BLACKROCK FLOATING RATE INCOME TRUST
Form 4
March 17, 2011

FORM 4

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

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

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL
OMB Number: 3235-0287
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(Print or Type Responses)

1. Name and Address of Reporting Person *
BANK OF AMERICA CORP /DE/

(Last) (First) (Middle)

BANK OF AMERICA CORPORATE CENTER, 100 N. TRYON STREET

(Street)

CHARLOTTE, NC 28255

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
BLACKROCK FLOATING RATE INCOME TRUST [BGT]

3. Date of Earliest Transaction (Month/Day/Year)
02/08/2010

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

_____ Director __X__ 10% Owner
_____ Officer (give title below) _____ Other (specify below)

6. Individual or Joint/Group Filing(Check Applicable Line)
___ Form filed by One Reporting Person
_X_ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock	02/08/2010		P		110	A	$ 14.44	110	I	By Subsidiary
Common Stock	02/08/2010		S		110	D	$ 14.43	0	I	By Subsidiary

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

Persons who respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB control number.

SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)		8. Price of Derivative Security (Instr. 5)	9. Nu Deriv Secur Bene Own Follo Repo Trans (Instr
								Date Exercisable	Expiration Date	Title	Amount or Number of Shares		
				Code	V	(A)	(D)						

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
BANK OF AMERICA CORP /DE/ BANK OF AMERICA CORPORATE CENTER 100 N. TRYON STREET CHARLOTTE, NC 28255		X		
MERRILL LYNCH, PIERCE, FENNER & SMITH INC. 4 WORLD FINANCIAL CENTER NORTH TOWER NEW YORK, NY 10080		X		

Signatures

Bank of America Corporation, By: /s/ Beth Dorfman, Authorized Signatory	03/17/2011
**Signature of Reporting Person	Date
Merrill Lynch, Pierce, Fenner & Smith Incorporated, By: /s/ Lawrence Emerson, Title: Attorney-In-Fact	03/17/2011
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

Remarks:

The transactions reported on this Form 4 were effected by Merrill Lynch, Pierce, Fenner & Smith Incorporated, an indirect, wh

Disgorgement of profits, if applicable, based on transactions reported above is being made by the Reporting Persons to the Issu

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. JUNE 30, JUNE 30, -------------------------- -------------------------- 2005 2006 2005 2006

------------ ------------ ------------ ------------ (IN MILLIONS, EXCEPT SHARE AND PER SHARE AMOUNTS) Basic earnings per share calculation: Income from continuing operations before extraordinary item ..... $ 27 $ 194 $ 94 $ 282 Discontinued operations, net of tax .... (3) -- (3) -- Extraordinary item, net of tax .... 30 -- 30 -- ------------ ------------ ------------ ------------ Net income .... $ 54 $ 194 $ 121 $ 282 ============ ============ ============ ============ Weighted average shares outstanding .... 309,098,000 311,440,000 308,786,000 311,145,000 ============ ============ ============ ============ Basic earnings per share: Income from continuing operations before extraordinary item ..... $ 0.09 $ 0.62 $ 0.30 $ 0.91 Discontinued operations, net of tax .... (0.01) -- (0.01) -- Extraordinary item, net of tax .... 0.10 -- 0.10 -- ------------ ------------ ------------ ------------ Net income .... $ 0.18 $ 0.62 $ 0.39 $ 0.91 ============ ============ ============ ============ Diluted earnings per share calculation: Net income .... $ 54 $ 194 $ 121 $ 282 Plus: Income impact of assumed conversions: Interest on 3.75% convertible senior notes .... 4 -- 7 -- ------------ ------------ ------------ ------------ Total earnings effect assuming dilution .... $ 58 $ 194 $ 128 $ 282 ============ ============ ============ ============ Weighted average shares outstanding .... 309,098,000 311,440,000 308,786,000 311,145,000 Plus: Incremental shares from assumed conversions: Stock options (1) .... 1,302,000 1,098,000 1,254,000 1,150,000 Restricted stock .... 1,365,000 1,160,000 1,365,000 1,160,000 3.75% convertible senior notes .... 49,655,000 3,118,000 49,655,000 4,289,000 6.25% convertible trust preferred securities .... 16,000 -- 16,000 -- ------------ ------------ ------------ ------------ Weighted average shares assuming dilution .... 361,436,000 316,816,000 361,076,000 317,744,000 ============ ============ ============ ============ Diluted earnings per share: Income from continuing operations before extraordinary item ..... $ 0.09 $ 0.61 $ 0.28 $ 0.89 Discontinued operations, net of tax .... (0.01) -- (0.01) -- Extraordinary item, net of tax .... 0.08 -- 0.08 -- ------------ ------------ ------------ ------------ Net income .... $ 0.16 $ 0.61 $ 0.35 $ 0.89 ============ ============ ============ ============ ---------- (1) Options to purchase 9,356,759 shares were outstanding for both the three months and six months ended June 30, 2005, and options to purchase 7,137,644 shares were outstanding for both the three months and six months ended June 30, 2006, but were not included in the computation of diluted earnings per share because the options' exercise price was greater than the average market price of the common shares for the respective periods. 23 In accordance with EITF 04-8, because all of the 2.875% contingently convertible senior notes and approximately $572 million of the 3.75% contingently convertible senior notes (subsequent to the August 2005 exchange discussed in Note 10) provide for settlement of the principal portion in cash rather than stock, the Company excludes the portion of the conversion value of these notes attributable to their principal amount from its computation of diluted earnings per share from continuing operations. The Company includes the conversion spread in the calculation of diluted earnings per share when the average market price of the Company's common stock in the respective reporting period exceeds the conversion price. The conversion prices for the 2.875% and the 3.75% contingently convertible senior notes are $12.66 and $11.44, respectively. (13) REPORTABLE BUSINESS SEGMENTS The Company's determination of reportable business segments considers the strategic operating units under which the Company manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. The accounting policies of the business segments are the same as those described in the summary of significant accounting policies except that some executive benefit costs have not been allocated to business segments. The Company uses operating income as the measure of profit or loss for its business segments. The Company's reportable business segments include the following: Electric Transmission & Distribution, Natural Gas Distribution, Competitive Natural Gas Sales and Services, Pipelines and Field Services and Other Operations. The electric transmission and distribution function (CenterPoint Houston) is reported in the Electric Transmission & Distribution business segment. Natural Gas Distribution consists of intrastate natural gas sales to, and natural gas transportation and distribution for, residential, commercial, industrial and institutional customers. The Company reorganized the oversight of its Natural Gas Distribution business segment and, as a result, beginning in the fourth quarter of 2005, the Company established a new reportable business segment, Competitive Natural Gas Sales and Services. Competitive Natural Gas Sales and Services represents the Company's non-rate regulated gas sales and services operations, which consist of three operational functions: wholesale, retail and intrastate pipelines. Pipelines and Field Services includes the interstate natural gas pipeline operations and the natural gas gathering and pipeline services businesses. Other Operations consists primarily of other corporate operations which support all of the Company's business operations. All prior period segment information has been reclassified to conform to the 2006 presentation. Long-lived assets include net property, plant and equipment, net goodwill and other intangibles and equity investments in unconsolidated subsidiaries. Intersegment sales are eliminated in consolidation. Financial data for business segments and products and services are as follows (in millions): FOR THE THREE MONTHS ENDED JUNE 30, 2005 --- REVENUES FROM EXTERNAL NET INTERSEGMENT CUSTOMERS REVENUES OPERATING INCOME (LOSS) --------------------- --------------- ---------------------- Electric Transmission & Distribution .... $ 414(1) $ -- $122 Natural Gas Distribution .... 538 3 9 Competitive Natural Gas Sales and Services ... 801 44 10 Pipelines and Field Services .... 87 38 52 Other Operations .... 2 2 (7) Eliminations .... -- (87) -- ------ ---- ---- Consolidated .... $1,842 $ -- $186 ====== ==== ==== 24 FOR THE THREE MONTHS ENDED JUNE 30, 2006 --- REVENUES FROM EXTERNAL NET INTERSEGMENT CUSTOMERS REVENUES OPERATING INCOME (LOSS) --------------------- --------------- ---------------------- Electric Transmission & Distribution .... $ 456(1) $ -- $151 Natural Gas Distribution .... 546 3 (2) Competitive Natural Gas Sales and Services ... 742 8 7 Pipelines and Field Services .... 96 39 61 Other Operations .... 3 2 3 Eliminations .... -- (52) -- ------ ---- ---- Consolidated .... $1,843 $ -- $220 ====== ==== ==== FOR THE SIX MONTHS ENDED JUNE 30, 2005 --- REVENUES FROM EXTERNAL NET INTERSEGMENT OPERATING TOTAL ASSETS AS OF CUSTOMERS REVENUES INCOME (LOSS) DECEMBER 31, 2005 --------------------- --------------- ------------ ----------------- Electric Transmission & Distribution .... $ 759(1) $ -- $202 $ 8,227 Natural Gas Distribution .... 1,867 3 132 4,612 Competitive Natural Gas Sales and Services ... 1,633 137 26 1,849 Pipelines and Field Services .... 171 75 116 2,968 Other Operations .... 7 4 (14) 2,202(2) Eliminations .... -- (219) -- (2,742) ------ ----- ---- ------- Consolidated .... $4,437 $ -- $462 $17,116 ====== ===== ==== ======= FOR THE SIX MONTHS ENDED JUNE 30, 2006 --- REVENUES FROM EXTERNAL NET INTERSEGMENT OPERATING TOTAL ASSETS AS OF CUSTOMERS REVENUES INCOME (LOSS) JUNE 30, 2006 --------------------- --------------- ------------ ----------------- Electric Transmission & Distribution .... $ 841(1) $ -- $261 $ 8,381 Natural Gas Distribution .... 2,023 6 101 3,959 Competitive Natural Gas Sales and Services ... 1,868 45 32 1,259 Pipelines and Field Services .... 183 77 134 3,057 Other Operations .... 5 4 (2) 2,146(2) Eliminations .... -- (132) -- (2,093) ------ ----- ---- ------- Consolidated .... $4,920 $ -- $526 $16,709 ====== ===== ==== ======= ---------- (1) Sales to subsidiaries of RRI in the three months ended June 30, 2005 and 2006 represented approximately $183 million and $182 million, respectively. Sales to subsidiaries of RRI in the six months ended June 30, 2005 and 2006 represented approximately $366 million and $344 million, respectively. (2) Included in total assets of Other Operations as of December 31, 2005 and June 30, 2006 is a pension asset of $654 million and $631 million, respectively. (14) SUBSEQUENT EVENT On July 27, 2006, the Company's board of directors declared a regular quarterly cash dividend of $0.15 per share of common stock payable on September 8, 2006, to the shareholders of record as of the close of business on August 16, 2006. 25 ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS OF CENTERPOINT ENERGY, INC. AND SUBSIDIARIES The following discussion and analysis should be read in combination with our Interim Condensed Financial Statements contained in this Form 10-Q. EXECUTIVE SUMMARY RECENT EVENTS DEBT FINANCING TRANSACTIONS In May 2006, CERC Corp. issued $325 million aggregate principal amount of senior notes due in May 2016 with an interest rate of 6.15%. The proceeds from the sale of the senior notes will be used for general corporate purposes, including repayment or refinancing of debt (including $145 million of CERC's 8.90% debentures due December 15, 2006), capital expenditures and working capital. AGREEMENT REGARDING TAX SETTLEMENT During the second quarter of 2006, we reached agreement with the Internal Revenue Service (IRS) on terms of a settlement regarding the tax treatment of our Zero Premium Exchangeable Subordinated Notes (ZENS) and our former Automatic Common Exchange Securities (ACES). On July 17, 2006, we signed a Closing Agreement prepared by the IRS and us for the tax years 1999 through 2029 with respect to the ZENS issue. The agreement reached with the IRS and the Closing Agreement are subject to approval by the Joint Committee on Taxation of the

