TAMPA ELECTRIC CO
Form 10-Q
May 01, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

x **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 No.	Exact name of each Registrant as specified in its charter, state of incorporation, address of principal executive offices, telephone number	I.R.S. Employer Identification Number
1-8180	TECO ENERGY, INC.	59-2052286

(a Florida corporation)
TECO Plaza
702 N. Franklin Street
Tampa, Florida 33602
(813) 228-1111

1-5007 **TAMPA ELECTRIC COMPANY** **59-0475140**
(a Florida corporation)
TECO Plaza
702 N. Franklin Street
Tampa, Florida 33602
(813) 228-1111

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

Title of each class	Name of each exchange on which registered
TECO Energy, Inc.	
Common Stock, $1.00 par value	**New York Stock Exchange**
Common Stock Purchase Rights	**New York Stock Exchange**

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

Indicate by check mark whether the registrants (1) have 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) have been subject to such filing requirements for the past 90 days. YES x NO ¨

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). YES ¨ NO ¨

Indicate by check mark whether TECO Energy, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

Indicate by check mark whether Tampa Electric Company is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer x Smaller reporting company ¨

Indicate by check mark whether TECO Energy, Inc. is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ¨ NO x

Indicate by check mark whether Tampa Electric Company is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ¨ NO x

The number of shares of TECO Energy, Inc. s common stock outstanding as of Apr. 24, 2009 was 212,877,953. As of Apr. 24, 2009, there were 10 shares of Tampa Electric Company s common stock issued and outstanding, all of which were held, beneficially and of record, by TECO Energy, Inc.

Tampa Electric Company meets the conditions set forth in General Instruction (H) (1) (a) and (b) of Form 10-Q and is therefore filing this form with the reduced disclosure format.

This combined Form 10-Q represents separate filings by TECO Energy, Inc. and Tampa Electric Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Each registrant makes representations only as to information relating to itself and its subsidiaries.

Index to Exhibits appears on page 54.

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PART I. FINANCIAL INFORMATION

Item 1. CONSOLIDATED CONDENSED FINANCIAL STATEMENTS

TECO ENERGY, INC.

In the opinion of management, the unaudited consolidated condensed financial statements include all adjustments that are of a recurring nature and necessary to state fairly the financial position of TECO Energy, Inc. and subsidiaries as of Mar. 31, 2009 and Dec. 31, 2008, and the results of their operations and cash flows for the periods ended Mar. 31, 2009 and 2008. The results of operations for the three month period ended Mar. 31, 2009 are not necessarily indicative of the results that can be expected for the entire fiscal year ending Dec. 31, 2009. References should be made to the explanatory notes affecting the consolidated financial statements contained in Amendment No. 1 to TECO Energy, Inc. s Annual Report on Form 10-K for the year ended Dec. 31, 2008 and to the notes on pages 8 through 24 of this report.

INDEX TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS

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TECO ENERGY, INC.

Consolidated Condensed Balance Sheets

Unaudited

Assets

(millions, except for share amounts)	*Mar. 31, 2009*	*Dec. 31, 2008*
Current assets		
Cash and cash equivalents	$ 34.9	$ 12.2
Short-term investments		2.4
Receivables, less allowance for uncollectibles of $4.5 and $3.5 at Mar. 31, 2009 and Dec. 31, 2008, respectively	295.0	285.9
Inventories, at average cost		
Fuel	122.8	90.2
Materials and supplies	67.9	72.8
Current regulatory assets	238.5	272.6
Prepayments and other current assets	20.6	25.8
Income tax receivables	2.1	3.5
Total current assets	781.8	765.4
Property, plant and equipment		
Utility plant in service		
Electric	5,590.5	5,528.3
Gas	984.2	964.4
Construction work in progress	521.5	463.5
Other property	362.4	354.8
Property, plant and equipment	7,458.6	7,311.0
Accumulated depreciation	(2,110.8)	(2,089.7)
Total property, plant and equipment, net	5,347.8	5,221.3
Other assets		
Deferred income taxes	312.6	333.8
Other investments	17.1	21.3
Long-term regulatory assets	326.2	325.3
Long-term derivative assets	0.3	0.1
Investment in unconsolidated affiliates	280.9	284.0
Goodwill	59.4	59.4
Deferred charges and other assets, including restricted cash of $7.3 and $7.5 at Mar. 31, 2009 and Dec. 31, 2008, respectively.	133.3	136.8
Total other assets	1,129.8	1,160.7
Total assets	$ 7,259.4	$ 7,147.4

The accompanying notes are an integral part of the consolidated condensed financial statements.

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TECO ENERGY, INC.

Consolidated Condensed Balance Sheets continued

Unaudited

Liabilities and Capital

(millions, except for share amounts)	*Mar. 31, 2009*	*Dec. 31, 2008*
Current liabilities		
Long-term debt due within one year		
Recourse	$ 5.5	$ 5.5
Non-recourse	1.4	1.4
Notes payable	136.0	93.0
Accounts payable	285.1	304.4
Customer deposits	146.5	144.6
Current regulatory liabilities	27.5	21.7
Current derivative liabilities	168.9	132.1
Interest accrued	78.7	45.1
Taxes accrued	32.9	21.2
Other current liabilities	15.7	15.3
Total current liabilities	898.2	784.3
Other liabilities		
Investment tax credits	11.1	11.2
Long-term regulatory liabilities	582.8	588.2
Long-term derivative liabilities	22.5	19.4
Deferred credits and other liabilities	532.1	530.0
Long-term debt, less amount due within one year		
Recourse	3,199.0	3,199.0
Non-recourse	6.2	7.6
Total other liabilities	4,353.7	4,355.4
Commitments and contingencies (see **Note 9**)		
Capital		
Common equity (400.0 million shares authorized; par value $1; 212.9 million shares outstanding at Mar. 31, 2009 and Dec. 31, 2008)	212.9	212.9
Additional paid in capital	1,521.4	1,518.2
Retained earnings	314.7	322.6
Accumulated other comprehensive loss	(41.5)	(46.0)
Total capital	2,007.5	2,007.7
Total liabilities and capital	$ 7,259.4	$ 7,147.4

The accompanying notes are an integral part of the consolidated condensed financial statements.

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TECO ENERGY, INC.

Consolidated Condensed Statements of Income

Unaudited

(millions, except per share amounts)		*Three months ended Mar. 31, 2009*	*2008*
Revenues			
Regulated electric and gas (includes franchise fees and gross receipts taxes of $30.1 in 2009 and $26.4 in 2008)		$ 653.8	$ 640.2
Unregulated		170.2	151.5
Total revenues		824.0	791.7
Expenses			
Regulated operations			
Fuel		228.7	163.6
Purchased power		42.2	81.9
Cost of natural gas sold		88.3	119.0
Other		77.0	71.3
Operation other expense			
Mining related costs		118.5	107.2
Other		4.1	4.3
Maintenance		52.4	46.0
Depreciation and amortization		69.7	65.0
Taxes, other than income		60.4	54.9
Gain on sale, net of transaction related costs			0.9
Total expenses		741.3	714.1
Income from operations		82.7	77.6
Other income			
Allowance for other funds used during construction		3.3	1.3
Other income		14.0	5.3
Income from equity investments		8.8	17.4
Total other income		26.1	24.0
Interest charges			
Interest expense		57.6	58.2
Allowance for borrowed funds used during construction		(1.3)	(0.5)
Total interest charges		56.3	57.7
Income before provision for income taxes		52.5	43.9
Provision for income taxes		17.8	13.1
Net income		$ 34.7	$ 30.8
Average common shares outstanding	Basic	211.4	209.7
	Diluted	212.2	210.6

Earnings per share	Basic	$ 0.16	$ 0.15
	Diluted	$ 0.16	$ 0.15
Dividends paid per common share outstanding		$ 0.20	$ 0.195

The accompanying notes are an integral part of the consolidated condensed financial statements.

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TECO ENERGY, INC.

Consolidated Condensed Statements of Comprehensive Income

Unaudited

(millions)	*Three months ended Mar. 31, 2009*	*2008*
Net income	$ 34.7	$ 30.8
Other comprehensive income (loss), net of tax		
Net unrealized gains on cash flow hedges	2.5	(5.9)
Amortization of unrecognized benefit costs	0.3	0.3
Change in benefit obligations due to remeasurement		(10.8)
Unrealized loss on available-for-sale securities		(1.0)
Reclassification to earnings - loss on available-for-sale securities	1.7	
Other comprehensive income (loss), net of tax	4.5	(17.4)
Comprehensive income	$ 39.2	$ 13.4

The accompanying notes are an integral part of the consolidated condensed financial statements.

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TECO ENERGY, INC.

Consolidated Condensed Statements of Cash Flows

Unaudited

(millions)	*Three months ended Mar. 31, 2009*	*2008*
Cash flows from operating activities		
Net income	$ 34.7	$ 30.8
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	69.7	65.0
Deferred income taxes	18.1	15.5
Investment tax credits, net	(0.1)	(0.7)
Allowance for funds used during construction	(3.3)	(1.3)
Non-cash stock compensation	1.8	2.4
Gain on sale of business/assets, pretax	(18.7)	(1.0)
Equity in earnings of unconsolidated affiliates, net of cash distributions on earnings	(7.1)	14.8
Deferred recovery clauses	66.9	(11.4)
Receivables, less allowance for uncollectibles	(9.1)	(13.1)
Inventories	(27.7)	7.2
Prepayments and other current assets	5.2	1.0
Taxes accrued	13.1	1.3
Interest accrued	33.6	32.7
Accounts payable	(23.4)	(5.6)
Other	25.0	15.4
Cash flows from operating activities	178.7	153.0
Cash flows from investing activities		
Capital expenditures	(191.0)	(136.9)
Allowance for funds used during construction	3.3	1.3
Net proceeds (settlement) from sale of business/assets	29.1	(7.3)
Restricted cash	0.2	
Distributions from unconsolidated affiliates		13.2
Other investments	2.4	76.3
Cash flows used in investing activities	(156.0)	(53.4)
Cash flows from financing activities		
Dividends	(42.6)	(41.1)
Proceeds from the sale of common stock	1.0	1.3
Proceeds from long-term debt		190.8
Repayment of long-term debt/Purchase in lieu of redemption	(1.4)	(288.1)
Net increase (decrease) in short-term debt	43.0	(7.0)
Cash flows used in financing activities		(144.1)
Net increase (decrease) in cash and cash equivalents	22.7	(44.5)
Cash and cash equivalents at beginning of period	12.2	162.6
Cash and cash equivalents at end of period	$ 34.9	$ 118.1

The accompanying notes are an integral part of the consolidated condensed financial statements.

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TECO ENERGY, INC.

NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS

UNAUDITED

1. Summary of Significant Accounting Policies

The significant accounting policies for both utility and diversified operations include:

Principles of Consolidation and Basis of Presentation

The consolidated condensed financial statements include the accounts of TECO Energy, Inc., its majority-owned and controlled subsidiaries, and the accounts of variable interest entities for which it is the primary beneficiary (TECO Energy or the company). All significant intercompany balances and intercompany transactions have been eliminated in consolidation. Generally, the equity method of accounting is used to account for investments in partnerships or other arrangements in which TECO Energy is not the primary beneficiary but is able to exert significant influence. In the opinion of management, the unaudited consolidated condensed financial statements include all adjustments that are of a recurring nature and necessary to state fairly the financial position of TECO Energy, Inc. and subsidiaries as of Mar. 31, 2009 and Dec. 31, 2008, and the results of operations and cash flows for the periods ended Mar. 31, 2009 and 2008. The results of operations for the three month period ended Mar. 31, 2009 are not necessarily indicative of the results that can be expected for the entire fiscal year ending Dec. 31, 2009.

The use of estimates is inherent in the preparation of financial statements in accordance with generally accepted accounting principles (GAAP). Actual results could differ from these estimates. The year-end condensed balance sheet data was derived from audited financial statements, however this quarterly report on Form 10-Q does not include all year-end disclosures required for an annual report on Form 10-K by GAAP in the United States of America.

Revenues

As of Mar. 31, 2009 and Dec. 31, 2008, unbilled revenues of $48.2 million and $47.4 million, respectively, are included in the Receivables line item on the Consolidated Condensed Balance Sheets.

Purchased Power

Tampa Electric purchases power on a regular basis to meet the needs of its customers. Tampa Electric purchased power from entities not affiliated with TECO Energy at a cost of $42.2 million for the three months ended Mar. 31, 2009, compared to $81.9 million for the three months ended Mar. 31, 2008. Prudently incurred purchased power costs at Tampa Electric have historically been recoverable through Florida Public Service Commission (FPSC)-approved cost recovery clauses.

Accounting for Franchise Fees and Gross Receipts

The regulated utilities (Tampa Electric and Peoples Gas System (PGS)) are allowed to recover from customers certain costs incurred through rates approved by the FPSC. The amounts included in customers bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Condensed Statements of Income. These amounts totaled $30.1 million for the three months ended Mar. 31, 2009, compared to $26.4 million for the three months ended Mar. 31, 2008. Franchise fees and gross receipt taxes payable by the regulated utilities are included as an expense on the Consolidated Condensed Statements of Income in Taxes, other than income . These totaled $30.0 million for the three months ended Mar. 31, 2009, compared to $26.2 million for the three months ended Mar. 31, 2008.

Cash Flows Related to Derivatives and Hedging Activities

The company classifies cash inflows and outflows related to derivative and hedging instruments in the appropriate cash flow sections associated with the item being hedged. In the case of heating oil swaps which are used to mitigate the fluctuations in the price of diesel fuel, the cash inflows and outflows are included in the operations section. For natural gas and ongoing interest rate swaps, the cash inflows and outflows are included in the operating section. For interest rate swaps that settle coincident with the debt issuance, the cash inflows and outflows are treated as premiums or discounts and included in the financing section of the Consolidated Condensed Statements of Cash Flows.

2. New Accounting Pronouncements

Fair Value Measurements

In September 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard (SFAS) No. 157, *Fair Value Measurements* (FAS 157). FAS 157 defines fair value, establishes a framework for measuring fair value under generally accepted accounting principles, and expands disclosures about fair value measurements. FAS 157 emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and states that a fair value measurement should be determined based on the assumptions that market participants would use in pricing the asset or liability. FAS 157 applies under other accounting pronouncements that require or permit fair value measurements.

The effective date was for fiscal years beginning after Nov. 15, 2007. In November of 2007, the FASB informally granted a one year deferral for non-financial assets and liabilities. In February 2008, the FASB issued FASB Staff Position (FSP) 157-2, which formally delayed the effective date of FAS 157 to fiscal years beginning after Nov. 15, 2008. This FSP is applicable to non-financial assets and non-financial liabilities except for items that are required to be recognized or disclosed at fair value at least annually in the company s financial statements. As a result, the company adopted FAS 157 effective Jan. 1, 2008 for financial assets and liabilities and Jan. 1, 2009 for non-financial assets and liabilities. No adoption adjustment was necessary. Financial assets and liabilities of the company measured at fair value include derivatives and certain investments, for which fair values are primarily based on observable inputs. Non-financial assets and liabilities of the company measured at fair value include asset retirement obligations (AROs) when they are incurred and any long-lived assets or equity-method investments that are impaired in a currently reported period.

In April 2009, the FASB issued FSP FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly* (FSP FAS 157-4), FSP FAS 115-2 and FAS 124-2 , *Recognition and Presentation of Other-Than-Temporary Impairments* (FSP FAS 115-2 and FAS124-2), and FSP FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments* (FSP FAS 107-1 and APB 28-1) to address fair value valuation concerns in the current market environment.

FSP FAS 157-4 affirms that when the market for an asset is not active, the objective of fair value is the price that would be received to sell the asset in an orderly transaction (that is, not a forced liquidation or distressed sale) between market participants at the measurement date in the inactive market. The determination of whether a transaction was not orderly should be based on the weight of the evidence. The FSP requires an entity to disclose a change in valuation technique and the related inputs resulting from the application of the FSP and to quantify its effects. Retrospective application is not permitted. The FSP is effective for interim and annual periods ending after Jun. 15, 2009. This is not expected to materially affect the company s results of operations, statement of position or cash flows.

FSP FAS 115-2 and FAS 124-2 are applicable to debt securities and require that a company recognize the credit component of an other-than-temporary impairment in earnings and the remaining portion in other comprehensive income if management asserts it does not have the intent to sell the security and it is more likely than not it will not have to sell the security before recovery of its cost basis. It requires an entity to present separately in the financial statement where the components of other comprehensive income are reported, amounts recognized in accumulated other comprehensive income related to the noncredit portion of other-than-temporary impairments recognized for available-for-sale and held-to-maturity debt securities. Additionally, disclosure requirements are amended and will be required for interim periods. The FSP is effective for interim and annual periods ending after Jun. 15, 2009 and is not expected to materially affect the company s results of operations, statement of position or cash flows.

FSP FAS 107-1 and APB 28-1 require an entity to disclose fair value information, including methods and significant assumptions in measuring fair value, of financial instruments within the scope of FAS 107 in interim periods. The FSP is effective for interim and annual periods ending after Jun. 15, 2009. The new disclosure requirements of FSP FAS 107-1 and APB 28-1 will have no effect on the company s results of operations, statement of position or cash flows.

Employers Disclosures about Postretirement Benefit Plan Assets

In December 2008, the FASB issued FSP No. FAS 132(R)-1, *Employers Disclosures about Postretirement Benefit Plan Assets* (FSP FAS 132(R)-1). This FSP requires enhanced disclosures about plan assets of defined benefit pension plans or other postretirement plans, including the concentrations of risk in those plans. The guidance in FSP FAS 132(R)-1 is effective for fiscal years ending after Dec. 15, 2009. These additional required disclosures will have no effect on the company s results of operations, statement of position or cash flows.

Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities

In June 2008, the FASB issued FSP No. Emerging Issues Task Force (EITF) 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (FSP EITF 03-6-1). FSP EITF 03-6-1 requires that the two-class method earnings per share calculation include unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents, whether the dividend or dividend equivalents are paid or not paid. The guidance in FSP EITF 03-6-1 is effective for fiscal years beginning after Dec. 15, 2008. The company adopted FSP EITF 03-6-1 effective Jan. 1, 2009 with no material impact to its results of operations, statement of position or cash flows.

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Disclosures about Derivative Instruments and Hedging Activities

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities* (FAS 161). FAS 161 was issued to enhance the disclosure framework in SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (FAS 133). FAS 161 requires enhanced disclosures about the purpose of an entity s derivative instruments, how derivative instruments and hedged items are accounted for, and how the entity s financial position, cash flows and performance are enhanced by the derivative instruments and hedged items. The guidance in FAS 161 is effective for fiscal years and interim periods beginning after Nov. 15, 2008. FAS 161 is significant to the company s financial statement disclosures but has no effect on its results of operations, statement of position or cash flows. The company adopted FAS 161 effective Jan. 1, 2009.

Additionally, in April 2008, the FASB revised Statement 133 Implementation Issues Nos. I1 and K4 to reflect the enhanced disclosures required by FAS 161. These revisions are significant to its financial statement disclosures but have no effect on the company s results of operations, statement of position or cash flows.

3. Regulatory

As discussed in **Note 1**, Tampa Electric s and PGS s retail businesses are regulated by the FPSC. Tampa Electric is subject to regulation by the Federal Energy Regulatory Commission (FERC) under the Public Utility Holding Company Act of 2005 (PUHCA 2005). However, pursuant to a waiver granted in accordance with FERC s regulations, TECO Energy is not subject to certain of the accounting, record-keeping and reporting requirements prescribed by FERC s regulations under PUHCA 2005.

Base Rates Tampa Electric

In order for Tampa Electric to continue meeting customers growing needs for reliable, efficient and affordable electric service, Tampa Electric filed with the FPSC for a base rate increase in August 2008. After an extensive review of the company s request, on Mar. 17, 2009, the FPSC approved an ROE mid-point of 11.25% with a range of 10.25% to 12.25% and an increase to base rates and miscellaneous service charges of $104 million starting May 7, 2009. Additionally, the FPSC approved a revenue requirement step increase of $33.6 million effective Jan. 1, 2010 for capital additions placed in service in 2009 bringing the total approved revenue requirement amount to approximately $138 million. As part of its base rate increase, Tampa Electric also requested modifications to its cost of service methodology and rate design, which were also approved by the FPSC. The new base rates and service charges will remain in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties.

In addition to several base rate design changes, residential base rates and fuel charges will reflect a two-block structure which offers a lower rate for the first 1,000 kilowatt-hours of usage each month.

Base Rates PGS

PGS s current rates, which became effective in January 2003, were agreed to in a settlement with all parties involved prior to a full rate proceeding, and a final FPSC order was granted on Dec. 17, 2002. PGS authorized rates provide an allowed ROE range from 10.25% to 12.25% with an 11.25% midpoint.

Recognizing the significant decline in ROE, PGS filed with the FPSC for a $3.7 million interim rate increase in August 2008. The FPSC approved an interim rate increase of $2.4 million effective Oct. 29, 2008. PGS also filed in August 2008, with the FPSC for a $26.5 million base rate increase. The major factors in the filing included a request for an ROE mid-point of 11.5%, 55% equity in the capital structure, and a rate base of $564 million. The formal hearings before the FPSC were held in March and the FPSC is scheduled to make its final decision on the requested increase in May, with final rates becoming effective in June 2009.

Cost Recovery Tampa Electric

Tampa Electric s fuel, purchased power, conservation and certain environmental costs are recovered through levelized monthly charges established pursuant to the FPSC s cost recovery clauses. These charges, which are reset annually in an FPSC proceeding, are based on estimated costs of fuel, environmental compliance, conservation programs and purchased power and estimated customer usage for a specific recovery period, with a true-up adjustment to reflect the variance of actual costs from the projected costs. The FPSC may disallow recovery of any costs that it considers imprudently incurred.

In September 2008, Tampa Electric filed with the FPSC for approval of rates for fuel and purchased power, capacity, environmental and conservation costs for the period January through December 2009. In November 2008, the FPSC approved Tampa Electric s requested rates. The rates included: 1) the 2009 projected costs for fuel and purchased power, including higher natural gas and coal prices, 2) the recovery of $132.9 million of under-recovered fuel and purchased power expenses in 2008 and 2007, 3) the over-recovery of $4.7 million of costs recovered through the Environmental Cost Recovery Clause (ECRC) for 2008 and 2007, and 4) the operating cost for and a return on the capital invested in the third selective catalytic reduction (SCR) project at the Big Bend Station as well as the operations and maintenance expense associated with the projects as required by the Environmental Protection Agency (EPA) Consent Decree and Florida Department of Environmental Protection (FDEP) Consent Final Judgment. Rates in 2009 also reflect a two-block fuel factor structure with a lower factor for the first 1,000 kilowatt-hours used each month.

On Mar. 5, 2009, Tampa Electric filed a mid-course adjustment of its fuel and purchased power costs to reflect the significant decline in fuel commodity prices. Tampa Electric s re-forecasted 2009 fuel and purchased power costs using actual costs for January and updated data for the balance of the year resulted in a decrease of projected fuel and purchased power costs of $190.8 million. Additionally, the FPSC approved Tampa Electric refunding the 2008 final true-up amount of $35.4 million as part of the mid-course adjustment. After, including the impacts of the rate case, Tampa Electric s residential customer rate per 1,000 kilowatt-hours will decrease $14.38 from $128.44 to $114.06 starting on May 7, 2009.

The FPSC determined in 2004 and 2005 that it was appropriate for Tampa Electric to recover SCR operating costs through the ECRC as well as earn a return on its SCR investment installed on Big Bend Units 1-4 for NO_x control in compliance with the environmental consent decree. The SCRs for Big Bend Units 4 and 3 entered service in May 2007 and 2008, respectively, and cost recovery started in 2007 and 2008. The SCR for Big Bend Unit 2 is scheduled to enter service in May 2009 and recovery is included in the ECRC rates approved by the FPSC. The SCR for Big Bend Unit 1 is scheduled to enter service in May 2010 and cost recovery for the capital investment, which is dependent on a filing, is expected to start in 2010.

Cost Recovery PGS

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through the purchased gas adjustment (PGA) clause. This charge is designed to recover the costs incurred by PGS for purchased gas, and for holding and using interstate pipeline capacity for the transportation of gas it delivers to its customers. These charges may be adjusted monthly based on a cap approved annually in an FPSC hearing. The cap is based on estimated costs of purchased gas and pipeline capacity, and estimated customer usage for a specific recovery period, with a true-up adjustment to reflect the variance of actual costs and usage from the projected charges for prior periods. In November 2008, the FPSC approved rates under PGS PGA for the period January 2009 through December 2009 for the recovery of the costs of natural gas purchased for its distribution customers.

In addition to PGS s base rates and purchased gas adjustment clause charges, PGS customers (except interruptible customers) also pay a per-therm conservation charge for all gas. This charge is intended to permit PGS to recover its costs incurred in developing and implementing energy conservation programs, which are mandated by Florida law and approved and supervised by the FPSC. PGS is permitted to recover, on a dollar-for-dollar basis, prudently incurred expenditures made in connection with these programs if it demonstrates that the programs are cost effective for its ratepayers.

Other Items

Storm Damage Cost Recovery

Tampa Electric accrues $4.0 million annually to a FERC-authorized and FPSC-approved, self-insured storm damage reserve. This reserve was created after Florida s investor owned utilities (IOUs) were unable to obtain transmission and distribution insurance coverage due to destructive acts of nature. Tampa Electric s storm reserve was $23.7 million and $22.7 million as of Mar. 31, 2009 and Dec. 31, 2008, respectively.

In Tampa Electric s base rate proceeding, the FPSC approved an increase in the annual storm damage accrual to $8.0 million effective May 2009.

Regulatory Assets and Liabilities

Tampa Electric and PGS maintain their accounts in accordance with recognized policies of the FPSC. In addition, Tampa Electric maintains its accounts in accordance with recognized policies prescribed or permitted by the FERC.

Tampa Electric and PGS apply the accounting treatment permitted by FAS 71, *Accounting for the Effects of Certain Types of Regulation* (FAS 71). Areas of applicability include: deferral of revenues under approved regulatory agreements; revenue recognition resulting from cost recovery clauses that provide for monthly billing charges to reflect increases or decreases in fuel, purchased power, conservation and environmental costs; and the deferral of costs as regulatory assets to the period that the regulatory agency recognizes them when cost recovery is ordered over a period longer than a fiscal year.

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Details of the regulatory assets and liabilities as of Mar. 31, 2009 and Dec. 31, 2008 are presented in the following table:

Regulatory Assets and Liabilities

(millions)	*Mar. 31, 2009*	*Dec. 31, 2008*
Regulatory assets:		
Regulatory tax asset [1]	$ 66.3	$ 65.1
Other:		
Cost recovery clauses	235.9	266.8
Postretirement benefit asset	218.3	220.3
Deferred bond refinancing costs [2]	20.7	21.7
Environmental remediation	10.7	10.8
Competitive rate adjustment	3.8	4.7
Other	9.0	8.5
Total other regulatory assets	498.4	532.8
Total regulatory assets	564.7	597.9
Less: Current portion	238.5	272.6
Long-term regulatory assets	$ 326.2	$ 325.3
Regulatory liabilities:		
Regulatory tax liability [1]	$ 17.2	$ 17.5
Other:		
Cost recovery clauses	2.8	3.4
Environmental remediation	10.4	10.6
Transmission and delivery storm reserve	23.7	22.7
Deferred gain on property sales [3]	4.7	4.1
Accumulated reserve-cost of removal	551.0	551.2
Other	0.5	0.4
Total other regulatory liabilities	593.1	592.4
Total regulatory liabilities	610.3	609.9
Less: Current portion	27.5	21.7
Long-term regulatory liabilities	$ 582.8	$ 588.2

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(1) Related to plant life and derivative positions.
(2) Amortized over the term of the related debt instrument.
(3) Amortized over a 5-year period with various ending dates.

All regulatory assets are being recovered through the regulatory process. The following table further details our regulatory assets and the related recovery periods:

Regulatory assets

(millions)	*Mar. 31, 2009*	*Dec 31, 2008*
Clause recoverable [1]	$ 239.7	$ 271.5
Components of rate base [2]	226.0	227.7
Regulatory tax assets [3]	66.3	65.1
Capital structure and other [3]	32.7	33.6
Total	$ 564.7	$ 597.9

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(1) To be recovered through cost recovery clauses approved by the FPSC on a dollar-for-dollar basis in the next year. The decrease between years is principally due to the recovery of previously unrecovered fuel costs.

(2) Primarily reflects allowed working capital, which is included in rate base and earns a rate of return as permitted by the FPSC.

(3) Regulatory tax assets and Capital structure and other regulatory assets have a recoverable period longer than a fiscal year and are recognized over the period authorized by the regulatory agency. Also included are unamortized loan costs, which are amortized over the life of the related debt instruments. See footnotes 1 and 2 in the prior table for additional information.

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4. Income Taxes

The company s U.S. subsidiaries join in the filing of a U.S. federal consolidated income tax return. The Internal Revenue Service (IRS) concluded its examination of the company s 2007 consolidated federal income tax return during 2008. The U.S. federal statute of limitations remains open for the year 2008 and onward. Year 2008 is currently under examination by the IRS under the Compliance Assurance Program, a program in which the company is a participant. The company does not expect the settlement of current IRS examinations to significantly change the total amount of unrecognized tax benefits by the end of 2009. Foreign and U.S. state jurisdictions have statutes of limitations generally ranging from 3 to 5 years from the filing of an income tax return. The state impact of any federal changes remains subject to examination by various states for a period of up to one year after formal notification to the states. Years still open to examination by tax authorities in major state and foreign jurisdictions include 2003 and forward.

The company recognizes interest and penalties associated with uncertain tax positions in the Consolidated Condensed Statements of Income in accordance with FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*. During the three month periods ended Mar. 31, 2009 and Mar. 31, 2008, the company recorded $0.3 million and $0.2 million, respectively, of pre-tax charges for interest only. No amounts have been recorded for penalties for the three month periods ended Mar. 31, 2009 and Mar. 31, 2008.

During the three month periods ended Mar. 31, 2009 and Mar. 31, 2008, the company experienced events that have impacted the overall effective tax rate on continuing operations. These events included depletion and the sale of a foreign subsidiary (see **Note 13**).

5. Employee Postretirement Benefits

Included in the table below is the periodic expense for pension and other postretirement benefits offered by the company.

Pension Expense

(millions)

	Pension Benefits		*Other Postretirement Benefits*	
Three months ended Mar. 31,	***2009***	***2008***	***2009***	***2008***
Components of net periodic benefit expense				
Service cost	$ 3.9	$ 3.9	$ 0.8	$ 1.0
Interest cost on projected benefit obligations	8.3	8.0	2.8	3.0
Expected return on assets	(9.5)	(9.8)		
Amortization of:				
Transition obligation			0.6	0.6
Prior service (benefit) cost	(0.1)	(0.1)	0.2	0.4
Actuarial loss	1.8	1.0		
Pension expense	4.4	3.0	4.4	5.0
Settlement cost		0.9		
Net pension expense recognized in the TECO Energy Consolidated Condensed Statements of Income	$ 4.4	$ 3.9	$ 4.4	$ 5.0

For the fiscal 2009 plan year, TECO Energy assumed an expected long-term return on plan assets of 8.25% and a discount rate of 6.05% for pension benefits under its qualified pension plan as of its Jan. 1, 2009 measurement date, and a discount rate of 6.05% for its SERP and other postretirement benefits as of their Jan. 1, 2009 measurement date. For the three month period ended Mar. 31, 2009, the pension plan trust experienced a net loss on its invested assets.

For the three months ended Mar. 31, 2009, TECO Energy and its subsidiaries reclassed $0.5 million of unamortized transition obligation, prior service cost and actuarial gains and losses from accumulated other comprehensive income to net income as part of periodic benefit expense. In addition, during the three months ended Mar. 31, 2009, Tampa Electric Company reclassed $2.0 million of unamortized transition obligation, prior service cost and actuarial losses from regulatory assets to net income as part of periodic benefit expense.

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6. Short-Term Debt

At Mar. 31, 2009 and Dec. 31, 2008, the following credit facilities and related borrowings existed:

Credit Facilities

(millions)	*Mar. 31, 2009* Credit Facilities	Borrowings Outstanding [1]	Letters of Credit Outstanding	*Dec. 31, 2008* Credit Facilities	Borrowings Outstanding [1]	Letters of Credit Outstanding
Tampa Electric Company:						
5-year facility	$ 325.0	$	$ 1.4	$ 325.0	$	$ 1.4
1-year accounts receivable facility	150.0	96.0		150.0	29.0	
TECO Energy/TECO Finance:						
5-year facility [2]	200.0	40.0	7.1	200.0	64.0	7.1
Total	$ 675.0	$ 136.0	$ 8.5	$ 675.0	$ 93.0	$ 8.5

(1) Borrowings outstanding are reported as notes payable.
(2) TECO Finance is the borrower and TECO Energy is the guarantor of this facility.

These credit facilities require commitment fees ranging from 9.0 to 125.0 basis points. The weighted-average interest rate on outstanding amounts payable under the credit facilities at Mar. 31, 2009 and Dec. 31, 2008 was 1.22% and 2.65%, respectively.

7. Other Comprehensive Income

TECO Energy reported the following other comprehensive income (OCI) for the three months ended Mar. 31, 2009 and 2008, related to changes in the fair value of cash flow hedges, amortization of unrecognized benefit costs associated with the company s pension plans and unrecognized gains and losses on available-for-sale securities:

Other Comprehensive Income

	Three months ended Mar. 31,		
(millions)	*Gross*	*Tax*	*Net*
2009			
Unrealized loss on cash flow hedges	$ (3.1)	$ 1.2	$ (1.9)
Less: Loss reclassified to net income	7.0	(2.6)	$ 4.4
Gain on cash flow hedges	3.9	(1.4)	2.5
Amortization of unrecognized benefit costs	0.5	(0.2)	0.3
Reclassification to earnings loss on available-for-sale securities	1.7		1.7
Total other comprehensive income	$ 6.1	$ (1.6)	$ 4.5
2008			
Unrealized (loss) gain on cash flow hedges	$ (9.6)	$ 3.7	$ (5.9)
Less: Gain reclassified to net income			$
Loss on cash flow hedges	(9.6)	3.7	(5.9)
Amortization of unrecognized benefit costs	0.4	(0.1)	0.3
Change in benefit obligation due to remeasurement	(17.6)	6.8	(10.8)
Unrealized loss on available-for-sale securities(1)	(1.0)		(1.0)
Total other comprehensive loss	$ (27.8)	$ 10.4	$ (17.4)

Accumulated Other Comprehensive Loss

(millions)	*Mar. 31, 2009*	*Dec. 31, 2008*
Unrecognized pension losses and prior service costs(2)	$ (29.5)	$ (29.8)
Unrecognized other benefit gains, prior service costs and transition obligations(3)	10.6	10.6
Net unrealized losses from cash flow hedges(4)	(22.6)	(25.1)
Net unrecognized loss on available-for-sale securities		(1.7)
Total accumulated other comprehensive loss	$ (41.5)	$ (46.0)

(1) Amount relates to an off-shore investment not subject to U.S. Federal income tax.
(2) Net of tax benefit of $18.2 million and $18.4 million as of Mar. 31, 2009 and Dec. 31, 2008, respectively.
(3) Net of tax expense of $6.3 million as of Mar. 31, 2009 and Dec. 31, 2008.
(4) Net of tax benefit of $13.5 million and $15.0 million as of Mar. 31, 2009 and Dec. 31, 2008, respectively.

