AUSLEY & MCMULLEN

ATTORNEYS AND COUNSELORS AT LAW

227 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

September 4, 2009

HAND DELIVERED

090439

Ms. Ann Cole, Director
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Application of Tampa Electric Company for authority to issue and sell securities pursuant to Section 366.04, Florida Statutes and Chapter 25-8, Florida Administrative Code.

Dear Ms. Cole:

Enclosed for filing in the above matter are the original and five (5) copies of Tampa Electric Company's Application for Authority to Issue and Sell Securities for the fiscal period of 12 months ending December 31, 2010.

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Enclosures

COM
ECR
GCL 1
OPC 1
RCP 3
SSC
SGA
ADM
CLK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Application of Tampa Electric Company for authority to issue and sell securities pursuant to Section 366.04, Florida Statutes and Chapter 25-8, Florida Administrative Code	))))))	DOCKET NO. ___________ Submitted for filing on September 4, 2009

TAMPA ELECTRIC COMPANY'S

APPLICATION FOR AUTHORITY TO ISSUE AND SELL SECURITIES

Tampa Electric Company ("the Company") files this, its Application under Section 366.04, Florida Statues and Rule 25-8.001, et seq., Florida Administrative Code, for authority to issue and/or sell securities for the Company's fiscal period of 12 months ending December 31, 2010, and says:

1. The exact name of the Company and the address of its principal business office are as follows: Tampa Electric Company, 702 North Franklin Street, Tampa, Florida, 33602.

2. The Company, a Florida corporation, was incorporated in 1899 and was reincorporated in 1949. The Company provides Commission-regulated retail electric services and natural gas distribution services through its Tampa Electric and Peoples Gas System divisions, respectively.

3. The names and addresses of persons authorized to receive notices and communications with respect to this Application are as follows:

Lee L. Willis James D. Beasley Ausley & McMullen P. O. Box 391 Tallahassee, FL 32302 (850) 224-9115	Paula K. Brown Administrator, Regulatory Coordination Tampa Electric Company P. O. Box 111 Tampa, FL 33601 (813) 228-1752

4. As of June 30, 2009, the date of the balance sheet submitted with this Application, the following information is shown for each class and series of capital stock and funded debt:

(a) Brief description	(b) Amount authorized (face value and number of shares)	(c) Amount outstanding (exclusive of any amount held in the treasury)	(d) Amount held as reacquired securities	(e) Pledged by applicant	(f) Amount owned by affiliated corporations	(g) Amount held in any fund
Common Stock	25,000,000 shares without par value	10 shares	None	None	10 shares	None
Preferred Stock	2,500,000 shares with no par value, 1,500,000 shares with $100 par value per share	None	None	None	None	None
Preference Stock - Subordinated Preferred Stock	2,500,000 shares with no par value	None	None	None	None	None
Funded Debt:						
Tampa Electric division						
Installment Contracts Payable:						
5.15% Series, due 2025	$51,600,000	$51,600,000	None	None	None	None
5.65% Series, due 2018	54,200,000	54,200,000	None	None	None	None
Variable Interest Series, due 2020	20,000,000	None	20,000,000	None	None	None
5% Series, due 2034	85,950,000	85,950,000	None	None	None	None
Variable Interest Series, due 2030	75,000,000	None	75,000,000	None	None	None
5.1 % Term Bonds, due 2013	60,685,000	60,685,000	None	None	None	None
5.5 % Term Bonds, due 2023	86,400,000	86,400,000	None	None	None	None
Unsecured Notes:						
6.875% Series, due 2012	210,000,000	210,000,000	None	None	None	None
6.10% Series, due 2018	100,000,000	100,000,000	None	None	None	None
6.375% Series, due 2012	330,000,000	330,000,000	None	None	None	None
6.25% Series, due 2016	250,000,000	250,000,000	None	None	None	None
6.55% Series, due 2036	250,000,000	250,000,000	None	None	None	None
6.15% Series, due 2037	190,000,000	190,000,000	None	None	None	None
Peoples Gas System division						
Senior Notes:						
10.30% Series, due 2009	1,800,000	1,800,000	None	None	None	None
9.93% Series, due 2010	2,000,000	2,000,000	None	None	None	None
8.00% Series, due 2012	12,200,000	12,200,000	None	None	None	None
Unsecured Notes:						
6.875% Series, due 2012	40,000,000	40,000,000	None	None	None	None
6.375% Series, due 2012	70,000,000	70,000,000	None	None	None	None
6.100% Series, due 2018	50,000,000	50,000,000	None	None	None	None
6.15% Series, due 2037	60,000,000	60,000,000	None	None	None	None
Total Funded Debt	$1,999,835,000	$1,904,835,000	$95,000,000			

5. <u>Statement of Proposed Transactions</u>

(a) The Company seeks the authority to issue, sell and/or exchange equity securities and issue, sell, exchange and/or assume long-term or short-term debt securities and/or to assume liabilities or obligations as guarantor, endorser or surety during the period covered by this Application. The Company also seeks authority to enter into interest rate swaps or other derivative instruments related to debt securities. Any exercise of the requested authority will be for the benefit of the Company. At no time will the Company borrow funds, incur debt or assume liabilities or obligations as guarantor, endorser or surety that are not for the benefit of either or both of the Company's electric and gas divisions.

The equity securities may take the form of preferred stock, preference stock, common stock, or options or rights with respect to the foregoing with such par values, terms and conditions, conversion and relative rights and preferences as may be permitted by the Company's Restated Articles of Incorporation, as the same may be amended to permit the issuance of any such securities. The long-term debt securities may take the form of first mortgage bonds, debentures, notes, bank borrowings, convertible securities, installment contracts and/or other obligations underlying pollution control or sewage and solid waste disposal revenue bonds or options, rights, interest rate swaps or other derivative instruments with respect to the foregoing, with maturities ranging from one to 100 years, and may be issued in both domestic and international markets.

The issuance and/or sale of equity securities and long-term debt requested may be through negotiated underwritten public offering, public offering at competitive bidding, direct public or private sale, sale through agents, or distribution to security holders of the Company or affiliated companies.

The short-term debt may take the form of commercial paper, short-term tax-exempt notes, borrowings under bank credit facilities or accounts receivable securitization credit facilities, or other bank borrowings. Short-term debt sold in the commercial paper market may bear an interest rate as determined by the market price at the date of issuance and will mature not more than one year from the date of issuance.

(b) The amount of all equity and long-term debt securities issued, sold, exchanged or assumed and liabilities and obligations assumed or guaranteed as guarantor, endorser, or surety will not exceed in the aggregate $950 million during the period covered by this Application, including any amounts issued to retire existing long-term debt securities. The maximum amount of short-term debt, as described above, outstanding at any one time, will be $900 million.

(c) With respect to equity and long-term debt securities and liabilities and obligations to be assumed or guaranteed as grantor, endorser or surety, the amount of $200 million is needed to accommodate the potential issuance of additional notes based on projected short-term debt levels; the amount of $200 million is needed for potential long-term emergency funding; and the amount of $550 million is needed for other purposes (swaps, refinancings, etc.). With respect to short-term debt, the amount of up to $700 million outstanding is needed to enable the Company to fully draw existing short-term credit facilities including upsize capability; and the balance of up to $200 million is needed to avail the Company of short-term emergency funding and other purposes.

(d) The present estimates of the interest rates for the aforementioned debt securities, based upon current trading levels of unsecured short-term debt and 10-year notes of the Company are

0.80% and 5.30%, respectively. Actual dividend rates for the aforementioned equity securities and interest rates will be determined at the time of the issuance and/or sale of the applicable securities.

6. Purpose of Issuance

Proceeds from any sale of securities will be added to the Company's general funds and used for working capital requirements and for other general business purposes, including financing of the Company's capital investments or the acquisition of additional properties or businesses. The net proceeds received from the sale of securities may also be used for the repurchase or repayment of debt or equity securities of the Company.

(a) Construction

The electric division of the Company currently estimates that construction expenditures during the 12 months ending December 31, 2010 will be $301 million. Estimates for specific, larger-scale, non-recurring investments for 2010 include:

Projects	(Millions) Amount
Big Bend SCR	$16
Transmission & Distribution	18
Polk Water Project	11
	$45

The gas division of the Company currently estimates that construction expenditures during the 12 months ending December 31, 2010 will be $50 million for maintenance and system expansion.

(b) Reimbursement of the Treasury

Among the general business purposes for which any net proceeds may be used is the reimbursement of the treasury for expenditures by the Company against which securities will not have been issued in advance.

(c) Refunding Obligations

One of the purposes of issuing the securities referred to herein will be to repay previously issued short-term debt, of the type described in paragraph 5, which matures from time to time on a regular basis. Subject to market conditions, the Company may refund such short-term debt with new short-term debt, long-term debt or preferred or preference stock.

In addition, the Company is continuing to monitor and evaluate market conditions in anticipation of refunding or refinancing long-term obligations where it is legally and economically feasible to do so. Recognizing that changes in market conditions could make such refunding transactions feasible, the Company is requesting authority to issue long-term debt and/or preferred or preference stock within a limitation that provides the Company with sufficient flexibility to respond to refunding or refinancing opportunities.

7. The Company submits that the proposed issuance and sale of securities is for lawful objectives within the corporate purposes of the Company, is necessary for the proper performance by the two divisions of the Company as public utilities, is compatible with the public interest and is reasonable, necessary and appropriate. In support thereof the Company states that the proposed issuance and sale of securities and the proposed application of funds derived therefrom, as

described in paragraphs 5 and 6 above, are consistent with similar actions the Company in the past has found to be lawful, reasonable, necessary and appropriate for the conduct of its business. The Company further states that this application for authority to issue and sell securities is consistent in its objectives with those of applications the Company has filed, and this Commission has found to be lawful, reasonable, necessary and appropriate, on numerous occasions in the past.

8. The names and addresses of counsel who will pass upon the legality of the proposed issuances are: Charles A. Attal, III, General Counsel, Tampa Electric Company, Tampa, Florida; David E. Schwartz, Associate General Counsel, Tampa Electric Company, Tampa, Florida; Holland & Knight LLP, Tampa, Florida; and/or Edwards Angell Palmer & Dodge LLP, Boston, Massachusetts and/or such other counsel as the Company may deem necessary in connection with any of the proposed issuances.

9. A Registration Statement with respect to each public offering of securities hereunder that is subject to and not exempt from the registration requirements of the Securities Act of 1933, as amended, will be filed with the Securities and Exchange Commission, 100 F St. N.E., Washington, D.C. 20549.

10. There is no measure of control or ownership exercised by or over the Company as to any other public utility except as noted below.

On April 14, 1981, the Company's shareholders approved a restructuring plan under which the Company and its subsidiaries became separate wholly owned subsidiaries of a holding company, TECO Energy, Inc.

Required Exhibits

1. The following exhibits required by Rule 25-8.003, Florida Administrative Code, are either attached hereto or incorporated by reference herein and made a part hereof:

   (a) Exhibit A: Items 1 through 5 are being satisfied through the provision of financial statements identified in Item 6 below.

   6. (i) Attached as Exhibit A-1 (Form 10-K)
      (ii) Attached as Exhibit A-2 (Most Recent Quarter's Form 10-Q)

   (b) Exhibit B: Projected Financial Information (Sources and Uses of Funds Statements and Construction Budgets)

WHEREFORE, Tampa Electric Company respectfully requests that the Commission enter its Order approving the Company's request for authority to issue and sell securities during the 12 month period ending December 31, 2010.

DATED this 4th day of September, 2009

TAMPA ELECTRIC COMPANY

By: J. Denise Jordan
J. Denise Jordan
Managing Director, Regulatory Affairs
702 North Franklin Street
Tampa, Florida 33602
Post Office Box 111
Tampa, Florida 33601

TAMPA ELECTRIC COMPANY'S
APPLICATION FOR AUTHORITY TO ISSUE AND SELL SECURITIES

INDEX TO EXHIBITS

Exhibit A-1

AS AMENDED

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

FORM 10-K

_X_ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2008

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.** (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	**59-2052286**
1-5007	**TAMPA ELECTRIC COMPANY** (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	**59-0475140**

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 if TECO Energy, Inc. is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
YES [X] NO [ ]

Indicate by check mark if Tampa Electric Company is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
YES [ ] NO [X]

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.
YES [ ] NO [X]

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

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 Act).
YES [ ] NO [X]

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

The aggregate market value of TECO Energy, Inc.'s common stock held by non-affiliates of the registrant as of June 30, 2008 was $4,571,687,786 based on the closing sale price as reported on the New York Stock Exchange.

The aggregate market value of Tampa Electric Company's common stock held by non-affiliates of the registrant as of June 30, 2008 was zero.

The number of shares of TECO Energy, Inc.'s common stock outstanding as of Feb. 23, 2009 was 212,928,549. As of Feb. 23, 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.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement relating to the 2009 Annual Meeting of Shareholders of TECO Energy, Inc. are incorporated by reference into Part III.

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

This combined Form 10-K 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. Tampa Electric Company makes no representations as to the information relating to TECO Energy, Inc.'s other operations.

Cover page of 186
Index to Exhibits begins on page 183

PART I

Item 1. BUSINESS.

TECO ENERGY

TECO Energy, Inc. (TECO Energy) was incorporated in Florida in 1981 as part of a restructuring in which it became the parent corporation of Tampa Electric Company. TECO Energy and its subsidiaries had approximately 4,400 employees as of Dec. 31, 2008.

TECO Energy's Corporate Governance Guidelines, the charter of each committee of the Board of Directors, and the code of ethics applicable to all directors, officers and employees, *the Standards of Integrity*, are available on the Investors section of TECO Energy's website, www.tecoenergy.com, or in print free of charge to any investor who requests the information. TECO Energy also makes its Securities and Exchange Commission (SEC) (www.sec.gov) filings available free of charge on the Investors section of TECO Energy's website as soon as reasonably practicable after they are filed with or furnished to the SEC.

TECO Energy is a holding company for regulated utilities and other businesses. TECO Energy currently owns no operating assets but holds all of the common stock of Tampa Electric Company, and through its subsidiary TECO Diversified, Inc., owns TECO Coal Corporation and through its subsidiary TECO Wholesale Generation, Inc., owns TECO Guatemala, Inc. Results for the year ended Dec. 31, 2007 include results from its former subsidiary, TECO Transport Corporation, through Dec. 3, 2007.

Unless otherwise indicated by the context, "TECO Energy" means the holding company, TECO Energy, Inc., and its subsidiaries, and references to individual subsidiaries of TECO Energy, Inc. refer to that company and its respective subsidiaries. TECO Energy's business segments, and revenues for those segments for the years indicated, are identified below.

Tampa Electric Company, a Florida corporation and TECO Energy's largest subsidiary, has two business segments. Its **Tampa Electric** division **(Tampa Electric)** provides retail electric service to more than 667,000 customers in West Central Florida with a net winter system generating capability of 4,477 megawatts (MW). **Peoples Gas System (PGS)**, the gas division of Tampa Electric Company, is engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in Florida. With more than 335,000 customers, PGS has operations in Florida's major metropolitan areas. Annual natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) in 2008 was 1.4 billion therms.

TECO Coal Corporation (TECO Coal), a Kentucky corporation, has 13 subsidiaries, located in Eastern Kentucky, Tennessee and Virginia. These entities own mineral rights, own or operate surface and underground mines and own interests in coal processing and loading facilities.

TECO Guatemala, Inc. (TECO Guatemala), a Florida corporation, primarily has investments in unconsolidated subsidiaries that participate in two long-term contracted power plants and has an ownership interest in Distribućion Eléctrica Centro Americana II, S.A. (DECA II), which has an ownership interest in Guatemala's largest distribution utility, Empresa Eléctrica de Guatemala, S.A. (EEGSA) and other affiliated energy-related companies.

TECO Transport Corporation (TECO Transport), a Florida corporation, was sold on Dec. 4, 2007. During 2007, it owned no operating assets but owned all of the common stock of, or membership interests in, nine subsidiaries which provided waterborne transportation, storage and transfer services of coal and other dry-bulk commodities.

Revenues from Continuing Operations

(millions)	*2008*	*2007*	*2006*
Tampa Electric	$ 2,091.2	$ 2,188.4	$ 2,084.9
PGS	688.4	599.7	577.6
Total regulated businesses	2,779.6	2,788.1	2,662.5
TECO Coal	588.4	544.5	574.9
TECO Guatemala [(1)]	8.4	8.0	7.6
TECO Transport	—	290.3	308.5
	3,376.4	3,630.9	3,553.5
Other and eliminations	(1.1)	(94.8)	(105.4)
Total revenues from continuing operations	$ 3,375.3	$ 3,536.1	$3,448.1

[(1)] Revenues are exclusive of entities deconsolidated as a result of Financial Accounting Standards Board Interpretation No. 46R, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51* (FIN 46R) and include only revenues for the consolidated Guatemalan entities.

For additional financial information regarding TECO Energy's significant business segments including geographic areas, see **Note 14** to the TECO Energy **Consolidated Financial Statements**. Also, see **Note 19** for additional information regarding the deconsolidation of Guatemala subsidiaries.

Discontinued Operations/Asset Dispositions

TECO Energy completed a number of asset dispositions in 2007 and 2006 as part of a business strategy to focus on the electric and gas utilities, eliminate exposure to the merchant power sector and retire parent debt.

In the fourth quarter of 2007, TECO Energy completed its sale of TECO Transport to an unaffiliated investment group. As a result of its continuing involvement via a water-borne transportation contract with Tampa Electric, all results through the date of sale were accounted for in continuing operations. In the second quarter of 2007, a favorable conclusion was reached with taxing authorities regarding the 2005 disposition of Union and Gila merchant power plants. This resulted in after-tax net income of $14.3 million reflected in discontinued operations.

In the first quarter of 2006, TPS McAdams, LLC (TPS McAdams), an indirect subsidiary of the company, sold combustion turbines to Tampa Electric and in the second quarter, all remaining assets of TPS McAdams were sold to a third party. Also, the company sold the remaining assets of TECO Thermal which were classified as held for sale as of Dec. 31, 2005. Two remaining unused steam turbines located in Arizona were sold in 2006.

TAMPA ELECTRIC – Electric Operations

Tampa Electric Company was incorporated in Florida in 1899 and was reincorporated in 1949. Tampa Electric Company is a public utility operating within the state of Florida. Its Tampa Electric division is engaged in the generation, purchase, transmission, distribution and sale of electric energy. The retail territory served comprises an area of about 2,000 square miles in West Central Florida, including Hillsborough County and parts of Polk, Pasco and Pinellas Counties, with an estimated population of over one million. The principal communities served are Tampa, Winter Haven, Plant City and Dade City. In addition, Tampa Electric engages in wholesale sales to utilities and other resellers of electricity. It has three electric generating stations in or near Tampa, one electric generating station in southwestern Polk County, Florida and one electric generating station located near Sebring, a city located in Highlands County in South Central Florida.

Tampa Electric had 2,535 employees as of Dec. 31, 2008, of which 919 were represented by the International Brotherhood of Electrical Workers and 205 were represented by the Office and Professional Employees International Union.

In 2008, approximately 47% of Tampa Electric's total operating revenue was derived from residential sales, 31% from commercial sales, 8% from industrial sales and 14% from other sales, including bulk power sales for resale. The sources of operating revenue and megawatt hour sales for the years indicated were as follows:

Operating Revenue

(millions)	*2008*	*2007*	*2006*
Residential	$ 981.7	$ 1,017.9	$ 956.7
Commercial	639.0	653.6	602.4
Industrial – Phosphate	66.1	73.0	61.5
Industrial – Other	111.2	118.2	113.0
Other retail sales of electricity	185.7	178.4	162.1
Total retail	1,983.7	2,041.1	1,895.7
Sales for resale	69.7	69.0	71.1
Other	37.8	78.3	118.1
Total operating revenues	$ 2,091.2	$ 2,188.4	$ 2,084.9

Megawatt-hour Sales

(millions)	*2008*	*2007*	*2006*
Residential	8,546	8,871	8,721
Commercial	6,399	6,542	6,357
Industrial	2,205	2,366	2,279
Other retail sales of electricity	1,840	1,754	1,668
Total retail	18,990	19,533	19,025
Sales for resale	884	905	862
Total energy sold	19,874	20,438	19,887

No significant part of Tampa Electric's business is dependent upon a single customer or a few customers, the loss of any one or more of whom would have a significant adverse effect on Tampa Electric. Tampa Electric's business is not highly seasonal, but winter peak loads are experienced due to electric space heating, fewer daylight hours and colder temperatures and summer peak loads are experienced due to the use of air conditioning and other cooling equipment.

Regulation

The retail operations of Tampa Electric are regulated by the Florida Public Service Commission (FPSC), which has jurisdiction over retail rates, quality of service and reliability, issuances of securities, planning, siting and construction of facilities, accounting and depreciation practices and other matters.

In general, the FPSC's pricing objective is to set rates at a level that allows the utility to collect total revenues (revenue requirements) equal to its cost of providing service, plus a reasonable return on invested capital.