U.S. Congress. Under the terms of the agreement reached with the IRS, we will pay approximately $64 million in previously accrued taxes associated with the ACES and the ZENS and will reduce our future interest deductions associated with the ZENS. As a result of the agreement reached with the IRS, we reduced our previously accrued tax and related interest reserves by approximately $119 million in the second quarter of 2006, and will no longer accrue a quarterly reserve. AGREEMENT REGARDING SETTLEMENT OF THE ELECTRIC TRANSMISSION & DISTRIBUTION RATE CASE AND THE 2001 UNBUNDLED COST OF SERVICE (UCOS) REMAND On July 31, 2006, CenterPoint Houston entered into a settlement agreement with the parties to the proceeding that would resolve the issues raised in its pending rate case. Under the terms of the agreement, CenterPoint Houston's base rate revenues will be reduced by approximately $58 million per year. Also, CenterPoint Houston will commit to increase its energy efficiency expenditures by an additional $10 million per year over the $13 million included in existing rates. The expenditures will be made to benefit both residential and commercial customers. CenterPoint Houston also will fund $10 million per year for programs providing financial assistance to qualified low-income customers in its service territory. The agreement provides for a rate freeze until June 30, 2010 under which CenterPoint Houston will not seek to increase its base rates and the other parties will not petition to decrease those rates. The agreement also resolves all issues that could be raised in the Public Utility Commission of Texas' (Texas Utility Commission) proceeding to review its decision in CenterPoint Houston's 2001 UCOS case. Under the terms of the agreement, CenterPoint Houston will add riders to its tariff rates under which it will provide rate credits to retail and wholesale customers for a total of approximately $8 million per year until a total of $32 million has been credited to customers under those tariff riders. CenterPoint Houston reduced revenues and established a corresponding regulatory liability for $32 million in the second quarter of 2006 to reflect this obligation. COMPETITION TRANSITION CHARGE (CTC) INTEREST RATE REDUCTION In January 2006, the Texas Utility Commission staff (Staff) proposed that the Texas Utility Commission adopt new rules governing the carrying charges on unrecovered true-up balances. In June 2006, the Texas Utility Commission adopted the revised rule as recommended by the Staff. The rule, which applies to CenterPoint Houston, reduces carrying costs on the unrecovered CTC balance prospectively from 11.075 percent to a weighted average cost of capital of 8.06 percent. The annualized impact on operating income is expected to be approximately $18 million per year for the first year with lesser impacts in subsequent years. In accordance with the agreement discussed above, CenterPoint Houston implemented the rule change effective August 1, 2006. 26 CONSOLIDATED RESULTS OF OPERATIONS All dollar amounts in the tables that follow are in millions, except for per share amounts. THREE MONTHS SIX MONTHS ENDED JUNE 30, ENDED JUNE 30, --------------- -------------- 2005 2006 2005 2006 ------ ------ ------ ------ Revenues .... $1,842 $1,843 $4,437 $4,920 Expenses .... 1,656 1,623 3,975 4,394 ------ ------ ------ ------ Operating Income .... 186 220 462 526 Interest and Other Finance Charges .... (189) (151) (371) (299) Other Income, net .... 48 9 84 11 ------ ------ ------ ------ Income From Continuing Operations Before Income Taxes and Extraordinary Item .... 45 78 175 238 Income Tax (Expense) Benefit .... (18) 116 (81) 44 ------ ------ ------ ------ Income From Continuing Operations Before Extraordinary Item .... 27 194 94 282 Discontinued Operations, net of tax .... (3) -- (3) -- ------ ------ ------ ------ Income Before Extraordinary Item .... 24 194 91 282 Extraordinary Item, net of tax .... 30 -- 30 -- ------ ------ ------ ------ Net Income .... $ 54 $ 194 $ 121 $ 282 ====== ====== ====== ====== BASIC EARNINGS PER SHARE: Income From Continuing Operations ...... $ 0.09 $ 0.62 $ 0.30 $ 0.91 Discontinued Operations, net of tax .... (0.01) -- (0.01) -- Extraordinary Item, net of tax .... 0.10 -- 0.10 -- ------ ------ ------ ------ Net Income .... $ 0.18 $ 0.62 $ 0.39 $ 0.91 ====== ====== ====== ====== DILUTED EARNINGS PER SHARE: Income From Continuing Operations ...... $ 0.09 $ 0.61 $ 0.28 $ 0.89 Discontinued Operations, net of tax .... (0.01) -- (0.01) -- Extraordinary Item, net of tax .... 0.08 -- 0.08 -- ------ ------ ------ ------ Net Income .... $ 0.16 $ 0.61 $ 0.35 $ 0.89 ====== ====== ====== ====== THREE MONTHS ENDED JUNE 30, 2006 COMPARED TO THREE MONTHS ENDED JUNE 30, 2005 Income from Continuing Operations. We reported income from continuing operations of $194 million ($0.61 per diluted share) for the three months ended June 30, 2006 as compared to $27 million ($0.09 per diluted share) for the same period in 2005. As discussed below, the increase in income from continuing operations of $167 million was primarily due to: - a $119 million reduction to previously accrued tax and related interest reserves related to our ZENS and ACES as a result of an agreement reached with the IRS discussed above; - a $62 million decrease in interest expense, excluding transition bond-related interest expense, due to lower borrowing costs and borrowing levels; - a $9 million increase in operating income from our Pipelines and Field Services business segment;

