CENTERPOINT ENERGY INC
Form 10-Q
April 29, 2009

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

FORM 10-Q

(Mark One)

R	QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2009
	OR
£	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	FOR THE TRANSITION PERIOD FROM TO

Commission file number 1-31447

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 R No £

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes £ No £

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

As of April 22, 2009, CenterPoint Energy, Inc. had 349,240,945 shares of common stock outstanding, excluding 166 shares held as treasury stock.

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CENTERPOINT ENERGY, INC.
QUARTERLY REPORT ON FORM 10-Q
FOR THE QUARTER ENDED MARCH 31, 2009

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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

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

- the resolution of the true-up components, including, in particular, the results of appeals to the courts regarding rulings obtained to date;
- state and federal legislative and regulatory actions or developments, including deregulation, re-regulation, environmental regulations, including regulations related to global climate change, and changes in or application of laws or regulations applicable to the various aspects of our business;
- timely and appropriate regulatory actions allowing securitization or other recovery of costs associated with Hurricane Ike;
- timely and appropriate rate actions and increases, allowing recovery of costs and a reasonable return on investment;
- cost overruns on major capital projects that cannot be recouped in prices;
- 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 and natural gas liquids;
- the timing and extent of changes in the supply of natural gas;
- the timing and extent of changes in natural gas basis differentials;
- weather variations and other natural phenomena;
- changes in interest rates or rates of inflation;
- 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 and any successor companies to satisfy their other obligations to us,

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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, 2008, which is incorporated herein by reference, and 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 March 31, 2008	Three Months Ended March 31, 2009
Revenues	$ 3,363	$ 2,766
Expenses:		
Natural gas	2,393	1,789
Operation and maintenance	365	413
Depreciation and amortization	158	166
Taxes other than income taxes	111	113
Total	3,027	2,481
Operating Income	336	285
Other Income (Expense):		
Loss on marketable securities	(54)	(34)
Gain on indexed debt securities	50	22
Interest and other finance charges	(116)	(129)
Interest on transition bonds	(33)	(33)
Equity in earnings of unconsolidated affiliates	9	—
Other, net	4	4
Total	(140)	(170)
Income Before Income Taxes	196	115
Income tax expense	(74)	(48)
Net Income	$ 122	$ 67
Basic Earnings Per Share	$ 0.37	$ 0.19
Diluted Earnings Per Share	$ 0.36	$ 0.19

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, 2008	March 31, 2009
Current Assets:		
Cash and cash equivalents	$ 167	$ 65
Investment in marketable securities	218	184
Accounts receivable, net	1,009	903
Accrued unbilled revenues	541	287
Natural gas inventory	441	12
Materials and supplies	128	135
Non-trading derivative assets	118	119
Prepaid expenses and other current assets	413	369
Total current assets	3,035	2,074
Property, Plant and Equipment:		
Property, plant and equipment	14,006	14,109
Less accumulated depreciation and amortization	3,710	3,709
Property, plant and equipment, net	10,296	10,400
Other Assets:		
Goodwill	1,696	1,696
Regulatory assets	3,684	3,643
Non-trading derivative assets	20	23
Investment in unconsolidated affiliates	345	343
Notes receivable from unconsolidated affiliates	323	323
Other	277	308
Total other assets	6,345	6,336
Total Assets	$ 19,676	$ 18,810

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, 2008	March 31, 2009
Current Liabilities:		
Short-term borrowings	$ 153	$ 215
Current portion of transition bond long-term debt	208	211
Current portion of other long-term debt	125	133
Indexed debt securities derivative	133	111
Accounts payable	897	436
Taxes accrued	189	123
Interest accrued	180	153
Non-trading derivative liabilities	87	63
Accumulated deferred income taxes, net	372	392
Other	504	358
Total current liabilities	2,848	2,195
Other Liabilities:		
Accumulated deferred income taxes, net	2,609	2,586
Unamortized investment tax credits	24	22
Non-trading derivative liabilities	47	47
Benefit obligations	833	838
Regulatory liabilities	821	847
Other	276	331
Total other liabilities	4,610	4,671
Long-term Debt:		
Transition bonds	2,381	2,274
Other	7,800	7,601
Total long-term debt	10,181	9,875
Commitments and Contingencies (Note 11)		
Shareholders' Equity:		
Common stock (346,088,548 shares and 349,216,548 shares outstanding at December 31, 2008 and March 31, 2009, respectively)	3	3
Additional paid-in capital	3,158	3,187
Accumulated deficit	(993)	(992)
Accumulated other comprehensive loss	(131)	(129)
Total shareholders' equity	2,037	2,069

Total Liabilities and Shareholders’ Equity	$	19,676	$	18,810

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)

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2009
Cash Flows from Operating Activities:		
Net income	$ 122	$ 67
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	158	166
Amortization of deferred financing costs	8	10
Deferred income taxes	27	30
Unrealized loss on marketable securities	54	34
Unrealized gain on indexed debt securities	(50)	(22)
Write-down of natural gas inventory	—	6
Equity in earnings of unconsolidated affiliates, net of distributions	(9)	—
Changes in other assets and liabilities:		
Accounts receivable and unbilled revenues, net	(84)	308
Inventory	327	416
Accounts payable	56	(425)
Fuel cost over recovery	29	(30)
Non-trading derivatives, net	28	8
Margin deposits, net	29	(62)
Interest and taxes accrued	(72)	(94)
Net regulatory assets and liabilities	14	21
Other current assets	34	43
Other current liabilities	(63)	(64)
Other assets	(6)	(4)
Other liabilities	(47)	24
Other, net	12	1
Net cash provided by operating activities	567	433
Cash Flows from Investing Activities:		
Capital expenditures	(187)	(260)
Decrease (increase) in restricted cash of transition bond companies	(13)	1
Increase in notes receivable from unconsolidated affiliates	(2)	—
Investment in unconsolidated affiliates	(105)	2
Other, net	(5)	(4)
Net cash used in investing activities	(312)	(261)
Cash Flows from Financing Activities:		
Increase (decrease) in short-term borrowings, net	(32)	62
Long-term revolving credit facilities, net	(231)	(706)
Proceeds from commercial paper, net	35	19
Proceeds from long-term debt	488	500
Payments of long-term debt	(515)	(110)

Debt issuance costs		—		(4)
Payment of common stock dividends		(60)		(66)
Proceeds from issuance of common stock, net		1		30
Other, net		—		1
Net cash used in financing activities		(314)		(274)
Net Decrease in Cash and Cash Equivalents		(59)		(102)
Cash and Cash Equivalents at Beginning of Period		129		167
Cash and Cash Equivalents at End of Period	$	70	$	65
Supplemental Disclosure of Cash Flow Information:				
Cash Payments:				
Interest, net of capitalized interest	$	173	$	182
Income taxes		39		26
Non-cash transactions:				
Accounts payable related to capital expenditures		72		67

See Notes to the Company's Interim Condensed Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(1) Background and Basis of Presentation

General. Included in this Quarterly Report on Form 10-Q (Form 10-Q) of CenterPoint Energy, Inc. are the condensed consolidated interim financial statements and notes (Interim Condensed Financial Statements) of CenterPoint Energy, Inc. and its subsidiaries (collectively, CenterPoint Energy, or the Company). The Interim Condensed Financial Statements are unaudited, omit certain financial statement disclosures and should be read with the Annual Report on Form 10-K of CenterPoint Energy for the year ended December 31, 2008 (CenterPoint Energy Form 10-K).

Background. CenterPoint Energy, Inc. is a public utility holding company. 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 March 31, 2009, 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. Subsidiaries of CERC own interstate natural gas pipelines and gas gathering systems and provide various ancillary services. A 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 generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

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

For a description of the Company's reportable business segments, reference is made to Note 14.

(2) New Accounting Pronouncements

In December 2007, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard (SFAS) No. 141 (Revised 2007), "Business Combinations" (SFAS No. 141R). SFAS No. 141R will significantly change the accounting for business combinations. Under SFAS No. 141R, an acquiring entity will be required to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition date fair value with limited exceptions. SFAS No. 141R also includes a substantial number of new disclosure requirements and applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. As the provisions of SFAS No. 141R are applied prospectively, the impact to the Company cannot be determined until applicable transactions occur.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements an Amendment of ARB No. 51" (SFAS No. 160). SFAS No. 160 establishes new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. This accounting standard is effective for fiscal years and interim periods within those fiscal years, beginning on or after

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December 15, 2008. The Company's adoption of SFAS No. 160 as of January 1, 2009 did not have a material impact on its financial position, results of operations or cash flows.

Effective January 1, 2009, the Company adopted SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133" (SFAS No. 161). SFAS No. 161 amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133) which requires enhanced disclosures of derivative instruments and hedging activities such as the fair value of derivative instruments and presentation of their gains or losses in tabular format, as well as disclosures regarding credit risks and strategies and objectives for using derivative instruments. These disclosures are included as part of the Company's Derivatives Instruments footnote (see Note 5).

In May 2008, the FASB issued FASB Staff Position (FSP) No. APB 14-1 "Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement)," which changed the accounting treatment for convertible securities that the issuer may settle fully or partially in cash. Under the final FSP, cash settled convertible securities are separated into their debt and equity components. The value assigned to the debt component is the estimated fair value, as of the issuance date, of a similar debt instrument without the conversion feature, and the difference between the proceeds for the convertible debt and the amount reflected as a debt liability is recorded as additional paid-in capital. As a result, the debt is recorded at a discount reflecting its below market coupon interest rate. The debt is then subsequently accreted to its par value over its expected life, with the rate of interest that reflects the market rate at issuance being reflected on the income statement. The Company adopted the FSP effective January 1, 2009, which required retrospective application to all periods presented. The Company currently has no convertible debt that is within the scope of this FSP, but did during prior periods presented. Accordingly, the implementation of the FSP had a non-cash effect on net income for prior periods and the consolidated balance sheets when the Company had contingently convertible debt outstanding. The effect on net income for the three months ended March 31, 2008 was a decrease in net income of $1 million, or $0.01 per basic share. There was no impact on diluted earnings per share. Upon adoption of this FSP, the effect on the balance sheet as of January 1, 2009 was a credit to Additional Paid-In-Capital of $23 million, with an offsetting debit to retained earnings of $23 million.

In December 2008, the FASB issued FASB Staff Position No. FAS 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets" (FSP 132(R)-1), which amends SFAS No. 132(R), "Employers' Disclosures about Pensions and Other Postretirement Benefits." FSP 132(R)-1 expands the disclosures about employers' plan assets to include more detailed disclosures about the employers' investment strategies, major categories of plan assets, concentrations of risk within plan assets and valuation techniques used to measure the fair value of plan assets. FSP 132(R)-1 is effective for fiscal years ending after December 15, 2009. The Company expects that the adoption of FSP 132(R)-1 will not have a material impact on its financial position, results of operations or cash flows.

In April 2009, the FASB issued FASB Staff Position No. FAS 107-1 and APB 28-1, "Interim Disclosures about Fair Value of Financial Instruments" (FSP 107-1), which amends SFAS No. 107, "Disclosures about Fair Value of Financial Instruments" (SFAS No. 107) and APB 28-1, "Interim Financial Reporting." FSP 107-1 expands the fair value disclosures required for all financial instruments within the scope of SFAS No. 107 to interim periods. FSP 107-1 also requires entities to disclose in interim periods the methods and significant assumptions used to estimate the fair value of financial instruments. FSP 107-1 is effective for interim reporting periods ending after June 15, 2009. The Company expects that the adoption of FSP 107-1 will not have a material impact on its financial position, results of operations or cash flows.