The costs of owning, operating and maintaining the utility system, other than fuel, purchased power, conservation and certain environmental costs, are recovered through base rates. These costs include operation and maintenance expenses, depreciation and taxes, as well as a return on Tampa Electric's investment in assets used and useful in providing electric service (rate base). The rate of return on rate base, which is intended to approximate Tampa Electric's weighted cost of capital, primarily includes its costs for debt, deferred income taxes at a zero cost rate and an allowed return on common equity. Base rates are determined in FPSC rate setting hearings which occur at irregular intervals at the initiative of Tampa Electric, the FPSC or other parties.

Tampa Electric's rates and allowed return on equity (ROE) range of 10.75% to 12.75%, with a midpoint of 11.75%, are 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.

Prior to August 2008, Tampa Electric had not sought a base rate increase since 1992. Since that rate proceeding, it had earned within its allowed ROE range while adding more than 200,000 customers and making significant investments in facilities and infrastructure. These facilities include baseload, intermediate and peaking generating capacity additions to reliably serve the growing customer base. Tampa Electric expects a continued high level of capital investment, and higher levels of non-fuel operations and maintenance expenditures. As a result of lower customer growth, lower energy sales growth, and ongoing high levels of capital investment, Tampa Electric's 13-month average regulatory ROE was 8.7% at the end of 2008.

Recognizing the significant decline in ROE, Tampa Electric filed for a $228.2 million base rate increase in August 2008. The filing included a request for an ROE mid-point of 12%, 55.3% equity in the capital structure and rate base of $3.7 billion. The formal hearings before the FPSC were held in late January and the FPSC is scheduled to make its final decision on the requested increase in mid-March, with final rates effective in May 2009.

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, 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 cost recovery 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 include the cost for natural gas and coal expected in 2009, the net recovery of $132.9 million of fuel and purchased power expenses, which were not collected in 2008 and underestimated in 2007, the net over-recovery of $4.7 million of costs recovered through the Environmental Cost Recovery Clause (ECRC) for the 2007 and 2008 periods, and the operating cost for and a return on the capital invested in the third Selective Catalytic Reduction (SCR) project to enter service 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 (see the **Environmental Compliance** section of **Management's Discussion and Analysis (MD&A)**). The rates also reflect an additional disallowance of $1.9 million to settle all outstanding issues associated with the 2004 fuel transportation contract (see the **Tampa Electric** section and the **2008 Reconciliation of GAAP Net Income from Continuing Operations to non-GAAP Results**). 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. Accordingly, Tampa Electric's residential customer rate per 1,000 kilowatt-hours increased $14.06 from $114.38 in 2008 to $128.44 in 2009.

The FPSC determined 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 Unit 4 and Big Bend Units 1-3 in October 2004 and May 2005, respectively, for NO_x control in compliance with the environmental consent decree. The SCR for Big Bend Unit 4 entered service in May 2007 and cost recovery started in 2007. The SCR for Big Bend Unit 3 entered service in May 2008 and cost recovery started in 2008. The SCRs for Big Bend Units 2 and 1 are scheduled to enter service by May 1, 2009 and 2010, respectively. Cost recovery for the capital investment for each unit, which is dependent on filings made in the year each SCR enters service, is expected to start in 2009 and 2010, respectively.

Tampa Electric is also subject to regulation by the Federal Energy Regulatory Commission (FERC) in various respects, including wholesale power sales, certain wholesale power purchases, transmission services, and accounting and depreciation practices. In June 2006, Tampa Electric received a notice that FERC had commenced an audit, which arose out of the normal course of the enforcement activities, to determine whether and how Tampa Electric and its affiliates complied with: 1) the practices and procedures contained within its Open Access Transmission Tariff (OATT); 2) the conditions by which FERC granted market-based rate authority to each respective affiliate of Tampa Electric; 3) the Standards of Conduct requirements; 4) the preservation of records requirements; 5) Tampa Electric's wholesale fuel adjustment clause tariff; and 6) Tampa Electric's reporting of capacity and energy shortages. The audit was completed and the company's compliance plan filed in October 2007, addressing the recommendations made by FERC, was approved in January 2008. See also the **Regulation** section of **MD&A**.

The Energy Policy Act of 2005 repealed the Public Utility Holding Company Act of 1935 (PUHCA), which established a regulatory regime overseen by the SEC, and replaced it with a new statute focused on increased access to holding-company books and records to assist the FERC and state utility regulators in protecting customers of regulated utilities. On Dec. 8, 2005, the FERC finalized rules to implement the congressional mandated repeal of the PUHCA of 1935 and enactment of the PUHCA of 2005. FERC issued its final rules effective Feb. 8, 2006. Pursuant to this Act, TECO Energy has a single-state waiver regarding FERC's access to its holding-company books and records.

Federal, state and local environmental laws and regulations cover air quality, water quality, land use, power plant, substation and transmission line siting, noise and aesthetics, solid waste and other environmental matters (see **Environmental Matters** section below).

The transactions between Tampa Electric and its affiliates are subject to regulation by the FPSC and FERC, and any charges deemed to be imprudently incurred may be disallowed for recovery from Tampa Electric's customers. (For information about Tampa Electric's contract for coal transportation and dry-bulk storage services with TECO Transport, see the **Regulation – Coal Transportation Contract** section of **MD&A**.)

Competition

Tampa Electric's retail electric business is substantially free from direct competition with other electric utilities, municipalities and public agencies. At the present time, the principal form of competition at the retail level consists of self-generation available to larger users of electric energy. Such users may seek to expand their alternatives through various initiatives, including legislative and/or regulatory changes that would permit competition at the retail level. Tampa Electric intends to retain and expand its retail business by managing costs and providing high quality service to retail customers.

Presently there is competition in Florida's wholesale power markets, largely as a result of the Energy Policy Act of 1992 and related federal initiatives. However, the state's Power Plant Siting Act, which sets the state's electric energy and environmental policy and governs the building of new generation involving steam capacity of 75 megawatts or more, requires that applicants demonstrate that a plant is needed prior to receiving construction and operating permits.

In 2003, the FPSC modified rules from 1994 that required Investor Owned Utilities (IOUs) to issue Request for Proposals (RFPs) prior to filing a petition for Determination of Need for construction of a power plant with a steam cycle greater than 75 megawatts. The modified rules provide a mechanism for expedited dispute resolution, allow bidders to submit new bids whenever the IOU revises its cost estimates for its self-build option, require IOUs to disclose the methodology and criteria to be used to evaluate the bids, and provide more stringent standards for the IOUs to recover cost overruns in the event the self-build option is deemed the most cost-effective. These rules became effective prospectively for RFPs for applicable capacity additions.

Fuel

Approximately 60% of Tampa Electric's generation of electricity for 2008 was coal-fired, with natural gas representing approximately 40% and oil representing less than 1%. Tampa Electric used its generating units to meet approximately 85% of the total system load requirements, with the remaining 15% coming from purchased power. Tampa Electric's average delivered fuel cost per million British thermal unit (Btu) and average delivered cost per ton of coal burned, have been as follows:

Average cost per million Btu	*2008*	*2007*	*2006*	*2005*	*2004*
Coal	$ 2.91	$ 2.57	$ 2.49	$ 2.25	$ 2.14
Oil	$ 20.48	$ 13.87	$ 13.39	$ 10.16	$ 6.81
Gas (Natural)	$ 10.61	$ 9.52	$ 9.61	$ 9.37	$ 7.14
Composite	$ 5.56	$ 5.05	$ 4.75	$ 4.79	$ 3.64
Average cost per ton of coal burned	$ 69.14	$ 60.72	$ 58.75	$ 53.00	$ 50.06

Tampa Electric's generating stations burn fuels as follows: H.L. Culbreath Bayside Power Station burns natural gas; Big Bend Power Station, which has sulfur dioxide scrubber capabilities, burns a combination of high-sulfur coal, petroleum coke and No. 2 fuel oil; Polk Power Station burns a blend of high-sulfur coal, petroleum coke, which is gasified and subject to sulfur and particulate matter removal prior to combustion, natural gas and oil; and Phillips Station burns residual fuel oil.

Coal. Tampa Electric burned approximately 4.6 million tons of coal and petroleum coke during 2008 and estimates that its combined coal and petroleum coke consumption will be about 4.9 million tons for 2009. During 2008, Tampa Electric purchased approximately 59% of its coal under long-term contracts with five suppliers, and approximately 41% of its coal and petroleum coke in the spot market. Tampa Electric attempts to maintain a portfolio of 60% long-term versus 40% spot contracts, but market conditions, actual deliveries and unit performance can change this portfolio on a year-by-year basis. Tampa Electric expects to obtain approximately 57% of its coal and petroleum coke requirements in 2009 under long-term contracts with six suppliers and the remaining 43% in the spot market.

Tampa Electric's long-term contracts provide for revisions in the base price to reflect changes in several important cost factors and for suspension or reduction of deliveries if environmental regulations should prevent Tampa Electric from burning the coal supplied, provided that a good faith effort has been made to continue burning such coal.

In 2008, approximately 70% of Tampa Electric's coal supply was deep-mined, approximately 21% was surface-mined and the remaining was a processed oil by-product known as petroleum coke. Federal surface-mining laws and regulations have not had any material adverse impact on Tampa Electric's coal supply or results of its operations. Tampa Electric, however, cannot predict the effect of any future mining laws and regulations.

Natural Gas. As of Dec. 31, 2008, approximately 66% of Tampa Electric's 850,000 MMBtu gas storage capacity was full. Tampa Electric has issued an RFP and is currently contracting for 80% of the expected gas needs for the April 2009 through September 2009 period, 75% for October 2009, 55% for November 2009 through March 2010 and 30% for April 2010 through October 2010. Additional volume requirements in excess of gas needs are purchased on the short-term spot market.

Oil. Tampa Electric has agreements in place to purchase No. 2 oil, low sulfur No. 2 oil and No. 6 oil for its Big Bend, Polk and Phillips power stations. All of these agreements have prices that are based on spot indices.

Franchises and Other Rights

Tampa Electric holds franchises and other rights that, together with its charter powers, govern the placement of Tampa Electric's facilities on the public rights-of-way as it carries on its retail business in the localities it serves. The franchises specify the negotiated terms and conditions governing Tampa Electric's use of public rights-of-way and other public property within the municipalities it serves during the term of the franchise agreement, and are irrevocable and not subject to amendment without the consent of Tampa Electric (except to the extent certain city ordinances relating to permitting and like matters are modified from time to time), although, in certain events, they are subject to forfeiture.

Florida municipalities are prohibited from granting any franchise for a term exceeding 30 years. None of the municipalities that have franchise agreements with Tampa Electric, except for the cities of Oldsmar and Temple Terrace, have reserved the right to purchase Tampa Electric's property used in the exercise of its franchise if the franchise is not renewed. In the absence of such right to purchase, based on judicial precedent, if the franchise agreement is not renewed Tampa Electric would be able to continue to use public rights-of-way within the municipality, subject to reasonable rules and regulations imposed by the municipalities.

Tampa Electric has franchise agreements with 13 incorporated municipalities within its retail service area. These agreements have various expiration dates through March 2036.

Franchise fees payable by Tampa Electric, which totaled $36.3 million in 2008, are calculated using a formula based primarily on electric revenues and are collected on customers' bills.

Utility operations in Hillsborough, Pasco, Pinellas and Polk Counties outside of incorporated municipalities are conducted in each case under one or more permits to use state or county rights-of-way granted by the Florida Department of Transportation or the county commissioners of such counties. There is no law limiting the time for which such permits may be granted by counties. There are no fixed expiration dates for the Hillsborough County, Pinellas County and Polk County agreements. The agreement covering electric operations in Pasco County expires in 2023. A franchise agreement with the City of Tampa expired in September 2006, and a new 25-year agreement with the City of Tampa was signed in December 2008.

Environmental Matters

Among our companies, Tampa Electric has a number of significant stationary sources with air emissions impacted by the Clean Air Act and material Clean Water Act implications. Tampa Electric has undertaken major steps to dramatically reduce its air emissions through a series of voluntary actions, including technology selection (e.g., Integrated Gasification Combined-Cycle (IGCC) and conversion of coal-fired units to natural-gas fired combined cycle); implementing a responsible fuel mix taking into account price and reliability effects on its customers; a substantial capital expenditure program to add Best Available Control Technology (BACT) emissions controls; implementation of additional controls to accomplish earlier reductions of certain emissions allowing for lower emission rates when BACT was ultimately installed; and enhanced controls and monitoring systems for certain pollutants. All of these improvements represent an investment in excess of $2 billion since 1994.

Through these actions, Tampa Electric has achieved significant reductions of all air pollutants, including CO_2, while maintaining a reasonable fuel mix through the clean use of coal for the economic benefit of its customers.

Consent Decree

Tampa Electric, through voluntary negotiations with the EPA, the U.S. Department of Justice (DOJ) and the FDEP, signed a Consent Decree, which became effective Feb. 29, 2000, and a Consent Final Judgment, which became effective Dec. 6, 1999, as settlement of federal and state litigation. Pursuant to these agreements, allegations of violations of New Source Review requirements of the Clean Air Act were resolved, provision was made for environmental controls and pollution reductions, and Tampa Electric began implementing a comprehensive program to dramatically decrease emissions from its power plants.

The emission reduction requirements included specific detail with respect to the availability of flue gas desulfurization systems (scrubbers) to help reduce SO_2, projects for NO_x reduction on Big Bend Units 1 through 4, and the repowering of the coal-fired Gannon Power Station to natural gas, which was renamed the H. L. Culbreath Bayside Power Station (Bayside Power Station), in 2003 and 2004. The completed station has total station capacity of about 1,800 megawatts (nominal) of natural gas-fueled, combined-cycle electric generation. The repowering has reduced the facility's

NO_x and SO_2 emissions by approximately 99% and particulate matter (PM) emissions by approximately 92% from 1998 levels.

In 2004, Tampa Electric made its NO_x reduction technology selection and decided to install SCR systems for NO_x control on Big Bend Unit 4, which was completed in May 2007. Tampa Electric is installing SCR technology on the remaining Big Bend units. Unit 3 went in service in June 2008, and Units 1 and 2 are expected to be in service by May 1, 2009 and May 1, 2010, respectively. The engineering and design is complete and construction of the remaining SCR systems is currently in progress. Tampa Electric's capital investment forecast includes amounts in the 2009 and 2010 periods for compliance with the NO_x, SO_2 and PM reduction requirements (see the **Capital Expenditures** section of **MD&A**).

The FPSC has determined that it is appropriate for Tampa Electric to recover the operating costs of and earn a return on the investment in the SCRs to be installed on all four of the units at the Big Bend Power Station and pre-SCR projects on Big Bend Units 1–3 (which are early plant improvements to reduce NO_x emissions prior to installing the SCRs) through the Environmental Cost Recovery Clause (ECRC) (see the **Regulation** section). The first SCR (Big Bend Unit 4) entered service in May 2007 and cost recovery for the capital investment started in 2007. The second SCR unit (Big Bend 3) entered service in May 2008 and cost recovery started in 2008. In November 2008 the FPSC approved cost recovery for the capital investment on the Big Bend Unit 2 SCR to start in 2009.

In November 2007, Tampa Electric entered into an agreement with the EPA and DOJ for a Second Amendment to the Consent Decree. The Second Amendment: 1) establishes a 0.12 lb/MMBtu NO_x limit on a 30-day rolling average for Big Bend Units 1 through 3, which is lower than the original Consent Decree that had a provision for a limit as high as 0.15 lb/MMBtu depending on certain conditions; 2) allows for the sale of NO_x allowances gained as a result of surpassing the emission limit goals of the Consent Decree; and 3) calls for Tampa Electric to install a second PM Continuous Emissions Monitoring System and potentially replace the originally installed system if the new system is successful.

Emission Reductions

Projects committed to under the Consent Decree and Consent Final Judgment have resulted in significant reductions in emissions. Since 1998, Tampa Electric has reduced annual SO_2, NO_x and PM emissions from its facilities by 162,000 tons, 42,000 tons, and 4,000 tons, respectively.

Reductions in SO_2 emissions were accomplished through the installation of scrubber systems on Big Bend Units 1 and 2 in 1999. Big Bend Unit 4 was originally constructed with a scrubber. The Big Bend Unit 4 scrubber system was modified in 1994 to allow it to scrub emissions from Big Bend Unit 3 as well. Currently the scrubbers at Big Bend Power Station remove more than 95% of the SO_2 emissions from the flue gas streams.

The repowering of the Gannon Station to the Bayside Power Station has resulted in a significant reduction in emissions of all pollutant types. We expect that Tampa Electric's actions to install additional NO_x emissions controls on all Big Bend units will result in the further reduction of emissions and that by 2010, the SCR projects will result in a total phased reduction of NO_x by 62,000 tons per year from 1998 levels.

In total, we expect that Tampa Electric's emission reduction initiatives will result in the reduction of SO_2, NO_x and PM emissions by 90%, 90% and 72%, respectively, below 1998 levels by 2010. With these state-of-the-art improvements in place, Tampa Electric's activities have helped to significantly enhance the quality of the air in the community. As a result of already completed emission reduction actions, and upon completion of the SCR projects, we expect that Tampa Electric will have achieved emission reduction levels called for in Phase I of the Clean Air Interstate Rule (CAIR) upon implementation in 2009.

Due to pollution control benefits from the environmental improvements, reductions in mercury emissions have occurred due to the repowering of Gannon Station to Bayside Power Station. At Bayside Power Station, where mercury levels have decreased 99% below 1998 levels, there are virtually zero mercury emissions. Additional mercury reductions are also anticipated from the installation of NO_x controls at Big Bend Power Station, which are expected to lead to a reduction of mercury emissions of more than 70% from 1998 levels by 2010. The Clean Air Mercury Rule (CAMR) Phase I requirements were scheduled for implementation in 2010, however, on Feb. 8, 2008, CAMR was vacated by the U.S. Court of Appeals for the District of Columbia Circuit. Prior to the court's decision, Tampa Electric expected that it would have been in compliance with CAMR Phase I without additional capital investment.

In 2007 the EPA modified the 24-hour coarse and fine PM ambient air standards. Based on the reduced emissions of PM, sulfates and nitrates resulting from projects associated with compliance with the Consent Decree, as well as local ambient air quality data, the Tampa Electric service area is expected to be in compliance with the proposed new PM standards without additional expenditures by Tampa Electric. (See the **Environmental Compliance** section of **MD&A.**)

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 Dec. 31, 2008, Tampa Electric Company has estimated its ultimate financial liability to be approximately $10.7 million (primarily related to PGS), and this amount has been reflected 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 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 credit worthy.

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 or changes in laws or regulations that could require additional remediation. Under current regulation, these additional costs would be eligible for recovery through customer rates.

Capital Expenditures

For 2009, Tampa Electric expects to spend $55 million for the addition of SCR equipment at the Big Bend Power Station for NO_x control, and $10 million for other environmental compliance programs. Tampa Electric expects to spend $15 million for compliance with the Environmental Consent Decree for the remaining SCR equipment and $25 million for other required environmental capital expenditures in the 2010 through 2013 period.

PEOPLES GAS SYSTEM – Gas Operations

PGS operates as the Peoples Gas System division of Tampa Electric Company. PGS is engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in the State of Florida.

Gas is delivered to the PGS system through three interstate pipelines. PGS does not engage in the exploration for or production of natural gas. PGS operates a natural gas distribution system that serves more than 335,000 customers. The system includes approximately 11,000 miles of mains and 6,000 miles of service lines. (See PGS' **Franchises** section below.)

In 2008, the total throughput for PGS was 1.4 billion therms. Of this total throughput, 9% was gas purchased and resold to retail customers by PGS, 68% was third-party supplied gas that was delivered for retail transportation-only customers, and 23% was gas sold off-system. Industrial and power generation customers consumed approximately 68% of PGS' annual therm volume, commercial customers used approximately 26%, and the balance was consumed by residential customers.

While the residential market represents only a small percentage of total therm volume, residential operations generally comprise almost 22% of total revenues.

Natural gas has historically been used in many traditional industrial and commercial operations throughout Florida, including production of products such as steel, glass, ceramic tile and food products. Within the PGS operating territory, large cogeneration facilities utilize gas-fired technology in the production of electric power and steam.

Revenues and therms for PGS for the years ended Dec. 31, are as follows:

	Revenues			***Therms***		
(millions)	*2008*	*2007*	*2006*	*2008*	*2007*	*2006*
Residential	$ 150.5	$ 140.2	$ 146.0	74.4	70.1	73.0
Commercial	155.6	158.4	164.4	375.9	370.9	375.7
Industrial	325.7	242.4	204.2	513.3	490.2	456.6
Power generation	12.7	14.6	14.0	455.6	471.7	395.7
Other revenues	36.5	37.4	43.3	—	—	—
Total	$ 681.0	$ 593.0	$ 571.9	1,419.2	1,402.9	1,301.0

PGS had 578 employees as of Dec. 31, 2008. A total of 82 employees in six of PGS' 14 operating divisions are represented by various union organizations.