and - a $6 million increase in operating income from the regulated utility operations of our Electric Transmission & Distribution business segment. These increases in income from continuing operations were partially offset by: - a $35 million decrease in other income related to a return on the true-up balance of our Electric Transmission & Distribution business segment recorded in the second quarter of 2005; - an $11 million decrease in operating income from our Natural Gas Distribution business segment; and 27 - a $3 million decrease in operating income from our Competitive Natural Gas Sales and Services business segment. SIX MONTHS ENDED JUNE 30, 2006 COMPARED TO SIX MONTHS ENDED JUNE 30, 2005 Income from Continuing Operations. We reported income from continuing operations of $282 million ($0.89 per diluted share) for the six months ended June 30, 2006 as compared to $94 million ($0.28 per diluted share) for the same period in 2005. As discussed below, the increase in income from continuing operations of $188 million was primarily due to: - a $120 million decrease in interest expense, excluding transition bond-related interest expense, due to lower borrowing costs and borrowing levels; - a $119 million reduction to previously accrued tax and related interest reserves related to our ZENS and ACES as discussed above; - a $18 million increase in operating income from our Pipelines and Field Services business segment; - a $13 million increase in operating income from the regulated utility operations of our Electric Transmission & Distribution business segment; and - a $6 million increase in operating income from our Competitive Natural Gas Sales and Services business segment. These increases in income from continuing operations were partially offset by: - a $69 million decrease in other income related to a return on the true-up balance of our Electric Transmission & Distribution business segment recorded in the first six months of 2005; and - a $31 million decrease in operating income from our Natural Gas Distribution business segment. INCOME TAX EXPENSE During the three months and six months ended June 30, 2005, our effective tax rate was 39.3% and 46.2%, respectively. The most significant item affecting our effective tax rates was an addition to the tax reserve relating to the ZENS and ACES of approximately $12 million and $22 million, respectively, during the three months and six months ended June 30, 2005. As discussed above, we reached an agreement with the IRS in July 2006 and have reduced our previously accrued tax and related interest reserves related to the ZENS and ACES by approximately $119 million as of June 30, 2006. Settlement of other tax issues during the three months and six months ended June 30, 2006 reduced income tax expense by approximately $21 million. The effective tax rate for the three months and six months ended June 30, 2006 was a net benefit as a result of these matters. EXTRAORDINARY ITEM AND LOSS ON DISPOSAL OF TEXAS GENCO Net income for both the three months and six months ended June 30, 2005 included an after-tax extraordinary gain of $30 million ($0.08 per diluted share) reflecting an adjustment to the extraordinary loss recorded in the last half of 2004 to write-down generation-related regulatory assets as a result of the final orders issued by the Texas Utility Commission. Net income for both the three months and six months ended June 30, 2005 included a net after-tax loss from discontinued operations of Texas Genco of $3 million ($0.01 per diluted share). RESULTS OF OPERATIONS BY BUSINESS SEGMENT The following table presents operating income (loss) for each of our business segments for the three and six months ended June 30, 2005 and 2006. Some amounts from the previous year have been reclassified to conform to the 2006 presentation of the financial statements. These reclassifications do not affect consolidated net income. 28 THREE MONTHS SIX MONTHS ENDED JUNE 30, ENDED JUNE 30, ------------- ------------- 2005 2006 2005 2006 ---- ---- ---- ---- (IN MILLIONS) Electric Transmission & Distribution .... $122 $151 $202 $261 Natural Gas Distribution .... 9 (2) 132 101 Competitive Natural Gas Sales and Services .. 10 7 26 32 Pipelines and Field Services .... 52 61 116 134 Other Operations .... (7) 3 (14) (2) ---- ---- ---- ---- Total Consolidated Operating Income ...... $186 $220 $462 $526 ==== ==== ==== ==== ELECTRIC TRANSMISSION & DISTRIBUTION For information regarding factors that may affect the future results of operations of our Electric Transmission & Distribution business segment, please read "Risk Factors -- Risk Factors Affecting Our Electric Transmission & Distribution Business," " -- Risk Factors Associated with Our Consolidated Financial Condition" and "-- Risks Common to Our Business and Other Risks" in Item 1A of Part I of our Annual Report on Form 10-K for the year ended December 31, 2005 (2005 Form 10-K). The following tables provide summary data of our Electric Transmission & Distribution business segment for the three and six months ended June 30, 2005 and 2006 (in millions, except throughput and customer data): THREE MONTHS ENDED JUNE 30, SIX MONTHS ENDED JUNE 30, ------------------------- ------------------------ 2005 2006 2005 2006 ---------- ---------- --------- ---------- Revenues: Electric transmission and distribution utility .... $ 388 $ 386 $ 711 $ 717 Transition bond companies .... 26 70 48 124 ---------- ---------- ---------- ---------- Total revenues .... 414 456 759 841 ---------- ---------- ---------- ---------- Expenses: Operation and maintenance .... 153 147 291 281 Depreciation and amortization .... 64 61 128 124 Taxes other than income taxes .... 58 59 108 115 Transition bond companies .... 17 38 30 60 ---------- ---------- ---------- ---------- Total expenses .... 292 305 557 580 ---------- ---------- ---------- ---------- Operating Income .... $ 122 $ 151 $ 202 $ 261 ========== ========== ========== ========== Operating Income - Electric transmission and distribution utility .. $ 113 $ 119 $ 184 $ 197 Operating Income - Transition bond companies (1) .... 9 32 18 64 ---------- ---------- ---------- ---------- Total segment operating income .... $ 122 $ 151 $ 202 $ 261 ========== ========== ========== ========== Throughput (in gigawatt-hours (GWh)): Residential .... 6,594 6,808 10,736 10,794 Total .... 18,956 20,422 34,783 36,409 Average number of metered customers: Residential .... 1,675,573 1,730,130 1,668,447 1,723,983 Total .... 1,904,090 1,965,180 1,895,556 1,958,005 ---------- (1) Represents the amount necessary to pay interest on the transition bonds. THREE MONTHS ENDED JUNE 30, 2006 COMPARED TO THREE MONTHS ENDED JUNE 30, 2005 Our Electric Transmission & Distribution business segment reported operating income of $151 million for the three months ended June 30, 2006, consisting of $119 million for the regulated electric transmission and distribution utility and $32 million related to the transition bonds. For the three months ended June 30, 2005, operating income totaled $122 million, consisting of $113 million for the regulated electric transmission and distribution utility and $9 million related to the transition bonds. Revenues for the regulated electric transmission and distribution utility continue to benefit from solid customer growth, with nearly 60,000 metered customers added since June 2005 ($10 29 million), recovery of our 2004 true-up balance through the CTC, which was implemented in September 2005 ($12 million) as well as favorable weather and increased usage ($6 million). This increase in revenues was more than offset by the impact related to the resolution of the 2001 UCOS order, which reduced revenues by $32 million. Operation and maintenance expense decreased primarily due to lower employee benefit expenses ($4 million). SIX MONTHS ENDED JUNE 30, 2006 COMPARED TO SIX MONTHS ENDED JUNE 30, 2005 Our Electric Transmission & Distribution business segment reported operating income of $261 million for the six months ended June 30, 2006, consisting of $197 million for the regulated electric transmission and distribution utility and $64 million related to the transition bonds. For the six months ended June 30, 2005, operating income totaled $202 million, consisting of $184 million for the regulated electric transmission and distribution utility and $18 million related to the transition bonds. Revenues for the regulated electric transmission and distribution utility increased due to continued customer growth, with nearly 60,000 metered customers added since June 2005 ($18 million), recovery of our 2004 true-up balance through the CTC ($26 million) and favorable weather ($2 million), partially offset by decreased usage ($8 million) and the impact related to the resolution of the 2001 UCOS order ($32 million). Operation and maintenance expense decreased primarily due to a gain on the sale of land in 2006 ($14 million) and lower employee benefit expenses ($5 million), which was partially offset by higher transmission costs ($5 million) and severance costs associated with staff reductions ($4 million). Additionally, taxes other than income taxes increased primarily due to higher franchise fees ($7 million). NATURAL GAS DISTRIBUTION For information regarding factors that may affect the future results of operations of our Natural Gas Distribution business segment, please read "Risk Factors -- Risk Factors Affecting Our Natural Gas Distribution, Competitive Natural Gas Sales and Services and Pipelines and Field Services Businesses," " -- Risk Factors Associated with Our Consolidated Financial Condition" and "-- Risks Common to Our Business and Other Risks" in Item 1A of Part I of our 2005 Form 10-K. The following table provides summary data of our Natural Gas Distribution business segment for the three and six months ended June 30, 2005 and 2006 (in millions, except throughput and customer data): THREE MONTHS ENDED JUNE 30, SIX MONTHS ENDED JUNE 30, ------------------------- ------------------------ 2005 2006 2005 2006 ---------- ---------- ---------- ---------- Revenues .... $ 541 $ 549 $ 1,870 $ 2,029 ---------- ---------- ---------- ---------- Expenses: Natural gas .... 341 343 1,338 1,489 Operation and maintenance .... 126 142 261 292 Depreciation and amortization .... 39 37 76 75 Taxes other than income taxes .... 26 29 63 72 ---------- ---------- ---------- ---------- Total expenses .... 532 551 1,738 1,928 ---------- ---------- ---------- ---------- Operating Income (Loss) .... $ 9 $ (2) $ 132 $ 101 ========== ========== ========== ========== Throughput (in billion cubic feet (Bcf)): Residential .... 21 17 98 84 Commercial and industrial .... 43 44 120 116 ---------- ---------- ---------- ---------- Total Throughput .... 64 61 218 200 ========== ========== ========== ========== Average number of customers: Residential 2,833,773 2,860,802

