatives was a net liability of $69 million. The net liability consisted of a $15 million net liability associated with price stabilization activities of our Natural Gas Distribution business segment and a net liability of $54 million related to our Competitive Natural Gas Sales and Services business segment. Net assets or liabilities related to the price stabilization activities correspond directly with net over/under recovered gas cost liabilities or assets on the balance sheet. A decrease of 10% in the market prices of energy commodities from their September 30, 2007 levels would have decreased the fair value of our non-trading energy derivatives by $90 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 hedging purposes associated with the hypothetical changes in commodity prices referenced above is expected to be substantially offset by a favorable impact on the underlying hedged physical transactions.

Interest Rate Risk

We have outstanding long-term debt, bank loans, some lease obligations and our obligations under the ZENS that subject us to the risk of loss associated with movements in market interest rates.

Our floating-rate obligations aggregated $806 million at September 30, 2007. If the floating interest rates were to increase by 10% from September 30, 2007 rates, our annual interest expense would increase by approximately $5 million.

At September 30, 2007, we had outstanding fixed-rate debt (excluding indexed debt securities) aggregating $8.8 billion in principal amount and having a fair value of $9.2 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 $333 million if interest rates were to decline by 10% from their levels at September 30, 2007. 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 $114 million at September 30, 2007 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 $18 million if interest rates were to decline by 10% from levels at September 30, 2007. 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, 2007 levels, the fair value of the derivative component would increase by approximately $5 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, 2007 market value of TW Common would result in a net loss of approximately $3 million, which

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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, 2007 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, 2007 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 4 and 10 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 2006 Form 10-

Item 1A. RISK FACTORS

Other than with respect to the risk factors set forth below, there have been no material changes from the risk factors disclosed in our 2006 Form 10-K.

The states in which CERC provides regulated local gas distribution may, either through legislation or rules, adopt restrictions similar to those under the Public Utility Holding Company Act of 1935 Act (1935 Act) regarding organization, financing and affiliate transactions that could have significant adverse effects on CERC s ability to operate its utility operations.

The 1935 Act provided a comprehensive regulatory structure governing the organization, capital structure, intracompany relationships and lines of business that could be pursued by registered holding companies and their member companies. Following repeal of that Act, some states in which CERC does business have sought to expand their own regulatory frameworks to give their regulatory authorities increased jurisdiction and scrutiny over similar aspects of the utilities that operate in their states. Some of these frameworks attempt to regulate financing activities, acquisitions and divestitures, and arrangements between the utilities and their affiliates, and to restrict the level of non-utility businesses that can be conducted within the holding company structure. Additionally they may impose record keeping, record access, employee training and reporting requirements related to affiliate transactions and reporting in the event of certain downgrading of the utility s bond rating.

These regulatory frameworks could have adverse effects on CERC s ability to operate its utility operations, to finance its business and to provide cost-effective utility service. In addition, if more than one state adopts restrictions over similar activities, it may be difficult for CenterPoint Energy and CERC to comply with competing regulatory requirements.

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

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

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

those transferred to Texas Genco Holdings, Inc. (Texas Genco) in connection with its organization and capitalization.

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

Prior to the Company s distribution of its ownership in RRI to its shareholders, CERC had guaranteed certain contractual obligations of what became RRI s trading subsidiary. Under the terms of the separation agreement between the companies, RRI agreed to extinguish all such guaranty obligations prior to separation, but at the time of separation in September 2002, RRI had been unable to extinguish all obligations. To secure the Company and CERC against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for the benefit of CERC and the Company, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. CERC currently holds letters of credit in the amount of $29.3 million issued on behalf of RRI against guaranties that have not been released. RRI may be unable to obtain a release of CERC under some of the remaining guarantees, and one of those guarantees has been issued to support long-term transportation contracts that extend to 2018. There can be no assurance that the letters of credit held by CERC will be sufficient to satisfy CERC s obligations on the remaining guaranties if RRI were to fail to perform its obligation to the counterparties, and RRI may be unable or unwilling to provide increased security from time to time to protect CERC if CERC s exposures on such guarantees were to exceed the amount of the letters of credit held as security.