8. Earnings Per Share

In accordance with FSP EITF 03-6-1, TECO Energy adopted the two-class method for computing earnings per share (EPS) in the first quarter of 2009. FSP EITF 03-6-1 defines share-based payment awards that participate in dividends prior to vesting as participating securities that should be included in the earnings allocation in computing EPS under the two-class method described in FAS 128¸ *Earnings Per Share* (FAS 128). FSP EITF 03-6-1 requires retrospective application for all prior periods presented.

The two-class method of calculating EPS requires TECO Energy to calculate EPS for its common stock and its participating securities (time-vested restricted stock and performance-based restricted stock) based on dividends declared and the pro-rata share each has to undistributed earnings. The application of the two-class method did not have a material effect on TECO Energy s EPS calculations.

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Earnings Per Share

(millions, except per share amounts)	*Three months ended Mar. 31,* *2009*	*2008*
Basic earnings per share		
Net income	$ 34.7	$ 30.8
Amount allocated to nonvested participating shareholders	(0.3)	(0.2)
Income available to common shareholders - basic	$ 34.4	$ 30.6
Average shares outstanding common	211.4	209.7
Basic earnings per share	$ 0.16	$ 0.15
Diluted earnings per share		
Net income	$ 34.7	$ 30.8
Amount allocated to nonvested participating shareholders	(0.3)	(0.2)
Income available to common shareholders - diluted	$ 34.4	$ 30.6
Average shares outstanding common	211.4	209.7
Assumed conversions of stock options, unvested restricted stock and contingent performance shares, net	0.8	0.9
Adjusted average shares outstanding common - diluted	212.2	210.6
Diluted earnings per share	$ 0.16	$ 0.15
Anti-dilutive shares	7.1	6.6

9. Commitments and Contingencies

Legal Contingencies

From time to time, TECO Energy and its subsidiaries are involved in various legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies in the ordinary course of its business. Where appropriate, accruals are made in accordance with SFAS No. 5, *Accounting for Contingencies*, to provide for matters that are probable of resulting in an estimable, material loss. While the outcome of such proceedings is uncertain, management does not believe that their ultimate resolution will have a material adverse effect on the company s results of operations or financial condition.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and PGS divisions, is a potentially responsible party (PRP) for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Mar. 31, 2009, Tampa Electric Company has estimated its ultimate financial liability to be approximately $10.4 million, and this amount has been accrued in the company s financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

The estimated amounts represent only the estimated portion of the cleanup costs attributable to Tampa Electric Company. The estimates to perform the work are based on actual estimates obtained from contractors or Tampa Electric Company s experience with similar work adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

Allocation of the responsibility for remediation costs among Tampa Electric Company and other PRPs is based on each party s relative ownership interest in or usage of a site. Accordingly, Tampa Electric Company s share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered creditworthy.

Factors that could impact these estimates include the ability of other PRPs to pay their pro-rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves and changes in laws or regulations that could require additional remediation. These costs are recoverable through customer rates established in subsequent base rate proceedings.

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Guarantees and Letters of Credit

A summary of the face amount or maximum theoretical obligation under TECO Energy s and Tampa Electric Company s letters of credit and guarantees as of Mar. 31, 2009 is as follows:

Letters of Credit and Guarantees-TECO Energy

(millions)

Letters of Credit and Guarantees for the Benefit of:	*2009*	*2010-2013*	*After (1) 2013*	*Total*	*Liabilities Recognized at Mar. 31, 2009*
Tampa Electric					
Letters of credit	$	$	$ 0.3	$ 0.3	$
Guarantees:					
Fuel purchase/energy management (2)			20.0	20.0	2.0
			20.3	20.3	2.0
TECO Coal					
Letters of credit			6.8	6.8	
Guarantees: Fuel purchase related (2)			1.4	1.4	2.2
			8.2	8.2	2.2
Other subsidiaries					
Guarantees:					
Fuel purchase/energy management (2)	69.8		2.9	72.7	19.4
Total	$ 69.8	$	$ 31.4	$ 101.2	$ 23.6

Letters of Credit-Tampa Electric Company

(millions)

Letters of Credit for the Benefit of:	*2009*	*2010-2013*	*After (1) 2013*	*Total*	*Liabilities Recognized at Mar. 31, 2009*
Tampa Electric					
Letters of credit	$	$	$ 1.4	$ 1.4	$
Total	$	$	$ 1.4	$ 1.4	$

(1) These guarantees renew annually and are shown on the basis that they will continue to renew beyond 2013.

(2) The amounts shown are the maximum theoretical amounts guaranteed under current agreements. Liabilities recognized represent the associated obligation of TECO Energy under these agreements at Mar. 31, 2009. The obligations under these letters of credit and guarantees include net accounts payable and net derivative liabilities.

Financial Covenants

In order to utilize their respective bank credit facilities, TECO Energy, TECO Finance and Tampa Electric Company must meet certain financial tests as defined in the applicable agreements. In addition, TECO Energy, TECO Finance and Tampa Electric Company and other operating companies have certain restrictive covenants in specific agreements and debt instruments. At Mar. 31, 2009, TECO Energy, TECO Finance, Tampa Electric Company and the other operating companies were in compliance with all applicable financial covenants.

10. Segment Information

TECO Energy is an electric and gas utility holding company with significant diversified activities. Segments are determined based on how management evaluates, measures and makes decisions with respect to the operations of the entity. The management of TECO Energy reports segments based on each subsidiary s contribution of revenues, net income and total assets, as required by SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information*. All significant intercompany transactions are eliminated in the Consolidated Condensed Financial Statements of TECO Energy, but are included in determining reportable segments.

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Segment Information [1]

(millions)

Three months ended Mar. 31,	*Tampa Electric*	*Peoples Gas*	*TECO Coal*	*TECO* [2] *Guatemala*	*Other & Eliminations*	*TECO Energy*
2009						
Revenues - external	$ 507.3	$ 146.5	$ 168.1	$ 2.1	$	$ 824.0
Sales to affiliates	0.3	6.5			(6.8)	
Total revenues	507.6	153.0	168.1	2.1	(6.8)	824.0
Equity earnings of unconsolidated affiliates				8.8		8.8
Depreciation	48.0	10.8	10.6	0.2	0.1	69.7
Total interest charges[1]	28.2	4.7	1.8	3.2	18.4	56.3
Internally allocated interest [1]			1.5	3.1	(4.6)	
Provision (benefit) for taxes	9.4	7.2	1.3	9.6	(9.7)	17.8
Net income (loss) from continuing operations	$ 18.3	$ 11.2	$ 8.0	$ 13.2	$ (16.0)	$ 34.7
2008						
Revenues - external	$ 461.2	$ 179.0	$ 149.1	$ 2.3	$ 0.1	$ 791.7
Sales to affiliates	0.3				(0.3)	
Total revenues	461.5	179.0	149.1	2.3	(0.2)	791.7
Equity earnings of unconsolidated affiliates				17.4		17.4
Depreciation	45.2	10.3	9.2	0.2	0.1	65.0
Total interest charges[1]	29.4	4.2	2.5	3.8	17.8	57.7
Internally allocated interest [1]			2.3	3.8	(6.1)	
Provision (benefit) for taxes	8.5	6.4	1.9	1.9	(5.6)	13.1
Net income (loss) from continuing operations	$ 15.9	$ 10.0	$ 7.5	$ 10.5	$ (13.1)	$ 30.8
At Mar. 31, 2009						
Goodwill	$	$	$	$ 59.4	$	$ 59.4
Investment in unconsolidated affiliates				280.9		280.9
Other non-current investments					17.1	17.1
Total assets	$ 5,659.8	$ 872.9	$ 326.8	$ 376.7	$ 23.2	$ 7,259.4
At Dec. 31, 2008						
Goodwill	$	$	$	$ 59.4	$	$ 59.4
Investment in unconsolidated affiliates				284.0		284.0
Other non-current investments					21.3	21.3
Total assets	$ 5,538.8	$ 878.0	$ 309.1	$ 383.1	$ 38.4	$ 7,147.4

(1) Segment net income is reported on a basis that includes internally allocated financing costs. Total interest charges include internally allocated interest costs that for 2009 and 2008 were at a pretax rate of 7.15% and 7.25%, respectively, based on an average of each subsidiary s equity and indebtedness to TECO Energy assuming a 50/50 debt/equity capital structure.

(2) Revenues are exclusive of entities deconsolidated as a result of FIN 46R. Total revenues for unconsolidated affiliates, attributable to TECO Guatemala based on ownership percentages, were $18.7 million and $29.9 million for the three months ended Mar. 31, 2009 and 2008, respectively. Earnings include the sale of a 16.5% interest in the Central American fiber optic telecommunications provider Navega (see **Note 13**).

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11. Accounting for Derivative Instruments and Hedging Activities

From time to time, TECO Energy and its affiliates enter into futures, forwards, swaps and option contracts for the following purposes:

- To limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric and PGS;

- To limit the exposure to interest rate fluctuations on debt securities at TECO Energy and its affiliates; and

- To limit the exposure to price fluctuations for physical purchases of fuel and explosives at TECO Coal.

TECO Energy and its affiliates use derivatives only to reduce normal operating and market risks, not for speculative purposes. The company s primary objective in using derivative instruments for regulated operations is to reduce the impact of market price volatility on ratepayers.

The risk management policies adopted by TECO Energy provide a framework through which management monitors various risk exposures. Daily and periodic reporting of positions and other relevant metrics are performed by a centralized risk management group which is independent of all operating companies.

The company applies the provisions of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by SFAS 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities,* SFAS 149, *Amendment on Statement 133 on Derivative Instruments and Hedging Activities*, and SFAS 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133* (FAS 161). These standards require companies to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as either components of OCI or in net income, depending on the designation of those instruments. The changes in fair value that are recorded in OCI are not immediately recognized in current net income. As the underlying hedged transaction matures or the physical commodity is delivered, the deferred gain or loss on the related hedging instrument must be reclassified from OCI to earnings based on its value at the time of the instrument s settlement. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the market change of the amount paid or received on the underlying physical transaction.

FAS 161 became effective for financial statements issued for fiscal years and interim periods beginning after Nov. 15, 2008. FAS 161 requires enhanced disclosures about a company s derivative activities and how the related hedged items affect a company s financial position, financial performance and cash flows. To meet the objectives, FAS 161 requires qualitative disclosures about the company s fair value amounts of gains and losses associated with derivative instruments, as well as disclosures about credit-risk-related contingent features in derivative agreements. The company adopted FAS 161 effective Jan. 1, 2009.

The company applies FAS 71 for financial instruments used to hedge the purchase of natural gas for our regulated companies. The provisions of FAS 71, in accordance with the FPSC, permit the changes in fair value of natural gas derivatives to be recorded as regulatory assets or liabilities to reflect the impact of hedging activities on the fuel recovery clause. As a result, these changes are not recorded in OCI (see **Note 3**).

A company s physical contracts qualify for the normal purchase/normal sale (NPNS) exception to derivative accounting rules, provided they meet certain criteria. Generally, NPNS applies if the company deems the counterparty creditworthy, if the counterparty owns or controls resources within the proximity to allow for physical delivery of the commodity, if the company intends to receive physical delivery and if the transaction is reasonable in relation to the company s business needs. As of Mar. 31, 2009, all of the company s physical contracts qualify for the NPNS exception.

The following table presents the derivatives that are designated as cash flow hedges at Mar. 31, 2009 and Dec. 31, 2008:

	Total Derivatives	
(millions)	***Mar. 31, 2009***	***Dec. 31, 2008***

Current assets	$	$
Long-term assets	0.3	0.1
Total assets	$ 0.3	$ 0.1
Current liabilities[(1)]	$ 172.7	$ 141.8
Long-term liabilities	22.5	19.4
Total liabilities	$ 195.2	$ 161.2

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(1) Amounts presented above are on a gross basis, with asset and liability positions netted by counterparty in accordance with FIN 39, *Offsetting of Amounts Related to Certain Contracts.* The Consolidated

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Condensed Balance Sheets reflect the company s net positions reduced by posted collateral of $3.8 million and $9.7 million at Mar. 31, 2009 and Dec. 31, 2008, respectively, permitted by FSP FIN 39-1, *Amendment of FASB Interpretation No. 39*.

The following table presents the derivative hedges of heating oil contracts at Mar. 31, 2009 and Dec. 31, 2008 to limit the exposure to changes in the market price for diesel fuel:

	Heating Oil Derivatives	
(millions)	***Mar. 31, 2009***	***Dec. 31, 2008***
Current assets	$	$
Long-term asset		
Total assets	$	$
Current liability	$ 17.8	$ 21.4
Long-term liability	4.6	4.6
Total liabilities	$ 22.4	$ 26.0

The following table presents the derivative hedges of natural gas contracts at Mar. 31, 2009 and Dec. 31, 2008 to limit the exposure to changes in market price for natural gas used to produce energy, natural gas purchased for resale to customers and natural gas used as a component price for explosives purchased:

	Natural Gas Derivatives	
(millions)	***Mar. 31, 2009***	***Dec. 31, 2008***
Current assets	$	$
Long-term asset	0.3	0.1
Total assets	$ 0.3	$ 0.1
Current liability	$ 154.9	$ 120.4
Long-term liability	17.9	14.8
Total liabilities	$ 172.8	$ 135.2

The ending balance in accumulated other comprehensive income (AOCI) related to the cash flow hedges and previously settled interest rate swaps at Mar. 31, 2009 is a net loss of $22.6 million after tax and accumulated amortization. This compares to a net loss of $25.1 million in AOCI after tax and accumulated amortization at Dec. 31, 2008.

The following table presents the fair values and locations of derivative instruments recorded in the balance sheet at Mar. 31, 2009:

	Derivatives Designated As Hedging Instruments			
	Asset Derivatives		**Liability Derivatives**	
(millions)	***Balance Sheet Location***	***Fair Value***	***Balance Sheet Location***	***Fair Value***

at Mar. 31, 2009				
Commodity Contracts:				
Heating oil derivatives:				
Current	Derivative assets	$	Derivative liabilities	$ 17.8
Long-term	Derivative assets		Derivative liabilities	4.6
Natural gas derivatives:				
Current	Derivative assets		Derivative liabilities	154.9
Long-term	Derivative assets	0.3	Derivative liabilities	17.9
Total derivatives designated as hedging instruments		$ 0.3		$ 195.2

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The following table presents the effect of energy related derivatives on the fuel recovery clause mechanism in the balance sheet as of Mar. 31, 2009:

(millions)	Asset Derivatives		Liability Derivatives	
at Mar. 31, 2009	*Balance Sheet Location(1)*	*Fair Value*	*Balance Sheet Location(1)*	*Fair Value*
Commodity Contracts:				
Natural gas derivatives:				
Current	Regulatory liabilities	$	Regulatory assets	$ 154.2
Long-term	Regulatory liabilities	0.3	Regulatory assets	17.9
Total		$ 0.3		$ 172.1

(1) Natural gas derivatives are deferred, in accordance with FAS 71 and all increases and decreases in the cost of natural gas supply are passed on to customers with the fuel recovery clause mechanism. As gains and losses are realized in future periods, they will be recorded as fuel costs in the Statements of Income.

Based on the fair value of the instruments at Mar. 31, 2009, net pretax losses of $154.2 million are expected to be reclassified from regulatory assets or liabilities to the Consolidated Statements of Income within the next twelve months.

The following table presents the effect of hedging instruments on OCI and income for the quarter ended Mar. 31, 2009:

(millions)	Amount of Gain/(Loss) on Derivatives Recognized in OCI	Location of Gain/(Loss) Reclassified From AOCI Into Income	Amount of Gain/(Loss) Reclassified From AOCI Into Income
Derivatives in SFAS No. 133 Cash Flow Hedging Relationships	Effective Portion(1)	Effective Portion	
Interest rate contracts:	$	Interest expense	$ (0.5)
Commodity Contracts:			
Heating oil derivatives	(1.4)	Mining related costs	(3.7)
Natural gas derivatives	(0.5)	Mining related costs	(0.2)
Total	$ (1.9)		$ (4.4)

(1) Changes in OCI are reported in after-tax dollars.

For derivative instruments that meet cash flow hedge criteria, the effective portion of the gain or loss on the derivative is reported as a component of OCI and reclassified into earnings in the same period or period during which the hedged transaction affects earnings. Gains and losses on the derivatives representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings. For the three months ended Mar. 31, 2009, all hedges were effective.

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The following table presents the derivative activity for instruments classified as qualifying cash flow hedges for the quarter ended Mar. 31, 2009:

(millions) *For the quarter ended Mar. 31, 2009*	Fair Value Asset/(Liability)	Amount of Gain/(Loss) Recognized in OCI[(1)]	Amount of Gain/(Loss) Reclassified From AOCI Into Income
Heating oil derivatives	$ (22.4)	$ (1.4)	$ (3.7)
Interest rate swaps			(0.5)
Natural gas derivatives	(172.5)	(0.5)	(0.2)
Total	$ (194.9)	$ (1.9)	$ (4.4)

(1) Changes in OCI are reported in after-tax dollars.