2,842,645 2,872,978 Commercial and industrial .... 246,032 253,725 247,429 253,505 ---------- ---------- ---------- ---------- Total .... 3,079,805 3,114,527 3,090,074 3,126,483 ========== ========== ========== ========== THREE MONTHS ENDED JUNE 30, 2006 COMPARED TO THREE MONTHS ENDED JUNE 30, 2005 Our Natural Gas Distribution business segment reported an operating loss of $2 million for the three months ended June 30, 2006 as compared to operating income of $9 million for the three months ended June 30, 2005. 30 Increases in operating margins (revenues less natural gas costs) from rate increases and rate design changes, along with the addition of nearly 32,000 customers since June 2005 ($6 million) and increased gross receipts taxes resulting from higher revenues ($3 million), were partially offset by decreased customer usage and unfavorable weather ($5 million). Operation and maintenance expenses increased primarily due to costs associated with staff reductions ($5 million), increased bad debt expense due to high natural gas prices ($3 million) and a write-off of certain rate case expenses ($3 million). Additionally, taxes other than income taxes increased $3 million primarily due to higher gross receipts taxes, which offset the corresponding increase in revenues discussed above. SIX MONTHS ENDED JUNE 30, 2006 COMPARED TO SIX MONTHS ENDED JUNE 30, 2005 Our Natural Gas Distribution business segment reported operating income of $101 million for the six months ended June 30, 2006 as compared to $132 million for the six months ended June 30, 2005. Increases in operating margins from rate increases and rate design changes, along with the addition of nearly 32,000 customers since June 2005 ($20 million) and increased gross receipts taxes resulting from higher revenues ($9 million), were partially offset by decreased customer usage and unfavorable weather ($21 million). Operation and maintenance expenses increased primarily due to costs associated with staff reductions ($11 million), increased bad debt expense due to high natural gas prices ($6 million), increased contracts and services expenses and corporate services ($8 million) and a write-off of certain rate case expenses ($3 million). Additionally, taxes other than income taxes increased $9 million primarily due to higher gross receipts taxes, which offset the corresponding increase in revenues discussed above. COMPETITIVE NATURAL GAS SALES AND SERVICES For information regarding factors that may affect the future results of operations of our Competitive Natural Gas Sales and Services business segment, please read "Risk Factors -- Risk Factors Affecting Our Natural Gas Distribution, Competitive Natural Gas Sales and Services and Pipelines and Field Services Business," " -- Risk Factors Associated with Our Consolidated Financial Condition" and "-- Risks Common to Our Business and Other Risks" in Item 1A of Part I of our 2005 Form 10-K. The following table provides summary data of our Competitive Natural Gas Sales and Services business segment for the three and six months ended June 30, 2005 and 2006 (in millions, except throughput and customer data): THREE MONTHS ENDED SIX MONTHS ENDED JUNE 30, JUNE 30, ----------------- --------------- 2005 2006 2005 2006 ------ ------ ------ ------ Revenues .... $ 845 $ 750 $1,770 $1,913 ------ ------ ------ ------ Expenses: Natural gas .... 828 735 1,730 1,864 Operation and maintenance ...... 7 7 12 15 Depreciation and amortization .. -- 1 1 1 Taxes other than income taxes .. -- -- 1 1 ------ ------ ------ ------ Total expenses .... 835 743 1,744 1,881 ------ ------ ------ ------ Operating Income .... $ 10 $ 7 $ 26 $ 32 ====== ====== ====== ====== Throughput (in Bcf): Wholesale - third parties ...... 72 72 154 161 Wholesale - affiliates .... 21 8 35 19 Retail .... 34 31 81 79 Pipeline .... 12 10 31 20 ------ ------ ------ ------ Total Throughput .... 139 121 301 279 ====== ====== ====== ====== Average number of customers: Wholesale .... 135 132 130 138 Retail .... 6,237 6,468 6,207 6,501 Pipeline .... 145 136 151 138 ------ ------ ------ ------ Total .... 6,517 6,736 6,488 6,777 ====== ====== ====== ====== 31 THREE MONTHS ENDED JUNE 30, 2006 COMPARED TO THREE MONTHS ENDED JUNE 30, 2005 Our Competitive Natural Gas Sales and Services business segment reported operating income of $7 million for the three months ended June 30, 2006 as compared to $10 million for the three months ended June 30, 2005. Increased operating income from higher sales to utilities and favorable basis differentials across the pipeline capacity that we control ($12 million) was more than offset by a charge of $17 million to reflect the write-down of natural gas inventory to the lower of average cost or market. Our Competitive Natural Gas Sales and Services business segment purchases and stores natural gas to meet future sales requirements and enters into derivative contracts to hedge the economic value of the future sales. Therefore, operating income in future periods when these sales occur is expected to be higher as a result of the inventory write-down taken in this quarter. SIX MONTHS ENDED JUNE 30, 2006 COMPARED TO SIX MONTHS ENDED JUNE 30, 2005 Our Competitive Natural Gas Sales and Services business segment reported operating income of $32 million for the six months ended June 30, 2006 as compared to $26 million for the six months ended June 30, 2005. Increased operating income from higher sales to utilities and favorable basis differentials across the pipeline capacity that we control ($35 million) was partially offset by a charge of $30 million to reflect the write-downs of natural gas inventory to the lower of average cost or market. Therefore, operating income in future periods when these sales occur is expected to be higher as a result of the inventory write-downs taken in the first two quarters of this year. PIPELINES AND FIELD SERVICES For information regarding factors that may affect the future results of operations of our Pipelines and Field Services business segment, please read "Risk Factors -- Risk Factors Affecting Our Natural Gas Distribution, Competitive Natural Gas Sales and Services and Pipelines and Field Services Businesses," " -- Risk Factors Associated with Our Consolidated Financial Condition" and "-- Risks Common to Our Business and Other Risks" in Item 1A of Part I of our 2005 Form 10-K. The following table provides summary data of our Pipelines and Field Services business segment for the three and six months ended June 30, 2005 and 2006 (in millions, except throughput data): THREE MONTHS SIX MONTHS ENDED JUNE 30, ENDED JUNE 30, -------------- -------------- 2005 2006 2005 2006 ---- ---- ---- ---- Revenues .... $125 $135 $246 $260 ---- ---- ---- ---- Expenses: Natural gas .... 18 7 25 3 Operation and maintenance .... 40 50 74 89 Depreciation and amortization .... 11 12 22 24 Taxes other than income taxes .... 4 5 9 10 ---- ---- ---- ---- Total expenses .... 73 74 130 126 ---- ---- ---- ---- Operating Income .... $ 52 $ 61 $116 $134 ==== ==== ==== ==== Operating Income - Pipeline business .... $ 35 $ 40 $ 83 $ 89 Operating Income - Field Services business .. 17 21 33 45 ---- ---- ---- ---- Total segment operating income .... $ 52 $ 61 $116 $134 ==== ==== ==== ==== Throughput (in Bcf): Natural Gas Sales .... 3 2 4 2 Transportation .... 230 240 501 514 Gathering .... 87 94 170 182 Elimination (1) .... (2) (1) (3) (1) ---- ---- ---- ---- Total Throughput .... 318 335 672 697 ==== ==== ==== ==== ---------- (1) Elimination of volumes both transported and sold. 32 THREE MONTHS ENDED JUNE 30, 2006 COMPARED TO THREE MONTHS ENDED JUNE 30, 2005 Our Pipelines and Field Services business segment reported operating income of $61 million for the three months ended June 30, 2006 as compared to $52 million for the three months ended June 30, 2005. This segment's businesses continue to benefit from favorable dynamics in the markets for natural gas gathering and transportation services in the Gulf Coast and Mid-Continent regions where they operate. Within this segment, the pipeline business achieved higher operating income of $40 million for the three months ended June 30, 2006 as compared to $35 million for the same period in 2005 resulting from increased demand for transportation due to favorable basis differentials across the system ($5 million), higher demand for ancillary services ($3 million) and increased project-related revenues ($5 million), offset by a corresponding increase in project-related expenses ($5 million) and higher operation and maintenance expenses ($3 million). The field services business achieved higher operating income of $21 million for the three months ended June 30, 2006 as compared to $17 million for the same period in 2005 driven by increased throughput ($3 million) and higher commodity prices ($2 million). Additionally, this business segment recorded equity income of $1 million and $2 million for the three months ended June 30, 2005 and 2006, respectively, from its 50 percent interest in a jointly-owned gas processing plant. These amounts are included in Other - net under the Other Income (Expense) caption in our Condensed Statements of Consolidated Income. SIX MONTHS ENDED JUNE 30, 2006 COMPARED TO SIX MONTHS ENDED JUNE 30, 2005 Our Pipelines and Field Services business segment reported operating income of $134 million for the six months ended June 30, 2006 as compared to $116 million for the six months ended June 30, 2005. The pipeline business achieved operating income of $89 million for the six months ended June 30, 2006 as compared to $83 million for the same period in 2005 resulting from increased demand for transportation due to favorable basis differentials across the system ($11 million), higher demand for ancillary services ($4 million) and increased project-related revenues ($6 million), partially offset by a corresponding increase in project-related expenses ($5 million) and increased operation and maintenance expenses ($6 million). The field services business achieved operating income of $45 million for the six months ended June 30, 2006 as compared to $33 million for the same period in 2005 driven by increased throughput ($7 million), higher commodity prices ($7 million) and higher demand for ancillary services ($2 million), partially offset by increased operation and maintenance expenses ($4 million). In addition, this business segment recorded equity income of $3 million and $5 million for the six months ended June 30, 2005 and 2006, respectively, from its 50 percent interest in a jointly-owned gas processing plant as discussed above. OTHER OPERATIONS The following table shows the operating loss of our Other Operations business segment for the three and six months ended June 30, 2005 and 2006 (in millions): THREE MONTHS SIX MONTHS ENDED JUNE 30, ENDED JUNE 30, -------------- -------------- 2005 2006 2005 2006 ---- ---- ---- ---- Revenues .... $ 4 $5 $ 11 $ 9 Expenses .... 