Regulation

The operations of PGS are regulated by the FPSC separately from the regulation of Tampa Electric. The FPSC has jurisdiction over rates, service, issuance of securities, safety, accounting and depreciation practices and other matters. In general, the FPSC sets rates at a level that allows a utility such as PGS to collect total revenues (revenue requirements) equal to its cost of providing service, plus a reasonable return on invested capital.

The basic costs of providing natural gas service, other than the costs of purchased gas and interstate pipeline capacity, are recovered through base rates. Base rates are designed to recover the costs of owning, operating and maintaining the utility system. The rate of return on rate base, which is intended to approximate PGS' weighted cost of capital, primarily includes its cost for debt, deferred income taxes at a zero cost rate, and an allowed return on common equity. Base rates are determined in FPSC proceedings which occur at irregular intervals at the initiative of PGS, the FPSC or other parties. For a description of recent proceeding activity, see the **Regulation – PGS Rates** section of **MD&A.**

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.

At the end of 2007, PGS' 13-month average regulatory ROE was below the bottom of its allowed range as a result of higher operating costs, continued investment in the distribution system and higher costs associated with required safety requirements, such as transmission and distribution pipeline integrity management.

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

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 its 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. The FPSC requires natural gas utilities to offer transportation-only service to all non-residential customers. As a result, PGS receives its base rate for distribution regardless of whether a customer decides to opt for transportation-only service or continue bundled service. As of Dec. 31, 2008, PGS had approximately 13,600 transportation-only customers out of 29,500 eligible customers.

In addition to economic regulation, PGS is subject to the FPSC's safety jurisdiction, pursuant to which the FPSC regulates the construction, operation and maintenance of PGS' distribution system. In general, the FPSC has implemented this by adopting the Minimum Federal Safety Standards and reporting requirements for pipeline facilities and transportation of gas prescribed by the U.S. Department of Transportation in Parts 191, 192 and 199, Title 49, Code of Federal Regulations.

PGS is also subject to federal, state and local environmental laws and regulations pertaining to air and water quality, land use, noise and aesthetics, solid waste and other environmental matters.

Competition

Although PGS is not in direct competition with any other regulated distributors of natural gas for customers within its service areas, there are other forms of competition. At the present time, the principal form of competition for residential and small commercial customers is from companies providing other sources of energy, including electricity, propane and fuel oil. PGS has taken actions to retain and expand its commodity and transportation business, including managing costs and providing high quality service to customers.

In Florida, gas service is unbundled for all non-residential customers. In 2000, PGS implemented its

"NaturalChoice" program, offering unbundled transportation service to all eligible customers and allowing non-residential customers to purchase commodity gas from a third party but continue to pay PGS for the transportation. As a result, PGS receives its base rate for distribution regardless of whether a customer decides to opt for transportation-only service or continue bundled service. PGS had approximately 13,600 transportation-only customers as of Dec. 31, 2008 out of approximately 29,500 eligible customers.

Competition is most prevalent in the large commercial and industrial markets. In recent years, these classes of customers have been targeted by companies seeking to sell gas directly by transporting gas through other facilities and thereby bypassing PGS facilities. In response to this competition, PGS has developed various programs, including the provision of transportation-only services at discounted rates.

Gas Supplies

PGS purchases gas from various suppliers depending on the needs of its customers. The gas is delivered to the PGS distribution system through three interstate pipelines on which PGS has reserved firm transportation capacity for delivery by PGS to its customers.

Gas is delivered by Florida Gas Transmission Company (FGT) through more than 59 interconnections (gate stations) serving PGS' operating divisions. In addition, PGS' Jacksonville Division receives gas delivered by the South Georgia Natural Gas Company pipeline through two gate stations located northwest of Jacksonville. Gulfstream Natural Gas Pipeline provides delivery through seven gate stations.

Companies with firm pipeline capacity receive priority in scheduling deliveries during times when the pipeline is operating at its maximum capacity. PGS presently holds sufficient firm capacity to permit it to meet the gas requirements of its system commodity customers, except during localized emergencies affecting the PGS distribution system and on abnormally cold days.

Firm transportation rights on an interstate pipeline represent a right to use the amount of the capacity reserved for transportation of gas on any given day. PGS pays reservation charges on the full amount of the reserved capacity whether or not it actually uses such capacity on any given day. When the capacity is actually used, PGS pays a volumetrically-based usage charge for the amount of the capacity actually used. The levels of the reservation and usage charges are regulated by FERC. PGS actively markets any excess capacity available on a day-to-day basis to partially offset costs recovered through the PGA clause.

PGS procures natural gas supplies using base-load and swing-supply contracts with various suppliers along with spot market purchases. Pricing generally takes the form of either a variable price based on published indices or a fixed price for the contract term.

Neither PGS nor any of the interconnected interstate pipelines have storage facilities in Florida. PGS occasionally faces situations when the demands of all of its customers for the delivery of gas cannot be met. In these instances, it is necessary that PGS interrupt or curtail deliveries to its interruptible customers. In general, the largest of PGS' industrial customers are in the categories that are first curtailed in such situations. PGS' tariff and transportation agreements with these customers give PGS the right to divert these customers' gas to other higher priority users during the period of curtailment or interruption. PGS pays these customers for such gas at the price they paid their suppliers, or at a published index price, and in either case pays the customer for charges incurred for interstate pipeline transportation to the PGS system.

Franchises

PGS holds franchise and other rights with approximately 100 municipalities throughout Florida. These franchises give PGS a right to occupy municipal rights-of-way within the franchise area. The franchises are irrevocable and are not subject to amendment without the consent of PGS, although in certain events, they are subject to forfeiture.

Municipalities are prohibited from granting any franchise for a term exceeding 30 years. Several franchises contain purchase options with respect to the purchase of PGS' property located in the franchise area, if the franchise is not renewed; otherwise, based on judicial precedent, PGS is able to keep its facilities in place subject to reasonable rules and regulations imposed by the municipalities.

PGS' franchise agreements with the incorporated municipalities within its service area have various expiration dates ranging from the present through 2038. PGS expects to negotiate 10 to 12 franchises in 2009, the majority of which will be renewals of existing agreements. Franchise fees payable by PGS, which totaled $9.6 million in 2008, are calculated using various formulas which are based principally on natural gas revenues. Franchise fees are collected from only those customers within each franchise area.

Utility operations in areas outside of incorporated municipalities are conducted in each case under one or more permits to use state or county rights-of-way granted by the Florida Department of Transportation or the county commissioners of such counties. There is no law limiting the time for which such permits may be granted by counties. There are no fixed expiration dates and these rights are, therefore, considered perpetual.

Environmental Matters

PGS' operations are subject to federal, state and local statutes, rules and regulations relating to the discharge of materials into the environment and the protection of the environment generally that require monitoring, permitting and ongoing expenditures.

Tampa Electric Company is one of several potentially responsible parties for certain superfund sites and, through PGS, for former manufactured gas plant sites. See the previous discussion in the **Environmental Matters** section of **Tampa Electric – Electric Operations**.

Capital Expenditures

During the year ended Dec. 31, 2008, PGS did not incur any material capital expenditures to meet environmental requirements, nor are any anticipated for 2009 through 2013.

TECO COAL

Overview

TECO Coal, with offices located in Corbin, Kentucky, is a wholly-owned subsidiary of TECO Energy, Inc. and through its subsidiaries operates surface and underground mines as well as coal processing facilities in eastern Kentucky, Tennessee and southwestern Virginia.

TECO Coal owns no operating assets but holds all of the common stock of Gatliff Coal Company, Rich Mountain Coal Company, Clintwood Elkhorn Mining Company, Pike Letcher Land Company, Premier Elkhorn Coal Company, Perry County Coal Corporation, Bear Branch Coal Company, and all of the membership interests in TECO Synfuel Holdings, LLC and TECO Synfuel Operations, LLC. The TECO Coal subsidiaries own or control, by lease, mineral rights, and own or operate surface and underground mines, synthetic fuel production facilities and coal processing and loading facilities. TECO Coal produces, processes and sells bituminous, predominately low sulfur coal of steam, industrial and metallurgical grades. TECO Coal uses two distinct extraction techniques: continuous underground mining and dozer and front-end loader surface mining.

TECO Coal subsidiaries currently operate 31 underground mines, which employ the room and pillar mining method, and 14 surface mines. In 2008, TECO Coal subsidiaries sold 9.3 million tons of coal. All of this coal was sold to customers other than Tampa Electric. For the reporting period, the TECO Coal operating companies had a combined estimated 266.6 million tons of proven and probable recoverable reserves.

History

In 1967, Cal-Glo Coal Company was formed. It mined a product containing low sulfur, low ash fusion characteristic and high energy content. Realizing the potential for this product to meet its combustion, quality and environmental requirements, Tampa Electric Company purchased Cal-Glo Coal Company in 1974. In 1982, after several years of continued growth and success, TECO Coal Corporation was formed and Cal-Glo Coal Company was renamed as Gatliff Coal Company. Rich Mountain Coal Company was established in 1987 when leases were signed for properties in Campbell County, Tennessee.

1988 saw a marketing change in which Gatliff Coal Company began selling ferro-silicon and silicon grade products. In addition, in that year properties were also acquired in Pike County, Kentucky and Clintwood Elkhorn Mining Company was formed. Premier Elkhorn Coal Company and Pike Letcher Land Company were formed in 1991, when additional property was acquired in Pike and Letcher Counties, Kentucky.

In 1997, Bear Branch Coal Company secured key leases for property located in Perry County and Knott County, Kentucky.

The newest mining company in the TECO Coal family is Perry County Coal Corporation, which was purchased in 2000 and is located in Perry, Knott and Leslie Counties, Kentucky.

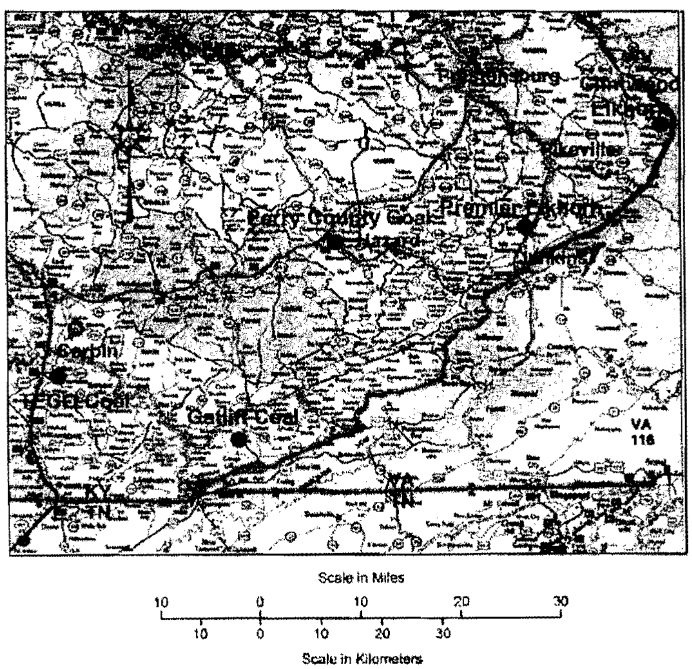
TECO Synfuel Holdings, LLC and TECO Synfuel Operations, LLC were formed in 2003 to administer the production and sale of synfuel product at various TECO Coal subsidiaries. Synfuel operations were terminated at the end of 2007 when the tax credit associated with production of non-conventional fuels expired by statute.

In 2004, the acquisition of properties and the Millard Preparation Facilities (currently idle) from American Electric

Power and Kentucky Coal, LLC was completed. The property and facility are located in Pike County, Kentucky.

Mining Operations

TECO Coal currently has four mining complexes, all operating in Kentucky with a portion of Clintwood Elkhorn Mining Company operating in Virginia as well. A mining complex is defined as all mines that supply a single wash plant, except in the case of Clintwood Elkhorn Mining Company, which provides production for two active wash plants. Clintwood Elkhorn's Millard Plant is currently idle. These complexes blend, process and ship coal that is produced from one or more mines, with a single complex handling the coal production of as many as 20 individual underground or surface mines. The complexes have been developed at strategic locations in close proximity to the TECO Coal preparation plants and rail shipping facilities. Coal is transported from TECO Coal's mining complexes to customers by means of railroad cars, trucks, barge or vessels, with rail shipments representing approximately 88.5% of 2008 coal shipments. The map below shows the locations of the four mining complexes and TECO Coal's offices in Corbin, Kentucky.



Facilities

Coal mined by the operating companies of TECO Coal is processed and shipped from facilities located at each of the operating companies, with Clintwood Elkhorn Mining Company having three facilities. The Clintwood facilities are located at Biggs, Kentucky, Hurley, Virginia and the Millard facility, which is presently idle, located at Millard, Kentucky. The equipment at each facility is in good condition and regularly maintained by qualified personnel. Table 1 below is a summary of the TECO Coal processing facilities:

PROCESSING FACILITIES SUMMARY
Table 1

COMPANY	FACILITY	LOCATION	RAILROAD SERVICE	UTILITY SERVICE
Gatliff Coal	Ada Tipple	Himyar, KY	CSXT Railroad	RECC
Clintwood Elkhorn	Clintwood #2 Plant	Biggs, KY	Norfolk Southern	American Electric Power
Clintwood Elkhorn	Clintwood #3 Plant	Hurley, VA	Norfolk Southern	American Electric Power
Clintwood Elkhorn	Millard Plant	Millard, KY	CSXT Railroad	American Electric Power
Premier Elkhorn	Burk Branch Plant	Myra, KY	CSXT Railroad	American Electric Power
Perry County Coal	Perry County Plant	Hazard, KY	CSXT Railroad	American Electric Power

Significant Projects

Significant projects for 2009 include the following:

Perry County Coal
- Surface development for the construction of the E3-1 and E4-1 ventilation shafts at Second Creek has begun. Project completion is not expected until 2011.

Premier Elkhorn Coal
- A surface disturbance permit was issued for the Little Fork area. The operation is scheduled to begin in 2009. An underground mine is expected to begin production in the Glamorgan seam in 2009.

Clintwood Elkhorn Mining
- New deep mines were brought into production in the Millard, Hagy, Blair and Splashdam seams. A new deep mine is being developed in the Lower Elkhorn seam and is expected to begin production in 2009.

Mining Complexes

Table 2 below shows annual production for each mining complex for each of the last three years.

MINING COMPLEXES
Table 2

	Location	Mine Type	Mining Equipment	Transportation	Tons Produced (in millions) 2008	2007	2006	Tons Sold (in millions) 2008	Year Established or Acquired
Gatliff Coal Company	Bell County, KY/ Knox County, KY/ Campbell County, TN	S	D/L	T	0.31	0.26	0.36	0.32	1974
Clintwood Elkhorn Mining	Pike County, KY/ Buchanan County, VA	U, S	CM, D/L, HM, A	R, R/V	2.60	2.66	2.63	2.63	1988
Premier Elkhorn Coal	Pike County, KY/Letcher County, KY/ Floyd County, KY	U, S	CM, D/L	R,T,R/B,T/B	3.19	3.15	3.33	3.30	1991
Perry County Coal	Perry County, KY/ Leslie County, KY/ Knott County, KY	U, S	CM, D/L, HM	R,T,R/B,T/B	3.09	3.05	3.57	3.11	2000
TOTAL					9.19	9.12	9.89	9.36	

S – Surface
U – Underground
CM – Continuous Miner
D/L – Dozers and Front-End loaders
HM – Highwall Miner
A - Auger
R – Rail
R/B – Rail to Barge
R/V – Rail to Ocean Vessel
T – Truck
T/B – Truck to Barge

Gatliff Coal Company

Located in Bell County, Kentucky, Gatliff Coal Company is supplied by one surface mine. Principal products at this location consist primarily of high quality steam coal for utilities. Products from this operation are transported by trucking contractors. Rich Mountain Coal Company formerly operated as a contractor for Gatliff Coal Company's Tennessee production which is currently in non-producing reclamation status. Gatliff Coal Company relinquished control of reserves in one area and produced 0.31 million tons of coal in 2008, leaving a reserve base of 3.5 million recoverable tons.

Clintwood Elkhorn Mining Company

Clintwood Elkhorn Mining Company has three facilities. One is located near Biggs, Kentucky in Pike County, and is supplied by seventeen underground mines and three surface mines. Principal products at the Biggs, Kentucky location include high volatile metallurgical coals and steam coals. The second Clintwood Elkhorn Mining Company facility is located near Hurley, Virginia and is supplied by two underground mines and four surface mines. The Hurley, Virginia operation facility also supplies high-volatile metallurgical coal as well as steam coal products. Products from both locations are shipped domestically to customers in North America via Norfolk Southern Corporation and vessels via the Great Lakes. International customers receive their products via ocean vessels from Lamberts Point, Virginia. The third facility, located at Millard, Kentucky in Pike County is currently idle. In total, Clintwood Elkhorn Mining Company produced 2.60 million tons of coal in 2008, leaving a reserve base of 52.2 million recoverable tons.

Premier Elkhorn Coal Company

Located near Myra, in Pike County, Kentucky, Premier Elkhorn Coal Company is supplied by production from nine underground mines and five surface mines. Principal products include high-quality steam coal for utilities, specialty stoker products for ferro-silicon and industrial customers, PCI and metallurgical coal for the steel mills. Facilities include a unit train load-out with a 200-car siding capable of loading at 6,000 tons per hour as well as a single car siding. Products from this location are shipped domestically via CSXT Railroad and trucking contractors. All production is performed by Premier Elkhorn Coal Company even though Pike Letcher Land Company controls by fee and lease all of the recoverable reserves. Premier Elkhorn Coal Company produced 3.19 million tons of coal in 2008 and a reduction of reserves was made because control was relinquished for an area, leaving a reserve base of 76.0 million recoverable tons.

Perry County Coal Corporation

Located near Hazard, Kentucky in Perry County, Perry County Coal Corporation is supplied by three underground mines and one surface mine. Principal products include high quality steam coal for utilities, industrial stoker and PCI products. Facilities include an upgraded 1,350 ton per hour preparation plant and two unit train load-outs, each capable of loading at 5,000 tons per hour. Products from this location are shipped domestically via CSXT Railroad and trucking contractors. Perry County Coal Corporation produced 3.09 million tons of coal in 2008, leaving a reserve base of 134.9 million recoverable tons.

Sales and Marketing

The TECO Coal marketing and sales force includes sales managers, distribution/transportation managers and administrative personnel. Primary customers are utility, steel and industrial companies. TECO Coal sells coal under long-term agreements, which are generally classified as greater than 12 months, and on a spot basis, which is generally classified as less than 12 months.

The terms of these coal sales contracts result from bidding and extensive negotiations with customers. Consequently, these contracts typically vary significantly in price, quantity, quality, length, and may contain terms and conditions that allow for periodic price reviews, price adjustment mechanisms, recovery of governmental impositions as well as provisions for force majeure, suspension, termination, treatment of environmental legislation and assignment.

Distribution

TECO Coal transports coal from its mining complexes to customers by rail, barge, vessel and trucks. TECO Coal employs transportation specialists who coordinate the development of acceptable shipping schedules with its customers, transportation providers and mining facilities.

Competition

Primary competitors of TECO Coal's subsidiaries are other coal suppliers, many of which are located in Central Appalachia. Even though consolidation and bankruptcy have decreased the number of coal suppliers, the industry is still intensely competitive. To date, TECO Coal has been able to compete for coal sales by mining high quality steam and specialty coals, including coals used for making coke and furnace injection, and by effectively managing production and processing costs.

Employees

As of Dec. 31, 2008, TECO Coal and its subsidiaries employed a total of 1,129 employees.

Regulations

Mine Safety and Health

The operations of underground mines, including all related surface facilities, are subject to the Federal Coal Mine Safety and Health Act of 1969, the 1977 Amendment and the new Miner Act of 2006. TECO Coal's subsidiaries are also subject to various Kentucky, Tennessee and Virginia mining laws which require approval of roof control, ventilation, dust control and other facets of the coal mining business. Federal and state inspectors inspect the mines to ensure compliance with these laws. TECO Coal believes it is in substantial compliance with the standards of the various enforcement agencies. It is unaware of any mining laws or regulations that would materially affect the market price of coal sold by its subsidiaries, although mining accidents within the industry could lead to new legislation that could impose additional costs on TECO Coal.

Black Lung Legislation

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each coal mine operator must make payment of federal black lung benefits to claimants who are current and former employees, certain survivors of a miner who dies from black lung disease, and to a trust fund for the payment of benefits and medical expenses to claimants who last worked in the coal industry prior to Jul. 1, 1973. Historically, a small percentage of the miners currently seeking federal black lung benefits are awarded these benefits by the federal government. The trust fund is funded by an excise tax on coal production of up to $1.10 per ton for deep-mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price.

In 2000, the Department of Labor issued amendments to the regulations implementing the federal black lung laws that, among other things, established a presumption in favor of a claimant's treating physician, limited a coal operator's ability to introduce medical evidence, and redefined Coal Workers Pneumoconiosis to include chronic obstructive pulmonary disease. These changes in the regulations increased the percentage of claims approved and the overall cost of black lung to coal operators. TECO Coal, with the help of its consulting actuaries, continues to monitor claims very closely.