The maximum length of time over which the company is hedging its exposure to the variability in future cash flows extends to Dec. 31, 2011 for both financial natural gas and financial heating oil fuel contracts. The following table presents the company s derivative volumes by commodity type that are expected to settle each year at Mar. 31, 2009:

(millions)	Heating Oil Contracts (Gallons)		Natural Gas Contracts (MMBTUs)	
Year	Physical	Financial	Physical	Financial
2009		9.4		37.6
2010		6.5		14.1
2011		3.4		2.2
Total		19.3		53.9

The company is exposed to credit risk primarily through entering into derivative instruments with counterparties to limit its exposure to the commodity price fluctuations associated with diesel fuel and natural gas. Credit risk is the potential loss resulting from a counterparty s nonperformance under an agreement. The company manages credit risk with policies and procedures for, among other things, counterparty analysis, exposure measurement, and exposure monitoring and mitigation.

It is possible that volatility in commodity prices could cause the company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the company could suffer a material financial loss. However, as of Mar. 31, 2009, approximately 99.9% of the counterparties with transaction amounts outstanding in the company s energy portfolio are rated investment grade by the major rating agencies while the remaining 0.1% are either rated below investment grade or are not rated by rating agencies. The company assesses credit risk internally for counterparties that are not rated.

The company has entered into commodity master arrangements with its counterparties to mitigate credit exposure to those counterparties. The company generally enters into the following master arrangements: (1) Edison Electric Institute agreements (EEI) - standardized power sales contracts in the electric industry; (2) International Swaps and Derivatives Association agreements (ISDA) - standardized financial gas and electric contracts; and (3) North American Energy Standards Board agreements (NAESB) - standardized physical gas contracts. The company believes that entering into such agreements reduces the risk from default by creating contractual rights relating to creditworthiness, collateral and termination.

The company has implemented procedures to monitor the creditworthiness of our counterparties and to consider nonperformance in valuing counterparty positions. The company monitors counterparties credit standing, including those that are experiencing financial problems, have significant swings in credit default swap rates, have credit rating changes by external rating agencies, or have changes in ownership. Net liability positions are generally not adjusted as the company uses derivative transactions as hedges and has the ability and intent to perform under each of their contracts. In the instance of net asset positions, the company considers general market conditions and the observable financial health and outlook of specific counterparties, forward looking data such as credit default swaps, when available, and historical default probabilities from credit rating agencies in evaluating the potential impact of nonperformance risk to derivative positions.

Certain TECO Energy derivative instruments contain provisions that require the company s debt, or in the case of derivative instruments where Tampa Electric Company is the counterparty, Tampa Electric Company s debt, to maintain an investment grade credit rating from any or all of the major credit rating agencies. If debt ratings, including Tampa Electric

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Company s, were to fall below investment grade, it could trigger these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The company has no other contingent risk features associated with any derivative instruments.

The table below presents the fair value of the overall contractual contingent liability positions for the company s derivative activity at Mar. 31, 2009:

(millions)

At Mar. 31, 2009

Contingent Feature	**Fair Value Asset/ (Liability)**	**Derivative Exposure Asset/ (Liability)**	**Posted Collateral**
Credit Rating	$ (194.9)	$ (191.1)	$ 3.8
Total	$ (194.9)	$ (191.1)	$ 3.8

12. Fair Value Measurements

Determination of Fair Value

The company measures fair value using the procedures set forth below for all assets and liabilities measured at fair value that were previously carried at fair value pursuant to other accounting guidelines.

When available, the company uses quoted market prices on assets and liabilities traded on an exchange to determine fair value and classifies such items as Level 1. In some cases where a market exchange price is available, but the assets and liabilities are traded in a secondary market, the company makes use of acceptable practical expedients to calculate fair value, and classifies such items as Level 2.

If observable transactions and other market data are not available, fair value is based upon internally developed models that use, when available, current market-based or independently-sourced market parameters such as interest rates, currency rates or option volatilities. Items valued using internally generated models are classified according to the lowest level input or value driver that is most significant to the valuation. Thus, an item may be classified in Level 3 even though there may be significant inputs that are readily observable.

Items Measured at Fair Value on a Recurring Basis

The following table sets forth by level within the fair value hierarchy the company s financial assets and liabilities that were accounted for at fair value on a recurring basis as of Mar. 31, 2009. As required by FAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. For natural gas and heating oil swaps, the market approach was used in determining fair value. For other investments, the income approach was used.

Recurring Fair Value Measures

	At fair value as of Mar. 31, 2009			
(millions)	***Level 1***	***Level 2***	***Level 3***	***Total***
<u>Assets</u>				
Natural gas swaps	$	$ 0.3	$	$ 0.3
Other investments			9.2	9.2

Total	$	$ 0.3	$ 9.2	$ 9.5
Liabilities				
Natural gas swaps	$	$ 172.7	$	$ 172.7
Heating oil swaps		18.7		18.7
Total	$	$ 191.4	$	$ 191.4

Natural gas and heating oil swaps are over-the-counter swap instruments. The primary pricing inputs in determining the fair value of these swaps are the New York Mercantile Exchange (NYMEX) quoted closing prices of exchange-traded instruments. These prices are applied to the notional amounts of active positions to determine the reported fair value.

The primary pricing inputs in determining the fair value of interest rate swaps are LIBOR swap rates as reported by Bloomberg. For each instrument, the projected forward swap rate is used to determine the stream of cash flows over the life of the contract. The cash flows are then discounted using a spot discount rate to determine the fair value. A $2.7 million liability, primarily in interest rate swaps, is held on the books of unconsolidated affiliates of TECO Guatemala, but is reflected in Investment in unconsolidated affiliates on the TECO Energy, Inc. Consolidated Condensed Balance Sheets.

Other investments reflect two auction rate securities, backed by pools of student loans, with a combined par value of $15.0 million. As a result of auction failures and the lack of an alternative active market, the valuation technique for these securities is an income approach using a discounted cash flow model and is considered Level 3 within FAS 157 s three tier fair value hierarchy. The model assumes a continuation of failed auctions and interest payments at the default rate. Cash flows are discounted at a rate reflecting current market spreads for similarly rated maturities. The valuation is sensitive to the discount rate used; a 100 basis point increase in the discount rate results in a $0.8 million decrease in value.

Based on the protracted disruption of the market for these securities and the uncertain potential for its recovery, the company no longer expects to hold the securities indefinitely to recover the original value. Accordingly, the impairment was deemed other-than-temporary and recognized in Other income on the Consolidated Condensed Statement of Income for the first quarter.

The company considered the impact of nonperformance risk in determining the fair value of derivatives. The company considered the net position with each counterparty, past performance of both parties and the intent of the parties, indications of credit deterioration, and whether the markets in which we transact have experienced dislocation. At Mar. 31, 2009, the fair value of derivatives was not materially affected by nonperformance risk. Net positions with substantially all counterparties were liability positions.

Assets Measured at Fair Value on a Recurring Basis Using Unobservable Inputs (Level 3)

(millions)		**Auction Rate Securities**
Balance at Dec. 31, 2008	$	13.3
Transfers to Level 3		
Change in fair market value included in earnings		(4.1)
Balance at Mar. 31, 2009	$	9.2

13. Mergers, Acquisitions and Dispositions

Sale of Navega

On Mar. 13, 2009, TECO Guatemala sold its 16.5% interest in the Central American fiber optic telecommunications provider Navega. The sale resulted in a pre-tax gain of $18.3 million and total proceeds of $29.0 million.

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TAMPA ELECTRIC COMPANY

In the opinion of management, the unaudited consolidated condensed financial statements include all adjustments that are of a recurring nature and necessary to state fairly the financial position of Tampa Electric Company as of Mar. 31, 2009 and Dec. 31, 2008, and the results of operations and cash flows for the periods ended Mar. 31, 2009 and 2008. The results of operations for the three months ended Mar. 31, 2009 are not necessarily indicative of the results that can be expected for the entire fiscal year ending Dec. 31, 2009. References should be made to the explanatory notes affecting the consolidated financial statements contained in Amendment No. 1 to Tampa Electric Company s Annual Report on Form 10-K for the year ended Dec. 31, 2008 and to the notes on pages 30 - 41 of this report.

INDEX TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS

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TAMPA ELECTRIC COMPANY

Consolidated Condensed Balance Sheets

Unaudited

Assets

(millions)	*Mar. 31, 2009*	*Dec. 31, 2008*
Property, plant and equipment		
Utility plant in service		
Electric	$ 5,577.0	$ 5,514.9
Gas	984.2	964.4
Construction work in progress	520.3	462.4
Property, plant and equipment, at original costs	7,081.5	6,941.7
Accumulated depreciation	(1,884.1)	(1,868.5)
	5,197.4	5,073.2
Other property	4.3	4.5
Total property, plant and equipment, net	5,201.7	5,077.7
Current assets		
Cash and cash equivalents	9.3	3.6
Receivables, less allowance for uncollectibles of $2.6 and $1.6 at Mar. 31, 2009 and Dec. 31, 2008, respectively	230.8	236.1
Inventories, at average cost		
Fuel	97.3	76.8
Materials and supplies	57.5	61.8
Current regulatory assets	238.5	272.6
Taxes receivable		0.2
Prepayments and other current assets	10.5	14.1
Total current assets	643.9	665.2
Deferred debits		
Unamortized debt expense	21.6	22.3
Long-term regulatory assets	326.2	325.3
Long-term derivative assets	0.3	0.1
Other	15.3	18.0
Total deferred debits	363.4	365.7
Total assets	$ 6,209.0	$ 6,108.6

The accompanying notes are an integral part of the consolidated condensed financial statements.

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TAMPA ELECTRIC COMPANY

Consolidated Condensed Balance Sheets continued

Unaudited

Liabilities and Capital

(millions)	*Mar 31, 2009*	*Dec. 31, 2008*
Capital		
Common stock	$ 1,802.4	$ 1,802.4
Accumulated other comprehensive loss	(6.6)	(6.8)
Retained earnings	278.1	295.0
Total capital	2,073.9	2,090.6
Long-term debt, less amount due within one year	1,894.8	1,894.8
Total capitalization	3,968.7	3,985.4
Current liabilities		
Long-term debt due within one year	5.5	5.5
Notes payable	96.0	29.0
Accounts payable	233.7	262.5
Customer deposits	146.5	144.6
Current regulatory liabilities	27.5	21.7
Current derivative liabilities	154.2	119.4
Current deferred income taxes	12.4	36.6
Interest accrued	40.2	27.1
Taxes accrued	42.2	20.1
Other	11.5	11.2
Total current liabilities	769.7	677.7
Deferred credits		
Non-current deferred income taxes	473.9	447.6
Investment tax credits	11.1	11.2
Long-term derivative liabilities	17.9	14.8
Long-term regulatory liabilities	582.8	588.2
Other	384.9	383.7
Total deferred credits	1,470.6	1,445.5
Total liabilities and capital	$ 6,209.0	$ 6,108.6

The accompanying notes are an integral part of the consolidated condensed financial statements.

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TAMPA ELECTRIC COMPANY

Consolidated Condensed Statements of Income and Comprehensive Income

Unaudited

(millions)	*Three months ended Mar. 31, 2009*	*2008*
Revenues		
Electric (includes franchise fees and gross receipts taxes of $22.1 in 2009 and $18.9 in 2008)	$ 501.0	$ 461.4
Gas (includes franchise fees and gross receipts taxes of $8.0 in 2009 and $7.5 million in 2008)	153.0	179.0
Total revenues	654.0	640.4
Expenses		
Operations		
Fuel	228.7	163.6
Purchased power	42.2	81.9
Cost of natural gas sold	88.3	119.0
Other	76.9	71.2
Maintenance	36.2	34.1
Depreciation	58.8	55.5
Taxes, federal and state	16.5	14.6
Taxes, other than income	48.2	43.6
Total expenses	595.8	583.5
Income from operations	58.2	56.9
Other income		
Allowance for other funds used during construction	3.3	1.3
Taxes, non-utility federal and state	(0.1)	(0.3)
Other income, net	1.0	1.5
Total other income	4.2	2.5
Interest charges		
Interest on long-term debt	31.4	31.4
Other interest	2.8	2.6
Allowance for borrowed funds used during construction	(1.3)	(0.5)
Total interest charges	32.9	33.5
Net income	29.5	25.9
Other comprehensive income (loss), net of tax		
Net unrealized gain (loss) on cash flow hedges	0.2	(5.0)
Total other comprehensive income (loss), net of tax	0.2	(5.0)
Comprehensive income	$ 29.7	$ 20.9

The accompanying notes are an integral part of the consolidated condensed financial statements.

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TAMPA ELECTRIC COMPANY

Consolidated Condensed Statements of Cash Flows

Unaudited

(millions)	*Three months ended Mar. 31, 2009*	*2008*
Cash flows from operating activities		
Net income	$ 29.5	$ 25.9
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation	58.8	55.5
Deferred income taxes	0.5	10.7
Investment tax credits, net	(0.1)	(0.6)
Allowance for funds used during construction	(3.3)	(1.3)
Deferred recovery clause	66.9	(11.4)
Receivables, less allowance for uncollectibles	5.3	(10.9)
Inventories	(16.2)	5.7
Prepayments	3.6	(0.6)
Taxes accrued	22.3	14.8
Interest accrued	13.1	12.5
Accounts payable	(32.8)	4.1
Gain on sale of business assets	(0.2)	(0.1)
Other	12.0	11.4
Cash flows from operating activities	159.4	115.7
Cash flows from investing activities		
Capital expenditures	(177.8)	(123.7)
Allowance for funds used during construction	3.3	1.3
Net proceeds from sale of assets	0.1	
Cash flows used in investing activities	(174.4)	(122.4)
Cash flows from financing activities		
Proceeds from long-term debt		190.8
Common stock		150.0
Repayment of long-term debt/Purchase in lieu of redemption		(286.8)
Net increase (decrease) in short-term debt	67.0	(7.0)
Dividends	(46.3)	(44.3)
Cash flows from financing activities	20.7	2.7
Net increase (decrease) in cash and cash equivalents	5.7	(4.0)
Cash and cash equivalents at beginning of period	3.6	11.9
Cash and cash equivalents at end of period	$ 9.3	$ 7.9

The accompanying notes are an integral part of the consolidated condensed financial statements.

TAMPA ELECTRIC COMPANY

NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS

UNAUDITED

1. Summary of Significant Accounting Policies

The significant accounting policies are as follows:

Principles of Consolidation and Basis of Presentation

Tampa Electric Company is a wholly-owned subsidiary of TECO Energy, Inc., and is comprised of the Electric division, generally referred to as Tampa Electric, and the Natural Gas division, generally referred to as Peoples Gas System (PGS). All significant intercompany balances and intercompany transactions have been eliminated in consolidation. In the opinion of management, the unaudited consolidated condensed financial statements include all adjustments that are of a recurring nature and necessary to state fairly the financial position of Tampa Electric Company and subsidiaries as of Mar. 31, 2009 and Dec. 31, 2008, and the results of operations and cash flows for the periods ended Mar. 31, 2009 and 2008. The results of operations for the three month period ended Mar. 31, 2009 are not necessarily indicative of the results that can be expected for the entire fiscal year ending Dec. 31, 2009.

The use of estimates is inherent in the preparation of financial statements in accordance with generally accepted accounting principles (GAAP). Actual results could differ from these estimates. The year-end condensed balance sheet data was derived from audited financial statements, however this quarterly report on Form 10-Q does not include all year-end disclosures required for an annual report on Form 10-K by GAAP in the United States of America.

Revenues

As of Mar. 31, 2009 and Dec. 31, 2008, unbilled revenues of $48.2 million and $47.4 million, respectively, are included in the Receivables line item on the Consolidated Condensed Balance Sheets.

Purchased Power

Tampa Electric purchases power on a regular basis to meet the needs of its customers. Tampa Electric purchased power from entities not affiliated with TECO Energy at a cost of $42.2 million for the three months ended Mar. 31, 2009, compared to $81.9 million for the three months ended Mar. 31, 2008. Prudently incurred purchased power costs at Tampa Electric have historically been recoverable through Florida Public Service Commission (FPSC)-approved cost recovery clauses.

Accounting for Franchise Fees and Gross Receipts

The regulated utilities (Tampa Electric and Peoples Gas System (PGS)) are allowed to recover from customers certain costs incurred through rates approved by the FPSC. The amounts included in customers bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Condensed Statements of Income. These amounts totaled $30.1 million for the three months ended Mar. 31, 2009, compared to $26.4 million for the three months ended Mar. 31, 2008. Franchise fees and gross receipt taxes payable by the regulated utilities are included as an expense on the Consolidated Condensed Statements of Income in Taxes, other than income . These totaled $30.0 million for the three months ended Mar. 31, 2009, compared to $26.2 million for the three months ended Mar. 31, 2008.

Cash Flows Related to Derivatives and Hedging Activities

Tampa Electric Company classifies cash inflows and outflows related to derivative and hedging instruments in the appropriate cash flow sections associated with the item being hedged. For natural gas and ongoing interest rate swaps, the cash inflows and outflows are included in the operating section. For interest rate swaps that settle coincident with the debt issuance, the cash inflows and outflows are treated as premiums or discounts and included in the financing section of the Consolidated Condensed Statements of Cash Flows.

2. New Accounting Pronouncements

Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (FAS 157). FAS 157 defines fair value, establishes a framework for measuring fair value under generally accepted accounting principles, and expands disclosures about fair value measurements. FAS 157 emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and states that a fair value measurement should be determined based on the assumptions that market participants would use in pricing the asset or liability. FAS 157 applies under other accounting pronouncements that require or permit fair value measurements.

The effective date was for fiscal years beginning after Nov. 15, 2007. In November of 2007, the FASB informally granted a one year deferral for non-financial assets and liabilities. In February 2008, the FASB issued FSP 157-2, which formally delayed the effective date of FAS 157 to fiscal years beginning after Nov. 15, 2008. This FSP is applicable to non-financial assets and non-financial liabilities except for items that are required to be recognized or disclosed at fair value at least annually in the company s financial statements. As a result, the company adopted FAS 157 effective Jan. 1, 2008 for financial assets and liabilities and Jan. 1, 2009 for non-financial assets and liabilities. No adoption adjustment was necessary. Financial assets and liabilities of the company measured at fair value include derivatives and certain investments, for which fair values are primarily based on observable inputs. Non-financial assets and liabilities of the company measured at fair value include asset retirement obligations (AROs) when they are incurred.