11 2 25 11 --- -- ---- --- Operating Income (Loss) .. $(7) $3 $(14) $(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 2005 Form 10-K. 33 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 six months ended June 30, 2005 and 2006 (in millions): SIX MONTHS ENDED JUNE 30, ------------- 2005 2006 ----- ----- Cash provided by (used in): Operating activities ...... $ 16 $ 517 Investing activities ...... 412 (396) Financing activities ...... (185) 202 CASH PROVIDED BY OPERATING ACTIVITIES Net cash provided by operating activities in the first six months of 2006 increased $533 million compared to the same period in 2005 primarily due to decreased tax payments of $345 million, the majority of which related to the tax payment in the first quarter of 2005 associated with the sale of our former electric generation business (Texas Genco), decreases in net regulatory assets/liabilities ($187 million), primarily due to the termination of excess mitigation credits effective April 29, 2005, decreased gas storage inventory ($53 million) and fuel under-recovery ($123 million) primarily related to declining gas prices during the first six months of 2006 and decreased cash used in the operations of Texas Genco ($38 million). These increases in cash provided by operating activities were partially offset by decreased net accounts receivable/payable ($208 million) primarily due to decreased gas prices in the first two quarters of 2006 as compared to the same period in 2005 and decreases in the amount of advances for the purchase of receivables under CERC Corp.'s receivables facility. Additionally, customer margin deposit requirements decreased ($88 million) primarily due to the decline in natural gas prices from December 2005 to June 2006 and our margin deposits increased ($32 million). CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES Net cash used in investing activities increased $808 million in the first six months of 2006 as compared to the same period in 2005 primarily due to increased capital expenditures of $49 million primarily related to our Electric Transmission & Distribution and Pipelines and Field Services business segments and the absence of $700 million in proceeds received in the second quarter of 2005 from the sale of our remaining interest in Texas Genco and cash of Texas Genco of $23 million. CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES Net cash provided by financing activities in the first six months of 2006 increased $387 million compared to the same period in 2005 primarily due to net proceeds from the issuance of long-term debt ($324 million), decreased payments under our revolving credit facility ($116 million) and decreased payments of long-term debt ($33 million), partially offset by the absence of borrowings under Texas Genco's revolving credit facility ($75 million) due to the sale of Texas Genco and increased dividend payments of $10 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 six months of 2006 include the following: - approximately $700 million of capital expenditures; - dividend payments on CenterPoint Energy common stock and debt service payments; and - long-term debt payments of $199 million, including $54 million of transition bonds. 34 We expect that borrowings under our credit facilities, liquidation of temporary investments and anticipated cash flows from operations will be sufficient to meet our cash needs for the next twelve months. Cash needs may also be met by issuing securities in the capital markets. Contractual Obligations. We negotiated new natural gas transportation contracts during the second quarter of 2006 which was the primary reason for an $809 million increase in the amount of other commodity commitments from the contractual obligations reported in our 2005 Form 10-K. Minimum payment obligations for natural gas supply and related transportation contracts are approximately $367 million for the remaining six months in 2006, $627 million in 2007, $174 million in 2008, $118 million in 2009, $118 million in 2010 and $721 million in 2011 and thereafter. Off-Balance Sheet Arrangements. Other than operating leases and the guarantees described below, we have no off-balance sheet arrangements. However, we do participate in a receivables factoring arrangement. CERC Corp. has a bankruptcy remote subsidiary, which we consolidate, which was formed for the sole purpose of buying receivables created by CERC and selling those receivables to an unrelated third-party. This transaction is accounted for as a sale of receivables under the provisions of Statement of Financial Accounting Standards (SFAS) No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," and, as a result, the related receivables are excluded from the Condensed Consolidated Balance Sheet. In January 2006, our $250 million facility was extended to January 2007. As of June 30, 2006, no amounts were funded under our receivables facility. The facility was temporarily increased to $375 million for the period from January 2006 to June 2006. Prior to the CenterPoint Energy's distribution of its ownership in RRI to its shareholders, CERC had guaranteed certain contractual obligations of what became RRI's trading subsidiary. Under the terms of the separation agreement between the companies, RRI agreed to extinguish all such guarantee obligations prior to separation, but when separation occurred in September 2002, RRI had been unable to extinguish all obligations. To secure the CenterPoint Energy and CERC against obligations under the remaining guarantees, RRI agreed to provide cash or letters of credit for the benefit of CERC and CenterPoint Energy, and agreed to use commercially reasonable efforts to extinguish the remaining guarantees. CenterPoint Energy's current exposure under the remaining guarantees relates to CERC's guarantee of the payment by RRI of demand charges related to transportation contracts with one counterparty. The demand charges are approximately $53 million per year in 2006 through 2015, $49 million in 2016, $38 million in 2017 and $13 million in 2018. As a result of changes in market conditions, the Company's potential exposure under that guarantee currently exceeds the security provided by RRI. CenterPoint Energy has requested RRI to increase the amount of its existing letters of credit or, in the alternative, to obtain a release of CERC's obligations under the guarantee, and CenterPoint Energy and RRI are pursuing other alternatives. On June 30, 2006, the RRI trading subsidiary and CERC jointly filed a complaint at the FERC against the counterparty on the CERC guarantee. In the complaint, the RRI trading subsidiary seeks a determination by the FERC that the security held by the counterparty exceeds the level permitted by the FERC's policies. The complaint asks the FERC to require the counterparty to release CERC from its guarantee obligation and, in its place accept (i) a guarantee from RRI of the obligations of the RRI trading subsidiary, and (ii) letters of credit equal to (A) one year of demand charges for a transportation agreement related to a 2003 expansion of the counterparty's pipeline, and (B) three months of demand charges for three other transportation agreements held by the RRI trading subsidiary. On July 20, 2006, the counterparty filed its answer to the complaint, arguing that CERC is contractually bound to continue the guarantee and that the amount of the guarantee does not violate the FERC's policies. The complaint is in its beginning stages, and it is presently unknown what action the FERC may take on the complaint. The RRI trading subsidiary continues to meet its obligations under the transportation contracts. Senior Notes. In May 2006, CERC Corp. issued $325 million aggregate principal amount of senior notes due in May 2016 with an interest rate of 6.15%. The proceeds from the sale of the senior notes will be used for general corporate purposes, including repayment or refinancing of debt (including $145 million of CERC's 8.90% debentures due December 15, 2006), capital expenditures and working capital. Credit Facilities. In March 2006, we, CenterPoint Houston and CERC Corp., entered into amended and restated bank credit facilities. We replaced our $1 billion five-year revolving credit facility with a $1.2 billion five-year revolving credit facility. The facility has a first drawn cost of LIBOR plus 60 basis points based on our current credit ratings, as compared to LIBOR plus 87.5 basis points for borrowings under the facility it replaced. The facility contains covenants, including a debt to earnings before interest, taxes, depreciation and amortization (EBITDA) covenant. 35 CenterPoint Houston replaced its $200 million five-year revolving credit facility with a $300 million five-year revolving credit facility. The facility has a first drawn cost of LIBOR plus 45 basis points based on CenterPoint Houston's current credit ratings, as compared to LIBOR plus 75 basis points for borrowings under the facility it replaced. The facility contains covenants, including a debt, excluding transition bonds, to total capitalization covenant of 65%. CERC Corp. replaced its $400 million five-year revolving credit facility with a $550 million five-year revolving credit facility. The facility has a first drawn cost of LIBOR plus 45 basis points based on CERC Corp.'s current credit ratings, as compared to LIBOR plus 55 basis points for borrowings under the facility it replaced. The facility contains covenants, including a debt to total capitalization covenant of 65%. Under each of the credit facilities, an additional utilization fee of 10 basis points applies to borrowings any time more than 50% of the facility is utilized, and the spread to LIBOR fluctuates based on the borrower's credit rating. Borrowings under each of the facilities are subject to customary terms and conditions. However, there is no requirement that we, CenterPoint Houston or CERC Corp. make representations prior to borrowings as to the absence of material adverse changes or litigation that could be expected to have a material adverse effect. Borrowings under each of the credit facilities are subject to acceleration upon the occurrence of events of default that we, CenterPoint Houston or CERC Corp. consider customary. We, CenterPoint Houston and CERC Corp. are currently in compliance with the various business and financial covenants contained in the respective credit facilities. As of August 1, 2006, we had the following credit facilities (in millions): AMOUNT UTILIZED AT DATE EXECUTED COMPANY SIZE OF FACILITY AUGUST 1, 2006 TERMINATION DATE ------------- ------- --------------- ----------------- ---------------- March 31, 2006 CenterPoint Energy $1,200 $28(1) March 31, 2011 March 31, 2006 CenterPoint Houston 300 4(1) March 31, 2011 March 31, 2006 CERC Corp. 550 -- March 31, 2011 ---------- (1) Represents outstanding letters of credit. The $1.2 billion