Workers' Compensation

TECO Coal is liable for workers' compensation benefits for traumatic injury and occupational exposure claims under state workers' compensation laws. Workers' compensation laws are administered by state agencies with each state having its own set of rules and regulations regarding compensation that is owed to an employee that is injured in the course of employment.

Environmental Laws

Surface Mining Control and Reclamation Act

Coal mining operations are subject to the Surface Mining Control and Reclamation Act of 1977 which places a charge of $0.15 and $0.35 on every net ton of underground and surface coal mined, respectively, to create a reserve for reclaiming land and water adversely affected by past coal mining. Other provisions establish standards for the control of environmental effects and reclamation of surface coal mining and the surface effects of underground coal mining and requirements for federal and state inspections.

Clean Air Act/Clean Water Act

While conducting their mining operations, TECO Coal's subsidiaries are subject to various federal, state and local air and water pollution standards. In 2008, TECO Coal spent approximately $2.7 million on environmental protection and reclamation programs. TECO Coal expects to spend a similar amount in 2009 on these programs.

CERCLA (Superfund)

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA" – commonly known as Superfund) affects coal mining and hard rock operations by creating liability for investigation and remediation in response to releases of hazardous substances into the environment and for damages to natural resources. Under Superfund, joint and several liabilities may be imposed on waste generators, site owners or operators and others regardless of fault.

Under EPA's Toxic Release Inventory process, companies are required to report annually listed toxic materials that exceed defined quantities.

Glossary of Selected Mining Terms

Assigned reserves. Coal which has been committed by the coal company to operating mine shafts, mining equipment, and plant facilities, and all coal which has been leased by the company to others.

Bituminous coal. The most common type of coal with moisture content less than 20% by weight and heating value of

10,500 to 14,000 Btu per pound. It is dense and black and often has well-defined bands of bright and dull material.

Btu. (British Thermal Unit). A measure of the energy required to raise the temperature of one pound of water one degree Fahrenheit.

Central Appalachia. Coal producing states and regions of eastern Kentucky, eastern Tennessee, western Virginia and southern West Virginia.

Coal seam. Coal deposits occur in layers. Each layer is called a "seam."

Coal washing. The process of removing impurities, such as ash and sulfur based compounds, from coal.

Compliance coal. Coal which, when burned, emits 1.2 pounds or less of sulfur dioxide per million Btu, which is equivalent to .72% sulfur per pound of 12,000 Btu coal. Compliance coal requires no mixing with other coals or use of sulfur dioxide reduction technologies by generators of electricity to comply with the requirements of the federal Clean Air Act.

Continuous miner. A machine used in underground mining to cut coal from the seam and load it onto conveyors or into shuttle cars in a continuous operation.

Continuous mining. One of two major underground mining methods now used in the United States. This process utilizes a continuous miner. The continuous miner removes or "cuts" the coal from the seam. The loosened coal then falls on a conveyor for removal to a shuttle car or larger conveyor belt system.

Deep mine. An underground coal mine.

Dozer and front-end loader mining. An open-cast method of mining that uses large dozers together with trucks and loaders to remove overburden, which is used to backfill pits after coal removal.

Ferro-silicon. An alloy of iron and silicon used in the production of carbon steel.

Force majeure. An event that may prevent the company from conducting its mining operations as a result of in whole or in part by: Acts of God, wars, riots, fires, explosions, breakdowns or accidents; strikes, lockouts or other labor difficulties; lack or shortages of labor, materials, utilities, energy sources, compliance with governmental rules, regulations or other governmental requirements; any other like causes.

High vol met coal. Coal that averages approximately 35% volatile matter. Volatile matter refers to a constituent that becomes gaseous when heated to certain temperatures.

Highwall miner. An auger-like apparatus that drives parallel rectangular entries to 1,000 feet into the coal seam.

Industrial coal. Coal used by industrial steam boilers to produce electricity or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal.

Long-term contracts. Contracts with terms of one year or longer.

Low ash fusion. Coal that when burned typically produces ash that has a melting point below 2,450 degrees Fahrenheit.

Low sulfur coal. Coal which, when burned, emits 1.6 pounds or less of sulfur dioxide per million Btus.

Metallurgical coal. The various grades of coal suitable for carbonization to make coke for steel manufacture. Also known as "met" coal, it possesses four important qualities: volatility, which affects coke yield; the level of impurities, which affects coke quality; composition, which affects coke strength; and basic characteristics, which affect coke oven safety. Met coal has a particularly high Btu, but low ash content.

Overburden. Layers of earth and rock covering a coal seam. In surface mining operations, overburden is removed prior to coal extraction.

Overburden ratio. The amount of overburden commonly stated in cubic yards that must be removed to excavate one ton of coal.

Pillar. An area of coal left to support the overlying strata in a mine; sometimes left permanently to support surface structures.

Pneumoconiosis. A lung disease caused by long-continued inhalation of mineral or metallic dust.

Preparation plant. Usually located on a mine site, although one plant may serve several mines. A preparation plant is a facility for crushing, sizing and washing coal to prepare it for use by a particular customer. The washing process has the added benefit of removing some of the coal's sulfur content.

Probable (Indicated) reserves. Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but the sites for inspection, sampling and measurement are farther apart; therefore, the degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation.

Proven (Measured) reserves. Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well established.

Pulverized coal injection (PCI). A system whereby coal is pulverized and injected into blast furnaces in the production of steel and/or steel products.

Reclamation. The process of restoring land and the environment to their approximate original state following mining activities. The process commonly includes "recontouring" or reshaping the land to its approximate original appearance, restoring topsoil and planting native grass and ground covers. Reclamation operations are usually underway before the mining of a particular site is completed. Reclamation is closely regulated by both state and federal law.

Recoverable reserves. The amount of proven and probable reserves that can actually be recovered from the reserve base taking into account all mining and preparation losses involved in producing a saleable product using existing methods and under current law.

Reserves. That part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination.

Resource (Non-reserve coal deposit). A coal-bearing body that does not qualify as a commercially viable coal reserve. Resources may be classified as such by either limited property control, geologic limitations, insufficient exploration or other limitations. In the future, it is possible that portions of the resource could be re-classified as reserve if those limitations are removed or mitigated by: improving market conditions, additional property control, favorable results of exploration, advances in technology, etc.

Roof. The stratum of rock or other mineral above a coal seam; the overhead surface of a coal working place. Same as "top."

Room and pillar mining. In the underground room and pillar method of mining, continuous mining machines cut three to nine entries into the coal bed and connect them by driving crosscuts, leaving a series of rectangular pillars, or columns of coal to help support the mine roof and control the flow of air. As mining advances, a grid-like pattern of entries and pillars is formed. Additional coal may be recovered from the pillars as this panel of coal is retreated.

Spot market. Sales of coal under an agreement for shipments over a period of one year or less.

Steam coal. Coal used by power plants and industrial steam boilers to produce electricity or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal.

Sulfur. One of the elements present in varying quantities in coal that contributes to environmental degradation when coal is burned. Sulfur dioxide is produced as a gaseous by-product of coal combustion.

Sulfur content. Coal is commonly described by its sulfur content due to the importance of sulfur in environmental regulations. "Low sulfur" coal has a variety of definitions but is typically used to describe coal consisting of 1.0% or less sulfur. A majority of TECO Coal's Central Appalachian reserves are of low sulfur grades.

Surface mine. A mine in which the coal lies near the surface and can be extracted by removing overburden.

Synthetic fuel (Synfuel). A solid fuel that is produced by mixing coal and/or coal waste with various additives, causing a chemical change to occur within the original product.

Tipple. A structure that facilitates the loading of coal into rail cars.

Tons. A "short" or net ton is equal to 2,000 pounds. A "long" or British ton is 2,240 pounds; a "metric" tonne is approximately 2,205 pounds. The short ton is the unit of measure referred to in this Form 10-K.

Unassigned reserves. Coal which has not been committed, and which would require new mineshafts, mining equipment, or plant facilities before operations could begin in the property.

Underground mine. Also known as a "deep" mine. Usually located several hundred feet below the earth's surface, an underground mine's coal is removed mechanically and transferred by shuttle car or conveyor to the surface.

Unit train. A train of a specified number of cars carrying only coal. A typical unit train can carry at least 10,000 tons of coal in a single shipment.

Utility coal. Coal used by power plants to produce electricity or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal.

TECO GUATEMALA

TECO Guatemala, Inc. (formerly TWG Non-Merchant, Inc.), has subsidiaries that have interests in independent power projects in Guatemala and a minority ownership interest in an electrical distribution utility and affiliated entities. The TECO Guatemala subsidiaries had 119 employees as of Dec. 31, 2008.

TECO Guatemala indirectly owns 100% of Central Generadora Eléctrica San José, Limitada (CGESJ), the owner of an electric generating station located in Guatemala, which consists of a single-unit pulverized-coal baseload facility (the San José Power Station). This facility was the first coal-fueled plant in Central America and meets environmental standards set by Guatemala and the World Bank. In 1996, CGESJ signed a U.S. dollar-denominated power purchase agreement (PPA) with EEGSA, the largest private distribution company in Central America, to provide 120 megawatts of capacity and energy for 15 years beginning in 2000. In 2001, CGESJ signed an option with EEGSA to extend that PPA for five years at the end of its current term for approximately $2.5 million. Tecnología Marítima, S.A. (TEMSA), an indirect wholly-owned subsidiary, in addition to receiving the coal shipments for CGESJ, provides unloading services to third parties.

Tampa Centro Americana de Electricidad, Limitada (TCAE), an entity 96.06% owned by TPS Guatemala One, Inc., a subsidiary of TECO Guatemala, and the owner of an oil-fired electric generating facility (the Alborada Power Station), has a U.S. dollar-denominated PPA with EEGSA to provide 78 megawatts of capacity for a 15-year period ending in 2010. In 2001, TCAE signed an option with EEGSA to extend that PPA for five years at the end of its current term for approximately $2.9 million. EEGSA is responsible for providing the fuel for the plant, with a subsidiary of TECO Guatemala providing assistance in fuel administration.

In 1998, DECA II, a consortium that includes an affiliate of TECO Energy, Iberdrola Energia, S.A. of Spain (Iberdrola), an electric utility in Spain, and Electricidade de Portugal, an electric utility in Portugal, completed the purchase of an 80.9% ownership interest in EEGSA for $520 million. TECO Guatemala contributed $100 million in equity and owns a 30% interest in this consortium. At this time, the consortium maintains a controlling interest in EEGSA and other affiliate companies which provide, among other things, electricity transmission services, telecommunication services and power sales to large electric customers and engineering services. EEGSA serves more than 800,000 customers in and around the metropolitan area of Guatemala City.

For CGESJ, TCAE and DECA II, TECO Guatemala has obtained political risk insurance for currency inconvertibility, expropriation and political violence covering TECO Guatemala's indirect equity investment and economic returns.

Our existing plants in Guatemala operate under environmental permits issued by the local environmental authorities. The plants were built in accordance to World Bank Guidelines of 1988 and 1994, at the time of construction of these facilities. TECO Guatemala complies with strict monitoring programs established by the local Ministry of Environment – MARN, which regulates local environmental laws and monitors compliance. TECO Guatemala has an environmental emission controls plan, monitoring programs as per the approved permits and lender requirements, pursuant to the referenced World Bank Guidelines.

TECO Guatemala operates its facilities under an approved environmental management plan, providing for efficient facility operation while promoting worker health and safety and reducing environmental impacts.

Item 1A. RISK FACTORS.

General Business and Operational Risks

General economic conditions may adversely affect our businesses.

Our businesses are affected by general economic conditions. In particular, growth in Tampa Electric's service area and in Florida is important to the realization of annual energy sales growth for Tampa Electric and PGS. A failure of market conditions to improve, or continued deterioration, such as the current worldwide economic slowdown and the currently depressed Florida housing markets, could adversely affect Tampa Electric's or PGS' expected performance. Continuation or worsening of the current economic conditions could affect these companies' ability to collect payments from customers.

TECO Coal and TECO Guatemala are also affected by general economic conditions in the industries and geographic areas they serve, both nationally and internationally.

Our electric and gas businesses are highly regulated, and any changes in regulations or the regulatory environment could lower revenues or increase costs or competition.

Tampa Electric and PGS operate in highly regulated industries. Their retail operations, including the prices charged, are regulated by the FPSC, and Tampa Electric's wholesale power sales and transmission services are subject to regulation by the FERC. Changes in regulatory requirements or adverse regulatory actions could have an adverse effect on Tampa Electric's or PGS' financial performance by, for example, increasing competition or costs, threatening investment recovery or impacting rate structure.

Tampa Electric and PGS are currently earning below the bottom of their respective allowed ROE ranges and have filed for base rate increases with the Florida Public Service Commission. Our financial results could be adversely affected if the base rate proceedings do not have favorable outcomes.

Tampa Electric and PGS are currently earning below the bottom of their respective allowed ROE ranges, and filed with the FPSC for base rate relief in 2008. While the FPSC has a history of constructive regulation, we cannot predict the outcome of any such regulatory proceeding. If cost recovery is not granted or if the allowed return on equity is reduced, our financial results could be adversely affected.

Changes in the environmental laws and regulations affecting our businesses could increase our costs or curtail our activities.

Our businesses are subject to regulation by various governmental authorities dealing with air, water and other environmental matters. Changes in compliance requirements or the interpretation by governmental authorities of existing requirements may impose additional costs on us or require us to curtail some of our businesses' activities.

Federal or state regulation of greenhouse gas (GHG) emissions, depending on how they are enacted, could increase our costs or the costs of our customers or curtail sales.

Among our companies, Tampa Electric has the most significant number of stationary sources with air emissions. While GHG emission regulations have been proposed, both at the federal and state level, none have been passed at this time and therefore costs to reduce GHGs are unknown. Presently there is no viable technology to remove CO_2 post-combustion from conventional coal-fired units such as Tampa Electric's Big Bend units.

Regulation in Florida allows utility companies to recover from customers prudently incurred costs for compliance with new environmental regulations. Tampa Electric would expect to recover from customers the costs of power plant modifications or other costs required to comply with new GHG emission regulation, but increased costs for electricity may cause customers to change usage patterns, which would impact Tampa Electric's sales. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the ECRC, Tampa Electric could seek to recover those costs through a base-rate proceeding, but we cannot predict whether the FPSC would grant such recovery.

In the case of TECO Coal, the use of coal to generate electricity is considered a significant source of GHG emissions. New regulations, depending on final form, could cause the consumption of coal to decrease or the cost of sales to increase, which could negatively impact TECO Coal's earnings.

The significant, phased reductions in GHG emissions called for by the executive orders signed by the governor of Florida in 2007 could add to Tampa Electric's costs and adversely affect its operating results.

The Governor of Florida signed three Executive Orders in July 2007 aimed at reducing Florida's emissions of GHG. The three orders include directives for reducing GHG emissions by electric utilities to 2000 levels by 2017; to 1990 levels by 2025; and by 80 percent of 1990 levels by 2050; and the creation of the Governor's Action Team on Energy and Climate Change to develop a plan to achieve the targets contained in the Executive Orders, including any necessary legislative initiatives required. The Action Team submitted its Phase One report to the Governor on Nov. 1, 2007. The final report was completed by the October 2008 deadline and included recommendations incorporating GHG emission reduction targets and strategies into Florida's energy future as well as energy efficiency and conservation targets.

Also in 2008, the state legislature passed broad energy and climate legislation that, among other items, affirmed the FDEP's authority to establish a utility carbon reduction schedule and a carbon dioxide cap and trade system by rule, but added a requirement for legislative ratification of the rule no sooner than January 2010. The FDEP has initiated the rule development process, but until the final rules are developed, the impact on Tampa Electric and its customers can not be determined. However, if the final rules result in increased costs to Tampa Electric, or further changes in customer usage patterns in response to higher rates, Tampa Electric's operating results could be adversely affected.

A mandatory renewable portfolio standard (RPS) could add to Tampa Electric's costs and adversely affect its operating results.

In connection with the executive orders signed by the Governor of Florida in July 2007, the FPSC was tasked with evaluating a renewable portfolio target. The FPSC has made a recommendation to the Florida legislature that the RPS percentage be 7% by Jan. 1, 2013, 12% by Jan. 1, 2016, 18% by Jan. 1, 2019 and 20% by Jan. 1, 2021. The FPSC recommendation is subject to ratification by the Florida legislature. In addition, there is proposed legislation in the U.S. Congress to introduce a renewable energy portfolio standard at the federal level. It remains unclear, however, if or when action on such legislation would be completed. Tampa Electric could incur significant costs to comply with a renewable energy portfolio standard, as proposed. Tampa Electric's operating results could be adversely affected if Tampa Electric were not permitted to recover these costs from customers, or if customers change usage patterns in response to increased rates.

Tampa Electric, the State of Florida and the nation as a whole are increasingly dependent on natural gas to generate electricity. There may not be adequate infrastructure to deliver adequate quantities of natural gas to meet the expected future demand and the expected higher demand for natural gas may lead to increasing costs for the commodity.

The deferral of Tampa Electric's IGCC unit and the cancellation of numerous proposed coal-fired generating stations in Florida and across the United States in response to GHG emissions concerns is expected to lead to an increasing reliance on natural gas-fired generation to meet the growing demand for electricity. Currently there is an adequate supply and infrastructure to meet demand for natural gas in Florida and nationally. There is, however, uncertainty regarding whether the available supply of both domestic and imported natural gas and the existing infrastructure to transport the natural gas into and within Florida are adequate to meet the projected increased demand.

If supplies are inadequate or if significant new investment is required to install the pipelines necessary to transport the gas, the cost of natural gas could rise. Currently Tampa Electric and PGS are allowed to pass the cost for the commodity gas and transportation services through to the customer without profit. Changes in regulations could reduce earnings for Tampa Electric and PGS if they required Tampa Electric and PGS to bear a portion of the increased cost. In addition, increased costs to customers could result in lower sales.

Our businesses are sensitive to variations in weather and the effects of extreme weather, and have seasonal variations.

Most of our businesses are affected by variations in general weather conditions and unusually severe weather. Tampa Electric's and PGS' energy sales are particularly sensitive to variations in weather conditions. Those companies forecast energy sales on the basis of normal weather, which represents a long-term historical average. Significant variations from normal weather could have a material impact on energy sales. Extreme weather conditions, such as hurricanes, could adversely affect operating costs and sales and cause damage to our facilities, requiring additional costs to repair.

PGS, which has a typically short but significant winter peak period that is dependent on cold weather, is more weather-sensitive than Tampa Electric, which has both summer and winter peak periods. Mild winter weather in Florida can be expected to negatively impact results at PGS.

Variations in weather conditions also affect the demand and prices for the commodities sold by TECO Coal. Severe weather conditions could interrupt or slow coal production or rail transportation and increase operating costs.

Commodity price changes may affect the operating costs and competitive positions of our businesses.

Most of our businesses are sensitive to changes in coal, gas, oil and other commodity prices. Any changes could affect the prices these businesses charge, their operating costs and the competitive position of their products and services.

In the case of Tampa Electric, fuel costs used for generation are affected primarily by the cost of coal and natural gas. Tampa Electric is able to recover prudently incurred costs of fuel through retail customers' bills, but increases in fuel costs affect electric prices and, therefore, the competitive position of electricity against other energy sources.

The ability to make sales and the margins earned on wholesale power sales are affected by the cost of fuel to Tampa Electric, particularly as it compares to the costs of other power producers.

In the case of PGS, costs for purchased gas and pipeline capacity are recovered through retail customers' bills, but increases in gas costs affect total retail prices, and therefore, the competitive position of PGS relative to electricity, other forms of energy and other gas suppliers.

In the case of TECO Coal, the selling price of coal may cause it to either decrease or increase production. If production is decreased, there may be costs associated with idling facilities or write-offs of reserves that are no longer economic.

In the case of TECO Guatemala, the dispatch price for some of the diesel generating resources in Guatemala, which use residual oil, is below the average price of coal used by the San José Power Station due to the current prices for crude oil. If this relationship persists, generation from the San José Power Station would continue to be limited, thus reducing non-fuel energy sales revenues and net income.

Changes in customer energy usage patterns and the impact of the housing market slowdown may affect sales at our utility companies.

Tampa Electric's weather-normalized residential per customer usage declined again in 2008. It is now apparent that some of the robust residential customer growth in the 2005 through mid-2007 period, which was measured by new meter installations, was actually vacant residences with minimal energy usage. The average number of residential customers with minimal usage increased more than 7% in 2008.

In general, energy usage per residential customer at both Tampa Electric and PGS has declined over the last three years. We believe that this was in response to mild weather, higher energy prices reflected both through the fuel charge on bills and for higher energy prices in general, increased appliance efficiency, and increased residential vacancies as a result of increasing foreclosures amid the economic slowdown.

The utilities' forecasts are based on normal weather patterns and historical trends in customer energy use patterns. Tampa Electric's and PGS' ability to increase energy sales and earnings could be negatively impacted if energy prices increase in general and customers continue to use less energy in response to higher energy prices.

We rely on some transmission and distribution assets that we do not own or control to deliver wholesale electricity, as well as natural gas. If transmission is disrupted, or if capacity is inadequate, our ability to sell and deliver electricity and natural gas may be hindered.