In April 2009, the FASB issued FSP FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly* (FSP FAS 157-4), FSP FAS 115-2 and FAS 124-2 , *Recognition and Presentation of Other-Than-Temporary Impairments* (FSP FAS 115-2 and FAS124-2), and FSP FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments* (FSP FAS 107-1 and APB 28-1) to address fair value valuation concerns in the current market environment.

FSP FAS 157-4 affirms that when the market for an asset is not active, the objective of fair value is the price that would be received to sell the asset in an orderly transaction (that is, not a forced liquidation or distressed sale) between market participants at the measurement date in the inactive market. The determination of whether a transaction was not orderly should be based on the weight of the evidence. The FSP requires an entity to disclose a change in valuation technique and the related inputs resulting from the application of the FSP and to quantify its effects. Retrospective application is not permitted. The FSP is effective for interim and annual periods ending after Jun. 15, 2009. This is not expected to materially affect the company s results of operations, statement of position or cash flows.

FSP FAS 115-2 and FAS 124-2 are applicable to debt securities and require that a company recognize the credit component of an other-than-temporary impairment in earnings and the remaining portion in other comprehensive income if management asserts it does not have the intent to sell the security and it is more likely than not it will not have to sell the security before recovery of its cost basis. It requires an entity to present separately in the financial statement where the components of other comprehensive income are reported, amounts recognized in accumulated other comprehensive income related to the noncredit portion of other-than-temporary impairments recognized for available-for-sale and held-to-maturity debt securities. Additionally, disclosure requirements are amended and will be required for interim periods. The FSP is effective for interim and annual periods ending after Jun. 15, 2009 and is not expected to materially affect the company s results of operations, statement of position or cash flows.

FSP FAS 107-1 and APB 28-1 require an entity to disclose fair value information, including methods and significant assumptions in measuring fair value, of financial instruments within the scope of FAS 107 in interim periods. The FSP is effective for interim and annual periods ending after Jun. 15, 2009. The new disclosure requirements of FSP FAS 107-1 and APB 28-1 will have no effect on the company s results of operations, statement of position or cash flows.

Employers Disclosures about Postretirement Benefit Plan Assets

In December 2008, the FASB issued FSP No. FAS 132(R)-1, *Employers Disclosures about Postretirement Benefit Plan Assets* (FSP FAS 132(R)-1). This FSP requires enhanced disclosures about plan assets of defined benefit pension plans or other postretirement plans, including the concentrations of risk in those plans. The guidance in FSP FAS 132(R)-1 is effective for fiscal years ending after Dec. 15, 2009. These additional required disclosures will have no effect on the company s results of operations, statement of position or cash flows.

Disclosures about Derivative Instruments and Hedging Activities

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities* (FAS 161). FAS 161 was issued to enhance the disclosure framework in SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (FAS 133). FAS 161 requires enhanced disclosures about the purpose of an entity s derivative instruments, how derivative instruments and hedged items are accounted for, and how the entity s financial position, cash flows, and performance are enhanced by the derivative instruments and hedged items. The guidance in FAS 161 is effective for fiscal years and interim periods beginning after Nov. 15, 2008. FAS 161 is significant to the company s financial statement disclosures but has no effect on its results of operations, statement of position or cash flows. The company adopted FAS 161 effective Jan. 1, 2009.

Additionally, in April 2008, the FASB revised Statement 133 Implementation Issues Nos. I1 and K4 to reflect the enhanced disclosures required by FAS 161. These revisions are significant to the company s financial statement disclosures but have no effect on its results of operations, statement of position or cash flows.

3. Regulatory

As discussed in **Note 1**, Tampa Electric s and PGS s retail businesses are regulated by the FPSC. Tampa Electric is subject to regulation by the Federal Energy Regulatory Commission (FERC) under the Public Utility Holding Company Act of 2005 (PUHCA 2005). However, pursuant to a waiver granted in accordance with FERC s regulations, Tampa Electric is not subject to certain of the accounting, record-keeping and reporting requirements prescribed by FERC s regulations under PUHCA 2005.

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Base Rates Tampa Electric

In order for Tampa Electric to continue meeting customers growing needs for reliable, efficient and affordable electric service, Tampa Electric filed with the FPSC for a base rate increase in August 2008. After an extensive review of the company s request, on Mar. 17, 2009, the FPSC approved an ROE mid-point of 11.25% with a range of 10.25% to 12.25% and an increase to base rates and miscellaneous service charges of $104 million starting May 7, 2009. Additionally, the FPSC approved a revenue requirement step increase of $33.6 million effective Jan. 1, 2010 for capital additions placed in service in 2009 bringing the total approved revenue requirement amount to approximately $138 million. As part of its base rate increase, Tampa Electric also requested modifications to its cost of service methodology and rate design, which were also approved by the FPSC. The new base rates and service charges will remain in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties.

In addition to several base rate design changes, residential base rates and fuel charges will reflect a two-block structure which offers a lower rate for the first 1,000 kilowatt-hours of usage each month.

Base Rates PGS

PGS current rates, which became effective in January 2003, were agreed to in a settlement with all parties involved prior to a full rate proceeding, and a final FPSC order was granted on Dec. 17, 2002. PGS authorized rates provide an allowed ROE range from 10.25% to 12.25% with an 11.25% midpoint.

Recognizing the significant decline in ROE, PGS filed with the FPSC for a $3.7 million interim rate increase in August 2008. The FPSC approved an interim rate increase of $2.4 million effective Oct. 29, 2008. PGS also filed in August 2008 with the FPSC for a $26.5 million base rate increase. The major factors in the filing included a request for an ROE mid-point of 11.5%, 55% equity in the capital structure, and a rate base of $564 million. The formal hearings before the FPSC were held in March and the FPSC is scheduled to make its final decision on the requested increase in May, with final rates becoming effective in June 2009.

Cost Recovery Tampa Electric

Tampa Electric s fuel, purchased power, conservation and certain environmental costs are recovered through levelized monthly charges established pursuant to the FPSC s cost recovery clauses. These charges, which are reset annually in an FPSC proceeding, are based on estimated costs of fuel, environmental compliance, conservation programs and purchased power and estimated customer usage for a specific recovery period, with a true-up adjustment to reflect the variance of actual costs from the projected costs. The FPSC may disallow recovery of any costs that it considers imprudently incurred.

In September 2008, Tampa Electric filed with the FPSC for approval of rates for fuel and purchased power, capacity, environmental and conservation costs for the period January through December 2009. In November 2008, the FPSC approved Tampa Electric s requested rates. The rates included: 1) the 2009 projected costs for fuel and purchased power, including higher natural gas and coal prices, 2) the recovery of $132.9 million of under-recovered fuel and purchased power expenses in 2008 and 2007, 3) the over-recovery of $4.7 million of costs recovered through the Environmental Cost Recovery Clause (ECRC) for 2008 and 2007, and 4) the operating cost for and a return on the capital invested in the third selective catalytic reduction (SCR) project at the Big Bend Station as well as the operations and maintenance expense associated with the projects as required by the Environmental Protection Agency (EPA) Consent Decree and Florida Department of Environmental Protection (FDEP) Consent Final Judgment. Rates in 2009 also reflect a two-block fuel factor structure with a lower factor for the first 1,000 kilowatt-hours used each month.

On Mar. 5, 2009, Tampa Electric filed a mid-course adjustment of its fuel and purchased power costs to reflect the significant decline in fuel commodity prices. Tampa Electric s re-forecasted 2009 fuel and purchased power costs using actual costs for January and updated data for the balance of the year resulted in a decrease of projected fuel and purchased power costs of $190.8 million. Additionally, the FPSC approved Tampa Electric refunding the 2008 final true-up amount of $35.4 million as part of the mid-course adjustment. After, including the impacts of the rate case, Tampa Electric s residential customer rate per 1,000 kilowatt-hours will decrease $14.38 from $128.44 to $114.06 starting on May 7, 2009.

The FPSC determined in 2004 and 2005 that it was appropriate for Tampa Electric to recover SCR operating costs through the ECRC as well as earn a return on its SCR investment installed on Big Bend Units 1-4 for NO_x control in compliance with the environmental consent decree. The SCRs for Big Bend Units 4 and 3 entered service in May 2007 and 2008, respectively, and cost recovery started in 2007 and 2008. The SCR for Big Bend Unit 2 is scheduled to enter service in May 2009 and recovery is included in the ECRC rates approved by the FPSC. The SCR for Big Bend Unit 1 is scheduled to enter service in May 2010 and cost recovery for the capital investment, which is dependent on a filing, is expected to start in 2010.

Cost Recovery PGS

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through the purchased gas adjustment (PGA) clause. This charge is designed to recover the costs incurred by PGS for purchased gas, and for holding and using interstate pipeline capacity for the transportation of gas it delivers to its customers. These charges may be adjusted monthly based on a cap approved annually in an FPSC hearing. The cap is based on estimated costs of purchased gas and pipeline capacity, and estimated customer usage for a specific recovery period, with a true-up adjustment to reflect the variance of actual costs and usage from the projected charges for prior periods. In November 2008, the FPSC approved rates under PGS PGA for the period January 2009 through December 2009 for the recovery of the costs of natural gas purchased for its distribution customers.

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In addition to PGS s base rates and purchased gas adjustment clause charges, PGS customers (except interruptible customers) also pay a per-therm conservation charge for all gas. This charge is intended to permit PGS to recover its costs incurred in developing and implementing energy conservation programs, which are mandated by Florida law and approved and supervised by the FPSC. PGS is permitted to recover, on a dollar-for-dollar basis, prudently incurred expenditures made in connection with these programs if it demonstrates that the programs are cost effective for its ratepayers.

Other Items

Storm Damage Cost Recovery

Tampa Electric accrues $4.0 million annually to a FERC-authorized and FPSC-approved, self-insured storm damage reserve. This reserve was created after Florida s investor owned utilities (IOUs) were unable to obtain transmission and distribution insurance coverage due to destructive acts of nature. Tampa Electric s storm reserve was $23.7 million and $22.7 million as of Mar. 31, 2009 and Dec. 31 2008, respectively.

In Tampa Electric s base rate proceeding, the FPSC approved an increase in the annual storm damage accrual to $8.0 million effective May 2009.

Regulatory Assets and Liabilities

Tampa Electric and PGS maintain their accounts in accordance with recognized policies of the FPSC. In addition, Tampa Electric maintains its accounts in accordance with recognized policies prescribed or permitted by the FERC.

Tampa Electric and PGS apply the accounting treatment permitted by FAS 71, *Accounting for the Effects of Certain Types of Regulation* (FAS 71). Areas of applicability include: deferral of revenues under approved regulatory agreements; revenue recognition resulting from cost recovery clauses that provide for monthly billing charges to reflect increases or decreases in fuel, purchased power, conservation and environmental costs; and the deferral of costs as regulatory assets to the period that the regulatory agency recognizes them when cost recovery is ordered over a period longer than a fiscal year.

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Details of the regulatory assets and liabilities as of Mar. 31, 2009 and Dec. 31, 2008 are presented in the following table:

Regulatory Assets and Liabilities

(millions)	*Mar. 31, 2009*	*Dec. 31, 2008*
Regulatory assets:		
Regulatory tax asset [(1)]	$ 66.3	$ 65.1
Other:		
Cost recovery clauses	235.9	266.8
Postretirement benefit asset	218.3	220.3
Deferred bond refinancing costs [(2)]	20.7	21.7
Environmental remediation	10.7	10.8
Competitive rate adjustment	3.8	4.7
Other	9.0	8.5
Total other regulatory assets	498.4	532.8
Total regulatory assets	564.7	597.9
Less: Current portion	238.5	272.6
Long-term regulatory assets	$ 326.2	$ 325.3
Regulatory liabilities:		
Regulatory tax liability [(1)]	$ 17.2	$ 17.5
Other:		
Cost recovery clauses	2.8	3.4
Environmental remediation	10.4	10.6
Transmission and delivery storm reserve	23.7	22.7
Deferred gain on property sales [(3)]	4.7	4.1
Accumulated reserve-cost of removal	551.0	551.2
Other	0.5	0.4
Total other regulatory liabilities	593.1	592.4
Total regulatory liabilities	610.3	609.9
Less: Current portion	27.5	21.7
Long-term regulatory liabilities	$ 582.8	$ 588.2

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(1) Related to plant life and derivative positions.
(2) Amortized over the term of the related debt instrument.
(3) Amortized over a 5-year period with various ending dates.

All regulatory assets are being recovered through the regulatory process. The following table further details our regulatory assets and the related recovery periods:

Regulatory assets

(millions)	*Mar. 31, 2009*	*Dec 31, 2008*
Clause recoverable [(1)]	$ 239.7	$ 271.5
Components of rate base [(2)]	226.0	227.7
Regulatory tax assets [(3)]	66.3	65.1
Capital structure and other [(3)]	32.7	33.6
Total	$ 564.7	$ 597.9

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(1) To be recovered through cost recovery clauses approved by the FPSC on a dollar-for-dollar basis in the next year. The decrease between years is principally due to the recovery of previously unrecovered fuel costs.

(2) Primarily reflects allowed working capital, which is included in rate base and earns a rate of return as permitted by the FPSC.

(3) Regulatory tax assets and Capital structure and other regulatory assets have a recoverable period longer than a fiscal year and are recognized over the period authorized by the regulatory agency. Also included are unamortized loan costs, which are amortized over the life of the related debt instruments. See footnotes 1 and 2 in the prior table for additional information.

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4. Income Taxes

Tampa Electric Company is included in the filing of a consolidated federal income tax return with TECO Energy and its affiliates. Tampa Electric Company s income tax expense is based upon a separate return computation. Tampa Electric Company s effective tax rates for the three months ended Mar. 31, 2009 and 2008 differ from the statutory rate principally due to state income taxes, equity portion of AFUDC, amortization of investment tax credits and the domestic activity production deduction.

The Internal Revenue Service (IRS) concluded its examination of the company s consolidated federal income tax return for the year 2007 during 2008. The U.S. federal statute of limitations remains open for the year 2008 and onward. Year 2008 is currently under examination by the IRS under the Compliance Assurance Program, a program in which TECO Energy is a participant. TECO Energy does not expect the settlement of current IRS examinations to significantly change the total amount of unrecognized tax benefits by the end of 2009. State jurisdictions have statutes of limitations generally ranging from three to five years from the filing of an income tax return. The state impact of any federal changes remains subject to examination by various states for a period of up to one year after formal notification to the states. Years still open to examination by tax authorities in major state jurisdictions include 2005 and onward.

The company does not currently have any uncertain tax positions and does not anticipate that the total amount of unrecognized tax benefits will significantly increase or decrease by the end of 2009.

5. Employee Postretirement Benefits

Tampa Electric Company is a participant in the comprehensive retirement plans of TECO Energy. Other than the remeasurement of the Supplemental Executive Retirement Plan (SERP) plan obligations at Jan. 1, 2008 for certain participant retirements and the impacts of the termination of TECO Transport employees participation in these plans as a result of the sale of TECO Transport in December 2007, no significant changes have been made to these benefit plans since Dec. 31, 2003.

Amounts allocable to all participants of the TECO Energy retirement plans are found in **Note 5**, **Employee Postretirement Benefits**, in the TECO Energy, Inc. **Notes to Consolidated Condensed Financial Statements**. Tampa Electric Company s portion of the net pension expense for the three months ended Mar. 31, 2009 and 2008, respectively, was $3.4 million and $2.1 million for pension benefits, and $3.4 million and $3.5 million for other postretirement benefits.

Included in the benefit expenses discussed above, for the three months ended Mar. 31, 2008, Tampa Electric Company reclassed $2.0 million of unamortized transition obligation, prior service cost and actuarial losses from regulatory assets to net income.

For the fiscal 2009 plan year, TECO Energy assumed an expected long-term return on plan assets of 8.25% and a discount rate of 6.05% for pension benefits under its qualified pension plan as of its Jan. 1, 2009 measurement date, and a discount rate of 6.05% for its SERP and other postretirement benefits as of their Jan. 1, 2009 measurement date. For the three month period ended Mar. 31, 2009, the pension plan trust experienced a net loss on its invested assets.

6. Short-Term Debt

At Mar. 31, 2009 and Dec. 31, 2008, the following credit facilities and related borrowings existed:

Credit Facilities

	Mar. 31, 2009			***Dec. 31, 2008***		
(millions)	**Credit Facilities**	**Borrowings Outstanding (1)**	**Letters of Credit Outstanding**	**Credit Facilities**	**Borrowings Outstanding (1)**	**Letters of Credit Outstanding**
Tampa Electric Company:						
5-year facility	$ 325.0	$	$ 1.4	$ 325.0	$	$ 1.4
1-year accounts receivable facility	150.0	96.0		150.0	29.0	
Total	$ 475.0	$ 96.0	$ 1.4	$ 475.0	$ 29.0	$ 1.4

(1) Borrowings outstanding are reported as notes payable.

These credit facilities require commitment fees ranging from 9.0 to 125.0 basis points. The weighted-average interest rate on outstanding amounts payable under the credit facilities at Mar. 31, 2009 and Dec. 31, 2008 was 1.25% and 2.13%, respectively.