CenterPoint Energy credit facility backstops a $1.0 billion commercial paper program under which CenterPoint Energy began issuing commercial paper in June 2005. As of June 30, 2006, there was no commercial paper outstanding. The commercial paper is rated "Not Prime" by Moody's Investors Service, Inc. (Moody's), "A-3" by Standard & Poor's Rating Services (S&P), a division of The McGraw-Hill Companies, and "F3" by Fitch, Inc. (Fitch) and, as a result, we do not expect to be able to rely on the sale of commercial paper to fund all of our short-term borrowing requirements. We cannot assure you that these ratings, or the credit ratings set forth below in "-- Impact on Liquidity of a Downgrade in Credit Ratings," will remain in effect for any given period of time or that one or more of these ratings will not be lowered or withdrawn entirely by a rating agency. We note that these credit ratings are not recommendations to buy, sell or hold our securities and may be revised or withdrawn at any time by the rating agency. Each rating should be evaluated independently of any other rating. Any future reduction or withdrawal of one or more of our credit ratings could have a material adverse impact on our ability to obtain short- and long-term financing, the cost of such financings and the execution of our commercial strategies. Securities Registered with the SEC. At June 30, 2006, CenterPoint Energy had a shelf registration statement covering senior debt securities, preferred stock and common stock aggregating $1 billion. After giving effect to CERC Corp.'s issuance of $325 million aggregate principal amount of senior notes due in May 2016, as discussed above under "--Senior Notes," at June 30, 2006, CERC Corp. had a shelf registration statement covering $175 million principal amount of debt securities. Temporary Investments. As of June 30, 2006, we had external temporary investments of $290 million. As of August 1, 2006, we had external temporary investments of $381 million. Money Pool. We have a "money pool" through which the holding company and participating subsidiaries can borrow or invest on a short-term basis. Funding needs are aggregated and external borrowing or investing is based 36 on the net cash position. The net funding requirements of the money pool are expected to be met with borrowings under CenterPoint Energy's revolving credit facility or the sale of commercial paper. Impact on Liquidity of a Downgrade in Credit Ratings. As of August 1, 2006, Moody's, S&P, and Fitch had assigned the following credit ratings to senior debt of CenterPoint Energy and certain subsidiaries: MOODY'S S&P FITCH ------------------- ------------------ ------------------- COMPANY/INSTRUMENT RATING OUTLOOK(1) RATING OUTLOOK(2) RATING OUTLOOK(3) ----------------- ------ ---------- ------ ---------- ------ ---------- CenterPoint Energy Senior Unsecured Debt.................................. Ba1 Stable BBB- Stable BBB- Stable CenterPoint Houston Senior Secured Debt (First Mortgage Bonds)............. Baa2 Stable BBB Stable A- Stable CERC Corp. Senior Unsecured Debt........... Baa3 Stable BBB Stable BBB Stable ---------- (1) A "stable" outlook from Moody's indicates that Moody's does not expect to put the rating on review for an upgrade or downgrade within 18 months from when the outlook was assigned or last affirmed. (2) An S&P rating outlook assesses the potential direction of a long-term credit rating over the intermediate to longer term. (3) A "stable" outlook from Fitch encompasses a one-to-two-year horizon as to the likely ratings direction. A decline in credit ratings could increase borrowing costs under our $1.2 billion credit facility, CenterPoint Houston's $300 million credit facility and CERC's $550 million revolving credit facility. A decline in credit ratings would also increase the interest rate on long-term debt to be issued in the capital markets and could negatively impact our ability to complete capital market transactions. Additionally, a decline in credit ratings could increase cash collateral requirements and reduce margins of our Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments. In September 1999, we issued 2.0% ZENS having an original principal amount of $1.0 billion of which $840 million remain outstanding. Each ZENS note is exchangeable at the holder's option at any time for an amount of cash equal to 95% of the market value of the reference shares of TW Common attributable to each ZENS note. If our creditworthiness were to drop such that ZENS note holders thought our liquidity was adversely affected or the market for the ZENS notes were to become illiquid, some ZENS note holders might decide to exchange their ZENS notes for cash. Funds for the payment of cash upon exchange could be obtained from the sale of the shares of TW Common that we own or from other sources. We own shares of TW Common equal to 100% of the reference shares used to calculate our obligation to the holders of the ZENS notes. ZENS note exchanges result in a cash outflow because deferred tax liabilities related to the ZENS notes and TW Common shares become current tax obligations when ZENS notes are exchanged and TW Common shares are sold. CenterPoint Energy Services, Inc. (CES), a wholly owned subsidiary of CERC Corp. operating in our Competitive Natural Gas Sales and Services business segment, provides comprehensive natural gas sales and services primarily to commercial and industrial customers and electric and gas utilities throughout the central and eastern United States. In order to hedge its exposure to natural gas prices, CES uses financial derivatives with provisions standard for the industry that establish credit thresholds and require a party to provide additional collateral on two business days' notice when that party's rating or the rating of a credit support provider for that party (CERC Corp. in this case) falls below those levels. We estimate that as of June 30, 2006, unsecured credit limits extended to CES by counterparties aggregate $133 million; however, utilized credit capacity is significantly lower. In addition, CERC and its subsidiaries purchase natural gas under supply agreements that contain an aggregate credit threshold of $100 million based on CERC'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. Cross Defaults. Under our revolving credit facility, a payment default on, or a non-payment default that permits acceleration of, any indebtedness exceeding $50 million by us or any of our significant subsidiaries will cause a default. Pursuant to the indenture governing our senior notes, a payment default by us, CERC Corp. or CenterPoint Houston in respect of, or an acceleration of, borrowed money and certain other specified types of obligations, in the aggregate principal amount of $50 million will cause a default. As of August 1, 2006, we had issued six series of 37 senior notes aggregating $1.4 billion in principal amount under this indenture. A default by CenterPoint Energy would not trigger a default under our subsidiaries' debt instruments or bank credit facilities. Other Factors that Could Affect Cash Requirements. In addition to the above factors, our liquidity and capital resources could be affected by: - cash collateral requirements that could exist in connection with certain contracts, including gas purchases, gas price hedging and gas storage activities of our Natural Gas Distribution and Competitive Natural Gas Sales and Services business segments, particularly given gas price levels and volatility; - acceleration of payment dates on certain gas supply contracts under certain circumstances, as a result of increased gas prices and concentration of suppliers; - increased costs related to the acquisition of gas; - increases in interest expense in connection with debt refinancings and borrowings under credit facilities; - various regulatory actions; - the ability of RRI and its subsidiaries to satisfy their obligations as the principal customers of CenterPoint Houston and in respect of RRI's indemnity obligations to us and our subsidiaries or in connection with the contractual arrangement pursuant to which CERC is a guarantor; - slower customer payments and increased write-offs of receivables due to higher gas prices; - cash payments in connection with the exercise of contingent conversion rights of holders of convertible debt; - the outcome of litigation brought by or against us; - contributions to benefit plans; - restoration costs and revenue losses resulting from natural disasters such as hurricanes; and - various other risks identified in "Risk Factors" in Item 1A of Part I of our 2005 Form 10-K. Certain Contractual Limits on Our Ability to Issue Securities, Borrow Money and Pay Dividends on Our Common Stock. CenterPoint Houston's credit facility limits CenterPoint Houston's debt, excluding transition bonds, as a percentage of its total capitalization to 65 percent. CERC Corp.'s bank facility and its receivables facility limit CERC's debt as a percentage of its total capitalization to 65 percent. Our $1.2 billion credit facility contains a debt to EBITDA covenant. Additionally, in connection with the issuance of a certain series of general mortgage bonds, CenterPoint Houston agreed not to issue, subject to certain exceptions, additional first mortgage bonds. 38 CRITICAL ACCOUNTING POLICIES A critical accounting policy is one that is both important to the presentation of our financial condition and results of operations and requires management to make difficult, subjective or complex accounting estimates. An accounting estimate is an approximation made by management of a financial statement element, item or account in the financial statements. Accounting estimates in our historical consolidated financial statements measure the effects of past business transactions or events, or the present status of an asset or liability. The accounting estimates described below require us to make assumptions about matters that are highly uncertain at the time the estimate is made. Additionally, different estimates that we could have used or changes in an accounting estimate that are reasonably likely to occur could have a material impact on the presentation of our financial condition or results of operations. The circumstances that make these judgments difficult, subjective and/or complex have to do with the need to make estimates about the effect of matters that are inherently uncertain. Estimates and assumptions about future events and their effects cannot be predicted with certainty. We base our estimates on historical experience and on various other assumptions that we believe to be reasonable under the circumstances, the results of which form the basis for making judgments. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. Our significant accounting policies are discussed in Note 2 to the consolidated financial statements in our 2005 Form 10-K. We believe the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the audit committee of the board of directors. ACCOUNTING FOR RATE REGULATION SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. Application of SFAS No. 71 to the electric generation portion of our business was discontinued as of June 30, 1999. Our Electric Transmission & Distribution business continues to apply SFAS No. 71 which results in our accounting for the regulatory effects of recovery of stranded costs and other regulatory assets resulting from the unbundling of the transmission and distribution business from our electric generation operations in our consolidated financial statements. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Significant accounting estimates embedded within the application of SFAS No. 71 with respect to our Electric Transmission & Distribution business segment relate to $321 million of recoverable electric generation-related regulatory assets as of June 30, 2006. These costs are recoverable under the provisions of the 1999 Texas Electric Choice Plan. Based on our analysis of the final order issued by the Public Utility Commission of Texas (Texas Utility Commission), we recorded an after-tax charge to earnings in 2004 of approximately $977 million to write-down our electric generation-related regulatory assets to their realizable value, which was reflected as an extraordinary loss. Based on subsequent orders received from the Texas Utility Commission, we recorded an extraordinary gain of $30 million after-tax in the second quarter of 2005 related to the regulatory asset. Additionally, a district court in Travis County, Texas issued a judgment that would have the effect of restoring approximately $650 million, plus interest, of disallowed costs. Appeals of the district court's judgment are still pending. Oral arguments have been scheduled for September 27, 2006. No amounts related to the district court's judgment have been recorded in our consolidated financial statements. IMPAIRMENT OF LONG-LIVED ASSETS AND INTANGIBLES We review the carrying value of our long-lived assets, including goodwill and identifiable intangibles, whenever events or changes in circumstances indicate that such carrying values may not be recoverable, and at least annually for goodwill as required by SFAS No. 142, "Goodwill and Other Intangible Assets." Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows, regulatory matters and operating costs could negatively affect the fair value of our assets and result in an impairment charge. Fair value is the amount at which the asset could be bought or sold in a current transaction between willing parties and may be estimated using a number of techniques, including quoted market prices or valuations by third parties, present value techniques based on estimates of cash flows, or multiples of earnings or revenue performance 39 measures. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques. ASSET RETIREMENT OBLIGATIONS We account for our long-lived assets under SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), and Financial Accounting Standards Board Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations -- An Interpretation of SFAS No. 143" (FIN 47). SFAS No. 143 and FIN 47 require that an asset retirement obligation be recorded at fair value in the period in which it is incurred if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. Rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with SFAS No. 143 and FIN 47, and costs recovered through the ratemaking process. We estimate the fair value of asset retirement obligations by calculating the discounted cash flows that are dependent upon the following components: - Inflation adjustment -- The estimated cash flows are adjusted for inflation estimates for labor, equipment, materials, and other disposal costs; - Discount rate -- The estimated cash flows include contingency factors that were used as a proxy for the market risk premium; and - Third party markup adjustments -- Internal labor costs included in the cash flow calculation were adjusted for costs that a third party would incur in performing the tasks necessary to retire the asset. Changes in these factors could materially affect the obligation recorded to reflect the ultimate cost associated with retiring the assets under SFAS No. 143 and FIN 47. For example, if the inflation adjustment increased 25 basis points, this would increase the balance for asset retirement obligations by approximately 3.0%. Similarly, an increase in the discount rate by 25 basis points would decrease asset retirement obligations by approximately the same percentage. At June 30, 2006, our estimated cost of retiring these assets is approximately $77 million. UNBILLED ENERGY REVENUES Revenues related to the sale and/or delivery of electricity or natural gas (energy) are generally recorded when energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. Unbilled electricity delivery revenue is estimated each month based on daily supply volumes, applicable rates and analyses reflecting significant historical trends and experience. Unbilled natural gas sales are estimated based on estimated purchased gas volumes, estimated lost and unaccounted for gas and tariffed rates in effect. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates. PENSION AND OTHER RETIREMENT PLANS We sponsor pension and other retirement plans in various forms covering all employees who meet eligibility requirements. We use several statistical and other factors which attempt to anticipate future events in calculating the expense and liability related to our plans. These factors include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as estimated by management, within certain guidelines. In addition, our actuarial consultants use subjective factors such as withdrawal and mortality rates. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact to the amount of pension expense recorded. Please read "-- Other Significant Matters -- Pension Plan" for further discussion. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations-- Other Significant Matters -- Pension Plan" in Item 7 of our 2005 Form 10-K. 40 NEW ACCOUNTING PRONOUNCEMENTS See Note 4 to the Interim Condensed Financial Statements for a discussion of new accounting pronouncements that affect us. ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK COMMODITY PRICE RISK FROM NON-TRADING ACTIVITIES We measure the commodity risk of our non-trading derivatives (Non-Trading Energy Derivatives) using a sensitivity analysis. The sensitivity analysis performed on our Non-Trading Energy Derivatives measures the potential loss based on a hypothetical 10% movement in energy prices. At June 30, 2006, the recorded fair value of our Non-Trading Energy Derivatives was a net liability of $6 million. A decrease of 10% in the market prices of energy commodities from their June 30, 2006 levels would have decreased the fair value of our Non-Trading Energy Derivatives from their levels on that date by $108 million. The above analysis of the Non-Trading Energy Derivatives utilized for price risk management purposes does not include the favorable impact that the same hypothetical price movement would have on our physical purchases and sales of natural gas to which the hedges relate. Furthermore, the Non-Trading Energy Derivative portfolio is managed to complement the physical transaction portfolio, reducing overall risks within limits. Therefore, the adverse impact to the fair value of the portfolio of Non-Trading Energy Derivatives held for hedging purposes associated with the hypothetical changes in commodity prices referenced above is expected to be substantially offset by a favorable impact on the underlying hedged physical transactions. INTEREST RATE RISK We have outstanding long-term debt, bank loans, mandatory redeemable preferred securities of subsidiary trusts holding solely our junior subordinated debentures (trust preferred securities), some lease obligations and our obligations under the ZENS that subject us to the risk of loss associated with movements in market interest rates. We had no floating-rate obligations at June 30, 2006. At June 30, 2006, we had outstanding fixed-rate debt (excluding indexed debt securities) and trust preferred securities aggregating $9.1 billion in principal amount and having a fair value of $9.2 billion. These instruments are fixed-rate and, therefore, do not expose us to the risk of loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately $389 million if interest rates were to decline by 10% from their levels at June 30, 2006. In general, such an increase in fair value would impact earnings and cash flows only if we were to reacquire all or a portion of these instruments in the open market prior to their maturity. Upon adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), effective January 1, 2001, the ZENS obligation was bifurcated into a debt component and a derivative component. The debt component of $110 million at June 30, 2006 is a fixed-rate obligation and, therefore, does not expose us to the risk of loss in earnings due to changes in market interest rates. However, the fair value of the debt component would increase by approximately $18 million if interest rates were to decline by 10% from levels at June 30, 2006. Changes in the fair value of the derivative component will be recorded in our Condensed Statements of Consolidated Income and, therefore, we are exposed to changes in the fair value of the derivative component as a result of changes in the underlying risk-free interest rate. If the risk-free interest rate were to increase by 10% from June 30, 2006 levels, the fair value of the derivative component would increase by approximately $6 million, which would be recorded as a loss in our Condensed Statements of Consolidated Income. EQUITY MARKET VALUE RISK We are exposed to equity market value risk through our ownership of 21.6