We depend on transmission and distribution facilities owned and operated by other utilities and energy companies to deliver the electricity and natural gas we sell to the wholesale and retail markets, as well as the natural gas we purchase for use in our electric generation facilities. If transmission is disrupted, or if capacity is inadequate, our ability to sell and deliver products and satisfy our contractual and service obligations may be hindered.

The FERC has issued regulations that require wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. Although these regulations are designed to encourage competition in wholesale market transactions for electricity, there is the potential that fair and equal access to transmission systems will not be available or that sufficient transmission capacity will not be available to transmit electric power as we desire. We cannot predict the timing of industry changes as a result of these initiatives or the adequacy of transmission facilities. Likewise, unexpected interruption in upstream natural gas supply or transmission could affect our ability to generate power or deliver natural gas to local distribution customers.

We may be unable to take advantage of our existing tax credits and deferred tax benefits.

We have generated significant tax credits and deferred tax assets that are being carried over to future periods to reduce future cash payments for income tax. Our ability to utilize the carry-over credits and deferred tax assets is dependent upon sufficient generation of future taxable income.

Impairment testing of certain long-lived assets and goodwill could result in impairment charges.

We test our long-lived assets and goodwill for impairment annually or more frequently if certain triggering events occur. Should the current carrying values of any of these assets not be recoverable, we would incur charges to write down the assets to fair market value. 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 Dominican-Republic-Central America-United States Free Trade Agreement (DR-CAFTA) claim is uncertain, and could impact this determination in the future. See the **TECO Guatemala** section of **Management's Discussion & Analysis** for additional discussion of the DR-CAFTA claim.

Problems with operations could cause us to incur substantial costs.

Each of our subsidiaries is subject to various operational risks, including accidents, or equipment failures and operations below expected levels of performance or efficiency. As operators of power generation facilities, our subsidiaries could incur problems such as the breakdown or failure of power generation equipment, transmission lines, pipelines or other equipment or processes that would result in performance below assumed levels of output or efficiency. Our outlook assumes normal operations and normal maintenance periods for our operating companies' facilities.

Failure to obtain the permits necessary to open new surface mines could reduce earnings from our coal company.

Our coal mining operations are dependent on permits from the U.S. Army Corp of Engineers (USACE) to open new surface mines necessary to maintain or increase production. For the past several years, new permits issued by the USACE under Section 404 of the Clean Water Act for new surface coal mining operations have been challenged in court resulting in a backlog of permit applications and very few permits being issued. Failure to obtain the necessary permits to open new surface mines, which are required to maintain and expand production, could reduce production or require purchasing coal at prices above our cost of production to fulfill contract requirements, which would reduce the earnings expected from our coal company.

Our international projects are subject to risks that could result in losses or increased costs.

Our projects in Guatemala involve numerous risks that are not present in domestic projects, including expropriation, political instability, currency exchange rate fluctuations, repatriation restrictions, and regulatory and legal uncertainties. TECO Guatemala attempts to manage these risks through a variety of risk mitigation measures, including specific contractual provisions, obtaining non-recourse financing and obtaining political risk insurance where appropriate.

Guatemala, similar to many countries, has been experiencing increasing fuel and corresponding electricity prices. As a result, TECO Guatemala's operations are exposed to increased risks as the country's government and regulatory authorities seek ways to reduce the cost of energy to its consumers.

If efforts to have the July 2008 value added distribution tariff (VAD) decision at EEGSA recalculated or revised are unsuccessful, earnings and cash flow from that company would be at risk as long as the current lower VAD remains in place.

On Jan. 13, 2009, our subsidiary, TECO Guatemala Holdings, LLC, delivered a Notice of Intent to the Guatemalan government indicating its intent to file an arbitration claim against the Republic of Guatemala under the 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. During this 90-day period, the parties may attempt to resolve the dispute amicably through consultation or negotiation. If these efforts are unsuccessful, all of EEGSA's earnings contribution to TECO Guatemala, estimated to be a minimum of $10.0 million annually, could be at risk as long as the lower VAD remains in effect.

Potential competitive changes may adversely affect our regulated electric and gas businesses.

The U.S. electric power industry has been undergoing restructuring. Competition in wholesale power sales has been introduced on a national level. Some states have mandated or encouraged competition at the retail level and, in some situations, required divestiture of generating assets. While there is active wholesale competition in Florida, the retail electric business has remained substantially free from direct competition. Although not expected in the foreseeable future, changes in the competitive environment occasioned by legislation, regulation, market conditions or initiatives of other electric power providers, particularly with respect to retail competition, could adversely affect Tampa Electric's business and its expected performance.

The gas distribution industry has been subject to competitive forces for several years. Gas services provided by PGS are now unbundled for all non-residential customers. Because PGS earns margins on distribution of gas but not on the commodity itself, unbundling has not negatively impacted PGS' results. However, future structural changes that we cannot predict could adversely affect PGS.

We are a party from time to time to legal proceedings that may result in a material adverse effect on our financial condition.

From time to time, we are a party to, or otherwise involved in, lawsuits, claims, proceedings, investigations and other legal matters that have arisen in the ordinary course of conducting our business. While the outcome of these lawsuits, claims, proceedings, investigations and other legal matters which we are a party to, or otherwise involved in, cannot be predicted with certainty, any adverse outcome to lawsuits against us may result in a material adverse effect on our financial condition.

Financing Risks

Turmoil in the financial markets could limit our access to capital and increase our costs of borrowing or have other adverse effects on our results.

The turmoil in the financial markets experienced in 2008 and continuing in 2009 has impacted access to both the short- and long-term capital markets and the cost of such capital. Tampa Electric Company expects to issue long-term debt in support of its capital spending programs. In addition, we have debt maturities, primarily beginning in 2011, which may require refinancing. Future capital market conditions could limit our ability to raise the capital we need, and could increase our interest costs which could reduce earnings.

We enter into derivative transactions with counterparties, most of which are financial institutions, to hedge our exposure to commodity price changes. Although we believe we have appropriate credit policies in place to manage the non-performance risk associated with these transactions, the recent turmoil in the financial markets could lead to a sudden decline in credit quality among these counterparties. If such a decline occurs for a counterparty with which we have an in-the-money position, we could be unable to collect from such counterparty.

Continued declines in the financial markets could increase our pension expense or the required cash contributions to maintain required levels of funding for our plan.

The value of our pension fund assets were negatively impacted by unfavorable market conditions in 2008. At Jan. 1, 2008 our plan was more than 100% funded under calculation requirements of the Pension Protection Act (PPA); however, as a result of investment performance the value of our plan assets declined in 2008. This will increase our required contributions to the plan beginning in 2009. Continued declines in financial markets could increase the amount of contributions required to fund our plan in the future.

We estimate that pension expense in 2009 will be higher than in 2008, due in large part to the asset value decline. Additional declines in asset values could cause pension expense to increase in future years.

We have substantial indebtedness, which could adversely affect our financial condition and financial flexibility.

We have significant indebtedness, which has resulted in fixed charges we are obligated to pay. The level of our indebtedness and restrictive covenants contained in our debt obligations could limit our ability to obtain additional financing and could prevent the payment of dividends if those payments would cause a violation of the covenants.

TECO Energy, TECO Finance and Tampa Electric Company must meet certain financial tests as defined in the applicable agreements to use their respective credit facilities. Also, TECO Energy, TECO Finance, Tampa Electric Company and other operating companies, have certain restrictive covenants in specific agreements and debt instruments. The restrictive covenants of our subsidiaries could limit their ability to make distributions to us, which would further limit our liquidity. See the **Credit Facilities** section and **Significant Financial Covenants** table in the **Liquidity, Capital Resources** sections of **MD&A** for descriptions of these tests and covenants.

As of Dec. 31, 2008, we were in compliance with required financial covenants, but we cannot be assured that we will be in compliance with these financial covenants in the future. Our failure to comply with any of these covenants or to meet our payment obligations could result in an event of default which, if not cured or waived, could result in the acceleration of other outstanding debt obligations. We may not have sufficient working capital or liquidity to satisfy our debt obligations in the event of an acceleration of all or a portion of our outstanding obligations.

We also incur obligations in connection with the operations of our subsidiaries and affiliates that do not appear on our balance sheet. These obligations take the form of guarantees, letters of credit and contractual commitments, as described under **Off-Balance Sheet Debt** and **Liquidity, Capital Resources** sections of the **MD&A**.

Our financial condition and results could be adversely affected if our capital expenditures are greater than forecast.

We are forecasting higher levels of capital expenditures, primarily at Tampa Electric, for compliance with our environmental consent decree, to support normal customer growth, to comply with the design changes mandated by the FPSC to harden transmission and distribution facilities against hurricane damage, to improve transmission and distribution system reliability, to improve coal-fired generating unit reliability, and to install peaking combustion turbines to meet peaking capacity needs.

If we are unable to maintain capital expenditures at the forecasted levels, we may need to draw on credit facilities or access the capital markets on unfavorable terms. We cannot be sure that we will be able to obtain additional financing, in which case our financial position, earnings and credit ratings could be adversely affected.

Our financial condition and ability to access capital may be materially adversely affected by ratings downgrades, and we cannot be assured of any rating improvements in the future.

Our senior unsecured debt is rated as investment grade by Moody's Investor's Services (Moody's) at Baa3 with a stable outlook, and by Fitch Ratings (Fitch) at BBB- with a stable outlook but below investment grade by Standard & Poor's (S&P) at BB+ with a positive outlook. The senior unsecured debt of Tampa Electric Company is rated by S&P at BBB- with a positive outlook, by Moody's at Baa2 with a positive outlook and by Fitch at BBB+ with a stable outlook. Any downgrades by the rating agencies may affect our ability to borrow, may change requirements for future collateral or margin postings, and may increase our financing costs, which may decrease our earnings. We also may experience greater interest expense than we may have otherwise if, in future periods, we replace maturing debt with new debt bearing higher interest rates due to any such downgrades. In addition, downgrades could adversely affect our relationships with customers and counterparties.

At current ratings, Tampa Electric and PGS are able to purchase electricity and gas without providing collateral. If the ratings of Tampa Electric Company decline to below investment grade, Tampa Electric and PGS could be required to post collateral to support their purchases of electricity and gas.

Because we are a holding company, we are dependent on cash flow from our subsidiaries, which may not be available in the amounts and at the times we need it.

We are a holding company and are dependent on cash flow from our subsidiaries to meet our cash requirements that are not satisfied from external funding sources. Some of our subsidiaries have indebtedness containing restrictive covenants which, if violated, would prevent them from making cash distributions to us. In particular, certain long-term debt at PGS prohibits payment of dividends to us if Tampa Electric Company's consolidated shareholders' equity is lower than $500 million. At Dec. 31, 2008, Tampa Electric Company's consolidated shareholders' equity was approximately $2.1 billion. Also, our wholly-owned subsidiary, TECO Diversified, Inc., the holding company for TECO Coal, has a guarantee related to a coal supply agreement that could limit the payment of dividends by TECO Diversified to us (see the **TECO Energy Significant Financial Covenants** table in the **Liquidity, Capital Resources** sections of **MD&A**).

Various factors could affect our ability to sustain our dividend.

Our ability to pay a dividend, or sustain it at current levels, could be affected by such factors as the level of our earnings and therefore our dividend payout ratio, and pressures on our liquidity, including unplanned debt repayments, unexpected capital spending and shortfalls in operating cash flow. These are in addition to any restrictions on dividends from our subsidiaries to us discussed above.

We are vulnerable to interest rate changes and may not have access to capital at favorable rates, if at all.

A portion of our debt bears interest at variable rates. Increases in interest rates, therefore, may require a greater portion of our cash flow to be used to pay interest. In addition, changes in interest rates and capital markets generally affect our cost of borrowing and access to these markets.

Item 1B. UNRESOLVED STAFF COMMENTS.

None.

Item 2. PROPERTIES.

TECO Energy believes that the physical properties of its operating companies are adequate to carry on their businesses as currently conducted. The properties of Tampa Electric are subject to a first mortgage bond indenture under which no bonds are currently outstanding.

TAMPA ELECTRIC

Tampa Electric has five electric generating plants in service, with December 2008 net generating capability of 4,477 MW. Tampa Electric assets include the Big Bend Power Station (1,607 MW capacity from four coal units and a combustion turbine (CT)), the Bayside Power Station (1,837 MW capacity from two natural gas combined cycle units), the Polk Power Station (255 MW capacity from the IGCC unit and 736 MW capacity from four CTs), the Phillips Power Station (36 MW capability from two diesel units) and a partnership interest with City of Tampa on 6 MW net winter generating capability from the Howard Curren Advanced Waste Water Treatment Plant.

Units at Big Bend went into service from 1970 to 1985, and two of its CTs were retired in 2008. The Polk IGCC unit began commercial operation in 1996. In 1991, Tampa Electric purchased two power stations (Dinner Lake Power Station and Phillips Power Station) from the Sebring Utilities Commission (Sebring). Phillips Power Station was placed in service by Sebring in 1983. Dinner Lake Power Station was retired from service in January 2003. Bayside Unit 1 was completed in April 2003, and Bayside Unit 2 was completed in January 2004.

Tampa Electric owns 178 substations having an aggregate transformer capacity of 21,314 Mega Volts Amps (MVA). The transmission system consists of approximately 1,309 pole miles (including underground and double-circuit) of high voltage transmission lines, and the distribution system consists of 6,413 pole miles of overhead lines and 4,472 trench miles of underground lines. As of Dec. 31, 2008, there were 666,347 meters in service. All of this property is located in Florida.

All plants and important fixed assets are held in fee except that titles to some of the properties are subject to easements, leases, contracts, covenants and similar encumbrances and minor defects of a nature common to properties of the size and character of those of Tampa Electric.

Tampa Electric has easements for rights-of-way adequate for the maintenance and operation of its electrical transmission and distribution lines that are not constructed upon public highways, roads and streets. It has the power of eminent domain under Florida law for the acquisition of any such rights-of-way for the operation of transmission and distribution lines. Transmission and distribution lines located in public ways are maintained under franchises or permits.

Tampa Electric Company has a long term lease for the office building in downtown Tampa which serves as headquarters for TECO Energy, Tampa Electric, PGS and TECO Guatemala.

PEOPLES GAS SYSTEM

PGS' distribution system extends throughout the areas it serves in Florida and consists of approximately 17,000 miles of pipe, including approximately 11,000 miles of mains and 6,000 miles of service lines. Mains and service lines are maintained under rights-of-way, franchises or permits.

PGS' operations are located in 14 operating divisions throughout Florida. While most of the operations and administrative facilities are owned, a small number are leased.

TECO COAL

Property Control

Operations of TECO Coal and its subsidiaries are conducted on both owned and leased properties totaling over 250,000 acres in Kentucky, Tennessee and Virginia. TECO Coal's current practice is to obtain a title review from a licensed attorney prior to purchasing or leasing property. As is typical in the coal mining industry, TECO Coal generally has not obtained title insurance in connection with its acquisitions of coal reserves and/or related surface properties. In many cases, the seller or lessor will grant the purchasing or leasing entity a warranty of property title. When leasing coal reserves and/or related surface properties where mining has previously occurred, TECO Coal may opt not to perform a separate title confirmation due to the previous mining activities on such a property. In cases involving less significant properties and consistent with industry practices, title and boundaries to less significant properties are now verified during lease or purchase negotiations.

In situations where property is controlled by lease, the lease terms are generally sufficient to allow the reserves for the associated operation to be mined within the initial lease term. In fact, the terms of many of these leases extend until the exhaustion of the mineable and merchantable coal from the leased property. If, however, extensions of the original lease term become necessary, provisions have generally been made within the original lease to extend the lease term upon continued payment of minimum royalties.

Coal Reserves

As of Dec. 31, 2008, the TECO Coal operating companies had a combined estimated 266.6 million tons of proven and probable recoverable reserves. All of the reserves consist of High Vol A Bituminous Coal. Reserves are the portion of the proven and probable tonnage that meet TECO Coal's economic criteria regarding mining height, preparation plant recovery, depth of overburden and stripping ratio. Generally, these reserves would be commercially mineable at year-end price and cost levels. Additionally, other controlled areas presently identified as resource now total 52.1 million tons of coal.

Reserves are defined by Security and Exchange Commission (SEC) Industry Guide 7 as that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination. Proven and probable coal reserves are defined by SEC Industry Guide 7 as follows:

> **Proven (Measured) Reserves** - Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, working or drill holes: grade and/or quality are computed from the results of detailed sampling; and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established.

> **Probable (Indicated) Reserves** - Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but for which the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation.

Drill hole spacing for confidence levels in reserve calculations is based on guidelines in U.S. Geological Survey Circular 891 (Coal Resource Classification System of the U.S. Geological Survey). In this method of classification, "proven" reserves are considered to be those lying within one-quarter mile (1,320 feet) of a valid point of measurement and "probable" reserves are those lying between one-quarter mile and three-quarters mile (3,960 feet) from such an observation point.

TECO Coal's reserve estimates are prepared by its staff of geologists, whose experience range from 20 years to 35 years. TECO Coal also has two chief geologists with the responsibility to track changes in reserve estimates, supervise TECO Coal's other geologists and coordinate third party reviews of our reserve estimates by qualified mining consultants. In 2008, a third-party reserve audit was performed by Marshall Miller & Associates on the portion of reserves acquired during 2008. The results of that audit are reflected in the numbers within this report.

Table 3 below shows recoverable reserves by quantity and the method of property control as well as the Assigned and Unassigned reserves per mining complex:

RECOVERABLE RESERVES BY QUANTITY [1]
(Millions of tons)
Table 3

Mining Complex	Location	Total	Proven	Probable	Owned	Leased	Assigned [2] 2008	Assigned [2] 2007	Unassigned [2] 2008	Unassigned [2] 2007
Gatliff Coal Company	Bell County, KY/ Knox County, KY/ Campbell County, TN	3.5	3.1	0.4	1.2	2.3	0.7	0.4	2.8	6.4
Clintwood Elkhorn Mining	Pike County, KY/ Buchanan County, VA	52.2	44.2	8.0	3.9	48.3	52.2	51.5	-	-
Premier Elkhorn Coal	Pike County, KY/Letcher County, KY/ Floyd County, KY	76.0	58.6	17.4	41.7	34.3	67.6	72.1	8.4	8.9
Perry County Coal	Perry County, KY/ Leslie County, KY/ Knott County, KY	134.9	49.4	85.5	-	134.9	134.9	137.8	-	-
	Total	266.6	155.3	111.3	46.8	219.8	255.4	261.8	11.2	15.3

Notes:

(1) Recoverable reserves represent the amount of proven and probable reserves that can actually be recovered from the reserve base taking into account all mining and preparation losses involved in producing a saleable product using existing methods under current law. Reserve information reflects a moisture of 6.5%. This moisture factor represents the average moisture present in TECO Coal's delivered coal.

(2) Assigned reserves means coal which has been committed by the coal company to operating mine shafts, mining equipment, and plant facilities, and all coal which has been leased by the company to others. Unassigned reserves represent coal which has not been committed, and which would require new mineshafts, mining equipment, or plant facilities before operations could begin in the property.

Table 4 below shows the recoverable reserves by quality, including sulfur content and coal type, per mining complex:

RECOVERABLE RESERVES BY QUALITY [1]
(Millions of tons)
Table 4

Mining Complex	Recoverable Reserves	Sulfur Content < 1% [2]	Sulfur Content >1% [2]	Compliance Tons [3]	Average BTU/lb As received	Coal Type [4]
Gatliff Coal Company	3.5	2.8	0.7	-	13,500	LSU
Clintwood Elkhorn Mining	52.2	24.6	27.6	26.3	13,400	HVM, LSU, PCI
Premier Elkhorn Coal	76.0	32.3	43.7	25.5	13,350	IS, LSU, PCI
Perry County Coal	134.9	127.6	7.3	76.6	13,195	LSU, PCI, V
Total	266.6			128.4		

Notes:

(1) Reserve information reflects a moisture factor of 6.5%. This moisture factor represents the average moisture present in TECO Coal's delivered coal.

(2) <1% or >1% refers to sulfur content as a percentage in coal by weight.

(3) Compliance coal is any coal that emits less than 1.2 pounds of sulfur dioxide per million BTU when burned. Compliance coal meets sulfur emission standards imposed by Title IV of the Clean Air Act.

(4) Reserve holdings include metallurgical coal reserves. Although these metallurgical coal reserves receive the highest selling price in the current market when marketed to steel-making customers, they can also be marketed as an ultra-high BTU, low sulfur utility coal for electricity generation.

HVM – High Vol Met
LSU – Low Sulfur Utility
PCI – Pulverized Coal Injection
V – Various
IS – Industrial Stoker

Reserve Estimation Procedure

TECO Coal's reserves are based on over 2,900 data points, including drill holes, prospect measurements and mine measurements. Our reserve estimates also include information obtained from our on-going exploration drilling and in-mine channel sampling programs. Reserve classification is determined by evaluation of engineering and geologic information along with economic analysis. These reserves are adjusted periodically to reflect fluctuations in the economics in the market and/or changes in engineering parameters and/or geologic conditions. Additionally, the information is constantly being updated to reflect new data for existing property as well as new acquisitions and depleted reserves.