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7. Commitments and Contingencies

Legal Contingencies

From time to time Tampa Electric Company and its subsidiaries are involved in various legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies in the ordinary course of its business. Where appropriate, accruals are made in accordance with FAS No. 5, *Accounting for Contingencies*, to provide for matters that are probable of resulting in an estimable, material loss. While the outcome of such proceedings is uncertain, management does not believe that their ultimate resolution will have a material adverse effect on the company s results of operations or financial condition.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party (PRP) for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Mar. 31, 2009, Tampa Electric Company has estimated its ultimate financial liability to be approximately $10.4 million, and this amount has been accrued in the company s financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

The estimated amounts represent only the estimated portion of the cleanup costs attributable to Tampa Electric Company. The estimates to perform the work are based on actual estimates obtained from contractors, or Tampa Electric Company s experience with similar work adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

Allocation of the responsibility for remediation costs among Tampa Electric Company and other PRPs is based on each party s relative ownership interest in or usage of a site. Accordingly, Tampa Electric Company s share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered creditworthy.

Factors that could impact these estimates include the ability of other PRPs to pay their pro-rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves and changes in laws or regulations that could require additional remediation. These costs are recoverable through customer rates established in subsequent base rate proceedings.

Guarantees and Letters of Credit

At Mar. 31, 2009, Tampa Electric Company was not obligated under guarantees, but had $1.4 million of letters of credit outstanding.

Letters of Credit -Tampa Electric Company

(millions)

Letters of Credit for the Benefit of:	*2009*	*2010-2013*	*After [(1)] 2013*	*Total*	*Liabilities Recognized at Mar. 31, 2009*
Tampa Electric					
Letters of credit	$	$	$ 1.4	$ 1.4	$
Total	$	$	$ 1.4	$ 1.4	$

(1) These renew annually and are shown on the basis that they will continue to renew beyond 2013.

At Mar. 31, 2009, TECO Energy had provided a $20.0 million fuel purchase guarantee and a $0.3 million letter of credit on behalf of Tampa Electric Company.

Financial Covenants

In order to utilize its bank credit facilities, Tampa Electric Company must meet certain financial tests as defined in the applicable agreements. In addition, Tampa Electric Company has certain restrictive covenants in specific agreements and debt instruments. At Mar. 31, 2009, Tampa Electric Company was in compliance with applicable financial covenants.

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8. Segment Information

(millions)

Three months ended Mar. 31,	*Tampa Electric*	*Peoples Gas*	*Other & Eliminations*	*Tampa Electric Company*
2009				
Revenues - external	$ 507.3	$ 146.5	$	$ 653.8
Sales to affiliates	0.3	6.5	(6.6)	0.2
Total revenues	507.6	153.0	(6.6)	654.0
Depreciation	48.0	10.8		58.8
Total interest charges	28.2	4.7		32.9
Provision for taxes	9.4	7.2		16.6
Net income	$ 18.3	$ 11.2	$	$ 29.5
2008				
Revenues - external	$ 461.2	$ 179.0	$	$ 640.2
Sales to affiliates	0.3		(0.1)	0.2
Total revenues	461.5	179.0	(0.1)	640.4
Depreciation	45.2	10.3		55.5
Total interest charges	29.4	4.2	(0.1)	33.5
Provision for taxes	8.5	6.4		14.9
Net income	$ 15.9	$ 10.0	$	$ 25.9
Total assets at Mar. 31, 2009	$ 5,398.9	$ 818.3	$ (8.2)	$ 6,209.0
Total assets at Dec. 31, 2008	$ 5,294.7	$ 823.4	$ (9.5)	$ 6,108.6

9. Accounting for Derivative Instruments and Hedging Activities

From time to time, Tampa Electric Company enters into futures, forwards, swaps and option contracts for the following purposes:

To limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations; and

To limit the exposure to interest rate fluctuations on debt securities

Tampa Electric Company uses derivatives only to reduce normal operating and market risks, not for speculative purposes. Tampa Electric Company s primary objective in using derivative instruments for regulated operations is to reduce the impact of market price volatility on ratepayers.

The risk management policies adopted by Tampa Electric Company provide a framework through which management monitors various risk exposures. Daily and periodic reporting of positions and other relevant metrics are performed by a centralized risk management group which is independent of all operating companies.

Tampa Electric Company applies the provisions of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by SFAS 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activity,* SFAS 149, *Amendment on Statement 133 on Derivative Instruments and Hedging Activities*, and SFAS 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment* *of FASB Statement No. 133* (FAS 161). These standards require companies to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as either components of other comprehensive income (OCI) or in net income, depending on the designation of those instruments. The changes in fair value that are recorded in OCI are not immediately recognized in current net income. As the underlying hedged transaction matures or the physical commodity is delivered, the deferred gain or loss on the related hedging instrument must be reclassified from OCI to earnings based on its value at the time of the instrument s settlement. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the market change of the amount paid or received on the underlying physical transaction.

FAS 161 became effective for financial statements issued for fiscal years and interim periods beginning after Nov. 15, 2008. FAS 161 requires enhanced disclosures about a company s derivative activities and how the related hedged items affect a company s financial position, financial performance and cash flows. To meet the objectives, FAS 161 requires qualitative disclosures about the company s fair value amounts of gains and losses associated with derivative instruments, as well as disclosures about credit-risk-related contingent features in derivative agreements. Tampa Electric Company adopted FAS 161 effective Jan. 1, 2009.

Tampa Electric Company applies FAS 71 for financial instruments used to hedge the purchase of natural gas for the regulated companies. The provisions of FAS 71, in accordance with the FPSC, permit the changes in fair value of natural gas derivatives to be recorded as regulatory assets or liabilities to reflect the impact of hedging activities on the fuel recovery clause. As a result, these changes are not recorded in OCI (See **Note 3**).

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A company s physical contracts qualify for the normal purchase/normal sale (NPNS) exception to derivative accounting rules, provided they meet certain criteria. Generally, NPNS applies if the company deems the counterparty creditworthy, if the counterparty owns or controls resources within the proximity to allow for physical delivery of the commodity, if the company intends to receive physical delivery and if the transaction is reasonable in relation to the company s business needs. As of Mar. 31, 2009, all of Tampa Electric Company s physical contracts qualify for the NPNS exception.

The following table presents the derivative hedges of natural gas contracts at Mar. 31, 2009 and Dec. 31, 2008 to limit the exposure to changes in the market price for natural gas used to produce energy and natural gas purchased for resale to customers:

	Natural Gas Derivatives	
(millions)	***Mar. 31, 2009***	***Dec. 31, 2008***
Current assets	$	$
Long-term assets	0.3	0.1
Total assets	$ 0.3	$ 0.1
Current liabilities(1)	$ 154.2	$ 120.1
Long-term liabilities	17.9	14.8
Total liabilities	$ 172.1	$ 134.9

-

(1) Amounts presented above are on a gross basis, with asset and liability positions netted by counterparty in accordance with FIN 39, *Offsetting of Amounts Related to Certain Contracts.* The Consolidated Condensed Balance Sheet as of Dec. 31, 2008 reflects posted collateral of $0.7 million permitted by FSP FIN 39-1, *Amendment of FASB Interpretation No. 39*.

The ending balance in accumulated other comprehensive income (AOCI) related to previously settled interest rate swaps at Mar. 31, 2009 is a net loss of $6.6 million after tax and accumulated amortization. This compares to a net loss of $6.8 million in AOCI after tax and accumulated amortization at Dec. 31, 2008.

The following table presents the effect of energy related derivatives on the fuel recovery clause mechanism in the balance sheet as of Mar. 31, 2009:

(millions)	**Asset Derivatives**		**Liability Derivatives**	
at Mar. 31, 2009	**Balance Sheet Location(1)**	**Fair Value**	**Balance Sheet Location(1)**	**Fair Value**
Commodity Contracts:				
Natural gas derivatives:				
Current	Regulatory liabilities	$	Regulatory assets	$ 154.2
Long-term	Regulatory liabilities	0.3	Regulatory assets	17.9
Total		$ 0.3		$ 172.1

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(1)

Natural gas derivatives are deferred in accordance with FAS 71 and all increases and decreases in the cost of natural gas supply are passed on to customers with the fuel recovery clause mechanism. As gains and losses are realized in future periods, they will be recorded as fuel costs in the Statements of Income.

Based on the fair value of the instruments at Mar. 31, 2009, net pretax losses of $154.2 million are expected to be reclassified from regulatory assets to the Consolidated Statements of Income within the next twelve months.

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The following table presents the effect of hedging instruments on OCI and income for the quarter ended Mar. 31, 2009:

(millions)	Amount of Gain/(Loss) on Derivatives Recognized in OCI	Location of Gain/(Loss) Reclassified From AOCI Into Income	Amount of Gain/(Loss) Reclassified From AOCI Into Income	Location of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income
Derivatives in SFAS No. 133 Cash Flow Hedging Relationships	Effective Portion[1]	Effective Portion		Ineffective Portion and Amount Excluded from Effectiveness Testing	
Interest rate contracts:	$	Interest expense	$ (0.2)	Interest expense	$
Total	$		$ (0.2)		$

1) Changes in OCI are reported in after-tax dollars.

For derivative instruments that meet cash flow hedge criteria, the effective portion of the gain or loss on the derivative is reported as a component of OCI and reclassified into earnings in the same period or period during which the hedged transaction affects earnings. Gains and losses on the derivatives representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings. For the three months ended Mar. 31, 2009, all hedges were effective.

The maximum length of time over which the company is hedging its exposure to the variability in future cash flows extends to 2011 for the financial natural gas contracts. The following table presents the company s derivative volumes by commodity type that are expected to settle each year at Mar. 31, 2009:

(millions)	Natural Gas Contracts (MMBTUs)	
Year	**Physical**	**Financial**
2009		37.3
2010		14.1
2011		2.2
Total		53.6

Tampa Electric Company is exposed to credit risk primarily through entering into derivative instruments with counterparties to limit its exposure to the commodity price fluctuations associated with natural gas. Credit risk is the potential loss resulting from a counterparty s nonperformance under an agreement. The company manages credit risk with policies and procedures for, among other things, counterparty analysis, exposure measurement, and exposure monitoring and exposure mitigation.

It is possible that volatility in commodity prices could cause the company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the company could suffer a material financial loss. However, as of Mar. 31, 2009, approximately 99.9% of the counterparties with transaction amounts outstanding in the company s energy portfolio are rated investment grade by the major rating agencies while the remaining 0.1% are either rated below investment grade or are not rated by rating agencies. Tampa Electric Company assesses credit risk internally for counterparties that are not rated.

Tampa Electric Company has entered into commodity master arrangements with its counterparties to mitigate credit exposure to those counterparties. The company generally enters into the following master arrangements: (1) Edison Electric Institute agreements (EEI) - standardized power sales contracts in the electric industry; (2) International Swaps and Derivatives Association agreements (ISDA) - standardized financial gas and electric contracts; and (3) North American Energy Standards Board agreements (NAESB) - standardized physical gas contracts. Tampa Electric Company believes that entering into such agreements reduces the risk from default by creating contractual rights relating to creditworthiness, collateral and termination.

Tampa Electric Company has implemented procedures to monitor the creditworthiness of our counterparties and to consider nonperformance in valuing counterparty positions. Tampa Electric Company monitors counterparties credit standing, including those that are experiencing financial problems, have significant swings in credit default swap rates, have credit rating changes by external rating agencies, or have changes in ownership. Net liability positions are generally not adjusted as Tampa Electric Company uses derivative transactions as hedges and has the ability and intent to perform under each of these contracts. In the instance of net asset positions, Tampa Electric Company considers general market conditions and the observable

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financial health and outlook of specific counterparties, forward looking data such as credit default swaps, when available, and historical default probabilities from credit rating agencies in evaluating the potential impact of nonperformance risk to derivative positions.

Certain of Tampa Electric Company s derivative instruments contain provisions that require Tampa Electric Company s debt to maintain an investment grade credit rating from any or all of the major credit rating agencies. If debt ratings were to fall below investment grade, it could trigger these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. Tampa Electric Company has no other contingent risk features associated with any derivative instruments.

The table below presents the fair value of the overall contractual contingent liability positions for Tampa Electric Company s derivative activity at Mar. 31, 2009:

(millions)

At Mar. 31, 2009

Contingent Feature	**Fair Value Asset/(Liability)**	**Derivative Exposure Asset/(Liability)**	**Posted Collateral**
Credit Rating	$ (171.8)	$ (171.8)	$
Total	$ (171.8)	$ (171.8)	$

10. Fair Value Measurements

Determination of Fair Value

Tampa Electric Company measures fair value using the procedures set forth below for all assets and liabilities measured at fair value that were previously carried at fair value pursuant to other accounting guidelines.

When available, Tampa Electric Company uses quoted market prices on assets and liabilities traded on an exchange to determine fair value and classifies such items as Level 1. In some cases where a market exchange price is available, but the assets and liabilities are traded in a secondary market, the company makes use of acceptable practical expedients to calculate fair value, and classifies such items as Level 2.

If observable transactions and other market data are not available, fair value is based upon internally developed models that use, when available, current market-based or independently-sourced market parameters such as interest rates, currency rates or option volatilities. Items valued using internally generated models are classified according to the lowest level input or value driver that is most significant to the valuation. Thus, an item may be classified in Level 3 even though there may be significant inputs that are readily observable.

Items Measured at Fair Value on a Recurring Basis

The following table sets forth by level within the fair value hierarchy the company s financial assets and liabilities that were accounted for at fair value on a recurring basis as of Mar. 31, 2009. As required by FAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. For all assets and liabilities presented below the market approach was used in determining fair value.

Recurring Derivative Fair Value Measures

At fair value as of Mar. 31, 2009

(millions)	*Level 1*	*Level 2*	*Level 3*	*Total*
Assets				
Natural gas swaps	$	$ 0.3	$	$ 0.3
Total	$	$ 0.3	$	$ 0.3
Liabilities				
Natural gas swaps	$	$ 172.1	$	$ 172.1
Total	$	$ 172.1	$	$ 172.1

Natural gas swaps are over-the-counter swap instruments. The primary pricing inputs in determining the fair value of natural gas swaps are the New York Mercantile Exchange (NYMEX) quoted closing prices of exchange-traded instruments. These prices are applied to the notional amounts of active positions to determine the reported fair value.

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Tampa Electric Company considered the impact of nonperformance risk in determining the fair value of derivatives. Tampa Electric Company considered the net position with each counterparty, past performance of both parties and the intent of the parties, indications of credit deterioration and whether the markets in which we transact have experienced dislocation. At Mar. 31, 2009, the fair value of derivatives was not materially affected by nonperformance risk. Tampa Electric Company s net positions with substantially all counterparties were liability positions.

11. Other Comprehensive Income

Other Comprehensive Income (millions)	***Three months ended Mar. 31, Gross***	***Tax***	***Net***
2009			
Unrealized gain (loss) on cash flow hedges	$	$	$
Add: Loss reclassified to net income	0.3	(0.1)	0.2
Gain on cash flow hedges	0.3	(0.1)	0.2
Total other comprehensive income	$ 0.3	$ (0.1)	$ 0.2
2008			
Unrealized loss on cash flow hedges	$ (8.1)	$ 3.1	$ (5.0)
Less: Loss reclassified to net income			$
Loss on cash flow hedges	(8.1)	3.1	(5.0)
Total other comprehensive loss	$ (8.1)	$ 3.1	$ (5.0)

Accumulated Other Comprehensive Loss

(millions)	***Mar. 31, 2009***	***Dec. 31, 2008***
Net unrealized losses from cash flow hedges [1]	$ (6.6)	$ (6.8)
Total accumulated other comprehensive loss	$ (6.6)	$ (6.8)

(1) Net of tax benefit of $4.2 million and $4.3 million as of Mar. 31, 2009 and Dec. 31, 2008, respectively.

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Item 2. MANAGEMENT S DISCUSSION & ANALYSIS OF FINANCIAL CONDITION & RESULTS OF OPERATIONS

This Management s Discussion and Analysis contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. Actual results may differ materially from those forecasted. The forecasted results are based on the company s current expectations and assumptions, and the company does not undertake to update that information or any other information contained in this Form 10-Q, except as may be required by law. Factors that could impact actual results include: regulatory actions by federal, state or local authorities, including the decision by the Florida Public Service Commission regarding new base rates at Peoples Gas System scheduled for May; unexpected capital needs or unanticipated reductions in cash flow that affect liquidity; access to capital and credit markets when required in the current unsettled economic conditions; the availability of adequate rail transportation capacity for the shipment of TECO Coal s production; general economic conditions affecting energy sales at the utility companies; economic conditions, both national and international, affecting the Florida economy and demand for TECO Coal s production; weather variations and changes in customer energy usage patterns affecting sales and operating costs at Tampa Electric and Peoples Gas and the effect of extreme weather conditions or hurricanes; operating conditions, commodity price and operating cost changes affecting the production levels and margins at TECO Coal, fuel cost recoveries and cash at Tampa Electric and natural gas demand at Peoples Gas; the ability of TECO Energy s subsidiaries to operate equipment without undue accidents, breakdowns or failures; the ability to increase the amount of power generated by the San Josè Power Station during a period of lower oil prices; and the ultimate outcome of efforts to revise the significantly lower EEGSA VAD tariff rates implemented by regulatory authorities in Guatemala effective Aug. 1, 2008 affecting TECO Guatemala s results. Additional information is contained under Risk Factors in TECO Energy, Inc. s Annual Report on Form 10-K for the period ended Dec. 31, 2008.