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(3) Employee Benefit Plans

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

	Three Months Ended March 31,			
	2008		2009	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(in millions)			
Service cost	$ 8	$ —	$ 6	$ —
Interest cost	25	7	28	7
Expected return on plan assets	(37)	(3)	(24)	(2)
Amortization of prior service cost	(2)	1	1	1
Amortization of net loss	6	—	17	—
Amortization of transition obligation	—	2	—	2
Net periodic cost	$ —	$ 7	$ 28	$ 8

The Company expects to contribute approximately $22 million to its pension plans in 2009, of which $2 million had been contributed as of March 31, 2009 and $13 million was funded on April 14, 2009.

The Company expects to contribute approximately $18 million to its postretirement benefits plan in 2009, of which $6 million had been contributed as of March 31, 2009.

(4) Regulatory Matters

(a) Hurricane Ike

CenterPoint Houston's electric delivery system suffered substantial damage as a result of Hurricane Ike, which struck the upper Texas coast in September 2008.

As is common with electric utilities serving coastal regions, the poles, towers, wires, street lights and pole mounted equipment that comprise CenterPoint Houston's transmission and distribution system are not covered by property insurance, but office buildings and warehouses and their contents and substations are covered by insurance that provides for a maximum deductible of $10 million. Current estimates are that total losses to property covered by this insurance were approximately $17 million.

CenterPoint Houston deferred the uninsured system restoration costs as management believes it is probable that such costs will be recovered through the regulatory process. As a result, system restoration costs did not affect the Company's or CenterPoint Houston's reported net income for 2008 or the first quarter of 2009. As of March 31, 2009, CenterPoint Houston had balances of $161 million in construction work in progress and $437 million in regulatory assets related to restoration costs incurred through March 31, 2009. In April 2009, CenterPoint Houston filed with the Public Utility Commission of Texas (Texas Utility Commission) an application for review and approval for recovery of approximately $608 million in system restoration costs identified as of the end of February 2009, plus $2 million in regulatory expenses, $13 million in certain debt issuance costs, and $55 million in carrying costs, pursuant to the legislation described below. CenterPoint Houston expects to incur additional costs, currently estimated at $12 million, related to Hurricane Ike, principally related to the reconstruction of certain substations on Galveston Island, and will seek to recover those costs through the regulatory process at a later date.

In April 2009, the Texas Legislature enacted legislation that authorizes the Texas Utility Commission to conduct proceedings to determine the amount of system restoration costs and related costs associated with hurricanes or other major storms that utilities are entitled to recover through charges to customers. The legislation authorizes the Texas Utility Commission to issue a financing order that would permit a utility like CenterPoint Houston to recover the distribution portion of those costs and related carrying costs through the issuance of non-recourse system restoration bonds similar to the securitization bonds issued previously. The legislation also allows such a utility to recover, or defer for future recovery, the transmission portion of its system restoration costs through the existing mechanisms established to recover transmission level costs. The legislation requires the Texas Utility Commission to make its determination of recoverable system restoration costs within 150 days of the filing of a utility's application and to rule on a utility's application for a financing order for the issuance of system restoration bonds

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within 90 days of the filing of that application. The time periods for the Texas Utility Commission to act on the two applications can run concurrently, but the Texas Utility Commission can delay issuing a financing order until it has ruled on the amount of recoverable system restoration costs. Alternatively, if securitization is not the least-cost option for rate payers, the legislation authorizes the Texas Utility Commission to allow a utility to recover those costs through a customer surcharge mechanism.

In the application it filed in April 2009, CenterPoint Houston seeks approval for recovery of a total of approximately $678 million, which includes the $608 million in system restoration costs described above plus related regulatory expenses, certain debt issuance costs, and carrying costs calculated through August 2009. CenterPoint Houston also plans to apply for a financing order which would authorize CenterPoint Houston to issue system restoration bonds to recover the portion of the $678 million related to distribution service, or approximately $657 million. Assuming those bonds are issued, CenterPoint Houston will recover the distribution portion of system restoration costs out of the bond proceeds, with the bonds being repaid over time through a charge imposed on customers. CenterPoint Houston will also seek to recover the remaining approximately $21 million related to transmission service through the existing annual transmission cost of service tariff. Although the Company and CenterPoint Houston believe the storm restoration costs CenterPoint Houston is seeking authorization to recover and the amounts it will seek authorization to securitize are in accordance with applicable regulatory requirements, as in any regulatory proceeding, there can be no assurance that the Texas Utility Commission will authorize recovery or securitization of the full amounts requested by CenterPoint Houston.

(b) Recovery of True-Up Balance

In March 2004, CenterPoint Houston filed its true-up application with the Texas Utility Commission, requesting recovery of $3.7 billion, excluding interest, as allowed under the Texas Electric Choice Plan (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 provided for adjustment of the amount to be recovered to include interest on the balance until recovery, along with the principal portion of additional excess mitigation credits (EMCs) returned to customers after August 31, 2004 and certain other adjustments.

CenterPoint Houston and other parties filed appeals of the True-Up Order to a district court in Travis County, Texas. In August 2005, that court issued its judgment on the various appeals. In its judgment, the district court:

- reversed the Texas Utility Commission's ruling that had denied recovery of a portion of the capacity auction true-up amounts;
- reversed the Texas Utility Commission's ruling that precluded CenterPoint Houston from recovering the interest component of the EMCs paid to retail electric providers (REPs); and
- affirmed the True-Up Order in all other respects.

The district court's decision would have had 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 to the Texas Third Court of Appeals, which issued its decision in December 2007. In its decision, the court of appeals:

- reversed the district court's judgment to the extent it restored the capacity auction true-up amounts;

- reversed the district court's judgment to the extent it upheld the Texas Utility Commission's decision to allow CenterPoint Houston to recover EMCs paid to Reliant Energy, Inc. (RRI);

- ordered that the tax normalization issue described below be remanded to the Texas Utility Commission as requested by the Texas Utility Commission; and

- affirmed the district court's judgment in all other respects.

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In April 2008, the court of appeals denied all motions for rehearing and reissued substantially the same opinion as it had rendered in December 2007.

In June 2008, CenterPoint Houston petitioned the Texas Supreme Court for review of the court of appeals decision. In its petition, CenterPoint Houston seeks reversal of the parts of the court of appeals decision that (i) denied recovery of EMCs paid to RRI, (ii) denied recovery of the capacity auction true up amounts allowed by the district court, (iii) affirmed the Texas Utility Commission's rulings that denied recovery of approximately $378 million related to depreciation and (iv) affirmed the Texas Utility Commission's refusal to permit CenterPoint Houston to utilize the partial stock valuation methodology for determining the market value of its former generation assets. Two other petitions for review were filed with the Texas Supreme Court by other parties to the appeal. In those petitions parties contend that (i) the Texas Utility Commission was without authority to fashion the methodology it used for valuing the former generation assets after it had determined that CenterPoint Houston could not use the partial stock valuation method, (ii) in fashioning the method it used for valuing the former generating assets, the Texas Utility Commission deprived parties of their due process rights and an opportunity to be heard, (iii) the net book value of the generating assets should have been adjusted downward due to the impact of a purchase option that had been granted to RRI, (iv) CenterPoint Houston should not have been permitted to recover construction work in progress balances without proving those amounts in the manner required by law and (v) the Texas Utility Commission was without authority to award interest on the capacity auction true up award.

Review by the Texas Supreme Court of the court of appeals decision is at the discretion of the court. In November 2008, the Texas Supreme Court requested the parties to the Petitions for Review to submit briefs on the merits of the issues raised. Briefing at the Texas Supreme Court should be completed in May 2009. Although the Texas Supreme Court has not indicated whether it will grant review of the lower court's decision, its request for full briefing on the merits allowed the parties to more fully explain their positions. There is no prescribed time in which the Texas Supreme Court must determine whether to grant review or, if review is granted, for a decision by that court. Although the Company and CenterPoint Houston believe that CenterPoint Houston's true-up request is consistent with applicable statutes and regulations and, accordingly, that it is reasonably possible that it will be successful in its appeal to the Texas Supreme Court, the Company can provide no assurance as to the ultimate court rulings on the issues to be considered in the appeal or with respect to the ultimate decision by the Texas Utility Commission on the tax normalization issue described below.

To reflect the impact of the True-Up Order, in 2004 and 2005, the Company recorded a net after-tax extraordinary loss of $947 million. No amounts related to the district court's judgment or the decision of the court of appeals have been recorded in the Company's consolidated financial statements. However, if the court of appeals decision is not reversed or modified as a result of further review by the Texas Supreme Court, the Company anticipates that it would be required to record an additional loss to reflect the court of appeals decision. The amount of that loss would depend on several factors, including ultimate resolution of the tax normalization issue described below and the calculation of interest on any amounts CenterPoint Houston ultimately is authorized to recover or is required to refund beyond the amounts recorded based on the True-up Order, but could range from $170 million to $385 million (pre-tax) plus interest subsequent to December 31, 2008.

In the True-Up Order, the Texas Utility Commission reduced CenterPoint Houston's stranded cost recovery by approximately $146 million, which was included in the extraordinary loss discussed above, for the present value of certain deferred tax benefits associated with its former electric generation assets. The Company believes that the Texas Utility Commission based its order on proposed regulations issued by the Internal Revenue Service (IRS) in March 2003 that 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, the IRS subsequently withdrew those proposed normalization regulations and in March 2008 adopted final regulations that would not permit utilities like CenterPoint

Houston to pass the tax benefits back to customers without creating normalization violations. In addition, the Company received a Private Letter Ruling (PLR) from the IRS in August 2007, prior to adoption of the final regulations that confirmed that the Texas Utility Commission's order reducing CenterPoint Houston's stranded cost recovery by $146 million for ADITC and EDFIT would cause normalization violations with respect to the ADITC and EDFIT.

If the Texas Utility Commission's order relating to the ADITC reduction is not reversed or otherwise modified on remand so as to eliminate the normalization violation, the IRS could require the Company to pay an amount equal to

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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 in addition to any potential loss resulting from final resolution of the True-Up Order. In its opinion, the court of appeals ordered that this issue be remanded to the Texas Utility Commission, as that commission requested. No party, in the petitions for review or briefs filed with the Texas Supreme Court, has challenged that order by the court of appeals, though the Texas Supreme Court, if it grants review, will have authority to consider all aspects of the rulings above, not just those challenged specifically by the appellants. The Company and CenterPoint Houston will continue to pursue a favorable resolution of this issue through the appellate or administrative process. 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 on remand.

The Texas electric restructuring law allowed the amounts awarded to CenterPoint Houston in the Texas Utility Commission's True-Up Order to be recovered either through securitization or through implementation of a competition transition charge (CTC) or both. Pursuant to a financing order issued by the Texas Utility Commission in March 2005 and affirmed 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% to 5.30% and final maturity dates ranging from February 2011 to August 2020. Through issuance of the transition bonds, CenterPoint Houston recovered approximately $1.7 billion of the true-up balance determined in the True-Up Order plus interest through the date on which the bonds were issued.

In July 2005, CenterPoint Houston received an order from the Texas Utility Commission allowing it to implement a CTC designed to collect the remaining $596 million from the True-Up Order over 14 years plus interest at an annual rate of 11.075% (CTC Order). The CTC Order authorized CenterPoint Houston to impose a charge on REPs to recover the portion of the true-up balance not recovered through a financing order. The CTC Order also allowed 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. The return on the CTC portion of the true-up balance was included in CenterPoint Houston's tariff-based revenues beginning September 13, 2005. Effective August 1, 2006, the interest rate on the unrecovered balance of the CTC was reduced from 11.075% to 8.06% pursuant to a revised rule adopted by the Texas Utility Commission in June 2006. Recovery of rate case expenses under Rider RCE was completed in September 2008.