This data may include elevation, thickness, and, where samples are available, the quality of the coal from individual drill holes and channel samples. The information is assembled by qualified geologists and engineers located throughout TECO Coal. Information is entered into sophisticated computer modeling programs from which preliminary reserves estimations are generated. The information derived from the geological database is then combined with data on ownership or control of the mineral and surface interests to determine the extent of the reserves in a given area. Determinations of reserves are made after in-house geologists have reviewed the computer models and manipulated the grids to better reflect regional trends.

During the company's reserve evaluation and mine planning, the company takes into account factors such as restrictions under railroads, roads, buildings, power lines, or other structures. Depending on these factors, coal recovery may be limited or, in some instances, entirely prohibited. Current engineering practices are used to determine potential subsidence zones. The footprint of the relevant structure, as well as a safety angle-of-draw, are considered when mining near or under such facilities. Also, as part of the company's reserve and mineability evaluation, the company reviews legal, economic and other technical factors. Final review and recoverable reserve determination is completed after a thorough analysis by in-house engineers, geologists and finance associates.

TECO GUATEMALA

TPS San José International, Inc., a subsidiary of TECO Guatemala, has a 100% ownership in a project entity, CGESJ, which owns approximately 152 acres in Masagua, Guatemala on which the 120 MW coal-fired San José Power Station is located. TPS Guatemala One, Inc., a subsidiary of TECO Guatemala, has a 96.06% interest in TCAE, which owns approximately 11 acres in Escuintla, Guatemala on which the 78 MW oil-fired Alborada Power Station is located. TPS Operaciones, a subsidiary of TECO Guatemala which provides operations, maintenance and administrative support to CGESJ and TCAE, owns approximately 43 acres in Masagua, Guatemala.

Item 3. LEGAL PROCEEDINGS.

From time to time, we are a party to, or otherwise involved in, lawsuits, claims, proceedings, investigations and other legal matters that have arisen in the ordinary course of conducting our business. While the outcome of these lawsuits, claims, proceedings, investigations and other legal matters which we are a party to, or otherwise involved in, cannot be predicted with certainty, any adverse outcome to lawsuits against us may result in a material adverse effect on our financial condition.

For a discussion of the resolution of previously disclosed legal proceedings and an update of previously disclosed environmental matters, see **Notes 12** and **8, Commitments and Contingencies**, of the TECO Energy, Inc. and Tampa Electric Company **Consolidated Financial Statements**, respectively.

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

No matter was submitted during the fourth quarter of 2008 to a vote of TECO Energy's security holders, through the solicitation of proxies or otherwise.

EXECUTIVE OFFICERS OF THE REGISTRANT

The names, ages, current positions and principal occupations during the last five years of the current executive officers of TECO Energy are described below.

Name	Age	Current Positions and Principal Occupations During Last Five Years
Sherrill W. Hudson	66	Chairman of the Board and Chief Executive Officer, TECO Energy, Inc. and Tampa Electric Company, July 2004 to date; and prior thereto, Managing Partner for South Florida, Deloitte & Touche, LLP (public accounting), Miami, Florida.
Charles A. Attal, III	49	Vice President-General Counsel and Chief Legal Officer, TECO Energy, Inc., and General Counsel of Tampa Electric Company, July 2007 to date; and prior thereto, Vice President and Deputy General Counsel, TECO Energy, Inc.
Charles R. Black	57	President, Tampa Electric Company, October 2004 to date; Senior Vice President-Generation, TECO Energy, Inc. and Tampa Electric Company, September 2003 to October 2004; and prior thereto, Vice President-Energy Supply, Engineering and Construction, Tampa Electric Company.
William N. Cantrell	56	President, Peoples Gas System, since prior to 2003; President, Tampa Electric Company, September 2003 to October 2004.
Clinton E. Childress	60	Senior Vice President-Corporate Services and Chief Human Resources Officer, TECO Energy, Inc., October 2004 to date and Chief Human Resources Officer and Procurement Officer, Tampa Electric Company, September 2003 to date; and prior thereto, Chief Human Resources Officer, TECO Energy, Inc. and Vice President-Human Resources, Tampa Electric Company.
Gordon L. Gillette	49	Executive Vice President and Chief Financial Officer, TECO Energy, Inc., July 2004 to date; President, TECO Guatemala, October 2004 to date; Senior Vice President-Finance and Chief Financial Officer, TECO Energy, Inc., April 2001 to July 2004; Senior Vice President-Finance and Chief Financial Officer, Tampa Electric Company, since prior to 2003.
John B. Ramil	53	President and Chief Operating Officer, TECO Energy, Inc., July 2004 to date; Executive Vice President and Chief Operating Officer, TECO Energy, Inc., September 2003 to July 2004; Executive Vice President, TECO Energy, Inc., December 2002 to September 2003; President, Tampa Electric Company, April 1998 to September 2003.
J. J. Shackleford	62	President of TECO Coal Corporation, since prior to 2003.

There is no family relationship between any of the persons named above or between executive officers and any director of the company. The term of office of each officer extends to the meeting of the Board of Directors following the next annual meeting of shareholders, scheduled to be held on Apr. 29, 2009, and until such officer's successor is elected and qualified.

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The following table shows the high and low sale prices for shares of TECO Energy common stock, which is listed on the New York Stock Exchange, and dividends paid per share, per quarter.

		1st Quarter	*2nd Quarter*	*3rd Quarter*	*4th Quarter*
2008					
	High	$ 17.75	$ 21.99	$ 21.80	$ 16.05
	Low	$ 14.48	$ 15.97	$ 15.36	$ 10.50
	Close	$ 15.95	$ 21.49	$ 15.73	$ 12.35
	Dividend	$ 0.195	$ 0.20	$ 0.20	$ 0.20
2007					
	High	$ 17.49	$ 18.58	$ 17.71	$ 17.91
	Low	$ 16.22	$ 16.40	$ 14.84	$ 15.58
	Close	$ 17.21	$ 17.18	$ 16.43	$ 17.21
	Dividend	$ 0.19	$ 0.195	$ 0.195	$ 0.195

The approximate number of shareholders of record of common stock of TECO Energy as of Feb. 23, 2009 was 15,584.

Dividends on TECO Energy's common stock are declared and paid at the discretion of its Board of Directors. The primary sources of funds to pay dividends to its common shareholders are dividends and other distributions from its operating companies. TECO Energy's $200 million credit facility contains a covenant that could limit the payment of dividends exceeding a calculated amount (initially $50 million) in any quarter under certain circumstances. Certain long-term debt at PGS contains restrictions that limit the payment of dividends and distributions on the common stock of Tampa Electric Company.

In addition, TECO Diversified, Inc., a wholly-owned subsidiary of TECO Energy and the holding company for TECO Coal, has a guarantee related to a coal supply agreement that limits the payment of dividends to its common shareholder, TECO Energy, but does not limit loans or advances.

See **Liquidity, Capital Resources – Covenants in Financing Agreements** section of **MD&A**, and **Notes 6, 7** and **12** to the TECO Energy **Consolidated Financial Statements** for additional information regarding significant financial covenants.

All of Tampa Electric Company's common stock is owned by TECO Energy, Inc. and, therefore, there is no market for the stock. Tampa Electric Company pays dividends on its common stock substantially equal to its net income. Such dividends totaled $159.9 million in 2008, $166.1 million in 2007, and $169.4 million in 2006. See the **Restrictions on Dividend Payments and Transfer of Assets** section in **Note 1** to the Tampa Electric Company **Consolidated Financial Statements** for a description of restrictions on dividends on its common stock.

Set forth below is a table showing shares of TECO Energy common stock deemed repurchased by the issuer.

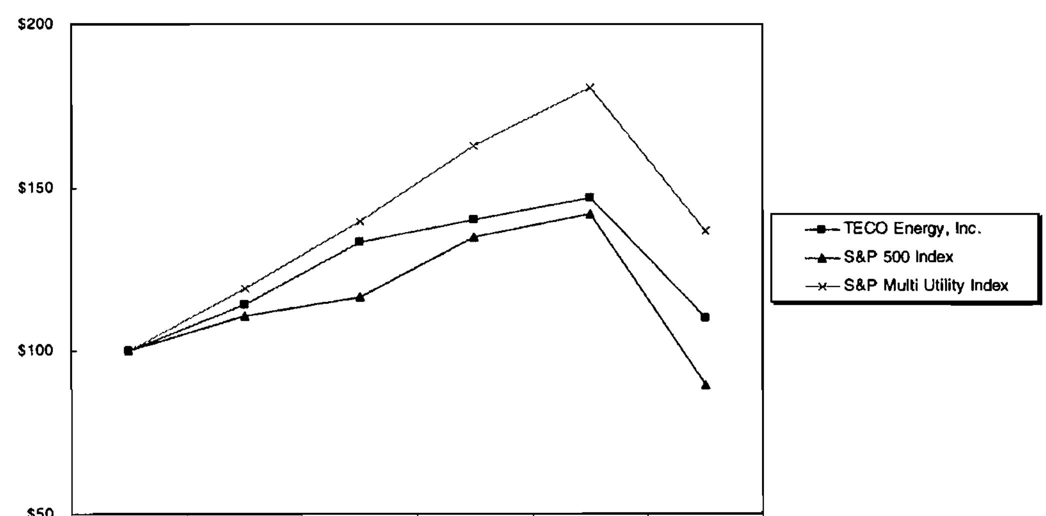
	(a) Total Number of Shares (or Units) Purchased [1]	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
Oct. 1, 2008 – Oct. 31, 2008	6,874	$14.04	—	—
Nov. 1, 2008 – Nov. 30, 2008	9,652	$12.67	—	—
Dec. 1, 2008 – Dec. 31, 2008	4,304	$11.77	—	—
Total 4th Quarter 2008	20,830	$12.94	—	—

(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.

Shareholder Return Performance Graph

The following graph shows the cumulative total shareholder return on our common stock on a yearly basis over the five-year period ended Dec. 31, 2008, and compares this return with that of the S&P 500 Index and the S&P Multi Utility Index. The graph assumes that the value of the investment in our common stock and each index was $100 on Dec. 31, 2003 and that all dividends were reinvested.

Shareholder Return Performance Graph



	2003	2004	2005	2006	2007	2008
TECO Energy, Inc.	$100	$114	$133	$140	$147	$110
S&P 500 Index	$100	$111	$116	$135	$142	$90
S&P Multi Utility Index	$100	$119	$140	$163	$181	$137

Item 6. SELECTED FINANCIAL DATA OF TECO ENERGY, INC.

(millions, except per share amounts) *Years ended Dec. 31,*	*2008*	*2007*	*2006*	*2005*	*2004*
Revenues [1]	$ 3,375.3	$ 3,536.1	$ 3,448.1	$ 3,010.1	$ 2,639.4
Net income (loss) from continuing operations [1]	$ 162.4	$ 398.9	$ 244.4	$ 211.0	$ (355.5)
Net income (loss) from discontinued operations [1][2]	-	14.3	1.9	63.5	(196.5)
Net income (loss)	$ 162.4	$ 413.2	$ 246.3	$ 274.5	$ (552.0)
Total assets	$ 7,147.4	$ 6,765.2	$ 7,361.8	$ 7,170.1	$ 8,972.4
Long-term debt	$ 3,206.6	$ 3,158.4	$ 3,212.6	$ 3,709.2	$ 3,880.0
Earnings per share (EPS) – basic;					
From continuing operations [1]	$ 0.77	$ 1.91	$ 1.18	$ 1.02	$ (1.85)
From discontinued operations [1]	-	0.07	0.01	0.31	(1.02)
EPS basic	$ 0.77	$ 1.98	$ 1.19	$ 1.33	$ (2.87)
Earnings per share (EPS) – diluted;					
From continuing operations [1]	$ 0.77	$ 1.90	$ 1.17	$ 1.00	$ (1.85)
From discontinued operations [1]	-	0.07	0.01	0.31	(1.02)
EPS diluted	$ 0.77	$ 1.97	$ 1.18	$ 1.31	$ (2.87)
Dividends declared per common share	$ 0.795	$ 0.775	$ 0.760	$ 0.760	$ 0.760

(1) Amounts shown include reclassifications to reflect discontinued operations as discussed in **Note 20** to the TECO Energy **Consolidated Financial Statements**.

(2) 2007 includes a $14.3 million gain on the 2005 sale of Union and Gila after reaching a favorable conclusion with taxing authorities. 2004 includes an impairment charge of $558.6 million.

Item 7. MANAGEMENT'S DISCUSSION & ANALYSIS OF FINANCIAL CONDITIONS & RESULTS OF OPERATIONS

This Management's Discussion & 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. Such statements are based on our current expectations, and we do not undertake to update or revise such forward-looking statements, except as may be required by law. These forward-looking statements include references to our anticipated capital expenditures, liquidity and financing requirements, projected operating results, future environmental matters, and regulatory and other plans. Important factors that could cause actual results to differ materially from those projected in these forward-looking statements are discussed under "Risk Factors."

TECO Energy, Inc. is a holding company, and all of its business is conducted through its subsidiaries. In this Management's Discussion & Analysis, "we," "our," "ours" and "us" refer to TECO Energy, Inc. and its consolidated group of companies, unless the context otherwise requires.

OVERVIEW

We are an energy-related holding company with four businesses consisting of regulated electric and gas utility operations in Florida, Tampa Electric and Peoples Gas System (PGS), respectively; TECO Coal, which owns and operates coal production facilities in the Central Appalachian coal production region; and TECO Guatemala, which is engaged in electric power generation and distribution and energy-related businesses in Guatemala.

Our regulated utility companies, Tampa Electric and PGS operate in the Florida market. Tampa Electric serves more than 667,000 retail customers in a 2,000 square mile service area in West Central Florida and has electric generating plants with a winter peak generating capacity of 4,477 megawatts. PGS, Florida's largest gas distribution utility, serves more than 335,000 residential, commercial, industrial and electric power generating customers in all of the major metropolitan areas of the state, with a total natural gas throughput of 1.4 billion therms in 2008.

We also have two unregulated companies. TECO Coal, through its subsidiaries, operates surface and underground mines and related coal processing facilities in eastern Kentucky, Tennessee and southwestern Virginia, producing metallurgical-grade and high-quality steam coals. Sales in 2008 were 9.3 million tons. TECO Guatemala, through its subsidiaries, owns a coal-fired generating facility and has a 96% ownership interest in an oil-fired peaking power generating plant, both under long-term contracts with a regulated distribution utility in Guatemala. It also has a 24% ownership interest in Guatemala's largest distribution utility, Empresa Eléctrica de Guatemala (EEGSA), and in affiliated companies (in combination called DECA II), which provide, among other things, electricity transmission services, telecommunication services, wholesale power sales to unregulated electric customers and engineering services.

In December 2007, we sold TECO Transport, a dry-bulk shipping company that had been a part of our business mix for many years. We used the cash from this sale to further our most important cash priorities to invest in our Florida utilities and to reduce parent company debt. The sale of TECO Transport allowed us to accelerate the retirement of parent debt, improve our balance sheet and credit ratings and reduce our business risk profile.

We have reduced parent and parent-guaranteed debt from a peak level of $2.7 billion in 2002 to $1.3 billion at the end of 2008. This debt was incurred in connection with a series of major investments in unregulated domestic power generation facilities outside Florida in anticipation of a movement toward competitive energy. The investments were ultimately unsuccessful and resulted in substantial losses when we exited this business segment in 2004 and 2005.

2008 PERFORMANCE

All amounts included in this Management's Discussion & Analysis are after tax, unless otherwise noted.

In 2008, our net income and earnings per share were $162.4 million or $0.77 per share, compared to $413.2 million or $1.98 per share in 2007. Net income in 2008 included a $21.6 million provision for taxes due to the repatriation of cash and investments from Guatemala, a $1.9 million charge associated with a regulatory settlement with the Florida Public Service Commission (FPSC) related to a dispute that arose in 2008 over the calculation of Tampa Electric's waterborne transportation disallowance over its five-year life, and $2.6 million of favorable adjustments to income taxes and working capital related to the sale of TECO Transport. Net income in 2007 included the $149.4 million gain from the sale of TECO Transport, $16.3 million of costs related to the sale of TECO Transport, and $20.2 million of charges related to debt extinguishment/exchange transactions. TECO Transport and the production of synthetic fuel contributed $34.0 million and $52.6 million, respectively, or $0.41 per share collectively, to 2007 net income. In 2007, net income reflected a $14.3 million tax benefit recorded in discontinued operations related to the 2005 disposition of the Union and Gila River merchant power plants.

Our non-GAAP results in 2008, which exclude the charges and gains discussed above, on a per share basis were $0.87 per share, compared to $1.07 in 2007 (see the **2008** and **2007 Reconciliation of GAAP net income from continuing operations to non-GAAP results** tables). Our results in 2008 reflected the impact on Tampa Electric of lower customer and energy sales growth, and the impact on TECO Coal of higher production costs. Performance in 2008 benefited from improved results at PGS and TECO Guatemala (excluding the taxes on the repatriation of cash and investments), and lower parent interest expense as a result of our debt retirement actions.

In 2008, we remained focused on supporting the growth of Tampa Electric and strengthening its capital structure through equity contributions from TECO Energy to Tampa Electric. Tampa Electric has capital requirements associated with its growing customer base, environmental compliance, peaking generation and future baseload generation. To accomplish our objectives of supporting Tampa Electric's growth and reducing parent debt, in 2007 we completed the sale of TECO Transport for $405 million of gross proceeds. The sale allowed us to accelerate the retirement in 2007 of almost $300 million of parent debt and $111 million of parent-guaranteed debt. The accelerated debt retirement allowed us to deploy 2008 cash generation that would otherwise have been applied to debt reduction to investment in Tampa Electric. In 2008, we made cash equity contributions totaling $292 million to Tampa Electric to strengthen its capital structure and to support its capital program.

OUTLOOK

We remain focused on our long-term goal of investing in and growing our Florida utility businesses, while generating significant cash and earnings from our other energy-related businesses, TECO Coal and TECO Guatemala. Continuing the process of paying down and restructuring the parent debt that remains from the failed merchant power investments that were made early in this decade, with portions of that debt maturing in 2010, 2011 and 2012, remains a priority as well.

Important factors in our 2009 results will be the decisions to be made by the FPSC in the base rate proceedings at Tampa Electric and PGS. Both utility companies expect that the FPSC will continue its long history of balanced regulatory decisions; however, the company believes that it would be inappropriate to provide an earnings guidance range until after these regulatory proceedings are concluded, which is expected to be in the spring of 2009. TECO Energy expects that its results in 2009 will be driven by the factors discussed below.

Assuming normal weather, Tampa Electric expects energy sales to be higher in 2009, after the very mild weather in 2008. Based on forecasts published by various investment banks and nationally recognized experts in early 2009, the weak economy was not expected to start to improve until at least the second half of 2009; however, continued deterioration of the national economy through February 2009 has raised new questions as to the timing of a start to an economic recovery. The Florida housing market is not expected to start to recover until after a general economic recovery begins. Until the economy and housing markets start to improve, it is difficult to forecast when customer and related energy sales growth will resume. Non-fuel operation and maintenance expense is expected to increase in 2009 compared to 2008 due to increased costs for subcontracted labor and materials; increased spending on coal-fired generating unit maintenance, tree trimming and shipping channel dredging; and higher bad debt expense. Depreciation expense is expected to increase from additions to facilities to serve customers; interest expense is expected to increase due to higher long-term debt balances associated with the construction program; and interest income is expected to decrease due to lower under-recovered FPSC-approved clause balances. Environmental Cost Recovery Clause-related earnings are expected to increase due to the completion of the third nitrogen oxide (NO_x) control project, which is expected to enter service in May. In November 2008, the FPSC approved Tampa Electric's fuel cost recovery filing, which included full recovery of waterborne and rail transportation costs for the delivery of solid fuel under a new contract effective Jan. 1, 2009. This approval eliminates the approximately $10 million annual reduction in net income that has occurred over the past five years of the previous transportation contract.

In 2009, customer and therm sales growth at PGS will be impacted by the uncertain timing of economic and housing market recoveries. Operation and maintenance and depreciation expenses are expected to increase. Interim base rate relief was granted in 2008 which amounts to approximately $2.4 million on an annualized basis.

TECO Coal expects 2009 net income to increase over 2008 from higher contract selling prices. Total sales are expected to be in a range between 9.8 million and 10.3 million tons in 2009, compared to 9.3 million tons in 2008. This level of expected production, which is lower than previously projected, is in response to the current world-wide supply and demand equation for metallurgical coal. Approximately 9.6 million tons of expected sales are currently contracted at an average selling price of approximately $73 per ton. The unsold tons are metallurgical and pulverized coal injection (PCI) coal. As of February 2009, the metallurgical and PCI coal normally sold to European customers had not been contracted due to the significant slowdown in the world-wide steel industry in response to the economic slowdown. In a normal contract year, these contracts would be expected to be signed by the end of March with the new contracts initiating in April. The fully-loaded, all-in cost of production is expected to be in a range between $63 and $66 per ton in 2009. Diesel fuel prices have been hedged for those contracts that do not have diesel price adjustments in the contract.