million shares of TW Common, which we hold to facilitate our ability to meet our obligations under the ZENS. A decrease of 10% from the June 30, 41 2006 market value of TW Common would result in a net loss of approximately $4 million, which would be recorded as a loss in our Condensed Statements of Consolidated Income. ITEM 4. CONTROLS AND PROCEDURES In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of June 30, 2006 to provide assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding disclosure. There has been no change in our internal controls over financial reporting that occurred during the three months ended June 30, 2006 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting. PART II. OTHER INFORMATION ITEM 1. LEGAL PROCEEDINGS For a description of certain legal and regulatory proceedings affecting CenterPoint Energy, please read Notes 5 and 11 to our Interim Condensed Financial Statements, each of which is incorporated herein by reference. See also "Business -- Regulation" and " -- Environmental Matters" in Item 1 and "Legal Proceedings" in Item 3 of our 2005 Form 10-K. ITEM 1A. RISK FACTORS There have been no material changes from the risk factors disclosed in our 2005 Form 10-K. ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS At the annual meeting of our shareholders held on May 25, 2006, the matters voted upon and the number of votes cast for, against or withheld, 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 Class I Directors were elected to serve three-year terms expiring at the 2009 annual meeting of shareholders (there were no broker non-votes): Nominees For Withheld -------- ----------- ---------- Derrill Cody 261,674,008 11,221,695 David M. McClanahan 263,381,498 9,514,205 Robert T. O'Connell 261,474,445 11,421,258 Donald R. Campbell, Milton Carroll, John T. Cater, Michael E. Shannon, O. Holcombe Crosswell, Janiece M. Longoria, Thomas F. Madison and Peter S. Wareing all continue as directors of CenterPoint Energy. The appointment of Deloitte & Touche LLP as independent accountants and auditors for CenterPoint Energy for 2006 was ratified with 255,050,291 votes for, 15,113,470 votes against and 2,731,940 abstentions. The material terms of the performance goals under the Company's Short Term Incentive Plan were reapproved, permitting certain awards to continue to qualify as performance-based compensation deductible under Section 162(m) of the Code, with 254,598,317 votes for, 14,236,776 votes against and 4,060,608 abstentions. 42 The material terms of the performance goals under the Company's Long-Term Incentive Plan were reapproved, permitting certain awards to continue to qualify as performance-based compensation deductible under Section 162(m) of the Code with 252,407,921 votes for, 16,236,795 votes against and 4,250,985 abstentions. The shareholder proposal regarding the future elections of directors annually and not by classes did not receive the required affirmative vote of a majority of the shares of common stock represented at the meeting. The proposal received 127,569,119 votes for, 73,718,809 votes against, 3,824,715 abstentions and 67,783,059 broker non-votes. ITEM 5. OTHER INFORMATION The ratio of earnings to fixed charges for the six months ended June 30, 2005 and 2006 was 1.46 and 1.76, respectively. We do not believe that the ratios for these six month periods are necessarily indicators of the ratios for the twelve month period due to the seasonal nature of our business. The ratios were calculated pursuant to applicable rules of the Securities and Exchange Commission. ITEM 6. EXHIBITS The following exhibits are filed herewith: Exhibits not incorporated by reference to a prior filing are designated by a cross (+); all exhibits not so designated are incorporated by reference to a prior filing of CenterPoint Energy, Inc. SEC FILE OR EXHIBIT REGISTRATION EXHIBIT NUMBER DESCRIPTION REPORT OR REGISTRATION STATEMENT NUMBER REFERENCE ------- ----------- ------------------------------- ------------ --------- 3.1.1 -- Amended and Restated Articles of Incorporation of CenterPoint Energy's Registration 3-69502 3.1 CenterPoint Energy Statement on Form S-4 3.1.2 -- Articles of Amendment to Amended and Restated Articles CenterPoint Energy's Form 10-K for 1-31447 3.1.1 of Incorporation of CenterPoint Energy the year ended December 31, 2001 3.2 -- Amended and Restated Bylaws of CenterPoint Energy CenterPoint Energy's Form 10-K for 1-31447 3.2 the year ended December 31, 2001 3.3 -- Statement of Resolution Establishing Series of Shares CenterPoint Energy's Form 10-K for 1-31447 3.3 designated Series A Preferred Stock of