Earnings Summary - Unaudited

(millions, except per share amounts)	*Three months ended Mar. 31, 2009*	*2008*
Consolidated revenues	$ 824.0	$ 791.7
Net income from continuing operations	34.7	30.8
Net income	$ 34.7	$ 30.8
Average common shares outstanding		
Basic	211.4	209.7
Diluted	212.2	210.6
Earnings per share - basic		
Continuing operations	$ 0.16	$ 0.15
Earnings per share - basic	$ 0.16	$ 0.15
Earnings per share - diluted		
Continuing operations	$ 0.16	$ 0.15
Earnings per share - diluted	$ 0.16	$ 0.15

Operating Results

Three Months Ended Mar. 31, 2009:

TECO Energy, Inc. reported first-quarter net income of $34.7 million or $0.16 per share, compared to $30.8 million, or $0.15 per share, in the first quarter of 2008. First-quarter 2009 net income included an $8.7 million net gain on the sale of TECO Guatemala s 16.5% interest in the Central American fiber optic telecommunications provider Navega, and a $3.6 million valuation adjustment to student loan securities held at TECO Energy parent. First-quarter 2008 net income included a $0.6 million charge for adjustments to previously estimated costs associated with the sale of TECO Transport.

Operating Company Results

All amounts included in the operating company and Other and Eliminations discussions are after-tax, unless otherwise noted.

Tampa Electric Company Electric division (Tampa Electric)

Tampa Electric reported net income for the first quarter of $18.3 million, compared with $15.9 million for the same period in 2008. Results for the quarter reflected slightly higher retail energy sales, a 0.2% lower average number of customers, and higher operations and maintenance expenses. Net income included $3.3 million of Allowance for Funds Used During Construction (AFUDC) - equity, which represents allowed equity cost capitalized to construction costs, related to the installation of nitrogen oxide pollution control equipment and combustion turbines for peak loads, compared with $1.3 million in the 2008 period. Sales to other utilities declined 23% from the 2008 period, reflecting lower demand and lower natural gas prices.

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In the first quarter of 2009, there was no reduction in net income due to the waterborne transportation disallowance for the transporation of solid fuel, compared to a $1.6 million reduction in the 2008 period. In November 2008, the Florida Public Service Commission (FPSC)-approved Tampa Electric s fuel adjustment filing, which included full recovery of waterborne transportation costs under new contracts effective Jan. 1, 2009. This approval eliminates the annual reduction in net income that occurred in 2004 through 2008 during the previous transportation contract.

Total retail energy sales increased 0.1%, driven primarily by higher sales to weather-sensitive residential customers partially offset by lower sales to commercial and non-phosphate industrial customers. Sales to the residential customer segment increased 6.2% in the first quarter primarily due to colder winter weather patterns. Total degree days in Tampa Electric s service area were 3% above normal and 14% above the first quarter 2008. Pretax base revenues increased $4.8 million in the quarter primarily due to the colder winter weather; other operating income was essentially unchanged from the 2008 period, as higher earnings on the new selective catalytic reduction equipment through the environmental cost recovery clause and increased by-product sales were offset primarily by lower off-system sales of electricity.

Operations and maintenance expense, excluding all FPSC-approved cost recovery clauses, increased $2.9 million. The increase included $0.8 million related to maintenance on power generating equipment, $0.3 million higher bad-debt expense, $1.0 million of higher employee benefit related costs, primarily pension, and $0.6 million higher distribution system maintenance expense.

Compared to the first quarter of 2008, depreciation expense increased $1.7 million, reflecting additions to facilities to serve customers. Interest expense at Tampa Electric decreased slightly due to lower interest on tax-exempt debt remarketed in March 2008, which more than offset the impact of higher long-term debt balances outstanding, and interest income decreased due to lower under-recovered fuel balances on which interest is accrued.

On Mar. 17, 2009 the FPSC made a final determination of the revenue requirements in Tampa Electric s base revenue increase filing. The total annual revenue increase in 2010 is approximately $138 million, consisting of two components. The first component is the 2009 annual base revenue increase of approximately $104 million, with new rates effective May 7, 2009. Tampa Electric will benefit from almost eight months of the new base rates in 2009, with a full-year benefit in 2010. The second component is a step increase effective in January 2010 of approximately $34 million to reflect the revenue requirements associated with combustion turbines to serve peak load requirements and rail unloading facilities to provide bimodal fuel delivery capability that are currently under construction and expected to be in service by year-end 2009. This second step increase is subject to two conditions: 1) the facilities being in service by year-end 2009, and 2) a prudence review as to whether the combustion turbines are required to serve customer load.

The revenue requirements for 2009 and 2010 reflect a mid-point return on equity (ROE) of 11.25%. The allowed equity in the capital structure is 53.94% from all financial sources of capital (and 46.04% including other regulatory sources of capital such as deferred taxes and customer deposits) on an allowed rate base of $3.4 billion. The allowed ROE also applies to other regulatory calculations such as AFUDC and the allowed return on investments recovered through the Environmental Cost Recovery Clause.

As part of its base rate increase Tampa Electric also requested modifications to its cost of service methodology and rate design, which were also approved by the FPSC. Based on the approved 2009 revenue requirements the FPSC voted on Apr. 7, 2009 to approve the resulting base rates and service charges, effective May 7, 2009. The new base rates and service charges will remain in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties.

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A summary of Tampa Electric s operating statistics for the three months ended Mar. 31, 2009 and 2008 follows:

	Operating Revenues			Kilowatt-hour sales		
(millions, except average customers)	*2009*	*2008*	*% Change*	*2009*	*2008*	*% Change*
Three months ended Mar. 31,						
By Customer Type						
Residential	$ 251.0	$ 207.0	21.3	1,887.7	1,778.1	6.2
Commercial	166.3	147.5	12.7	1,399.9	1,468.0	(4.6)
Industrial Phosphate	21.0	16.6	26.5	246.8	244.7	0.9
Industrial Other	29.3	27.3	7.3	272.2	305.8	(11.0)
Other sales of electricity	50.0	42.6	17.4	414.5	418.6	(1.0)
Deferred and other revenues [1]	(32.5)	(7.3)	345.2			
	485.1	433.7	11.9	4,221.1	4,215.2	0.1
Sales for resale	12.1	16.0	(24.4)	145.5	189.1	(23.1)
Other operating revenue	10.4	10.8	(3.7)			
SO_2 Allowance sales		1.0	(100.0)			
	$ 507.6	$ 461.5	10.0	4,366.6	4,404.3	(0.9)
Average customers (thousands)	667.3	668.9	(0.2)			
Retail output to line (kilowatt hours)				4,362.6	4,357.7	0.1

(1) Primarily reflects the timing of environmental and fuel clause recoveries.

Tampa Electric Company Natural gas division (PGS)

Peoples Gas reported net income of $11.2 million for the first quarter, compared to $10.0 million in the same period in 2008. Quarterly results reflect a 0.2% lower average number of customers, increased sales to residential and commercial customers due to colder winter weather, and higher base rates due to an interim rate increase of $2.4 million (annual) granted in October 2008. Gas transported for power generation customers increased over the first quarter of 2008, when volumes were reduced due to mild weather and the use of other fuels for power generation. Non-fuel operations and maintenance expense increased, primarily due to higher spending on pipeline integrity inspections partially offset by lower medical claims costs. Results also reflect higher depreciation expense due to routine plant additions.

A summary of PGS regulated operating statistics for the three months ended Mar. 31, 2009 and 2008 follows:

Tampa Electric Company Natural gas division (PGS)

	Operating Revenues			Therms		
(millions, except average customers)	*2009*	*2008*	*% Change*	*2009*	*2008*	*% Change*
Three months ended Mar. 31,						
By Customer Type						
Residential	$ 59.4	$ 48.8	21.7	33.1	27.8	19.1
Commercial	47.2	44.3	6.5	110.1	107.0	2.9
Industrial	2.2	2.2		46.9	46.7	0.4
Off system sales	26.4	68.6	(61.5)	51.0	78.6	(35.1)
Power generation	2.7	3.4	(20.6)	108.1	106.7	1.3
Other revenues	13.0	9.8	32.7			
Total	$ 150.9	$ 177.1	(14.8)	349.2	366.8	(4.8)

By Sales Type						
System supply	$ 113.7	$ 142.7	(20.3)	102.2	123.9	(17.5)
Transportation	24.2	24.6	(1.6)	247.0	242.9	1.7
Other revenues	13.0	9.8	32.7			
Total	$ 150.9	$ 177.1	(14.8)	349.2	366.8	(4.8)
Average customers (thousands)	335.6	336.1	(0.2)			

TECO Coal

TECO Coal achieved first-quarter net income of $8.0 million, compared to $7.5 million in the same period in 2008. In 2008, net income included a $0.6 million after-tax benefit reflecting the final adjustment to the 2007 inflation factor applied to the tax credit available on the production of synthetic fuel. Due to tax depletion differences between periods, in the first quarter of 2009, TECO Coal s effective income tax rate was 14% compared to 20% in the 2008 period. TECO Coal s normal effective tax rate is expected to be about 25% annually.

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Total sales were 2.3 million tons in the 2009 first quarter, compared with 2.4 million tons in the 2008 period and reflected a sales mix more heavily weighted to lower-margin steam coal due to the timing of metallurgical coal shipments. Average net selling prices, excluding all transportation allowances, in the first quarter of 2009 increased 22% over the average net selling prices in the first quarter of 2008 due to the benefit of contracts signed in the favorable 2008 price environment. The average selling price increase was restrained in the first quarter due to carry-over tons from 2008 at lower contract prices. In the first quarter of 2009, the fully-loaded per-ton cost of production, which includes depreciation, depletion, amortization, interest expense, taxes other than income and general and administrative expense, at $66 per ton, was 23% higher than in the first quarter of 2008, driven by higher costs for petroleum-related products hedged in 2008, higher royalties related to higher selling prices and higher labor costs.

For the past several years, the issuance of permits by the U.S. Army Corp of Engineers (USACE) under Section 404 of the Clean Water Act required for surface mining activities in the Central and Northern Appalachian mining regions has been challenged in the courts. These challenges have been appealed by various mining companies affected on a number of occasions, but very few permits have been issued over the past several years. In March 2009, the U.S. Environmental Protection Agency (EPA) announced that it would further review new permits to be issued by the USACE. The impact of additional reviews by EPA is uncertain. To date, TECO Coal has had one permit for one new mine delayed by the ongoing court challenges to new permits; however, a portion of TECO Coal s planned 2009 production, approximately 3%, is based on the expectation that it will receive a new surface mine permit in a timely manner. In the event that the permit is not received as anticipated, TECO Coal expects to meet contract requirements through production from other facilities or through purchased coal.

TECO Guatemala

TECO Guatemala reported first-quarter net income of $13.2 million in 2009, compared to $10.5 million in the 2008 period. TECO Guatemala s first quarter net income included the $8.7 million gain on the sale of Navega. The 2009 results reflect $2.0 million of lower net income from the distribution utility, Empresa Eléctrica de Guatemala (EEGSA), as a result of the reduction in the value added distribution tariff (VAD) in August 2008, which was partially offset by customer and energy sales growth. The 2009 results also reflect significantly lower contract and spot energy sales by the San Jose Power Station due to unplanned outages for most of the first quarter as a result of turbine and generator problems.

In Guatemala, the electricity rates for regulated end-users consist of several components, including the costs associated with electricity generation and transmission, as well as the VAD. The VAD serves as the principal source of income for the Guatemalan electricity distribution companies such as EEGSA and is recalculated through regulatory proceedings every five years. In accordance with established regulatory procedures, EEGSA submitted its proposal for the VAD reset to the National Electric Energy Commission (CNEE) on Mar. 31, 2008. CNEE and EEGSA were unable to agree on the VAD reset and a Technical Committee was formed to settle the disagreement over the VAD. Rejecting the report of the Technical Committee, the CNEE ordered the dissolution of the Technical Committee and then issued resolutions establishing new tariff schedules for end-users which came into force on Aug. 1, 2008. The new tariff rates imposed by CNEE deviated significantly from the rates calculated in accordance with the Technical Committee s ruling and are, on average, approximately 50% lower than the VAD rates that were in force during the 2003-2008 tariff period. The new lower VAD set by CNEE essentially puts all of EEGSA s earnings at risk during the time this tariff remains in effect. TECO Guatemala s share of EEGSA s net income had previously averaged about $10 million annually.

As a result of these actions, on Jan. 13, 2009, our subsidiary, TECO Guatemala Holdings, LLC, (TGH) delivered a Notice of Intent to the Guatemalan government indicating its intent to file an arbitration claim against the Republic of Guatemala under the Dominican Republic-Central America-United States Free Trade Agreement (DR-CAFTA). A Notice of Intent is the first step in the process of filing an arbitration claim under the DR-CAFTA. A claimant must wait at least 90 days after the Notice of Intent before submitting a claim to arbitration. EEGSA continues to seek to resolve the VAD issue with the Guatemalan regulators; however an arbitration filing under DR-CAFTA by TECO Guatemala remains an option.

In the normal course of business, TECO Guatemala evaluated its $150.3 million investment in DECA II, including associated goodwill at Dec. 31, 2008 and determined that the value was not impaired. However, the outcome of the ongoing efforts and a potential arbitration under a DR-CAFTA claim is uncertain, and could impact this determination in the future.

An uncertainty has emerged with respect to TECO Guatemala s extension of its power purchase agreement (PPA) with EEGSA for the Alborada Power Station. The original 15-year term of the PPA expires in September 2010. In 2001, the owner of the Alborada Power Station paid for and secured an option to extend the term of the PPA for five years (the Option). At that time, the CNEE expressly authorized the pass-through of all costs under the extension of the PPA to EEGSA s regulated customer base. Most recently, the same entity issued a letter to EEGSA denying the pass-through of any costs under an extension of the PPA, citing electricity regulations adopted in 2007. EEGSA has initiated an appeal of CNEE s position on this matter and TECO Guatemala continues to evaluate the situation considering potential political and legal action to protect the interests of the owner of the Alborada Power Station.

Other and Eliminations

The cost for Parent/other in the first quarter was $16.0 million compared to a cost of $13.1 million in the 2008 period. Included in first quarter 2009 Parent/other cost was the $3.6 million valuation adjustment on student-loan securities held at TECO Energy parent. In 2008, the cost for Parent/other in the first quarter included the $0.6 million of after-tax adjustment to previously estimated transaction costs related to the sale of TECO Transport.

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Income Taxes

The provisions for income taxes from continuing operations for the three month periods ended Mar. 31, 2009 and Mar. 31, 2008 were $17.8 million and $13.1 million, respectively. The provision for income taxes from continuing operations in the three months ended Mar. 31, 2009 was impacted by TECO Guatemala s sale of its 16.5% interest in Navega.

Liquidity and Capital Resources

The table below sets forth the Mar. 31, 2009 consolidated liquidity and cash balances, the cash balances at the operating companies and TECO Energy parent, and amounts available under the TECO Energy/TECO Finance and Tampa Electric Company credit facilities.

	Balances as of Mar. 31, 2009			
(millions)	*Consolidated*	*Tampa Electric Company*	*Other*	*Parent*
Credit facilities	$ 675.0	$ 475.0	$	$ 200.0
Drawn amounts / LCs	144.5	97.4		47.1
Available credit facilities	530.5	377.6		152.9
Cash and short-term investments	34.9	9.3	8.3	17.3
Total liquidity	$ 565.4	$ 386.9	$ 8.3	$ 170.2

Consolidated other cash and short-term investments includes $8.2 million of cash at the unregulated operating companies for normal operations. In addition to consolidated cash, as of Mar. 31, 2009, unconsolidated affiliates owned by TECO Guatemala, CGESJ (San José) and TCAE (Alborada) had unrestricted cash balances of $29.0 million, which are not included in the table above. As a result of the sale of Navega, $29.0 million of cash was repatriated to TECO Energy in the first quarter.

In general, we target to maintain consolidated liquidity (unrestricted cash on hand plus undrawn credit facilities) of at least $500 million. As shown in the preceding table, at Mar. 31, 2009 our consolidated liquidity was $565 million, consisting of $387 million at Tampa Electric Company, $170 million at TECO Energy parent and $8 million at the other consolidated operating companies.

We expect our sources of cash in 2009 to include the expected collection of under-recovered fuel balances from 2008, supplemented by an expected issuance of long-term debt by Tampa Electric Company. We plan to use cash in 2009 for capital spending and for dividends to shareholders. We have no significant debt maturities in 2009.

Tampa Electric Company expects to access the debt capital markets in 2009 for long-term debt to support its capital spending program, and expects to utilize its credit facilities for normal working capital fluctuations.

Covenants in Financing Agreements

In order to utilize their respective bank credit facilities, TECO Energy, TECO Finance and Tampa Electric Company must meet certain financial tests as defined in the applicable agreements. In addition, TECO Energy, TECO Finance, Tampa Electric Company and other operating companies have certain restrictive covenants in specific agreements and debt instruments. TECO Energy, TECO Finance, Tampa Electric Company and the other operating companies are in compliance with all applicable financial covenants. The table that follows lists the covenants and the performance relative to them at Mar. 31, 2009. Reference is made to the specific agreements and instruments for more details.