Certain parties appealed the CTC Order to a district court in Travis County. In May 2006, the district court issued a judgment reversing the CTC Order in three respects. First, the court ruled that the Texas Utility Commission had improperly relied on provisions of its rule dealing with the interest rate applicable to CTC amounts. The district court reached that conclusion based on its belief that the Texas Supreme Court had previously invalidated that entire section of the rule. The 11.075% 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 revised rule discussed above. 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 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 appealed the district court's judgment to the Texas Third Court of Appeals, and in July 2008, the court of appeals reversed the district court's judgment in all respects and affirmed the Texas Utility Commission's order. Two of the appellants have requested further review from the Texas Supreme Court. In March 2009, the Texas Supreme Court requested that the parties file briefs on the merits in their appeals. Briefing at the Texas Supreme Court should be completed in May 2009. Review by the Texas Supreme Court is discretionary with that court, and there is no deadline for its action on appeals. 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.

During the 2007 legislative session, the Texas legislature amended statutes prescribing the types of true-up balances that can be securitized by utilities and authorized the issuance of transition bonds to recover the balance of the CTC. In June 2007, CenterPoint Houston filed a request with the Texas Utility Commission for a financing order that would allow the securitization of the remaining balance of the CTC, adjusted to refund certain unspent environmental retrofit costs and to recover the amount of the final fuel reconciliation settlement. 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. In February 2008, pursuant to the financing order, a new special purpose subsidiary of CenterPoint Houston issued approximately $488 million of transition bonds in two tranches with interest rates of 4.192% and 5.234% and final maturity dates of February 2020 and February 2023, respectively. Contemporaneously with the issuance of those bonds, the CTC was terminated and a transition charge was implemented.

During the three months ended March 31, 2008 and 2009, CenterPoint Houston recognized approximately $5 million and $-0-, respectively, in operating income from the CTC. Additionally, during each of the three months ended March 31, 2008 and 2009, CenterPoint Houston recognized approximately $2 million of the allowed equity return not previously recognized. As of March 31, 2009, the Company had not recognized an allowed equity return of $205 million on CenterPoint Houston's true-up balance because such return will be recognized as it is recovered in rates.

(c) Rate Proceedings

Texas. In March 2008, the natural gas distribution businesses of CERC (Gas Operations) filed a request to change its rates with the Railroad Commission of Texas (Railroad Commission) and the 47 cities in its Texas Coast service territory, an area consisting of approximately 230,000 customers in cities and communities on the outskirts of Houston. The request sought to establish uniform rates, charges and terms and conditions of service for the cities and environs of the Texas Coast service territory. Of the 47 cities, 23 either affirmatively approved or allowed the filed rates to go into effect by operation of law. Nine other cities were represented by the Texas Coast Utilities Coalition (TCUC) and 15 cities were represented by the Gulf Coast Coalition of Cities (GCCC). In July 2008, Gas Operations reached a settlement agreement with the GCCC. That settlement agreement, if implemented across the entire Texas Coast service territory, would allow Gas Operations a $3.4 million annual increase in revenues. The TCUC cities denied the rate change request and Gas Operations appealed the denial of rates to the Railroad Commission. The Railroad Commission issued an order in October 2008, which, if implemented across the entire Texas Coast service territory, would result in an annual revenue increase of $3.7 million. Both the Railroad Commission order and the settlement provide for an annual rate adjustment mechanism to reflect changes in operating expenses and revenues as well as changes in capital investment and associated changes in revenue-related taxes. In December 2008, the Railroad Commission issued an order on rehearing. Parties filed second motions for rehearing on this order. In December 2008, Gas Operations implemented the approved rates for the nine TCUC cities and the environs. In February 2009, the Railroad Commission denied the second motions on rehearing reaffirming its original decision. Cities with settled rates have the opportunity to adopt the rates established by the Railroad Commission or retain the rates agreed to in their settlements. In March 2009, TCUC and the State of Texas appealed the Railroad Commission's decision to the 353rd Judicial District Court, Travis County, Texas. The Company and CERC do not expect the outcome of this litigation to have a material adverse impact on the financial condition, results of operations or cash flows of either the Company or CERC.

Minnesota. In November 2006, the Minnesota Public Utilities Commission (MPUC) denied a request filed by Gas Operations for a waiver of MPUC rules in order to allow Gas Operations to recover approximately $21 million in unrecovered purchased gas costs related to periods prior to July 1, 2004. Those unrecovered gas costs were identified as a result of revisions to previously approved calculations of unrecovered purchased gas costs. Following that denial, Gas Operations recorded a $21 million adjustment to reduce pre-tax earnings in the fourth quarter of 2006 and reduced the regulatory asset related to these costs by an equal amount. In March 2007, following the MPUC's denial of reconsideration of its ruling, Gas Operations petitioned the Minnesota Court of Appeals for review of the MPUC's decision, and in May 2008 that court ruled that the MPUC had been arbitrary and capricious in denying Gas Operations a waiver. The court ordered the case remanded to the MPUC for reconsideration under the same principles the MPUC had applied in previously granted waiver requests. The MPUC sought further review of the court of appeals decision from the Minnesota Supreme Court, and in July 2008, the Minnesota Supreme Court agreed to review the decision. In January 2009, the Minnesota Supreme Court heard oral arguments. While there is no deadline for a decision, a decision is expected by the end of the third quarter of 2009. While no prediction can be made as to the ultimate outcome, this matter will have no negative impact on the Company’s financial condition, results of operations or cash flows.

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In November 2008, Gas Operations filed a request with the MPUC to increase its rates for utility distribution service. If approved by the MPUC, the proposed new rates would result in an overall increase in annual revenue of $59.8 million. The proposed increase would allow Gas Operations to recover increased operating costs, including higher bad debt and collection expenses, the cost of improved customer service and inflationary increases in other expenses. It also would allow recovery of increased costs related to conservation improvement programs and provide a return for the additional capital invested to serve its customers. In addition, Gas Operations is seeking an adjustment mechanism that would annually adjust rates to reflect changes in use per customer. In December 2008, the MPUC accepted the case and approved an interim rate increase of $51.2 million, which became effective on January 2, 2009, subject to refund. CERC and the Company do not expect an order from the MPUC until early 2010.

(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 to mitigate the impact of changes in commodity prices, weather and interest rates on its operating results and cash flows. Such contracts are recognized in the Company's Condensed Consolidated Balance Sheets at their fair value unless the Company elects the normal purchase and sales exemption for qualified physical transactions. A derivative contract may be designated as a normal purchase or sale if the intent is to physically receive or deliver the product for use or sale in the normal course of business. If derivative contracts are designated as a cash flow hedge according to SFAS No. 133, the effective portions of the changes in their fair values are reflected initially as a separate component of shareholders' equity and subsequently recognized in income at the same time the hedged items impact earnings. The ineffective portions of changes in fair values of derivatives designated as hedges are immediately recognized in income. Changes in other derivatives not designated as normal or as a cash flow hedge are recognized in income as they occur. The Company does not enter into or hold derivative instruments for trading purposes.

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

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

(a) Non-Trading Activities

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 March 31, 2008, the Company decreased natural gas revenues from unrealized net losses of $20 million and increased natural gas expense from unrealized net losses of $2 million, resulting in a net unrealized loss of $22 million. During the three months ended March 31, 2009, the Company increased revenues from unrealized net gains of $3 million and increased natural gas expense from unrealized net losses of $22 million, resulting in a net unrealized loss of $19 million.

In prior years, the Company entered into certain derivative instruments that were designated as cash flow hedges under SFAS No. 133. The objective of these derivative instruments was 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. In 2007, the Company discontinued designating these instruments as cash flow hedges under SFAS No. 133. As of March 31, 2009, there are no remaining amounts deferred in other comprehensive income related to these instruments that had previously been designated as cash flow hedges.

Weather Derivatives. The Company has weather normalization or other rate mechanisms that mitigate the impact of weather on its operations in Arkansas, Louisiana, Oklahoma and a portion of Texas. The remaining Gas

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Operations jurisdictions, Minnesota, Mississippi and most of Texas, do not have such mechanisms. As a result, fluctuations from normal weather may have a significant positive or negative effect on the results of these operations.

In 2007, the Company entered into heating-degree day swaps to mitigate the effect of fluctuations from normal weather on its financial position and cash flows for the 2007/2008 winter heating season. The swaps were based on ten-year normal weather. In July 2008, the Company entered into heating-degree day swaps to mitigate the effect of fluctuations from normal weather on its financial position and cash flows for the 2008-2009 winter heating season. The swaps are based on ten-year normal weather and provide for a maximum payment by either party of $11 million. During the three months ended March 31, 2008 and 2009, the Company recognized losses of $11 million and $3 million, respectively, related to these swaps. Such amounts were substantially offset by increased margin due to colder than normal weather. These weather derivative losses are included in revenues in the Condensed Statements of Consolidated Income.

(b) Derivative Fair Values and Income Statement Impacts

The following tables present information about the Company's derivative instruments and hedging activities. The first table provides a balance sheet overview of the Company's Derivative Assets and Liabilities as of March 31, 2009, while the latter table provides a breakdown of the related income statement impact for the three months ended March 31, 2009.

Fair Value of Derivative Instruments

		March 31, 2009			
Total derivatives not designated as hedging instruments under SFAS 133	Balance Sheet Location	Derivative Assets Fair Value (2) (3)		Derivative Liabilities Fair Value (2) (3)	
		(in millions)			
Commodity contracts (1)	Current Assets	$	133	$	(14)
Commodity contracts (1)	Other Assets		24		(1)
Commodity contracts (1)	Current Liabilities		12		(222)
Commodity contracts (1)	Other Liabilities		1		(149)
Indexed debt securities derivative	Current Liabilities		—		(111)
Total		$	170	$	(497)

(1) Commodity contracts are subject to master netting arrangements and are presented on a net basis in the Consolidated Balance Sheet. This netting causes derivative assets (liabilities) to be ultimately presented net in a liability (asset) account within the Consolidated Balance Sheet.

(2) The fair value shown for commodity contracts is comprised of derivative volumes totaling 688 billion cubic feet (Bcf). These volumes are disclosed in absolute terms, not net. Basis swaps constitute 261 Bcf of the total.

(3) The net of total non-trading derivative assets and liabilities is $32 million as shown on the Company's Condensed Consolidated Balance Sheets, and is comprised of the commodity contracts derivative assets and liabilities separately shown above offset by collateral netting of $248 million.

For the Company's price stabilization activities of the Natural Gas Distribution business segment, the settled costs of derivatives are ultimately recovered through purchase gas adjustments. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of recovery through purchase gas adjustments are recorded as net regulatory assets. For those derivatives that are not included in purchase gas adjustments, unrealized gains and losses and settled amounts are recognized on the Condensed Statements of Consolidated Income as revenue for retail sales derivative contracts and as natural gas expense for natural gas derivatives and non-retail related physical gas derivatives. Indexed debt securities are recorded as Other Income (Expense) on the Condensed Statements of Consolidated Income.

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Income Statement Impact of Derivative Activity

Total derivatives not designated as hedging instruments under SFAS 133	Income Statement Location	Three Months Ended March 31, 2009 (in millions)	
Commodity contracts	Gains (Losses) in Revenue	$	77
Commodity contracts (1)	Gains (Losses) in Expense: Natural Gas		(149)
Indexed debt securities derivative	Gains (Losses) in Other Income (Expense)		22
Total		$	(50)

(1) The Gains (Losses) in Expense: Natural Gas contains $(78) million of costs associated with price stabilization activities of our Natural Gas Distribution business segment which are ultimately recovered through purchased gas adjustments. In addition, for the period a $(91) million unrealized loss associated with unsettled price stabilization derivatives was recorded into the net regulatory asset account.