CenterPoint the year ended December 31, 2001 Energy 4.1 -- Form of CenterPoint Energy Stock Certificate CenterPoint Energy's Registration 3-69502 4.1 Statement on Form S-4 4.2 -- Rights Agreement dated January 1, 2002, between CenterPoint Energy's Form 10-K for 1-31447 4.2 CenterPoint Energy and JPMorgan Chase Bank, as Rights the year ended December 31, 2001 Agent 4.3 -- $1,200,000,000 Amended and Restated Credit Agreement CenterPoint Energy's Form 8-K 1-31447 4.1 dated as of March 31, 2006, among CenterPoint Energy, dated March 31, 2006 as Borrower, and the banks named therein 4.4 -- $300,000,000 Amended and Restated Credit Agreement CenterPoint Energy's Form 8-K 1-31447 4.2 dated as of March 31, 2006, among CenterPoint Houston, dated March 31, 2006 as Borrower, and the Initial Lenders named therein, as Initial Lenders 4.5 -- $550,000,000 Amended and Restated Credit Agreement CenterPoint Energy's Form 8-K 1-31447 4.3 dated as of March 31, 2006 among CERC Corp., as dated March 31, 2006 Borrower, and the banks named therein 43 SEC FILE OR EXHIBIT REGISTRATION EXHIBIT NUMBER DESCRIPTION REPORT OR REGISTRATION STATEMENT NUMBER REFERENCE ------- ----------- ------------------------------- ------------ --------- 4.6 -- Indenture, dated as of February 1, 1998, between CERC Corp.'s Form 8-K dated 1-13265 4.1 CERC Corp. (formerly NorAm Energy Corp.) and JPMorgan February 5, 1998 Chase Bank, National Association (successor to Chase Bank of Texas, National Association), as trustee (the "Indenture") +4.7 -- Supplemental Indenture No. 9 to the Indenture, dated as of May 18, 2006, providing for the issuance of CERC Corp.'s 6.15% Senior Notes due 2016 +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 -- First Amendment to CenterPoint Energy Savings Plan dated June 26, 2006 +99.2 -- Items incorporated by reference from the CenterPoint Energy Form 10-K. Item 1A "Risk Factors" 44 SIGNATURES Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. CENTERPOINT ENERGY, INC. By: /s/ James S. Brian ----------------------------------- James S. Brian Senior Vice President and Chief Accounting Officer Date: August 3, 2006 45 EXHIBIT INDEX SEC FILE OR EXHIBIT REGISTRATION EXHIBIT NUMBER DESCRIPTION REPORT OR REGISTRATION STATEMENT NUMBER REFERENCE ------- ----------- ------------------------------- ------------ --------- 3.1.1 -- Amended and Restated Articles of Incorporation of CenterPoint Energy's Registration 3-69502 3.1 CenterPoint Energy Statement on Form S-4 3.1.2 -- Articles of Amendment to Amended and Restated Articles CenterPoint Energy's Form 10-K for 1-31447 3.1.1 of Incorporation of CenterPoint Energy the year ended December 31, 2001 3.2 -- Amended and Restated Bylaws of CenterPoint Energy CenterPoint Energy's Form 10-K for 1-31447 3.2 the year ended December 31, 2001 3.3 -- Statement of Resolution Establishing Series of Shares CenterPoint Energy's Form 10-K for 1-31447 3.3 designated Series A Preferred Stock of CenterPoint the year ended December 31, 2001 Energy 4.1 -- Form of CenterPoint Energy Stock Certificate CenterPoint Energy's Registration 3-69502 4.1 Statement on Form S-4 4.2 -- Rights Agreement dated January 1, 2002, between CenterPoint Energy's Form 10-K for 1-31447 4.2 CenterPoint Energy and JPMorgan Chase Bank, as Rights the year ended December 31, 2001 Agent 4.3 -- $1,200,000,000 Amended and Restated Credit Agreement CenterPoint Energy's Form 8-K 1-31447 4.1 dated as of March 31, 2006, among CenterPoint Energy, dated March 31, 2006 as Borrower, and the banks named therein 4.4 -- $300,000,000 Amended and Restated Credit Agreement CenterPoint Energy's Form 8-K 1-31447 4.2 dated as of March 31, 2006, among CenterPoint Houston, dated March 31, 2006 as Borrower, and the Initial Lenders named therein, as Initial Lenders 4.5 -- $550,000,000 Amended and Restated Credit Agreement CenterPoint Energy's Form 8-K 1-31447 4.3 dated as of March 31, 2006 among CERC Corp., as dated March 31, 2006 Borrower, and the banks named therein SEC FILE OR EXHIBIT REGISTRATION EXHIBIT NUMBER DESCRIPTION REPORT OR REGISTRATION STATEMENT NUMBER REFERENCE ------- ----------- ------------------------------- ------------ --------- 4.6 -- Indenture, dated as of February 1, 1998, between CERC Corp.'s Form 8-K dated 1-13265 4.1 CERC Corp. 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