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Significant Financial Covenants

(millions, unless otherwise indicated)

Instrument	*Financial Covenant [1]*	*Requirement/Restriction*	*Calculation at Mar. 31, 2009*
Tampa Electric Company			
PGS senior notes	EBIT/interest [2]	Minimum of 2.0 times	3.0 times
	Restricted payments	Shareholder equity at least $500	$2,074
	Funded debt/capital	Cannot exceed 65%	49.4%
	Sale of assets	Less than 20% of total assets	0%
Credit facility [3]	Debt/capital	Cannot exceed 65%	49.1%
Accounts receivable credit facility [3]	Debt/capital	Cannot exceed 65%	49.1%
6.25% senior notes	Debt/capital	Cannot exceed 60%	49.1%
	Limit on liens [5]	Cannot exceed $700	$0 liens outstanding
Insurance agreements relating to certain pollution bonds	Limit on liens [5]	Cannot exceed $416 (7.5% of net assets)	$0 liens outstanding
TECO Energy/TECO Finance			
Credit facility [3]	Debt/EBITDA [2]	Cannot exceed 5.0 times	4.4 times
	EBITDA/interest [2]	Minimum of 2.6 times	3.6 times
	Limit on additional indebtedness	Cannot exceed $1,087	$0
	Dividend restriction [4]	Cannot exceed $51 per quarter	$43
TECO Energy 7.5% notes	Limit on liens [5][7]	Cannot exceed $283 (5% of tangible assets)	$0 liens outstanding
TECO Energy floating rate and 6.75% notes and TECO Finance 6.75% notes	Restrictions on secured debt [7]	[6]	[6]
TECO Diversified			
Coal supply agreement guarantee	Dividend restriction	Net worth not less than $305 (40% of tangible net assets)	$536

(1) As defined in each applicable instrument.
(2) EBIT generally represents earnings before interest and taxes. EBITDA generally represents EBIT before depreciation and amortization. However, in each circumstance, the term is subject to the definition prescribed under the relevant agreements.
(3) See description of credit facilities in **Note 6** to Amendment No. 1 to the 2008 TECO Energy, Inc. Annual Report on Form 10-K.
(4) TECO Energy cannot declare quarterly dividends in excess of the restricted amount unless liquidity projections demonstrating sufficient cash or cash equivalents to make each of the next three quarterly dividend payments are delivered to the Administrative Agent.
(5) If the limitation on liens is exceeded, the company is required to provide ratable security to the holders of these notes.
(6) The indentures for these notes contain restrictions which limit secured debt of TECO Energy if secured by Principal Property or Capital Stock or indebtedness of directly held subsidiaries (with exceptions as defined in the indentures) without equally and ratably securing these notes.
(7) These limitations would not include first mortgage bonds of Tampa Electric Company if any were outstanding.

Credit Ratings of Senior Unsecured Debt at Mar. 31, 2009

	Standard & Poor s	*Moody s*	*Fitch*
Tampa Electric Company	BBB-	Baa2	BBB+
TECO Energy/TECO Finance	BB+	Baa3	BBB-

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Off-Balance Sheet Financing

Unconsolidated affiliates have project debt balances as follows at Mar. 31, 2009. TECO Energy has no debt payment obligations with respect to these financings. Although the company is not directly obligated on the debt, the equity interest in those unconsolidated affiliates is at risk if those projects are not operated successfully.

(millions)	*Long-term Debt*	*Ownership Interest*
San José Power Station	$ 61.3	100%
Alborada Power Station	$ 4.3	96%
DECA II	$ 185.9	30%

2009 Outlook

TECO Energy expects 2009 earnings per share, excluding all charges and gains, to be in a range between $1.00 and $1.15.

Tampa Electric expects higher net income, driven by the $104 million of annual higher base rates approved by the FPSC which will become effective in early May. Assuming normal weather and an economic recovery starting in late 2009, retail sales, which are being affected by the weak Florida economy and housing markets are expected to grow approximately 0.3%, and customer growth is expected to be about 0.1%. The current forecast for energy sales and customer growth is significantly below prior forecasts. Tampa Electric will be seeking to control capital and operations and maintenance expenditures driven by its current slower customer and energy sales growth while reliably serving customers in a cost effective manner and earning within the return on equity range recently set by the FPSC. Results in 2009 will not be impacted by the waterborne transportation disallowance, which had reduced net income approximately $10 million annually in 2004 through 2008. In November 2008, the FPSC approved Tampa Electric s fuel adjustment filing, which included full recovery of waterborne transportation costs under new contracts effective Jan. 1, 2009.

Peoples Gas System 2009 results will also be driven by the FPSC s final decision in its request for a base rate increase, which is scheduled for May 5th. Due to its state-wide service area and the more severe housing market downturn in some of the areas served by Peoples Gas the average number of customers and therm sales are expected to decline in 2009 in the current weak economy and housing markets.

TECO Coal expects higher earnings in 2009 from higher average selling prices from contracts signed in the more favorable 2008 market. TECO Coal has 9.5 million tons of its expected 2009 sales under contract at an average price of approximately $73 per ton, excluding all transportation allowances. The previous sales forecast was a range between 9.9 million and 10.3 million tons. Some metallurgical coal customers in Europe and North America, and some steam coal customers, have indicated that 2009 purchases will be below previously forecast levels due to the sharp decline in the world-wide steel industry and generally weak economic conditions. As a result, current expectations are for 2009 sales to be about 9.9 million tons, but this number is dependent on coal market conditions for the remainder of the year. The fully loaded cost of production, which includes depreciation, depletion, amortization, interest expense, royalties, taxes other than income and general and administrative expense is expected to be in a range between $63 and $66 per ton. The higher costs are expected to be driven by higher average diesel fuel costs, which were hedged primarily in the third quarter of 2008, higher labor costs, and higher royalties, which are based on selling price.

TECO Guatemala expects lower earnings in 2009 due to the current unplanned outages at the San José Power Station, the lower VAD at EEGSA, the loss of earnings from Navega, which was sold in March, and lower interest income on lower cash balances due to the repatriation of cash from TECO Guatemala in December. In addition, the $3.1 million benefit related to an adjustment to previously estimated 2007 income and year-end equity balances at EEGSA that occurred in 2008 will not recur in 2009. Shortly after the San José Power Station s return to service in early March, later in the month it experienced a second equipment failure, which is expected to keep the unit out of service into July. EEGSA continues to experience customer and energy sales growth, and has taken steps to control costs in order to mitigate the impact of the VAD reduction; however, these factors will only partially offset the lower VAD related revenues. EEGSA continues to seek to resolve the VAD issue with the Guatemalan regulators; however an arbitration filing under DR-CAFTA remains an option.

2010 Factors

In 2010, Tampa Electric and Peoples Gas System will have the benefit of a full year of higher base rates, and Tampa Electric expects to fulfill the requirements to have the second step base rate increase of $34 million effective Jan. 1st. Assuming an economic recovery starts in late 2009, Tampa Electric expects customer growth of almost 0.6% and energy sales growth slightly below that level. Peoples Gas does not expect customer growth to resume until 2011.

TECO Coal currently has approximately 5.2 million tons of its expected 2010 production under contract, which is predominately steam coal, at average prices similar to 2009 levels. The cost of production is expected to be stable based on expectations of a more stable labor market and the potential for stable to lower commodity input prices. Diesel fuel for contracted 2010 tons has been hedged at levels below 2009 prices.

TECO Guatemala expects higher results from improved performance of the San José Power Station, assuming no unplanned outages, and continued customer growth at EEGSA. TECO Guatemala s outlook for 2010 makes no assumption that the VAD issue at EEGSA is resolved in 2009. TECO Energy Parent/other expects to benefit from lower interest expense after retiring the $100 million of floating rate notes at maturity in May 2010.

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Fair Value Measurements

Effective Jan. 1, 2008, the company adopted SFAS No. 157, *Fair Value Measurements* (FAS 157). FAS 157 defines fair value, establishes a framework for measuring fair value under generally accepted accounting principles, and expands disclosures about financial assets and liabilities carried at fair value. The majority of the company s financial assets and liabilities are in the form of natural gas, heating oil and interest rate derivatives classified as cash flow hedges and auction rate securities. The implementation of FAS 157 did not have a material impact on our results of operations, liquidity or capital.

All natural gas derivatives were entered into by the regulated utilities to manage the impact of natural gas prices on customers. As a result of applying the provisions of FAS 71, the changes in value of natural gas derivatives of Tampa Electric and PGS are recorded as regulatory assets or liabilities to reflect the impact of the risks of hedging activities in the fuel recovery clause. Because the amounts are deferred and ultimately collected through the fuel clause, the unrealized gains and losses associated with the valuation of these assets and liabilities do not impact our results of operations.

Heating oil hedges are used to mitigate the fluctuations in the price of diesel fuel which is a significant component in the cost of coal production at TECO Coal and its subsidiaries.

Other investments reflect two auction rate securities backed by pools of student loans, with a combined par value of $15.0 million and a fair value of $9.2 million. As a result of market conditions, an impairment was previously recorded in other comprehensive income as the company originally viewed the impairment to be temporary. Based on the protracted disruption of the market for these securities and the uncertain potential for their recovery, the company no longer expects to hold the securities indefinitely to recover the original value, and a $5.8 million pretax charge ($3.6 million after tax) was recorded to the income statement in Other Income for the 3-month period ended Mar. 31, 2009.

The valuation methods we used to determine fair value are described in **Note 13** to the **TECO Energy, Inc. Consolidated Condensed Financial Statements**. In addition, the company considered the impact of nonperformance risk in determining the fair value of derivatives. The company considered the net position with each counterparty, past performance of both parties and the intent of the parties, indications of credit deterioration, and whether the markets in which we transact have experienced dislocation. At Mar. 31, 2009 the fair value of derivatives was not materially affected by nonperformance risk. Our net positions with substantially all counterparties were liability positions.

Critical Accounting Policies and Estimates

Our critical accounting policies relate to deferred income taxes, employee postretirement benefits, long-lived assets and regulatory accounting. For further discussion of our critical accounting policies, see our Annual Report on Form 10-K for the year ended Dec. 31, 2008.

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Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest Rate Risk

We are exposed to changes in interest rates primarily as a result of our borrowing activities. We may enter into futures, swaps and option contracts, in accordance with the approved risk management policies and procedures, to moderate this exposure to interest rate changes and achieve a desired level of fixed and variable rate debt.

In March 2008, Tampa Electric Company converted $191.8 million aggregate principal amount of tax-exempt bonds originally issued for its benefit in auction rate mode and remarketed them in long-term interest rate modes. In addition, Tampa Electric purchased in lieu of redemption $95.0 million aggregate value of tax-exempt bonds previously in auction rate mode and held such bonds at Mar. 31, 2009, pending a determination of their disposition. The result of these transactions lowered our exposure to variable interest rate risk.

Commodity Risk

We face varying degrees of exposure to commodity risks including coal, natural gas, fuel oil and other energy commodity prices. Any changes in prices could affect the prices these businesses charge, their operating costs and the competitive position of their products and services, and affect the net fair value of derivatives. We assess and monitor risk using a variety of measurement tools based on the degree of exposure of each operating company to commodity risk. Our most significant commodity risk exposure for the remainder of 2009 is the potential effect of high natural gas prices on our cash flows. Prudently incurred costs for natural gas are recoverable through FPSC-approved cost recovery clauses, and therefore do not affect our earnings. However, higher than expected prices for natural gas can affect the timing of recovery and thus impact cash flows.

The change in fair value of derivatives is largely due to the decrease in the price of natural gas of about 40% from Dec. 31, 2008 to Mar. 31, 2009. For natural gas, the company maintains a similar volume hedged as of Mar. 31, 2009 from Dec. 31, 2008.

The following tables summarize the changes in and the fair value balances of derivative assets (liabilities) for the three months ended Mar. 31, 2009:

Changes in Fair Value of Derivatives *(millions)*

Net fair value of derivatives as of Dec. 31, 2008	$ (151.4)
Additions and net changes in unrealized fair value of derivatives	27.9
Changes in valuation techniques and assumptions	
Realized net settlement of derivatives	(67.6)
Net fair value of derivatives as of Mar. 31, 2009	(191.1)

Roll-Forward of Derivative Net Assets (Liabilities) *(millions)*

Total derivative net liabilities as of Dec. 31, 2008	$ (151.4)
Change in fair value of net derivative assets:	
Recorded as regulatory assets and liabilities or other comprehensive income	27.9
Recorded in earnings	
Realized net settlement of derivatives	(67.6)
Net option premium payments	
Net purchase (sale) of existing contracts	
Net fair value of derivatives as of Mar. 31, 2009	(191.1)

Below is a summary table of sources of fair value, by maturity period, for derivative contracts at Mar. 31, 2009:

Maturity and Source of Derivative Contracts Net Assets (Liabilities) at Mar. 31, 2009 *(millions)*

Contracts Maturing in	*Current*	*Non-current*	*Total Fair Value*
Source of fair value			
Actively quoted prices	$	$	$
Other external sources [1]	(168.9)	(22.2)	(191.1)
Model prices [2]			
Total	$ (168.9)	(22.2)	(191.1)

(1) Reflects over-the-counter natural gas or heating oil swaps for which the primary pricing inputs in determining fair value are NYMEX quoted closing prices of exchange traded instruments.

(2) Model prices are used for determining the fair value of energy derivatives where price quotes are infrequent or the market is illiquid. Significant inputs to the models are derived from market-observable data and actual historical experience.

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For all unrealized derivative contracts, the valuation is an estimate based on the best available information. Actual cash flows could be materially different from the estimated value upon maturity.

Item 4. CONTROLS AND PROCEDURES

TECO Energy, Inc.

(a) **Evaluation of Disclosure Controls and Procedures**. TECO Energy s management, with the participation of its principal executive officer and principal financial officer, has evaluated the effectiveness of TECO Energy s disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of the end of the period covered by this quarterly report (the Evaluation Date). Based on such evaluation, TECO Energy s principal financial officer and principal executive officer have concluded that, as of the Evaluation Date, TECO Energy s disclosure controls and procedures are effective.

(b) **Changes in Internal Controls**. There was no change in TECO Energy s internal control over financial reporting (as defined in Rules 13a 15(f) and 15d-15(f) under the Exchange Act) identified in connection with the evaluation of TECO Energy s internal controls that occurred during TECO Energy s last fiscal quarter that has materially affected, or is reasonably likely to materially affect, such controls.

Tampa Electric Company

(a) **Evaluation of Disclosure Controls and Procedures**. Tampa Electric Company s management, with the participation of its principal executive officer and principal financial officer, has evaluated the effectiveness of Tampa Electric Company s disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the Evaluation Date. Based on such evaluation, Tampa Electric Company s principal financial officer and principal executive officer have concluded that, as of the Evaluation Date, Tampa Electric Company s disclosure controls and procedures are effective.

(b) **Changes in Internal Controls**. There was no change in Tampa Electric Company s internal control over financial reporting (as defined in Rules 13a 15(f) and 15d-15(f) under the Exchange Act) identified in connection with the evaluation of Tampa Electric Company s internal controls that occurred during Tampa Electric Company s last fiscal quarter that has materially affected, or is reasonably likely to materially affect, such controls.

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PART II. OTHER INFORMATION

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table shows the number of shares of TECO Energy common stock deemed to have been repurchased by TECO Energy.

	(a) Total Number of Shares (or Units) Purchased [(1)]	*(b) Average Price Paid per Share (or Unit)*	*(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs*	*(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs*
Jan. 1, 2009 Jan. 31, 2009	2,730	$ 11.99		
Feb. 1, 2009 Feb. 28, 2009	19,030	$ 9.69		
Mar. 1, 2009 Mar. 31, 2009	64,762	$ 10.58		
Total 1st Quarter 2009	86,522	$ 10.43		

(1) These shares were not repurchased through a publicly announced plan or program, but rather relate to compensation or retirement plans of the company. Specifically, these shares represent shares delivered in satisfaction of the exercise price and/or tax withholding obligations by holders of stock options who exercised options (granted under TECO Energy s incentive compensation plans), shares delivered or withheld (under the terms of grants under TECO Energy s incentive compensation plans) to offset tax withholding obligations associated with the vesting of restricted shares and shares purchased by the TECO Energy Group Retirement Savings Plan pursuant to directions from plan participants or dividend reinvestment.

Item 6. EXHIBITS

Exhibits - See index on page 54.

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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.

	TECO ENERGY, INC. (Registrant)
Date: May 1, 2009	By: /s/ G. L. GILLETTE G. L. GILLETTE Executive Vice President and Chief Financial Officer (Principal Financial Officer)
	TAMPA ELECTRIC COMPANY (Registrant)
Date: May 1, 2009	By: /s/ G. L. GILLETTE G. L. GILLETTE Senior Vice President - Finance and Chief Financial Officer (Principal Financial Officer)

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INDEX TO EXHIBITS

Exhibit No.	Description	
3.1	Articles of Incorporation of TECO Energy, Inc., as amended on Apr. 20, 1993 (Exhibit 3, Form 10-Q for the quarter ended Mar. 31, 1993 of TECO Energy, Inc.).	*
3.2	Bylaws of TECO Energy, Inc., as amended effective Apr. 29, 2009 (Exhibit 3.1, Form 8-K dated Feb. 4, 2009 of TECO Energy, Inc.).	*
3.3	Articles of Incorporation of Tampa Electric Company (Exhibit 3 to Registration Statement No. 2-70653 of Tampa Electric Company).	*
3.4	Bylaws of Tampa Electric Company, as amended effective Jan. 30, 2008 (Exhibit 3.4, Form 10-K for 2007 of TECO Energy, Inc. and Tampa Electric Company).	*
12.1	Ratio of Earnings to Fixed Charges TECO Energy, Inc.	
12.2	Ratio of Earnings to Fixed Charges Tampa Electric Company.	
31.1	Certification of the Chief Executive Officer of TECO Energy, Inc. pursuant to Securities Exchange Act Rules 13a-14(a) and 15d-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
31.2	Certification of the Chief Financial Officer of TECO Energy, Inc. pursuant to Securities Exchange Act Rules 13a-14(a) and 15d-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
31.3	Certification of the Chief Executive Officer of Tampa Electric Company pursuant to Securities Exchange Act Rules 13a-14(a) and 15d-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
31.4	Certification of the Chief Financial Officer of Tampa Electric Company pursuant to Securities Exchange Act Rules 13a-14(a) and 15d-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
32.1	Certification of the Chief Executive Officer and Chief Financial Officer of TECO Energy, Inc. pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (1)	
32.2	Certification of the Chief Executive Officer and Chief Financial Officer of Tampa Electric Company pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (1)	

(1) This certification accompanies the Quarterly Report on Form 10-Q and is not filed as part of it.