TECO Guatemala expects 2009 net income to decrease from 2008 levels, primarily due to the Value Added Distribution (VAD) tariff decision in 2008, which significantly lowered rates charged by EEGSA beginning in August 2008, and lower generation from the San José Power Station. The lower VAD is expected to put all of the earnings from EEGSA to TECO Guatemala, which had previously averaged about $10 million annually, at risk as long as the lower rates are in effect. In

2008, there was a five-month reduction in earnings from the VAD decision, but if the situation remains unresolved there would be a full year reduction in earnings in 2009. TECO Guatemala has served a Notice of Intent under DR-CAFTA indicating its intent to file an arbitration claim against the Republic of Guatemala for damages to its EEGSA partnership interest as a result of the VAD decision. The San José Power Station has been off-line since mid-January due to an equipment failure and is not expected to return to service until approximately mid-March. After its return to service, the economic dispatch of the San José Power Station will be dependent on the price of fuel for other generators. Currently, the dispatch price for some of the diesel generating resources in Guatemala, which use residual fuel oil, is below the dispatch price for the San José Power Station, which includes the cost of coal plus a non-fuel variable cost component. If this relationship persists, generation from the San José Power Station could continue to be limited, thus limiting non-fuel energy sales revenues. However, the station has a 65% minimum take provision under its power sales agreement, which could be reduced if the plant does not meet an 85% availability rating under the power sales agreement. Results in 2009 will also be impacted by the much lower spot energy sales and margins from the San José Power Station, driven by the same oil/coal price differential condition, lower interest income on lower cash balances after the repatriation of cash in 2008, lower operator fees associated with the DECA II companies and the absence of 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.

These forecasts are based on our current assumptions described in each operating company discussion, which are subject to risks and uncertainties (see the **Risk Factors** section).

We are maintaining our priorities for the use of cash, which are investing in the utility companies, and restructuring and paying down parent debt as opportunities arise. We expect to make additional equity contributions to Tampa Electric in 2009 to support its continued capital spending for environmental controls and its capital investment program.

Capital expenditures increased in 2008, primarily at Tampa Electric for equipment to control NO_x emissions, compliance with the FPSC-mandated transmission and distribution system storm hardening requirements, distribution system reliability improvement and heat rate and capacity factor improvements to our coal-fired units. We also invested in new mining equipment and continued development of mines at TECO Coal. We forecast capital expenditures to increase further to more than $600 million in 2009 at Tampa Electric and to fluctuate between $370 million and more than $600 million per year through 2013 to meet the expected resumption of customer growth and generation plant maintenance, for peak load generating capacity expansion, for distribution system improvements to provide higher reliability, for its portion of transmission system expansion and for upgrades in the Central Florida area to meet the new National Electric Reliability Council (NERC) reliability standards. We also plan to invest in modest distribution system expansion at PGS, and for normal maintenance capital and regulatory compliance at TECO Coal in 2009 (see the **Liquidity, Capital Resources** section).

RESULTS SUMMARY

Since July 2006, we have provided two measures to allow comparison of our results with and without synthetic fuel. They are non-GAAP results from continuing operations including benefits from the production of synthetic fuel (Non-GAAP Results With Synthetic Fuel), which exclude certain charges and gains but include synthetic fuel benefits or costs, and non-GAAP results excluding synthetic fuel (Non-GAAP Results Excluding Synthetic Fuel), which exclude charges, gains and benefits associated with the production of synthetic fuel (see the **Non-GAAP Information** section). Although, with the expiration of the synthetic fuel tax credits at the end of 2007, we no longer produce synthetic fuel, we are continuing to provide both non-GAAP measures for historical comparison purposes.

The table below compares our GAAP net income to our non-GAAP measures. A reconciliation between GAAP net income and the two non-GAAP measures is contained in the **Reconciliation of GAAP net income from continuing operations to non-GAAP results** tables included for each year. A non-GAAP financial measure is a numerical measure that includes or excludes amounts, or is subject to adjustments that have the effect of including or excluding amounts, that are included or excluded from the most directly comparable GAAP measure (see the **Non-GAAP Information** section).

Results Comparisons

(millions)	*2008*	*2007*	*2006*
Net income	**$162.4**	$413.2	$246.3
Net income from continuing operations	**$162.4**	$398.9	$244.4
Non-GAAP Results With Synthetic Fuel	**$183.3**	$276.3	$233.6
Non-GAAP Results Excluding Synthetic Fuel	**$183.3**	$223.7	$201.5

In 2008, net income and earnings per share were $162.4 million or $0.77 per share, compared to $413.2 million or $1.98 per share in 2007, which included a gain on the December 2007 sale of TECO Transport. Our non-GAAP results in 2008, which exclude the charges and gains, on a per share basis were $0.87 per share, compared to $1.07 in 2007 (see the **2008** and **2007 Reconciliation of GAAP net income from continuing operations to non-GAAP results** tables). TECO Transport and the production of synthetic fuel contributed $34.0 million and $52.6 million, respectively, or $0.41 per share collectively, to 2007 net income. Compared to 2007, our results in 2008 reflected higher earnings at PGS, lower interest expense at the TECO Energy parent level and lower earnings from both Tampa Electric and TECO Coal. Our net income and earnings per share were reduced by $21.6 million and $0.10 per share, respectively, for income taxes related to the repatriation of cash and investments from TECO Guatemala, of which $9.6 million was recognized by TECO Guatemala and $12.0 million by TECO Energy parent. Our 2008 results benefited from improved performance by TECO Guatemala, exclusive of the tax charge.

Compared to 2006, our results in 2007 reflected higher earnings from the production of synthetic fuel at TECO Coal, higher earnings at Tampa Electric and TECO Guatemala and lower parent-level interest expense partially offset by lower results at PGS. As a result of the sale transaction, results at TECO Transport are included only through Dec. 3, 2007. Net income and earnings per share were $413.2 million or $1.98 per share in 2007, compared to $246.3 million or $1.19 per share in 2006. Results in 2007 included the $149.4 million gain and the $16.3 million of costs related to the sale of TECO Transport, which closed in December, and $20.2 million of charges related to the debt extinguishment/exchange transactions completed in December. Net income and earnings per share from continuing operations were $398.9 million or $1.91 per share in 2007, compared to $244.4 million or $1.18 per share in 2006. In 2007, results reflected a $14.3 million tax benefit recorded in discontinued operations in the second quarter as a result of reaching a favorable conclusion with taxing authorities related to the 2005 disposition of the Union and Gila River merchant power plants. TECO Transport was not classified as a discontinued operation due to its ongoing contractual relationship with Tampa Electric for solid fuel waterborne transportation services.

Results in 2007 included a $52.6 million, or $0.25 per share, benefit to earnings from synthetic fuel production. The $52.6 million of benefits from the production of synthetic fuel in 2007 reflected a $91.1 million reduction in earnings benefits due to an estimated 67% phase-out of benefits as a result of high oil prices, compared to a $36.7 million reduction due to a 35% phase-out in 2006. The results for synthetic fuel production also reflected a $53.8 million benefit from adjusting to market the valuation of the oil price hedges placed to protect the 2007 synthetic fuel benefits against high oil prices. In 2006, full-year results included a $1.7 million mark-to-market charge (see the **TECO Coal** section).

In 2006, results from continuing operations also included an $8.1 million gain from the sale of the McAdams Power Station assets, $5.7 million of gains from the sale of two unused steam turbines, and $3.0 million of charges net of insurance recoveries related to Hurricane Katrina damage at TECO Transport. Results from discontinued operations in 2006 primarily included the recovery of amounts that had been previously written off and tax adjustments at the small energy services companies.

2008 Earnings Summary

(millions) Except per-share amounts	***2008***	*2007*	*2006*
Consolidated revenues	**$3,375.3**	$3,536.1	$3,448.1
Earnings per share – basic			
Earnings per share	**$ 0.77**	$ 1.98	$ 1.19
Discontinued operations	—	0.07	0.01
Earnings per share from continuing operations	**$ 0.77**	$ 1.91	$ 1.18
Earnings per share – diluted			
Earnings per share	**$ 0.77**	$ 1.97	$ 1.18
Discontinued operations	—	0.07	0.01
Earnings per share from continuing operations	**$ 0.77**	$ 1.90	$ 1.17
Net income	**$ 162.4**	$ 413.2	$ 246.3
Net income from discontinued operations	—	(14.3)	(1.9)
Charges and (gains) from continuing operations(1)	**20.9**	(122.6)	(10.8)
Non-GAAP results with synthetic fuel(2)	**183.3**	276.3	233.6
Synthetic fuel impact(1)	—	(52.6)	(32.1)
Non-GAAP results excluding synthetic fuel(2)	**$ 183.3**	$ 223.7	$ 201.5
Average common shares outstanding			
Basic	**210.6**	209.1	207.9
Diluted	**211.4**	209.9	208.7

(1) See the GAAP to non-GAAP reconciliation tables that follow.

(2) A non-GAAP financial measure is a numerical measure that includes amounts, or is subject to adjustments that have the effect of including amounts, that are excluded from the most directly comparable GAAP measure (see the **Non-GAAP Information** section).

The following tables show the specific adjustments made to GAAP net income for each segment to develop our non-GAAP results:

2008 Reconciliation of GAAP net income from continuing operations to non-GAAP results

Net income impact (millions)	*Tampa Electric*	*Peoples Gas*	*TECO Coal*	*TECO Guatemala*	*Parent/ Other*	*Total*
GAAP Net income from continuing operations	$135.6	$27.1	$18.0	$36.9	$(55.2)	$162.4
Waterborne transportation dispute settlement	1.9	—	—	—	—	1.9
Final adjustments associated with the sale of TECO Transport recorded at Parent	—	—	—	—	(2.6)	(2.6)
Taxes on repatriation of cash and investments from Guatemala	—	—	—	9.6	12.0	21.6
Total charges and (gains)	1.9	—	—	9.6	9.4	20.9
Non-GAAP results	$137.5	$27.1	$18.0	$46.5	$(45.8)	$183.3

2007 Reconciliation of GAAP net income from continuing operations to non-GAAP results

Net income impact (millions)	*Tampa Electric*	*Peoples Gas*	*TECO Coal*	*TECO Transport**	*TECO Guatemala*	*Parent/ Other*	*Total*
GAAP Net income from continuing operations	$150.3	$26.5	$90.9	$34.0	$44.7	$52.5	$398.9
Gain on sale of TECO Transport	—	—	—	—	—	(149.4)	(149.4)
Asset held for sale - depreciation	—	—	—	(9.7)	—	—	(9.7)
Costs associated with the sale of TECO Transport recorded at Parent	—	—	—	—	—	16.3	16.3
Debt extinguishment/exchange	—	—	—	—	—	20.2	20.2
Total charges and (gains)	—	—	—	(9.7)	—	(112.9)	(122.6)
Non-GAAP results with synthetic fuel*	150.3	26.5	90.9	24.3	44.7	(60.4)	276.3
Synthetic fuel impact	—	—	(52.6)	—	—	—	(52.6)
Non-GAAP results excluding synthetic fuel*	$150.3	$26.5	$38.3	$24.3	$44.7	$(60.4)	$223.7

*Results for TECO Transport include activity through Dec. 3, 2007.

2006 Reconciliation of GAAP net income from continuing operations to non-GAAP results

Net income impact (millions)	*Tampa Electric*	*Peoples Gas*	*TECO Coal*	*TECO Transport*	*TECO Guatemala*	*Parent/ Other*	*Total*
GAAP Net income (loss) from continuing operations	$135.9	$29.7	$78.8	$22.8	$37.6	$(60.4)	$244.4
Hurricane costs	—	—	—	4.5	—	—	4.5
Hurricane insurance cost recoveries	—	—	—	(1.5)	—	—	(1.5)
Dell and McAdams valuation adjustment and gain on sale, net	—	—	—	—	—	(8.1)	(8.1)
Gain on sale of unused steam turbines	—	—	—	—	—	(5.7)	(5.7)
Total charges and (gains)	—	—	—	3.0	—	(13.8)	(10.8)
Non-GAAP results with synthetic fuel	135.9	29.7	78.8	25.8	37.6	(74.2)	233.6
Synthetic fuel impact	—	—	(32.1)	—	—	—	(32.1)
Non-GAAP results excluding synthetic fuel	$135.9	$29.7	$46.7	$25.8	$37.6	$(74.2)	$201.5

Non-GAAP Information

From time to time, in this Management's Discussion & Analysis of Financial Condition and Results of Operations, we present non-GAAP results, which present financial results after elimination of the effects of certain identified gains and charges. We believe that the presentation of this non-GAAP financial performance provides investors a measure that reflects the company's operations under our business strategy. We also believe that it is helpful to present a non-GAAP measure of performance that clearly reflects the ongoing operations of our business and allows investors to better understand and evaluate the business as it is expected to operate in future periods. Management and the Board of Directors use this non-GAAP presentation as a yardstick for measuring our performance, making decisions that are dependent upon the profitability of our various operating units and in determining levels of incentive compensation.

The non-GAAP measure of financial performance we use is not a measure of performance under accounting principles generally accepted in the United States and should not be considered an alternative to net income or other GAAP figures as an indicator of our financial performance or liquidity. Our non-GAAP presentation of results may not be comparable to similarly titled measures used by other companies.

While none of the particular excluded items is expected to recur, there may be adjustments to previously estimated gains or losses related to the disposition of assets or additional debt extinguishment activities. We recognize that there may be items that could be excluded in the future. Even though charges may occur, we believe the non-GAAP measure is important in addition to GAAP net income for assessing our potential future performance, because excluded items are limited to those that we believe are not indicative of future performance.

OPERATING RESULTS

This Management's Discussion & Analysis of Financial Condition and Results of Operations utilizes TECO Energy's consolidated financial statements, which have been prepared in accordance with GAAP and separate non-GAAP measures, to analyze the financial condition of the company. Our reported operating results are affected by a number of critical accounting estimates such as those involved in our accounting for regulated activities, asset impairment testing and others (see the **Critical Accounting Policies and Estimates** section).

The following table shows the segment revenues, net income, and earnings per share contributions from continuing operations of our business segments on a GAAP basis (see **Note 14** to the **TECO Energy Consolidated Financial Statements**).

(millions) Except per share amounts		***2008***	*2007*	*2006*
Segment Revenues (1)				
Regulated companies	Tampa Electric	**$2,091.2**	$2,188.4	$2,084.9
	Peoples Gas	**688.4**	599.7	577.6
Total regulated		**$2,779.6**	$2,788.1	$2,662.5
Unregulated companies	TECO Coal	**$ 588.4**	$ 544.5	$ 574.9
	TECO Guatemala(3)	**8.4**	8.0	7.6
	TECO Transport(2)	—	290.3	308.5
Total unregulated		**$ 596.8**	$ 842.8	$ 891.0
Net Income (4)				
Regulated companies	Tampa Electric	**$ 135.6**	$ 150.3	$ 135.9
	Peoples Gas	**27.1**	26.5	29.7
Total regulated		**162.7**	176.8	165.6
Unregulated companies	TECO Coal	**18.0**	90.9	78.8
	TECO Guatemala	**36.9**	44.7	37.6
	TECO Transport(2)(5)	—	34.0	22.8
Total unregulated		**54.9**	169.6	139.2
Parent/other		**(55.2)**	52.5	(60.4)
Net income from continuing operations		**162.4**	398.9	244.4
Discontinued operations		—	14.3	1.9
Net income		**$ 162.4**	$ 413.2	$ 246.3
Earnings per Share - Basic (6)				
Regulated companies	Tampa Electric	**$ 0.64**	$ 0.72	$ 0.65
	Peoples Gas	**0.13**	0.13	0.14
Total regulated		**0.77**	0.85	0.79
Unregulated companies	TECO Coal	**0.08**	0.44	0.38
	TECO Guatemala	**0.18**	0.21	0.18
	TECO Transport(2) (5)	—	0.16	0.11
Total unregulated		**0.26**	0.81	0.67
Parent/other		**(0.26)**	0.25	(0.28)
Earnings from continuing operations		**0.77**	1.91	1.18
Discontinued operations		—	0.07	0.01
EPS Total		**$ 0.77**	$ 1.98	$ 1.19
Average shares outstanding – basic		**210.6**	209.1	207.9

(1) Segment revenues include intercompany transactions that are eliminated in the preparation of TECO Energy's consolidated financial statements.

(2) 2007 results for TECO Transport reflect activities through Dec. 3, 2007.

(3) Guatemalan entities CGESJ (San José) and TCAE (Alborada) were deconsolidated under Financial Accounting Standards Board Interpretation No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51* (FIN 46R) effective Jan. 1, 2004.

(4) Segment net income and earnings are reported on a basis that includes internally allocated financing costs to the non-utility companies. Internally allocated finance costs for 2008, 2007 and 2006 were at pretax rates of 7.25%, 7.5% and 7.5%, respectively, based on the average investment in each unregulated subsidiary.

(5) Results at TECO Transport reflect the $9.7 million benefit in depreciation expense from not recording depreciation expense due to its classification as Assets Held for Sale effective Apr. 1, 2007 through Dec. 3, 2007.

(6) The number of shares used in the earnings-per-share calculations is basic shares.

TAMPA ELECTRIC

Electric Operations Results

In 2008, net income was $135.6 million, compared to $150.3 million in 2007. Tampa Electric's 2008 non-GAAP results were $137.5 million, which excluded a $1.9 million charge related to the settlement with the FPSC related to a dispute that arose in 2008 over the calculation of Tampa Electric's waterborne transportation disallowance over its five-year life (see the **2008 Reconciliation of GAAP net income from continuing operations to non-GAAP results** table). These results were driven primarily by lower retail energy sales, higher depreciation, lower interest income and higher interest expense, partially offset by higher earnings on emissions control equipment recovered through the Environmental Cost Recovery Clause (ECRC) (see the **Environmental Compliance** section), slightly lower operation and maintenance and property tax expense, and higher revenues from the sales of sulfuric acid, which is a by-product from the production of electricity at the Polk Power Station. These results reflect retail energy sales 2.8% lower than in 2007. The average number of retail customers increased 0.1% for the year, significantly lower than in prior years as a result of the slowdown in the Florida economy and housing market. Total heating and cooling degree days were 5% below normal and 8% below 2007 levels.

In 2008, excluding all FPSC-approved cost recovery clause-related expenses, operation and maintenance expense decreased $0.8 million, compared to 2007, primarily due to $4.0 million higher spending on generating unit maintenance and repairs and $0.8 million higher bad-debt expense, more than offset by $4.2 million lower employee-related expenses and other smaller cost reductions totaling $0.6 million in aggregate. Property tax expense decreased $0.7 million reflecting adjustments to property valuations agreed to with taxing authorities. Depreciation and amortization expense increased $4.3 million reflecting additional facilities to serve customers. Interest expense increased $1.5 million due to higher interest rates, and interest income decreased $2.9 million due to lower under-recovered fuel balances. Net income also included $6.3 million of Allowance for Funds Used During Construction (AFUDC)-equity related to the construction of the peaking generation units and the installation of NO_x pollution control equipment, compared to $4.5 million in 2007.

In 2007, Tampa Electric recorded net income of $150.3 million compared to $135.9 million in 2006. These results were driven primarily by lower depreciation and property tax expense and higher retail energy sales, partially offset by higher operation and maintenance and interest expense. These results reflect 2.7% higher retail energy sales and off-system energy sales that were 5.0% higher than in 2006. The positive effects of 1.9% average retail customer growth and total heating and cooling degree days that were more than 2% above normal and 5% above 2006 total heating and cooling degree days were partially offset by changes in residential customers' energy consumption patterns.

Since Tampa Electric's last base rate proceeding in 1992, it has added more than 200,000 customers and has made significant investments in facilities and infrastructure. These facilities include baseload, intermediate and peaking generating capacity additions to reliably serve the growing customer base. Tampa Electric expects a continued high level of capital investment, and higher levels of non-fuel operation and maintenance expenditures. At the end of 2007, Tampa Electric's 13-month average regulatory ROE was 11.4%, as a result of the positive impact of favorable weather in the second half of 2007 and lower depreciation expense and lower property taxes in the second half of the year. However, because of lower customer growth, slower energy sales growth, and ongoing high levels of capital investment, Tampa Electric's 13-month average regulatory ROE was 8.7% at the end of 2008. We made cash equity contributions totaling $292 million to Tampa Electric to strengthen its capital structure and to support its capital program in 2008.

Recognizing the significant decline in ROE, Tampa Electric filed for a $228 million base rate increase in August 2008. The major factors in the filing included a request for an ROE mid-point of 12.0%, 55.3% equity in the capital structure, and rate base of $3.7 billion. The formal hearings before the FPSC were held in January, and the FPSC is scheduled to make its final decision on the requested increase in mid-March, with final rates effective in May 2009.