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

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

In connection with the organization and capitalization of Texas Genco, Texas Genco assumed liabilities associated with the electric generation assets Reliant Energy transferred to it. Texas Genco also agreed to indemnify, and cause the applicable transferee subsidiaries to indemnify, us and our subsidiaries, including CenterPoint Houston, with respect to liabilities associated with the transferred assets and businesses. In many cases the liabilities assumed were obligations of CenterPoint Houston and CenterPoint Houston was not released by third parties from these liabilities. The indemnity provisions were intended generally to place sole financial responsibility on Texas Genco and its subsidiaries for all liabilities associated with the current and historical businesses and operations of Texas Genco, regardless of the time those liabilities arose. In connection with the sale of Texas Genco s fossil generation assets (coal, lignite and gas-fired plants) to Texas Genco LLC, the separation agreement we entered into with Texas Genco in connection with the organization and capitalization of Texas Genco was

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amended to provide that all of Texas Genco s rights and obligations under the separation agreement relating to its fossil generation assets, including Texas Genco s obligation to indemnify us with respect to liabilities associated with the fossil generation assets and related business, were assigned to and assumed by Texas Genco LLC. In addition, under the amended separation agreement, Texas Genco is no longer liable for, and we have assumed and agreed to indemnify Texas Genco LLC against, liabilities that Texas Genco originally assumed in connection with its organization to the extent, and only to the extent, that such liabilities are covered by certain insurance policies or other similar agreements held by us. If Texas Genco or Texas Genco LLC were unable to satisfy a liability that had been so assumed or indemnified against, and provided Reliant Energy had not been released from the liability in connection with the transfer, CenterPoint Houston could be responsible for satisfying the liability.

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

Item 5. OTHER INFORMATION

Ratio of Earnings to Fixed Charges

The ratio of earnings to fixed charges for the nine months ended September 30, 2006 and 2007 was 1.82 and 1.85, 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.

Carthage to Perryville Pipeline

In September 2007, CEGT initiated an investigation into allegations received from two former employees of the manufacturer of pipe installed in CEGT s Carthage to Perryville pipeline segment. That pipeline segment was placed in commercial service in May 2007 after satisfactory completion of hydrostatic testing designed to ensure that the pipe and its welds would be structurally sound when placed in service and operated at design pressure. According to the complainants, records relating to radiographic inspections of certain welds made at the fabrication facility had been altered resulting in the possibility that pipe with the alleged substandard welds had been installed in the pipeline. In addition to commencing an investigation utilizing outside legal counsel and other experts, CEGT immediately informed appropriate government officials. CEGT has continued to keep those officials informed of CEGT s activities and developments during its investigation. In conducting its investigation, among other things, CEGT has interviewed the complainants and other individuals, including CEGT and contractor personnel, and reviewed documentation related to the manufacture and construction of the pipeline, including radiographic records related to the allegedly deficient welds. CEGT has also consulted appropriate technical consultants and pre-existing regulatory guidance. Although its investigation is continuing, CEGT has found no basis, as a result of the allegations received to date, to cease or modify operations of its Carthage to Perryville line or take other significant action. CEGT further believes that, absent new findings, the Carthage to Perryville line can be operated at expected operating pressures without threat to the public health or safety.

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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 File or Registration Number	Exhibit Reference
3.1.1	Amended and Restated Articles of Incorporation of CenterPoint Energy	CenterPoint Energy s Registration Statement on Form S-4	3-69502	3.1
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	1-31447	3.1.1
3.2	Amended and Restated Bylaws of CenterPoint Energy	CenterPoint Energy s Form 8-K dated October 25, 2007	1-31447	3.1
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	1-31447	3.3
4.1	Form of CenterPoint Energy Stock Certificate	CenterPoint Energy s Registration Statement on Form S-4	3-69502	4.1
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	1-31447	4.2
4.3	$1,200,000,000 Second Amended and Restated Credit Agreement dated as of June 29, 2007, among CenterPoint Energy, as Borrower, and the banks named therein	CenterPoint Energy s Form 10-Q for the quarter ended June 30, 2007	1-31447	4.3
4.4	$300,000,000 Second Amended and Restated Credit Agreement dated as of June 29, 2007, among CenterPoint Houston, as Borrower, and the banks named therein	CenterPoint Energy s Form 10-Q for the quarter ended June 30, 2007	1-31447	4.4
4.5	$950,000,000 Second Amended and Restated Credit Agreement dated as of June 29, 2007, among	CenterPoint Energy s Form 10-Q for the quarter ended June 30, 2007	1-31447	4.5