(c) Credit Risk Contingent Features

The Company enters into financial derivative contracts containing material adverse change provisions. These provisions require the Company to post additional collateral if the Standard & Poor's Rating Services or Moody's Investors Service, Inc. credit rating of the Company is downgraded. The total fair value of the derivative instruments that contain credit risk contingent features that are in a net liability position at March 31, 2009 is $250 million. The aggregate fair value of assets that are already posted as collateral at March 31, 2009 is $162 million. If all derivative contracts (in a net liability position) containing credit risk contingent features were triggered at March 31, 2009, $88 million of additional assets would be required to be posted as collateral.

(6) Fair Value Measurements

Effective January 1, 2008, the Company adopted SFAS No. 157, "Fair Value Measurements" (SFAS No. 157), which requires additional disclosures about the Company's financial assets and liabilities that are measured at fair value. Effective January 1, 2009, the Company adopted SFAS No. 157 for nonfinancial assets and liabilities, which adoption had no impact on the Company's financial position, results of operations or cash flows. Beginning in January 2008, assets and liabilities recorded at fair value in the Consolidated Balance Sheet are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels, as defined in SFAS No. 157 and directly related to the amount of subjectivity associated with the inputs to fair valuations of these assets and liabilities, are as follows:

Level 1: Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date. The types of assets carried at Level 1 fair value generally are financial derivatives, investments and equity securities listed in active markets.

Level 2: Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are derivatives with fair values based on inputs from actively quoted markets.

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. In certain cases, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. In such cases, the level in the fair value hierarchy within which the fair value measurement in its entirety falls has been determined based on the lowest level input that is significant to the fair value measurement in its entirety. Unobservable inputs reflect the Company's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Company develops these inputs based on the best information available, including the Company's own data. The Company's Level 3 derivative instruments primarily consist of options that are not traded on recognized exchanges and are valued using option pricing models.

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The following table presents information about the Company's assets and liabilities (including derivatives that are presented net) measured at fair value on a recurring basis as of March 31, 2009, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3) (in millions)	Netting Adjustments (1)	Balance as of March 31, 2009
Assets					
Corporate equities	$ 184	$ —	$ —	$ —	$ 184
Investments, including money market funds	69	—	—	—	69
Derivative assets	1	164	7	(30)	142
Total assets	$ 254	$ 164	$ 7	$ (30)	$ 395
Liabilities					
Indexed debt securities derivative	$ —	$ 111	$ —	$ —	$ 111
Derivative liabilities	41	314	33	(278)	110
Total liabilities	$ 41	$ 425	$ 33	$ (278)	$ 221

(1) Amounts represent the impact of legally enforceable master netting agreements that allow the Company to settle positive and negative positions and also cash collateral of $248 million posted with the same counterparties.

The following table presents additional information about assets or liabilities, including derivatives that are measured at fair value on a recurring basis for which the Company has utilized Level 3 inputs to determine fair value, for the three months ended March 31, 2009:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3) Derivative assets and liabilities, net (in millions)
Beginning liability balance as of January 1, 2009	$ (58)
Total gains or (losses) (unrealized and realized):	
Included in earnings	(3)
Included in regulatory assets	(17)
Purchases, sales, other settlements, net (1)	52

Ending liability balance as of March 31, 2009	$	(26)
The amount of total losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at the reporting date	$	(2)

(1) Purchases, sales, other settlements, net includes $50 million associated with price stabilization activities of the Company's Natural Gas Distribution business segment.

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(7) Goodwill

Goodwill by reportable business segment as of both December 31, 2008 and March 31, 2009 is as follows (in millions):

Natural Gas Distribution	$	746
Interstate Pipelines		579
Competitive Natural Gas Sales and Services		335
Field Services		25
Other Operations		11
Total	$	1,696

(8) Comprehensive Income

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

	For the Three Months Ended March 31, 2008	For the Three Months Ended March 31, 2009
	(in millions)	
Net income	$ 122	$ 67
Other comprehensive income (loss):		
Adjustment to pension and other postretirement plans (net of tax of $1 and $1)	2	2
Net deferred loss from cash flow hedges (net of tax of $5)	(9)	—
Reclassification of deferred gain from cash flow hedges realized in net income (net of tax of $2)	(4)	—
Other comprehensive income (loss)	(11)	2
Comprehensive income	$ 111	$ 69

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

	December 31, 2008	March 31, 2009
	(in millions)	
Adjustment to pension and post retirement plans	$ (127)	$ (125)
Net deferred loss from cash flow hedges	(4)	(4)
Total accumulated other comprehensive loss	$ (131)	$ (129)

(9) Capital Stock

CenterPoint Energy has 1,020,000,000 authorized shares of capital stock, comprised of 1,000,000,000 shares of $0.01 par value common stock and 20,000,000 shares of $0.01 par value preferred stock. At December 31, 2008, 346,088,714 shares of CenterPoint Energy common stock were issued and 346,088,548 shares of CenterPoint Energy common stock were outstanding. At March 31, 2009, 349,216,714 shares of CenterPoint Energy common stock were issued and 349,216,548 shares of CenterPoint Energy common stock were outstanding. Outstanding common shares exclude 166 treasury shares at both December 31, 2008 and March 31, 2009.

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

(a) Short-term Borrowings

Receivables Facility. On November 25, 2008, CERC replaced a receivables facility that had terminated on October 28, 2008 with a new 364-day receivables facility. Availability under the new facility ranges from $128 million to $375 million, reflecting seasonal changes in receivables balances. At December 31, 2008 and March 31, 2009 the facility size was $128 and $375 million, respectively. As of December 31, 2008 and March 31, 2009, advances under the receivables facilities were $78 million and $215 million, respectively.

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Inventory Financing. In December 2008, CERC entered into an asset management agreement whereby it sold $110 million of its natural gas in storage and agreed to repurchase an equivalent amount of natural gas during the 2008/2009 winter heating season for payments totaling $114 million. This transaction was accounted for as a financing and, as of December 31, 2008 and March 31, 2009, the Company's financial statements reflect natural gas inventory of $75 million and $-0-, respectively, and a financing obligation of $75 million and $-0-, respectively, related to this transaction.

Revolving Credit Facility. CenterPoint Houston's $600 million 364-day credit facility is secured by a pledge of $600 million of general mortgage bonds issued by CenterPoint Houston. This credit facility will terminate if bonds are issued to securitize the distribution-related costs incurred as a result of Hurricane Ike and if those bonds are issued prior to the November 24, 2009 expiration of the facility. In April 2009, the Texas Legislature enacted legislation that authorizes the Texas Utility Commission to conduct proceedings to determine the amount of system restoration costs associated with hurricanes or other major storms that utilities are entitled to recover. The legislation authorizes the Texas Utility Commission to issue a financing order that would permit a utility like CenterPoint Houston to recover the distribution portion of those costs through the issuance of non-recourse system restoration bonds similar to the securitization bonds issued previously. CenterPoint Houston expects to seek regulatory approval for the issuance of such bonds during 2009.

Borrowing costs for London Interbank Offered Rate (LIBOR)-based loans will be at a margin of 2.25 percent above LIBOR rates, based on CenterPoint Houston's current ratings. In addition, CenterPoint Houston will pay lenders, based on current ratings, a per annum commitment fee of 0.5 percent for their commitments under the facility and a quarterly duration fee of 0.75 percent on the average amount of outstanding borrowings during the quarter. The spread to LIBOR and the commitment fee fluctuate based on the borrower's credit rating. The facility contains covenants, including a debt (excluding transition and other securitization bonds) to total capitalization covenant. Bank fees associated with the establishment of this credit facility aggregated approximately $13 million. From inception through March 31, 2009, there have been no borrowings under the credit facility.

(b) Long-term Debt

General Mortgage Bonds. In January 2009, CenterPoint Houston issued $500 million aggregate principal amount of general mortgage bonds, due in March 2014 with an interest rate of 7.00%. The proceeds from the sale of the bonds were used for general corporate purposes, including the repayment of outstanding borrowings under its revolving credit facility and the money pool, capital expenditures and storm restoration costs associated with Hurricane Ike.

Revolving Credit Facilities. The Company's $1.2 billion credit facility has a first drawn cost of LIBOR plus 55 basis points based on the Company's current credit ratings. The facility contains a debt (excluding transition and other securitization bonds) to earnings before interest, taxes, depreciation and amortization (EBITDA) covenant, which was modified (i) in August 2008 so that the permitted ratio of debt to EBITDA would continue at its then-current level for the remaining term of the facility and (ii) in November 2008 so that the permitted ratio of debt to EBITDA would be temporarily increased until the earlier of December 31, 2009 or CenterPoint Houston's issuance of bonds to securitize the costs incurred as a result of Hurricane Ike, after which time the permitted ratio would revert to the level that existed prior to the November 2008 modification.

CenterPoint Houston's $289 million credit facility's first drawn cost is LIBOR plus 45 basis points based on CenterPoint Houston's current credit ratings. The facility contains a debt (excluding transition bonds) to total capitalization covenant.

CERC Corp.'s $950 million credit facility's first drawn cost is LIBOR plus 45 basis points based on CERC Corp.'s current credit ratings. The facility contains a debt to total capitalization covenant.

Under the Company’s $1.2 billion credit facility, CenterPoint Houston’s $289 million credit facility and CERC Corp’s $950 million credit facility, 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.

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As of December 31, 2008 and March 31, 2009, the following loan balances were outstanding under the Company's long-term revolving credit facilities (in millions):

	December 31, 2008	March 31, 2009
CenterPoint Energy $1.2 billion credit facility borrowings	$ 264	$ 234
CenterPoint Houston $289 million credit facility borrowings	251	—
CERC Corp. $950 million credit facility borrowings	926	501
Total credit facility borrowings	$ 1,441	$ 735

In addition, as of December 31, 2008 and March 31, 2009, the Company had approximately $27 million and $29 million, respectively, of outstanding letters of credit under its $1.2 billion credit facility and CenterPoint Houston had approximately $4 million of outstanding letters of credit under its $289 million credit facility as of both December 31, 2008 and March 31, 2009. There was no commercial paper outstanding that would have been backstopped by the Company's $1.2 billion credit facility at December 31, 2008 and March 31, 2009. There was $-0- and $19 million of commercial paper outstanding that was backstopped by CERC Corp.'s $950 million credit facility at December 31, 2008 and March 31, 2009, respectively. The Company, CenterPoint Houston and CERC Corp. were in compliance with all debt covenants as of March 31, 2009.

(11) Commitments and Contingencies

(a) Natural Gas Supply Commitments

Natural gas supply commitments include natural gas contracts related to the Company's Natural Gas Distribution and Competitive Natural Gas Sales and Services 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, 2008 and March 31, 2009 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 March 31, 2009, minimum payment obligations for natural gas supply commitments are approximately $333 million for the remaining nine months in 2009, $460 million in 2010, $396 million in 2011, $393 million in 2012, $381 million in 2013 and $930 million after 2013.

(b) Legal, Environmental and Other Regulatory Matters

Legal Matters

RRI Indemnified Litigation

Gas Market Manipulation Cases. The Company, CenterPoint Houston or their predecessor, Reliant Energy, Incorporated (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 RRI (formerly Reliant Resources, Inc.), the Company and its subsidiaries are entitled to be indemnified by RRI for any losses, including attorneys' fees and other costs, arising out of these lawsuits. Pursuant to the indemnification obligation, RRI is defending the Company and its subsidiaries to the extent named in these lawsuits. A large number of lawsuits were filed against numerous gas market participants in a number of federal and western state courts in connection with the operation of the natural gas markets in 2000-2002. The Company's former affiliate, RRI, was a participant in gas trading in the California and Western markets. These lawsuits, many of which have been filed as class actions, allege violations of state and federal antitrust laws. Plaintiffs in these lawsuits are seeking a variety of forms of relief, including, among others, recovery of compensatory damages (in some cases in excess of $1 billion), a trebling of compensatory damages, full consideration damages and attorneys' fees. The Company and/or Reliant Energy were named in approximately 30 of these lawsuits, which were instituted between 2003 and 2009. Most of these cases have settled or the Company has been dismissed from them. CenterPoint Energy Services, Inc. (CES), a subsidiary of CERC Corp., is a defendant or sought to be added as a defendant in two cases now pending in federal court in Wisconsin and Nevada alleging a conspiracy to inflate Wisconsin natural gas prices in 2000-2002. Additionally, the Company was a defendant in a lawsuit filed in state court in Nevada that was dismissed in 2007, but the plaintiffs have asked for reconsideration of the dismissal. The Company believes that neither it nor CES is a proper defendant in the

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remaining cases and will continue to pursue dismissal from those cases. The Company does not expect the ultimate outcome of these matters to have a material impact on its financial condition, results of operations or cash flows.

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. In October 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 sought review of that dismissal from the Tenth Circuit Court of Appeals, which affirmed the district court's dismissal in March 2009. The plaintiff has indicated that he intends to seek rehearing of the Tenth Circuit decision.

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 these lawsuits are without merit. CERC and the Company do not expect the ultimate outcome of the lawsuits to have a material impact on the financial condition, results of operations or cash flows of either the Company or CERC.

Gas Cost Recovery Litigation. In October 2002, a lawsuit was filed on behalf of certain CERC ratepayers in state district court in Wharton County, Texas against the Company, CERC Corp., 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 Pipeline Services, Inc. (CEPS), and certain other subsidiaries of CERC, 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.

In October 2004, a lawsuit was filed by certain CERC ratepayers in Texas and Arkansas in circuit court in Miller County, Arkansas against the Company, CERC Corp., EGMC, CenterPoint Energy Gas Transmission Company (CEGT), CenterPoint Energy Field Services (CEFS), CEPS, Mississippi River Transmission Corp. (MRT) and various 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 CEGT and MRT as defendants. Although the plaintiffs in the Miller County case sought class certification, no class was certified. In June 2007, the Arkansas Supreme Court determined that the Arkansas claims were within the sole and exclusive jurisdiction of the Arkansas Public Service Commission (APSC). In response to that ruling, in August 2007 the Miller County court stayed but refused to dismiss the Arkansas claims. In February 2008, the Arkansas Supreme Court directed the Miller County court to dismiss the entire case for lack of jurisdiction. The Miller County court subsequently dismissed the case in accordance with the Arkansas Supreme Court’s mandate and all appellate deadlines have expired.

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In June 2007, the Company, CERC Corp., 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 exclusive original jurisdiction over the Texas claims asserted in the Miller County case. In October 2007, CEFS and CEPS joined the petition in the Travis County case. In October 2008, the district court ruled that the Railroad Commission had exclusive original jurisdiction over the Texas claims asserted against the Company, CERC Corp., EGMC and the other defendants in the Miller County case. In January 2009, the court entered a final declaratory judgment ruling that the Railroad Commission has exclusive jurisdiction over Texas claims. The Company does not anticipate that an appeal will be filed.

In August 2007, the Arkansas plaintiff in the Miller County litigation 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 February 2009, the Arkansas plaintiff notified the APSC that he would no longer pursue his claims. That complaint remains pending at the APSC, subject to the review of the Arkansas Attorney General, APSC Staff and the APSC. The Company and CERC do not expect the outcome of this proceeding to have a material adverse impact on the financial condition, results of operations or cash flows of either the Company or CERC.

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 lawsuits were stayed pending the resolution of the petitions filed with 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 the LPSC 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, including interest, related to certain off-system sales. The refund was completed in the fourth quarter of 2008. A similar review by the LPSC related to the Caddo Parish litigation was resolved without additional payment by CERC. In October 2008, the courts considering the Caddo and Calcasieu Parish cases dismissed these cases pursuant to motions to dismiss and these proceedings have been concluded.

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 the 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 that 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

Manufactured Gas Plant Sites. CERC and its predecessors operated manufactured gas plants (MGPs) 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.

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At March 31, 2009, 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 March 31, 2009, 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 the suit 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’s 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. Under the terms of the arrangements regarding separation of the generating business from the Company and its sale to NRG Texas LP, ultimate financial responsibility for uninsured losses from claims relating to the generating business has been assumed by NRG Texas LP, 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.

Groundwater Contamination Litigation. Predecessor entities of CERC, along with several other entities, are defendants in litigation, St. Michel Plantation, LLC, et al, v. White, et al., pending in civil district court in Orleans

Parish, Louisiana. In the lawsuit, the plaintiffs allege that their property in Terrebonne Parish, Louisiana suffered salt water contamination as a result of oil and gas drilling activities conducted by the defendants. Although a predecessor of CERC held an interest in two oil and gas leases on a portion of the property at issue, neither it nor any other CERC entities drilled or conducted other oil and gas operations on those leases. In January 2009, CERC and the plaintiffs reached agreement on the terms of a settlement that, if ultimately approved by the Louisiana Department of Natural Resources and the court, is expected to finally resolve this litigation. The Company and

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CERC do not expect the outcome of this litigation to have a material adverse impact on the financial condition, results of operations or cash flows of either the Company or CERC.

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

Other Proceedings

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

Guaranties

Prior to 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 CERC against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for CERC's benefit, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. In December 2007, the Company, CERC and RRI amended that agreement and CERC released the letters of credit it held as security. Under the revised agreement RRI agreed to provide cash or new letters of credit to secure CERC against exposure under the remaining guaranties as calculated under the new agreement if and to the extent changes in market conditions exposed CERC to a risk of loss on those guaranties.

The potential exposure to CERC under the guaranties relates to payment of demand charges related to transportation contracts. The present value of the demand charges under these transportation contracts, which will be effective until 2018, was approximately $108 million as of March 31, 2009. RRI continues to meet its obligations under the contracts, and, on the basis of market conditions, the Company and CERC have not required additional security. However, if RRI should fail to perform its obligations under the contracts or if RRI should fail to provide adequate security in the event market conditions change adversely, the Company would retain exposure to the counterparty under the guaranty.

(12) Income Taxes

During the three months ended March 31, 2008 and 2009, the effective tax rate was 37% and 42%, respectively. The most significant item affecting the comparability of the effective tax rate is a $4 million increase in the 2009 income tax expense as a result of a state tax audit.

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The following table summarizes the Company's uncertain tax positions in accordance with FASB Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes — an Interpretation of FASB Statement No. 109," at December 31, 2008 and March 31, 2009:

	December 31, 2008	March 31, 2009
	(in millions)	
Liability for uncertain tax positions	$ 117	$ 154
Portion of liability for uncertain tax positions that, if recognized, would reduce the effective income tax rate	14	15
Interest accrued on uncertain tax positions	10	11

(13) Earnings Per Share

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

	Three Months Ended March 31, 2008	2009
	(in millions, except share and per share amounts)	
Basic earnings per share calculation:		
Net income	$ 122	$ 67
Weighted average shares outstanding	327,279,000	347,496,000
Basic earnings per share:		
Net income	$ 0.37	$ 0.19
Diluted earnings per share calculation:		
Net income	$ 122	$ 67
Weighted average shares outstanding	327,279,000	347,496,000
Plus: Incremental shares from assumed conversions:		
Stock options (1)	869,000	511,000
Restricted stock	1,127,000	1,150,000
3.75% convertible senior notes	10,173,000	—
Weighted average shares assuming dilution	339,448,000	349,157,000
Diluted earnings per share:		
Net income	$ 0.36	$ 0.19

(1) Options to purchase 2,848,340 and 2,662,903 shares were outstanding for the three months ended March 31, 2008 and 2009, respectively, 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.

Substantially all of the 3.75% contingently convertible senior notes provided for settlement of the principal portion in cash rather than stock. In accordance with Emerging Issues Task Force Issue No. 04-8, "Accounting Issues related to Certain Features of Contingently Convertible Debt and the Effect on Diluted Earnings Per Share," the portion of the conversion value of such notes that must be settled in cash rather than stock is excluded from the computation of diluted earnings per share from continuing operations. The Company included 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 exceeded the conversion price. In April 2008, the Company called its 3.75% convertible senior notes for redemption on May 30, 2008. Substantially all of the Company's 3.75% convertible senior notes were submitted for conversion on or prior to the May 30, 2008 redemption date.

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(14) Reportable Business Segments

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

The Company's reportable business segments include the following: Electric Transmission & Distribution, Natural Gas Distribution, Competitive Natural Gas Sales and Services, Interstate Pipelines, Field Services and Other Operations. The electric transmission and distribution function (CenterPoint Houston) is reported in the Electric Transmission & Distribution business segment. Natural Gas Distribution consists of intrastate natural gas sales to, and natural gas transportation and distribution for, residential, commercial, industrial and institutional customers. Competitive Natural Gas Sales and Services represents the Company's non-rate regulated gas sales and services operations, which consist of three operational functions: wholesale, retail and intrastate pipelines. The Interstate Pipelines business segment includes the interstate natural gas pipeline operations. The Field Services business segment includes the natural gas gathering operations. Other Operations consists primarily of other corporate operations which support all of the Company's business operations.

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

For the Three Months Ended March 31, 2008

	Revenues from External Customers	Net Intersegment Revenues	Operating Income	Total Assets as of December 31, 2008
Electric Transmission & Distribution	$ 409(1)	$ —	$ 91	$ 8,880
Natural Gas Distribution	1,697	3	121	4,961
Competitive Natural Gas Sales and Services	1,109	11	6	1,315
Interstate Pipelines	91	42	71	3,578
Field Services	54	4	45	826
Other Operations	3	—	2	2,185(2)
Eliminations	—	(60)	—	(2,069)
Consolidated	$ 3,363	$ —	$ 336	$ 19,676

For the Three Months Ended March 31, 2009

	Revenues from External Customers	Net Intersegment Revenues	Operating Income	Total Assets as of March 31, 2009
Electric Transmission & Distribution	$ 412(1)	$ —	$ 70	$ 8,836
Natural Gas Distribution	1,418	3	118	4,344
Competitive Natural Gas Sales and Services	760	5	2	1,169
Interstate Pipelines	117	36	69	3,579
Field Services	56	1	26	829

Other Operations		3		—		—	2,037(2)
Eliminations		—		(45)		—	(1,984)
Consolidated	$	2,766	$	—	$	285	$ 18,810

(1) Sales to subsidiaries of RRI in each of the three months ended March 31, 2008 and 2009 represented approximately $142 million of CenterPoint Houston's transmission and distribution revenues.

(2) Included in total assets of Other Operations as of December 31, 2008 and March 31, 2009 are pension related regulatory assets of $800 million and $786 million, respectively.

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(15) Subsequent Event

On April 23, 2009, the Company’s board of directors declared a regular quarterly cash dividend of $0.19 per share of common stock payable on June 10, 2009, to shareholders of record as of the close of business on May 15, 2009.

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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 and our Annual Report on Form 10-K for the year ended December31, 2008 (2008 Form 10-K).