	CERC Corp., as Borrower, and the banks named therein			
4.6	Indenture, dated as of February 1, 1998, between Reliant Energy Resources Corp. and Chase Bank of Texas, National Association, as Trustee	CERC Corp. s Form 8-K dated February 5, 1998	1-13265	4.1
4.7	Supplemental Indenture No. 10 to Exhibit 4.6, dated as of February 6, 2007, providing for the issuance of CERC Corp. s 6.25% Senior Notes due 2037	CenterPoint Energy s Form 10-K for the year ended December 31, 2006	1-31447	4(f)(11)
+4.8	Supplemental Indenture No. 11 dated as of October 23, 2007, to the Indenture between CenterPoint Energy Resources Corp. and The Bank of New York Trust Company, National Association, as trustee			

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Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
+4.9	Supplemental Indenture No. 12 dated as of October 23, 2007, to the Indenture between CenterPoint Energy Resources Corp. and The Bank of New York Trust Company, National Association, as trustee			
4.10	Indenture, dated as of May 19, 2003, between CenterPoint Energy and JPMorgan Chase Bank, as Trustee	CenterPoint Energy s Form 8-K dated May 19, 2003	1-31447	4.1
4.11	Supplemental Indenture No. 7 to Exhibit 4.8, dated as of February 6, 2007, providing for the issuance of CenterPoint Energy s 5.95% Senior Notes due 2017	CenterPoint Energy s Form 10-K for the year ended December 31, 2006	1-31447	4(g) (8)
+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			

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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

James S. Brian
Senior Vice President and Chief Accounting Officer

Date: November 2, 2007

Index to 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 File or Registration Number	Exhibit Reference
3.1.1	Amended and Restated Articles of Incorporation of CenterPoint Energy	CenterPoint Energy s Registration Statement on Form S-4	3-69502	3.1
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	1-31447	3.1.1
3.2	Amended and Restated Bylaws of CenterPoint Energy	CenterPoint Energy s Form 10-K for the year ended December 31, 2001	1-31447	3.2
3.3	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	1-31447	3.3
4.1	Form of CenterPoint Energy Stock Certificate	CenterPoint Energy s Registration Statement on Form S-4	3-69502	4.1
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	1-31447	4.2
4.3	$1,200,000,000 Second Amended and Restated Credit Agreement dated as of June 29, 2007, among CenterPoint Energy, as Borrower, and the banks named therein	CenterPoint Energy s Form 10-Q for the quarter ended June 30, 2007	1-31447	4.3
4.4	$300,000,000 Second Amended and Restated Credit Agreement dated as of June 29, 2007, among CenterPoint Houston, as Borrower, and the banks named therein	CenterPoint Energy s Form 10-Q for the quarter ended June 30, 2007	1-31447	4.4

4.5	$950,000,000 Second Amended and Restated Credit Agreement dated as of June 29, 2007, among CERC Corp., as Borrower, and the banks named therein	CenterPoint Energy s Form 10-Q for the quarter ended June 30, 2007	1-31447	4.5
4.6	Indenture, dated as of February 1, 1998, between Reliant Energy Resources Corp. and Chase Bank of Texas, National Association, as Trustee	CERC Corp. s Form 8-K dated February 5, 1998	1-13265	4.1
4.7	Supplemental Indenture No. 10 to Exhibit 4.6, dated as of February 6, 2007, providing for the issuance of CERC Corp. s 6.25% Senior Notes due 2037	CenterPoint Energy s Form 10-K for the year ended December 31, 2006	1-31447	4(f)(11)
+4.8	Supplemental Indenture No. 11 dated as of October 23, 2007, to the Indenture between CenterPoint Energy Resources Corp. and The Bank of New York Trust Company, National Association, as trustee			

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