EXECUTIVE SUMMARY

Recent Events

Hurricane Ike

CenterPoint Houston's electric delivery system suffered substantial damage as a result of Hurricane Ike, which struck the upper Texas coast in September 2008.

As is common with electric utilities serving coastal regions, the poles, towers, wires, street lights and pole mounted equipment that comprise CenterPoint Houston's transmission and distribution system are not covered by property insurance, but office buildings and warehouses and their contents and substations are covered by insurance that provides for a maximum deductible of $10 million. Current estimates are that total losses to property covered by this insurance were approximately $17 million.

CenterPoint Houston deferred the uninsured system restoration costs as management believes it is probable that such costs will be recovered through the regulatory process. As a result, system restoration costs did not affect the Company's or CenterPoint Houston's reported net income for 2008 or the first quarter of 2009. As of March 31, 2009, CenterPoint Houston had balances of $161 million in construction work in progress and $437 million in regulatory assets related to restoration costs incurred through March 31, 2009. In April 2009, CenterPoint Houston filed with the Public Utility Commission of Texas (Texas Utility Commission) an application for review and approval for recovery of approximately $608 million in system restoration costs identified as of the end of February 2009, plus $2 million in regulatory expenses, $13 million in certain debt issuance costs, and $55 million in carrying costs, pursuant to the legislation described below. CenterPoint Houston expects to incur additional costs, currently estimated at $12 million, related to Hurricane Ike, principally related to the reconstruction of certain substations on Galveston Island, and will seek to recover those costs through the regulatory process at a later date.

In April 2009, the Texas Legislature enacted legislation that authorizes the Texas Utility Commission to conduct proceedings to determine the amount of system restoration costs and related costs associated with hurricanes or other major storms that utilities are entitled to recover through charges to customers. The legislation authorizes the Texas Utility Commission to issue a financing order that would permit a utility like CenterPoint Houston to recover the distribution portion of those costs and related carrying costs through the issuance of non-recourse system restoration bonds similar to the securitization bonds issued previously. The legislation also allows such a utility to recover, or defer for future recovery, the transmission portion of its system restoration costs through the existing mechanisms established to recover transmission level costs. The legislation requires the Texas Utility Commission to make its determination of recoverable system restoration costs within 150 days of the filing of a utility's application and to rule on a utility's application for a financing order for the issuance of system restoration bonds within 90 days of the filing of that application. The time periods for the Texas Utility Commission to act on the two applications can run concurrently, but the Texas Utility Commission can delay issuing a financing order until it has ruled on the amount of recoverable system restoration costs. Alternatively, if securitization is not the least-cost option for rate payers, the legislation authorizes the Texas Utility Commission to allow a utility to recover those costs through a customer surcharge mechanism.

In the application it filed in April 2009, CenterPoint Houston seeks approval for recovery of a total of approximately $678 million, which includes the $608 million in system restoration costs described above plus related regulatory expenses, certain debt issuance costs, and carrying costs calculated through August 2009. CenterPoint Houston also plans to apply for a financing order which would authorize CenterPoint Houston to issue system restoration bonds to recover the portion of the $678 million related to distribution service, or approximately $657 million. Assuming those bonds are issued, CenterPoint Houston will recover the distribution portion of system restoration costs out of the bond proceeds, with the bonds being repaid over time through a charge imposed on customers. CenterPoint Houston will also seek to recover the remaining approximately $21 million related to transmission service through the existing annual transmission cost of service tariff. Although the Company and

CenterPoint Houston believe the storm restoration costs CenterPoint Houston is seeking authorization to recover and the amounts it will seek authorization to securitize are in accordance with applicable regulatory requirements, as in any regulatory proceeding, there can be no assurance that the Texas Utility Commission will authorize recovery or securitization of the full amounts requested by CenterPoint Houston.

Debt Financing Transactions

In January 2009, CenterPoint Houston issued $500 million aggregate principal amount of general mortgage bonds due in March 2014 with an interest rate of 7.00%. The proceeds from the sale of the bonds were used for general corporate purposes, including the repayment of outstanding borrowings under its revolving credit facility and the money pool, capital expenditures and storm restoration costs associated with Hurricane Ike.

Equity Financing Transactions

During the three months ended March 31, 2009, we received proceeds of approximately $26 million from the sale of approximately 2.2 million common shares to our defined contribution plan and proceeds of approximately $3 million from the sale of approximately 0.4 million common shares to participants in our enhanced dividend reinvestment plan.

CONSOLIDATED RESULTS OF OPERATIONS

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

	Three Months Ended March 31,	
	2008	2009
Revenues	$ 3,363	$ 2,766
Expenses	3,027	2,481
Operating Income	336	285
Interest and Other Finance Charges	(116)	(129)
Interest on Transition Bonds	(33)	(33)
Equity in earnings of unconsolidated affiliates	9	—
Other Income (Expense), net	—	(8)
Income Before Income Taxes	196	115
Income Tax Expense	(74)	(48)
Net Income	$ 122	$ 67
Basic Earnings Per Share	$ 0.37	$ 0.19
Diluted Earnings Per Share	$ 0.36	$ 0.19

Three months ended March 31, 2009 compared to three months ended March 31, 2008

We reported consolidated net income of $67 million ($0.19 per diluted share) for the three months ended March 31, 2009 as compared to $122 million ($0.36 per diluted share) for the same period in 2008. The decrease in net income of $55 million was primarily due to a $51 million decrease in operating income, a $28 million decrease in the gain on our indexed debt securities, a $13 million increase in interest expense, excluding transition bond-related interest expense and a $9 million decrease in the equity in earnings of unconsolidated affiliates. These decreases were partially offset by a $26 million decrease in income tax expense and a $20 million decrease in the loss on marketable securities.

Income Tax Expense. During the three months ended March 31, 2008 and 2009, the effective tax rate was 37% and 42%, respectively. The most significant item affecting the comparability of the effective tax rate is a $4 million increase in the 2009 income tax expense as a result of a state tax audit.

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RESULTS OF OPERATIONS BY BUSINESS SEGMENT

The following table presents operating income (in millions) for each of our business segments for the three months ended March 31, 2008 and 2009.

	Three Months Ended March 31, 2008	2009
Electric Transmission & Distribution	$ 91	$ 70
Natural Gas Distribution	121	118
Competitive Natural Gas Sales and Services	6	2
Interstate Pipelines	71	69
Field Services	45	26
Other Operations	2	—
Total Consolidated Operating Income	$ 336	$ 285

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 t Our Business and Other Risks" in Item 1A of Part I of our 2008 Form 10-K.

The following tables provide summary data of our Electric Transmission & Distribution business segment for the three months ended March 31, 2008 and 2009 (in millions, except throughput and customer data):

	Three Months Ended March 31, 2008	2009
Revenues:		
Electric transmission and distribution utility	$ 346	$ 346
Transition bond companies	63	66
Total revenues	409	412
Expenses:		
Operation and maintenance, excluding transition bond companies	168	188
Depreciation and amortization, excluding transition bond companies	66	68
Taxes other than income taxes	53	53
Transition bond companies	31	33
Total expenses	318	342
Operating Income	$ 91	$ 70
Operating Income:		
Electric transmission and distribution utility	54	37
Competition transition charge	5	—
	32	33

Transition bond companies (1)		
Total segment operating income	$ 91	$ 70
Throughput (in gigawatt-hours (GWh)):		
Residential	4,403	3,967
Total	16,570	15,142
Number of metered customers at period end:		
Residential	1,806,542	1,838,766
Total	2,048,316	2,082,930

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

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Three months ended March 31, 2009 compared to three months ended March 31, 2008

Our Electric Transmission & Distribution business segment reported operating income of $70 million for the three months ended March 31, 2009, consisting of $37 million for the regulated electric transmission and distribution utility (TDU) and $33 million related to the transition bonds. For the three months ended March 31, 2008, operating income totaled $91 million, consisting of $54 million for the TDU, $5 million for the competition transition charge and $32 million related to the transition bonds. TDU revenues were unchanged as higher transmission-related revenues ($12 million), higher revenues due to customer growth ($4 million) from the addition of over 34,000 new customers and revenues from implementation of the advanced metering system (AMS) ($5 million) were offset by declines in use ($18 million), in part caused by milder weather, and lower other revenues ($2 million). Operation and maintenance expenses increased primarily due to higher transmission costs billed by transmission providers ($9 million), higher pension expense ($5 million), the AMS project expenses ($2 million) and other expense increases ($4 million). Future changes in pension expense over our 2007 base year will be deferred until our next general rate case pursuant to Texas regulatory provisions.

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 2008 Form 10-K.

The following table provides summary data of our Natural Gas Distribution business segment for the three months ended March 31, 2008 and 2009 (in millions, except throughput and customer data):

	Three Months Ended March 31,	
	2008	2009
Revenues	$ 1,700	$ 1,421
Expenses:		
Natural gas	1,333	1,045
Operation and maintenance	156	169
Depreciation and amortization	39	40
Taxes other than income taxes	51	49
Total expenses	1,579	1,303
Operating Income	$ 121	$ 118
Throughput (in billion cubic feet (Bcf)):		
Residential	84	78
Commercial and industrial	83	73
Total Throughput	167	151
Number of customers at period end:		
Residential	2,974,411	2,996,455
Commercial and industrial	251,612	246,405
Total	3,226,023	3,242,860

Three months ended March 31, 2009 compared to three months ended March 31, 2008

Our Natural Gas Distribution business segment reported operating income of $118 million for the three months ended March 31, 2009 compared to operating income of $121 million for the three months ended March 31, 2008. Operating margin (revenues less cost of gas) increased $9 million primarily due to increased rates ($10 million), recovery of energy-efficiency costs ($3 million) and higher miscellaneous revenue ($3 million), partially offset by reduced customer usage ($6 million) and decreased gross receipts taxes ($3 million). Margin increases from residential customer growth ($1 million), with the addition of approximately 22,000 residential customers, were offset by reduced margin caused by the loss of commercial customers. Revenues related to both energy-efficiency costs and gross receipts taxes were offset by the related expenses. Operation and maintenance expenses increased $13 million

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primarily due to increased pension expense ($9 million), the energy-efficiency costs above and higher bad debt expense ($2 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 2008 Form 10-K.

The following table provides summary data of our Competitive Natural Gas Sales and Services business segment for the three months ended March 31, 2008 and 2009 (in millions, except throughput and customer data):

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2009
Revenues	$ 1,120	$ 765
Expenses:		
Natural gas	1,105	752
Operation and maintenance	8	10
Depreciation and amortization	1	1
Taxes other than income taxes	—	—
Total expenses	1,114	763
Operating Income	$ 6	$ 2
Throughput (in Bcf):	138	141
Number of customers at period end	8,751	10,862

Three months ended March 31, 2009 compared to three months ended March 31, 2008

Our Competitive Natural Gas Sales and Services business segment reported operating income of $2 million for the three months ended March 31, 2009 compared to $6 million for the three months ended March 31, 2008. The decrease in operating income of $4 million was primarily due to a $6 million write down of gas in the first quarter of 2009 to the lower of cost or market as compared to no write down in the first quarter of 2008. Our Competitive Natural Gas Sales and Services business segment purchases and stores natural gas to meet certain future sales requirements and enters into derivative contracts to hedge the economic value of the future sales. The unfavorable impact of mark-to-market accounting for non-trading financial derivatives for the first quarter of 2009 of $19 million versus $22 million for the same period in 2008 accounted for a $3 million increase in operating income.

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 2008 Form 10-K.

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The following table provides summary data of our Interstate Pipelines business segment for the three months ended March 31, 2008 and 2009 (in millions, except throughput data):

	Three Months Ended March 31,			
	2008		2009	
Revenues	$	133	$	153
Expenses:				
Natural gas		15		29
Operation and maintenance		30		35
Depreciation and amortization		12		12
Taxes other than income taxes		5		8
Total expenses		62		84
Operating Income	$	71	$	69
Transportation throughput (in Bcf)		424		467

Three months ended March 31, 2009 compared to three months ended March 31, 2008

The Interstate Pipeline business segment reported operating income of $69 million for the three months ended March 31, 2009 compared to $71 million for the same period of 2008. The decrease in operating income of $2 million was primarily driven by higher operation and maintenance expenses ($5 million) primarily related to costs associated with incremental facilities and increased pension expense, and higher taxes other than income ($3 million), $1 million of which was due to 2008 tax refunds. These increases are partially offset by increased margins (revenues less natural gas costs) on Phase III of the Carthage to Perryville pipeline that went into service in April 2008 ($6 million).

Equity Earnings. In addition, this business segment recorded equity income (loss) of $5 million and $(2) million for the three months ended March 31, 2008 and 2009, respectively, from its 50 percent interest in the Southeast Supply Header (SESH), a jointly-owned pipeline that went into service in September 2008. The $5 million income in the first quarter of 2008 was pre-operating allowance for funds used during construction in 2008. The $2 million loss in the first quarter of 2009 resulted from a non-cash charge of $5 million to reflect SESH's decision to discontinue the use of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." The loss more than offset the equity income from SESH of $3 million for the first quarter of 2009. These amounts are included in Equity in Earnings of Unconsolidated Affiliates under the Other Income (Expense) caption.

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 Consolidated Financial Condition" and "— Risks Common to Our Business and Other Risks" in Item 1A of Part I of our 2008 Form 10-K.

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The following table provides summary data of our Field Services business segment for the three months ended March 31, 2008 and 2009 (in millions, except throughput data):

	Three Months Ended March 31,	
	2008	2009
Revenues	$ 58	$ 57
Expenses:		
Natural gas	(2)	7
Operation and maintenance	11	19
Depreciation and amortization	3	4
Taxes other than income taxes	1	1
Total expenses	13	31
Operating Income	$ 45	$ 26
Gathering throughput (in Bcf)	98	104

Three months ended March 31, 2009 compared to three months ended March 31, 2008

The Field Services business segment reported operating income of $26 million for the three months ended March 31, 2009 compared to $45 million for the same period of 2008. The decrease in operating income of $19 million was primarily driven by a one-time gain ($11 million) related to a settlement and contract buyout of one of our customers and a one-time gain ($6 million) related to the sale of assets, both recognized in the first quarter of 2008. The remaining decrease is due to a decrease in commodity pricing offsetting the increase in margin relating to new projects.

Equity Earnings. In addition, this business segment recorded equity income of $4 million and $2 million in the three months ended March 31, 2008 and 2009, respectively, from its 50 percent interest in a jointly-owned gas processing plant. The decrease is driven by a decrease in liquids pricing. These amounts are included in Equity in Earnings of Unconsolidated Affiliates under the Other Income (Expense) caption.

Other Operations

The following table shows the operating income of our Other Operations business segment for the three months ended March 31, 2008 and 2009 (in millions):

	Three Months Ended March 31,	
	2008	2009
Revenues	$ 3	$ 3
Expenses	1	3
Operating Income	$ 2	$ —

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 and "Risk Factors" in Item 1A of Part I of our 2008 Form 10-K and "Cautionary Statement Regarding Forward-Looking Information."

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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 three months ended March 31, 2008 and 2009:

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2009
	(in millions)	
Cash provided by (used in):		
Operating activities	$ 567	$ 433
Investing activities	(312)	(261)
Financing activities	(314)	(274)

Cash Provided by Operating Activities

Net cash provided by operating activities in the first quarter of 2009 decreased $134 million compared to the same period in 2008 primarily due to increased net margin deposits ($91 million), decreased net accounts receivable/payable ($89 million) and decreased net income $(55 million), which were partially offset by decreased gas storage inventory ($105 million).

Cash Used in Investing Activities

Net cash used in investing activities decreased $51 million in the first quarter of 2009 compared to the same period in 2008 due to decreased investment in unconsolidated affiliates of $107 million primarily related to the SESH pipeline project, and decreased restricted cash of transition bond companies of $14 million, offset by increased capital expenditures of $73 million primarily related to our Electric Transmission & Distribution, Interstate Pipelines and Field Services business segments.

Cash Used In Financing Activities

Net cash used in financing activities in the first quarter of 2009 decreased $40 million compared to the same period in 2008 primarily due to decreased repayments of long-term debt ($405 million), increased short-term borrowings ($94 million), increased proceeds from the issuance of common stock ($29 million) and increased proceeds from the issuance of long-term debt ($12 million), which were partially offset by decreased borrowings under revolving credit facilities ($475 million) and decreased proceeds from commercial paper ($16 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 nine months of 2009 include the following:

- approximately $895 million of capital expenditures;

- $104 million of maturing transition bonds;
- dividend payments on CenterPoint Energy common stock and interest payments on debt.

We expect that borrowings under our credit facilities and anticipated cash flows from operations will be sufficient to meet our anticipated cash needs for the remaining nine months of 2009. Cash needs or discretionary financing or refinancing may result in the issuance of equity or debt securities in the capital markets or the arrangement of additional credit facilities. Issuances of equity or debt in the capital markets and additional credit facilities may not, however, be available to us on acceptable terms.

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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 CERC against obligations under the remaining guaranties, RRI agreed to provide cash or letters of credit for CERC's benefit, and undertook to use commercially reasonable efforts to extinguish the remaining guaranties. In December 2007, we, CERC and RRI amended that agreement and CERC released the letters of credit it held as security. Under the revised agreement RRI agreed to provide cash or new letters of credit to secure CERC against exposure under the remaining guaranties as calculated under the new agreement if and to the extent changes in market conditions exposed CERC to a risk of loss on those guaranties.

The potential exposure to CERC under the guaranties relates to payment of demand charges related to transportation contracts. The present value of the demand charges under these transportation contracts, which will be effective until 2018, was approximately $108 million as of March 31, 2009. RRI continues to meet its obligations under the contracts, and, on the basis of market conditions, we and CERC have not required additional security. However, if RRI should fail to perform its obligations under the contracts or if RRI should fail to provide adequate security in the event market conditions change adversely, we would retain exposure to the counterparty under the guaranty.

Equity Financing Transactions. During the three months ended March 31, 2009, we received proceeds of approximately $26 million from the sale of approximately 2.2 million common shares to our defined contribution plan and proceeds of approximately $3 million from the sale of approximately 0.4 million common shares to participants in our enhanced dividend reinvestment plan.

Credit and Receivables Facilities. As of April 22, 2009, we had the following facilities (in millions):

Date Executed	Company	Type of Facility	Size of Facility	Amount Utilized at April 22, 2009	Termination Date
June 29, 2007	CenterPoint Energy	Revolver	$ 1,156	$ 261(2)	June 29, 2012
June 29, 2007	CenterPoint Houston	Revolver	289	4(3)	June 29, 2012
June 29, 2007	CERC Corp.	Revolver	950(1)	449	June 29, 2012
November 25, 2008	CERC Corp.	Receivables	375	—	November 24, 2009
November 25, 2008	CenterPoint Houston	Revolver	600	—	November 24, 2009

(1) Lehman Brothers Bank, FSB, stopped funding its commitments following the bankruptcy filing of its parent in September 2008, effectively causing a reduction to the total available capacity of $20 million under CERC Corp.'s facility.

(2) Includes $232 million of borrowings and $29 million of outstanding letters of credit.

(3) Includes $4 million of outstanding letters of credit.

Our $1.2 billion credit facility has a first drawn cost of London Interbank Offered Rate (LIBOR) plus 55 basis points based on our current credit ratings. The facility contains a debt (excluding transition and other securitization bonds) to earnings before interest, taxes, depreciation and amortization (EBITDA) covenant, which was modified (i) in August 2008 so that the permitted ratio of debt to EBITDA would continue at its then-current level for the remaining term of the facility and (ii) in November 2008 so that the permitted ratio of debt to EBITDA would be temporarily increased until the earlier of December 31, 2009 or CenterPoint Houston's issuance of bonds to securitize the costs incurred as a result of Hurricane Ike, after which time the permitted ratio would revert to the level that existed prior to the November 2008 modification.

CenterPoint Houston's $289 million credit facility's first drawn cost is LIBOR plus 45 basis points based on CenterPoint Houston's current credit ratings. The facility contains a debt (excluding transition and other securitization bonds) to total capitalization covenant.

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CERC Corp.'s $950 million credit facility's first drawn cost is LIBOR plus 45 basis points based on CERC Corp.'s current credit ratings. The facility contains a debt to total capitalization covenant.

Under our $1.2 billion credit facility, CenterPoint Houston's $289 million credit facility and CERC Corp's $950 million credit facility, 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.

CenterPoint Houston's $600 million 364-day credit facility is secured by a pledge of $600 million of general mortgage bonds issued by CenterPoint Houston. Borrowing costs for LIBOR-based loans will be at a margin of 2.25 percent above LIBOR rates, based on CenterPoint Houston's current ratings. In addition, CenterPoint Houston will pay lenders, based on current ratings, a per annum commitment fee of 0.5 percent for their commitments under the facility and a quarterly duration fee of 0.75 percent on the average amount of outstanding borrowings during the quarter. The spread to LIBOR and the commitment fee fluctuate based on the borrower's credit rating. The facility contains covenants, including a debt (excluding transition and other securitization bonds) to total capitalization covenant. The credit facility will terminate if bonds are issued to securitize the distribution-related costs incurred as a result of Hurricane Ike and if those bonds are issued prior to the November 24, 2009 expiration of the facility.

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.

Availability under CERC's 364-day receivables facility ranges from $128 million to $375 million, reflecting seasonal changes in receivables balances. At December 31, 2008 and March 31, 2009 the facility size was $128 million and $375 million, respectively. As of December 31, 2008 and March 31, 2009, advances under the receivables facility were $78 million and $215 million, respectively.

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

Our $1.2 billion credit facility backstops a $1.0 billion CenterPoint Energy commercial paper program under which we began issuing commercial paper in June 2005. The $950 million CERC Corp. credit facility backstops a $915 million commercial paper program under which CERC Corp. began issuing commercial paper in February 2008. The CenterPoint Energy 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). The CERC Corp. commercial paper is rated "P-3" by Moody's, "A-2" by S&P, and "F2" by Fitch. As a result of the credit ratings on the two commercial paper programs, 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. In October 2008, CenterPoint Energy and CenterPoint Houston jointly registered indeterminate principal amounts of CenterPoint Houston's general mortgage bonds and CenterPoint Energy's senior debt securities and junior subordinated debt securities and an indeterminate number of CenterPoint Energy's shares of common stock, shares of preferred stock, as well as stock purchase contracts and equity units. In addition, CERC Corp. has a shelf registration statement covering $500 million principal amount of senior debt securities.

In February 2009, we entered into a continuous offering program equity distribution agreement with Citigroup Global Markets Inc. (Citi). Pursuant to the agreement, we may offer and sell shares of our common stock, having an

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aggregate gross sales price of up to $150 million from time to time through Citi as our sales agent. Any shares sold under the agreement will be issued pursuant to the joint registration statement described above. No sales had occurred through March 31, 2009.

Temporary Investments. As of April 22, 2009, we had no external temporary investments.

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 our revolving credit facility or the sale of our commercial paper.

Impact on Liquidity of a Downgrade in Credit Ratings. As of April 22, 2009, Moody's, S&P, and Fitch had assigned the following credit ratings to senior debt of CenterPoint Energy and certain subsidiaries:

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

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

(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 these credit ratings could increase borrowing costs under our $1.2 billion credit facility, CenterPoint Houston's $289 million credit facility and $600 million 364-day 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% Zero-Premium Exchangeable Subordinated Notes due 2029 (ZENS) having an original principal amount of $1.0 billion of which $840 million remain outstanding at March 31, 2009. Each ZENS note was originally 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 such note. The number and identity of the reference shares attributable to each ZENS note are adjusted for certain corporate events. As of March 31, 2009, the reference shares for each ZENS note consisted of 0.5 share of TW Common and 0.125505 share of Time Warner Cable Inc. common stock (TWC Common), which reflects adjustments resulting from the March 2009 distribution by Time Warner Inc. of shares of TWC Common and Time Warner Inc.'s March 2009 reverse stock split. 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 and TWC Common that we own or from other sources. We own shares of TW Common and TWC 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 tax deferrals related to the ZENS notes and TW Common and TWC Common shares would typically cease when ZENS notes are exchanged or otherwise retired and TW Common and TWC Common shares are sold. The ultimate tax liability 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. The American Recovery and Reinvestment Act of 2009 allows us to defer until 2014 taxes due as a result of the retirement

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of ZENS notes that would have otherwise been payable in 2009 or 2010 and pay such taxes over the period from 2014 through 2018. Accordingly, if on March 31, 2009, all ZENS notes had been exchanged for cash, we could have deferred taxes of approximately $395 million that would have otherwise been payable in 2009.

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 March 31, 2009, the amount posted as collateral aggregated approximately $292 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 one business days' notice up to the amount of its previously unsecured credit limit. We estimate that as of March 31, 2009, unsecured credit limits extended to CES by counterparties aggregate $260 million; however, utilized credit capacity was $83 million. 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.

Pipeline tariffs and contracts typically provide that if the credit ratings of a shipper or the shipper's guarantor drop below a threshold level, which is generally investment grade ratings from both Moody's and S&P, cash or other collateral may be demanded from the shipper in an amount equal to the sum of three months' charges for pipeline services plus the unrecouped cost of any lateral built for such shipper. If the credit ratings of CERC Corp. decline below the applicable threshold levels, CERC Corp. might need to provide cash or other collateral of as much as $158 million as of March 31, 2009, the amount depending on seasonal variations in transportation levels.

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, four outstanding series of our senior notes, aggregating $950 million in principal amount as of April 22, 2009, 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.

Possible Acquisitions, Divestitures and Joint Ventures. From time to time, we consider the acquisition or the disposition of assets or businesses or possible joint ventures or other joint ownership arrangements with respect to assets or businesses. Any determination to take any action in this regard will be based on market conditions and opportunities existing at the time, and accordingly, the timing, size or success of any efforts and the associated potential capital commitments are unpredictable. We may seek to fund all or part of any such efforts with proceeds from debt and/or equity issuances. Debt or equity financing may not, however, be available to us at that time due to a variety of events, including, among others, maintenance of our credit ratings, industry conditions, general economic conditions, market conditions and market perceptions.

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

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cash collateral requirements that could exist in connection with certain contracts, including gas purchases, gas price and weather 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;

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- increases in interest expense in connection with debt refinancings and borrowings under credit facilities;
- various regulatory actions;
- the ability of RRI and its subsidiaries and any successor companies 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;
- 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 the timing of recovery of such restoration costs; and
- various other risks identified in "Risk Factors" in Item 1A of our 2008 Form 10-K.

Certain Contractual Limits on Our Ability to Issue Securities and Borrow Money. CenterPoint Houston's credit facilities limit CenterPoint Houston's debt (excluding transition and other securitization bonds) as a percentage of its total capitalization to 65%. CERC Corp.'s bank facility and its receivables facility limit CERC's debt as a percentage of its total capitalization to 65%. Our $1.2 billion credit facility contains a debt, excluding transition bonds, to EBITDA covenant. Such covenant was modified twice in 2008 to provide additional debt capacity. The second modification was to provide debt capacity for the financing of system restoration costs following Hurricane Ike. Additionally, CenterPoint Houston has contractually agreed that it will not issue additional first mortgage bonds, subject to certain exceptions.

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 use derivative instruments as economic hedges to offset the commodity price exposure inherent in our businesses. The stand-alone commodity risk created by these instruments, without regard to the offsetting effect of the underlying exposure these instruments are intended to hedge, is described below. We measure the commodity risk of our non-trading energy derivatives using a sensitivity analysis. The sensitivity analysis performed on our non-trading energy derivatives measures the potential loss in fair value based on a hypothetical 10% movement in energy prices. At March 31, 2009, the recorded fair value of our non-trading energy derivatives was a net liability of $216 million (before collateral). The net liability consisted of a net liability of $251 million associated with price stabilization activities of our Natural Gas Distribution business segment and a net asset of $35 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 March 31, 2009 levels would have increased the fair value of our non-trading energy derivatives net liability by $43 million. However, the consolidated income statement impact of this same 10% decrease in market prices would be an increase in income of $1 million.

The above analysis of the non-trading energy derivatives utilized for commodity 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.

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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

As of March 31, 2009, we had outstanding long-term debt, bank loans, lease obligations, and our obligations under our ZENS that subject us to the risk of loss associated with movements in market interest rates.

Our floating-rate obligations aggregated $1.5 billion and $969 million at December 31, 2008 and March 31, 2009, respectively. If the floating interest rates were to increase by 10% from March 31, 2009 rates, our combined interest expense would increase by approximately $1 million annually.

At December 31, 2008 and 2009, we had outstanding fixed-rate debt (excluding indexed debt securities) aggregating $9.0 billion and $9.3 billion, respectively, in principal amount and having a fair value of $8.5 billion and $8.9 billion, respectively. Because these instruments are fixed-rate, they do not expose us to the risk of loss in earnings due to changes in market interest rates (please read Note 10 to our consolidated financial statements). However, the fair value of these instruments would increase by approximately $345 million if interest rates were to decline by 10% from their levels at March 31, 2009. 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,” effective January 1, 2001, the ZENS obligation was bifurcated into a debt component and a derivative component. The debt component of $119 million at March 31, 2009 was a fixed-rate obligation and, therefore, did not expose us to the risk of loss in earnings due to changes in market interest rates. However, the fair value of the debt component would increase by approximately $19 million if interest rates were to decline by 10% from levels at March 31, 2009. Changes in the fair value of the derivative component, a $111 million recorded liability at March 31, 2009, are 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 March 31, 2009 levels, the fair value of the derivative component liability would increase by approximately $2 million, which would be recorded as an unrealized loss in our Condensed Statements of Consolidated Income.

Equity Market Value Risk

We are exposed to equity market value risk through our ownership of 7.2 million shares of TW Common and 1.8 million shares of TWC Common, which we hold to facilitate our ability to meet our obligations under the ZENS. A decrease of 10% from the March 31, 2009 aggregate market value of TW Common and TWC Common would result in a net loss of approximately $4 million, which would be recorded as an unrealized loss in our 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 March 31, 2009 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 March 31, 2009 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

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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 11 to our Interim Condensed Financial Statements, each of which is incorporated herein by reference. See also "Business — Regulation" and " — Environmental Matters" in Item 1 and "Legal Proceedings" in Item 3 of our 2008 Form 10-K.

Item 1A. RISK FACTORS

There have been no material changes from the risk factors disclosed in our 2008 Form 10-K.

Item 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

At the annual meeting of our shareholders held on April 23, 2009, the matters voted upon and the number of votes cast for or against, as well as the number of abstentions and broker non-votes as to such matters (including a separate tabulation with respect to each nominee for office), were as stated below:

The following nominees for directors were elected to serve one-year terms expiring at the 2010 annual meeting of shareholders (abstentions and broker non-votes were not counted):

Nominee	For	Against
Derrill Cody	282,157,616	14,458,047
Michael P. Johnson	283,304,535	13,275,541
David M. McClanahan	285,172,798	11,749,508
Robert T. O'Connell	283,935,477	12,768,232
Susan O. Rheney	285,442,085	11,287,279
Michael E. Shannon	283,576,884	13,067,331

Donald R. Campbell, Milton Carroll, O. Holcombe Crosswell, Janiece M. Longoria, Thomas F. Madison, Peter S. Wareing and Sherman M. Wolff all continue as directors of CenterPoint Energy.

The appointment of Deloitte & Touche LLP as independent registered public accountants for CenterPoint Energy for 2009 was ratified with 292,625,719 votes for, 4,702,075 votes against, 685,494 abstentions and no broker non-votes.

The adoption of the CenterPoint Energy, Inc. 2009 Long Term Incentive Plan was approved with 204,762,048 votes for, 28,721,721 votes against, 2,025,667 abstentions and 62,503,852 broker non-votes.

Item 5. OTHER INFORMATION

The ratio of earnings to fixed charges for the three months ended March 31, 2008 and 2009 was 2.24 and 1.66, respectively. We do not believe that the ratios for these three-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.

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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.

Agreements included as exhibits are included only to provide information to investors regarding their terms. Agreements listed below may contain representations, warranties and other provisions that were made, among other things, to provide the parties thereto with specified rights and obligations and to allocate risk among them, and no such agreement should be relied upon as constituting or providing any factual disclosures about CenterPoint Energy, Inc., any other persons, any state of affairs or other matters.

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
3.1	—Amended and Restated Articles of Incorporation of CenterPoint Energy	CenterPoint Energy's Form 8-K dated July 24, 2008	1-31447	3.1
3.2	—Restated Bylaws of CenterPoint Energy	CenterPoint Energy's Form 8-K dated July 24, 2008	1-31447	3.2
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	—$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
4.3.2	—First Amendment to Exhibit 4.3.1, dated as of August 20, 2008, among CenterPoint Energy, as Borrower, and the banks named therein	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2008	1-31447	4.4
4.3.3	—Second Amendment to Exhibit 4.3.1, dated as of November 18, 2008,	CenterPoint Energy's Form 8-K dated November 18, 2008	1-31447	4.1

	among CenterPoint Energy, as Borrower, and the banks named therein			
4.4.1	—$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
4.4.2	—First Amendment to Exhibit 4.4.1, dated as of November 18, 2008, among CenterPoint Houston, as Borrower, and the banks named therein	CenterPoint Energy's Form 8-K dated November 18, 2008	1-31447	4.2
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

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Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4.6	—$600,000,000 Credit Agreement dated as of November 25, 2008, among CenterPoint Houston, as Borrower, and the banks named therein	CenterPoint Energy's Form 8-K dated November 25, 2008	1-31447	4.1
10.1	—Form of Performance Share Award Agreement for 2009 — 2011 Performance Cycle under the Long-Term Incentive Plan of CenterPoint Energy, Inc.	CenterPoint Energy's Form 8-K dated February 24, 2009	1-31447	10.1
10.2	—Form of Stock Award Agreement (With Performance Goal) under the Long-Term Incentive Plan of CenterPoint Energy, Inc.	CenterPoint Energy's Form 8-K dated February 24, 2009	1-31447	10.2
10.3	—Equity Distribution Agreement, dated as of February 25, 2009, between CenterPoint Energy and Citigroup Global Markets Inc.	CenterPoint Energy's Form 8-K dated February 25, 2009	1-31447	1.1
+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/ Walter L. Fitzgerald
Walter L. Fitzgerald
Senior Vice President and Chief Accounting Officer

Date: April 29, 2009

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Index to Exhibits

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