Summary of Operating Results

(millions)	*2008*	*% Change*	*2007*	*% Change*	*2006*
Revenues	**$2,091.2**	(4.4)	$2,188.4	5.0	$2,084.9
Other operating expenses	**207.7**	(0.3)	208.4	(5.4)	220.3
Maintenance	**116.2**	6.3	109.3	1.5	107.7
Depreciation	**185.6**	3.9	178.6	(4.1)	186.3
Taxes, other than income	**136.5**	(2.8)	140.4	1.7	138.1
Non-fuel operating expenses	**646.0**	1.5	636.7	(2.4)	652.4
Fuel	**819.4**	(13.6)	947.9	4.5	906.8
Purchased power	**305.4**	12.3	271.9	22.9	221.3
Total fuel expense	**1,124.8**	(7.8)	1,219.8	8.1	1,128.1
Total operating expenses	**1,770.8**	(4.6)	1,856.5	4.3	1,780.5
Operating income	**320.4**	(3.5)	331.9	9.0	304.4
AFUDC equity	**6.3**	40.0	4.5	66.7	2.7
Net income	**$ 135.6**	(9.8)	$ 150.3	10.6	$ 135.9
Megawatt-Hour Sales (thousands)					
Residential	**8,546**	(3.7)	8,871	1.7	8,721
Commercial	**6,399**	(2.2)	6,542	2.9	6,357
Industrial	**2,205**	(6.8)	2,366	3.8	2,279
Other	**1,840**	4.9	1,754	5.2	1,668
Total retail	**18,990**	(2.8)	19,533	2.7	19,025
Sales for resale	**884**	(2.3)	905	5.0	862
Total energy sold	**19,874**	(2.8)	20,438	2.8	19,887
Retail customers-thousands (average)	**667.3**	0.1	666.4	1.9	653.7

Operating Revenues

In 2008, retail megawatt-hour sales declined 2.8%, which resulted in a $19.0 million reduction in base revenue, due to milder than normal weather and voluntary conservation by customers, which we believe to be in response to the generally weaker economic conditions. Total heating and cooling degree days were 5% below normal and 8% below 2007 levels. Weather-normalized residential per-customer usage declined again in 2008. It is now apparent that some of the robust residential customer growth in the 2005 through mid-2007 period, which was measured by new meter installations, was actually vacant residences with minimal energy usage. The average number of residential customers with minimal usage increased more than 7% in 2008.

Retail megawatt-hour sales rose 2.7% in 2007, driven by customer growth, total heating and cooling degree days above normal and 2006 and a rebound in the phosphate industry. In 2007, average annual customer growth of 1.9% was partially offset by lower weather normalized average residential per-customer energy usage. Total heating and cooling degree days in Tampa Electric's service area were 2% above normal and 5% above 2006.

In 2008 and 2007, weather-normalized energy consumption per residential customer declined due to the combined effects of conservation efforts, residential vacancies and changes in residential building trends. One of the factors contributing to this phenomenon was an increase in the number of multi-family units, such as apartments and condominiums, completed in the Tampa metropolitan area. It is now apparent that a number of the new condominium units and other new residential units were never occupied and had minimal electricity usage, which reduced the average per customer usage. In addition, we believe that the higher costs for natural gas and coal, which are reflected in customers' bills through the fuel adjustment clause, may have caused customers to use less electricity in general.

Electricity sales to the phosphate industry decreased 7.7% in 2008 following a 12.2% increase in 2007. The decline in sales to phosphate customers was partially attributable to equipment outages at their production facilities and the very high level of sales in 2007 when the phosphate fertilizer producers experienced increased demand for their product. Base revenues from phosphate sales represented less than 2% of base revenues in 2008 and 2007. Sales to commercial customers decreased 2.2% in 2008, reflecting the weaker local economy.

Base rates for all customers were unchanged in 2008. Fuel-related rates decreased in 2008, after an increase in 2007 under the FPSC-approved fuel cost recovery clause. The 2008 decrease was due to an $18 million over-recovery of fuel costs in 2007 from more stable natural gas prices in 2007 and a forecast for continued stable natural gas prices in 2008. The 2007 increase was due to the recovery of previous under-recoveries of fuel expense in 2006. In 2007, the impact of higher fuel clause recovery was partially offset by the planned sale of a net $72 million of excess sulfur dioxide (SO_2)

emission credits, which appeared as a credit on customers' bills through the Environmental Cost Recovery Clause (see the **Regulation** section).

Customer rates under the fuel clause will increase in 2009, under the rates approved by the FPSC in November 2008. The 2009 fuel rates reflect the under-recovery of fuel costs in 2008 due to the rapid increase in natural gas prices in the first half of the year and higher coal prices expected in 2009 (see the **Regulation** section).

Energy sold to other utilities for resale decreased 2.3% in 2008, due to lower coal unit availability in the first six months of the year. Energy sold to other utilities for resale increased 5% in 2007 due to a planned increase under a contract with an existing customer.

Customer and Energy Sales Growth Forecast

In March 2008, Tampa Electric revised its 2008 and 2009 average annual customer growth forecasts to 0.8% and 1.2%, respectively. Actual average 2008 customer growth was 0.1% reflecting customer growth in the first six months of the year that was partially offset by a decline in the number of customers in the last three months. This actual level of customer growth was below the revised growth forecast, which makes the previous forecast of 1.2% total customer growth in 2009 difficult to achieve. Due to the slower growth experienced in 2008, Tampa Electric is reassessing its forecast of long-term energy demand and sales growth.

Assuming normal weather, Tampa Electric expects energy sales to grow in 2009 after the very mild weather in 2008. Based on forecasts published by various investment banks and nationally recognized experts in early 2009, the weak economy was not expected to start to improve until at least the second half of 2009; however, continued deterioration of the national economy through February 2009 has raised new questions as to the timing of a start to an economic recovery. The Florida housing market is not expected to start to recover until after a general economic recovery begins. Until the economy and housing markets start to improve it is difficult to forecast when customer and related energy sales growth will resume (see the **Risk Factors** section).

Longer-term, assuming that an economic recovery starts in the second half of 2009, and that growth from population increases and business expansion will resume, Tampa Electric expects average annual customer growth to return to a level of nearly 2% and weather-normalized average retail energy sales growth at about that same level. This energy sales growth projection is lower than previous projections, reflecting changes in usage patterns that continued in 2008, and changes in population trends. Tampa Electric's forecasts indicate that summer retail peak demand growth is expected to average 85 megawatts per year for the next five years. These growth projections assume a resumption of local area economic growth, normal weather, a slow recovery in the housing market over time, and a continuation of the current energy market structure.

The economy in Tampa Electric's service area contracted in 2008 after modest growth in 2007. Initially, the contraction was centered in the housing and related industries, but spread to the general economy later in the year. The Tampa metropolitan area's employment decreased 2.7% in 2008, led by a 9% decrease in construction jobs. This level of job loss is greater than statewide losses in Florida. The local Tampa area unemployment rate increased to 8.3% at year-end 2008, compared with 4.7% in December 2007, and 3.0% in December 2006. The 2008 unemployment rate is higher than the 8.1% unemployment rate for the state of Florida and higher than the 7.2% for the nation at Dec. 31, 2008, which is contrary to the trends experienced in previous economic slowdowns. The more severe downturn in the Tampa area and Florida was initially driven by the sharp downturn in construction activity following the boom in the 2005 and 2006 periods, which has since spread to other housing-related businesses and the economy in general. Since its peak in June 2006, construction employment for the Tampa area and the state of Florida is down 20% and 26%, respectively.

As in many areas of the country, the housing market in Tampa Electric's service area weakened further in 2008, continuing the slowdown that started in 2007 after the growth in 2005 and 2006. The numbers of existing homes for sale and unsold new homes has increased significantly, driven by excess builder inventory, the curtailment of speculative investing and sub-prime mortgage issues. Florida is often cited in economic reports as one of the states that experienced the most overbuilding during the housing boom and is now experiencing the most significant downturn. The number of residential building permits declined 25% in 2008 following a 40% decline in 2007. Economists and real estate associations indicate that the housing market is expected to remain weak throughout 2009 with a recovery possibly starting in 2010, depending on the timing of a general economic recovery and the absorption of excess inventory.

At the same time, Florida continues to experience population growth, although at a slower rate than in previous years. According to the most recent U.S. Census Bureau data, Florida added 128,000 new residents in 2008.

Operating Expenses

Total operating expense decreased 4.6% in 2008, driven by lower fuel expense and lower taxes other than income including lower property taxes and sales-related taxes and lower franchise fees. In 2008, excluding all FPSC-approved cost recovery clause-related expenses, operation and maintenance expense decreased $0.8 million, compared to 2007, primarily due to $4.0 million higher spending on generating unit maintenance and repairs and $0.8 million higher bad debt expense more than offset by $4.2 million lower employee related expenses, and $1.4 million of other smaller cost reductions. Property tax expense decreased $0.7 million driven by adjustments to property valuations agreed to with taxing authorities.

Total operating expense increased in 2007, primarily due to higher costs for coal, increased usage of natural gas and increased levels of power purchased as a result of decreased coal-fired generation due to the planned outages to install NO_x control equipment (see the **Environmental Compliance** section). Excluding all FPSC-approved cost recovery clause-related expenses, operation and maintenance expense increased by $3.6 million, or 1.9%, primarily due to $2.1 million of higher employee-related costs, $1.5 million of incremental additional spending on the distribution system to comply with the FPSC-mandated storm hardening requirements and $2.4 million of administrative costs, including higher bad debt expense, more than offsetting a $2.4 million decrease in actuarially determined self-insurance reserves. In addition, property tax expense decreased $2.7 million.

Tampa Electric expects operation and maintenance expense, excluding fuel and purchased power, to increase significantly in 2009 after the slight decline in 2008 and 1.9% growth in 2007. The 2009 non-fuel operation and maintenance expense increase is expected to be driven by increased costs for subcontracted labor and materials, increased spending on coal-fired generating unit maintenance, increased spending on tree trimming and shipping channel dredging, and higher bad debt expense.

Depreciation expense increased $4.3 million in 2008, reflecting additional facilities to serve customers. Depreciation expense decreased $4.7 million in 2007 primarily due to a depreciation study approved by the FPSC, which lowered depreciation rates on power generation assets due to longer lives. Depreciation expense is projected to increase in 2009 due to routine plant additions to serve Tampa Electric's growing customer base and maintain system reliability, a partial year of depreciation on combustion turbines expected to be placed in service in April, August and October and a partial year of depreciation on the third NO_x control project, which is expected to enter service in May.

On a GAAP basis, which includes all FPSC-approved cost recovery clauses, operation and maintenance expense decreased in 2007 compared to 2006. Under regulatory accounting, the cost of fuel or revenue for the sale of excess SO_2 credits on the income statement represents the amounts authorized by the FPSC for recovery through the fuel adjustment clause or refunded through the Environmental Cost Recovery Clause, but the actual cost of fuel purchased or SO_2 credits sold may differ from those amounts. The difference between actual fuel cost or SO_2 revenues and the amount recovered through revenues is deferred on the balance sheet through an adjustment to operating income as either under- or over-recovered costs and therefore does not impact net income. These costs are, in turn, either recovered or refunded to customers typically in the subsequent year.

Fuel Prices and Fuel Cost Recovery

Included in Tampa Electric's 2008 fuel rates were $18 million of 2007 over-recovered fuel costs, net of a $2 million final adjustment to the under-recovery related to 2006 fuel filing, and the expected costs for coal, natural gas and fuel oil in 2008. An increase in amounts recovered through the ECRC occurred in 2008 due to the completion of an additional NO_x control project and lower sales of excess SO_2 emission credits (see the **Regulation** section).

In November 2008, the FPSC approved Tampa Electric's requested 2009 fuel rates. The rates include the costs for natural gas and coal expected in 2009, the net recovery of $132.9 million of fuel and purchased power expenses, which were not collected in 2008, and the net over-recovery of $4.7 million of costs recovered through the ECRC for the 2007 and 2008 periods (see the **Regulation** section).

Total fuel prices decreased in 2008, but purchased power increased due to lower generation from natural gas fired facilities. Average delivered coal and natural gas prices increased 13.0% and 11.4%, respectively, to $2.91 per million BTU (/mmBTU) and $10.61/mmBTU, respectively, in 2008. Fuel prices increased in 2007 primarily due to the shift to higher usage of higher cost natural gas from lower cost coal, despite delivered natural gas costs declining slightly to $9.52/mmBTU in 2007 from $9.61/mmBTU in 2006. Average delivered coal prices increased in 2007 to $2.57/mmBTU, compared to $2.49/mmBTU in 2006.

Natural gas prices were extremely volatile in 2008, as a result of supply and demand conditions in the markets, a spike in commodity prices in general, and in response to record crude oil prices. Natural gas prices dropped significantly in the second half of 2008 and early 2009 due to the world-wide economic slowdown, which has reduced demand by industrial customers across the country. Natural gas prices were more stable in 2006 and 2007, but at consistently higher levels in 2007 due to supply and demand conditions. Assuming no major supply disruptions, natural gas prices are forecast to remain at lower levels in 2009 than in 2008. Coal prices, while less volatile, increased in 2008 and 2007. The coal markets experienced a significant increase in prices for much of 2008, before dropping sharply in the last quarter of 2008. Tampa Electric's primary coal supplies are from the Illinois Basin, which experienced an upward movement in prices in 2008 but not of the same magnitude that prices in the Central Appalachian coal producing region did. Tampa Electric's coal prices are expected to remain stable in 2009 due to new longer-term supply contracts signed in 2008.

Energy Supply

On a retail energy supply basis, Tampa Electric generation accounted for 94%, 93% and 95% of the total retail energy sales in 2008, 2007 and 2006, respectively, with the remainder of the energy supplied by purchased power. Purchased power expense increased 12.3% due to the higher per-unit prices associated with the purchases, but the volume of power purchased decreased 5.6% in 2008 as a result of improved coal-fired unit availability during the high-load summer period. Per-unit purchased power expense increased due to purchasing power from higher-cost natural gas fired generating sources. The cost for purchased power is expected to decrease in 2009 due to lower natural gas prices and a lower volume of purchases driven by a shorter duration of the planned maintenance period for the completion of the SCR project compared to the 2008 SCR outage.

Prior to 2003, nearly all of Tampa Electric's generation was from coal. Starting in April 2003, the mix started to shift with increased use of natural gas at the Bayside Power Station, which was converted from the coal-fired Gannon Station. Nevertheless, coal is expected to continue to represent more than half of Tampa Electric's fuel mix due to the baseload units at the Big Bend Power Station and the coal gasification unit, Polk Unit One. In 2009 and 2010, one of the remaining two Big Bend Power Station coal-fired units will undergo an extensive outage each year to complete the construction of the NO_x control equipment (see the **Environmental Compliance** section), which is expected to reduce the generation from coal in each of those years.

Hurricane Storm Hardening

Due to extensive storm damage to utility facilities during the 2004 and 2005 hurricane seasons and the resulting outages utility customers experienced throughout the state, in 2006 the FPSC initiated proceedings to explore methods of designing and building transmission and distribution systems that would minimize long-term outages and restoration costs related to severe weather.

The FPSC subsequently issued an order requiring all investor owned utilities (IOUs) to implement a 10-point storm preparedness plan designed to improve the statewide electric infrastructure to better withstand severe storms and expedite recovery from future storms. Tampa Electric implemented its plan in 2007 and estimates the average non-fuel operation and maintenance expense of this plan to be approximately $20 million annually for the foreseeable future.

The FPSC also modified its rule regarding the design standards for new and replacement transmission and distribution line construction, including certain critical circuits in a utility's system. Future capital expenditures required under the storm hardening program are expected to average approximately $19 million annually for the foreseeable future (see the **Regulation** section).

Higher Capital Spending

Tampa Electric is in a period of increased capital spending for infrastructure to reliably serve its customer base and for peaking generating capacity additions. In addition to the capital spending to comply with the storm hardening plan described above and the need for additional generating capacity discussed below, Tampa Electric expects to make additional capital investments for its pro-rata portion of state-wide transmission system improvements in Florida and to meet the new NERC reliability standards. It also expects to invest additional amounts in its transmission and distribution system to improve reliability and reduce customer outages.

Due to the dramatic slowdown in the Florida and national economies and the Florida housing market, Tampa Electric is reassessing its forecast of long-term energy demand and sales growth. Tampa Electric had previously identified a need for new baseload capacity in early 2013; however, the current capital forecast reflects a deferral of construction of new baseload capacity beyond this forecast period. This forecast for proposed new generation includes additional combustion turbines in service in the 2012 time frame; however, Tampa Electric may seek to purchase power rather than build additional capacity based on the economics of a decision to purchase rather than build new capacity (see the **Capital Expenditures** and **Regulation** sections).

Pending action by the Florida Legislature on a Florida renewable energy portfolio standard (RPS), the need for additional capital spending on renewable energy sources is likely but not yet defined (see the **Environmental Compliance** section). Depending on the final rules, which the legislature is expected to enact in the 2009 legislative session, Tampa Electric may need to invest capital to develop additional sources of renewable power generation.

PEOPLES GAS (PGS)

Operating Results

PGS reported net income of $27.1 million in 2008, compared to $26.5 million in 2007. Results reflect higher volumes for weather-sensitive residential and small commercial customers due to colder than normal weather in the northern portion of Florida in the fourth quarter, which more than offset mild weather earlier in the year. Higher volumes transported for industrial customers and higher volumes for off-system sales offset lower volumes for power generation customers. Average customer growth of 0.2% was a result of the continued weak Florida housing market. Therm sales to industrial customers increased due to two new customers with significant usage but at lower transportation rates, which partially offset lower volumes for other customers due to the economic conditions. Sales to commercial and industrial customers were impacted by the weak Florida housing market and overall weak economy, which reduced sales to customers such as restaurants and wallboard, asphalt and concrete producers. Results also reflect a $1.5 million benefit from the recognition of environmental remediation insurance recoveries and a $0.9 million benefit related to the completion of pipeline installations for a power generation customer.

In 2008, the total throughput for PGS was 1.4 billion therms. Industrial and power generation customers consumed approximately 45% of PGS' annual therm volume, commercial customers used approximately 26%, approximately 23% was sold off-system, and the balance was consumed by residential customers.

PGS reported net income of $26.5 million in 2007 compared to $29.7 million in 2006. These results reflect 1.6% average customer growth, lower 2007 volumes for retail customers due to one of the warmest months of January on record, which limited the number of heating degree days, and changes in customer usage patterns. Sales to industrial customers, such as wallboard, asphalt and concrete producers, which were impacted by the slowdown in the Florida housing market, were lower. Results also reflected higher low-margin off-system sales and volumes transported for power generation customers.

In 2007, the total throughput for PGS was 1.4 billion therms. Industrial and power generation customers consumed approximately 47% of PGS' annual therm volume, commercial customers used approximately 26%, approximately 22% was sold off-system, and the balance was consumed by residential customers.

While the residential market represents only a small percentage of total therm volume, residential operations generally comprise between 20% and 25% of total revenues depending on the cost of natural gas. New residential construction that includes natural gas and conversions of existing residences to gas has slowed significantly due to the weak Florida housing market. Like most other natural gas distribution utilities, PGS is adjusting to lower per-customer usage due to improving appliance efficiency. As customers replace existing gas appliances with newer, more efficient models, per-customer usage tends to decline.

Natural gas has historically been used in many traditional industrial and commercial operations throughout Florida, including production of products such as steel, glass, ceramic tile and food products. Within the PGS operating territory, large cogeneration facilities utilize gas-fired technology in the production of electric power and steam.

The actual cost of gas and upstream transportation purchased and resold to end-use customers is recovered through a Purchased Gas Adjustment (PGA). Because this charge may be adjusted monthly based on a cap approved by the FPSC annually, PGS normally has a lower percentage of under- or over-recovered gas cost variances than Tampa Electric.

Excluding costs recovered through the FPSC-approved conservation clause, operation and maintenance expenses decreased $1.2 million in 2008, driven primarily by a benefit to environmental remediation expenses discussed above and lower employee-related expenses. Depreciation expense increased $1.1 million due to additions to facilities to serve customers.

Total operating expenses increased 1.6% in 2007, compared to 2006. Non-fuel operation and maintenance expense decreased slightly in 2007, primarily due to lower employee-related costs from more efficient operations and lower actuarially determined self-insurance reserves more than offsetting the increased use of contract labor and higher cost of supplies such as gasoline to operate vehicles. Depreciation expense increased $2.2 million in 2007 due to higher depreciation rates resulting from a routine depreciation study approved by the FPSC in January 2007 and routine plant additions. Results in 2007 also reflected $0.7 million lower property tax expense due to lower property tax rates from legislation passed in Florida to reduce property taxes.

At the end of 2007, PGS' 13-month average regulatory ROE was below the bottom of its allowed range as a result of higher operating costs, continued investment in the distribution system and higher costs associated with required safety requirements, such as transmission and distribution pipeline integrity management.

Recognizing the significant decline in ROE, PGS filed for a $26.5 million base rate increase in August 2008. The major factors in the filing included a request for an ROE mid-point of 11.5%, 54.7% equity in the capital structure, and rate base of $564 million. The formal hearings before the FPSC are scheduled to be held in March, and the FPSC is scheduled to make its final decision on the requested increase in May, with final rates effective in June 2009.

Summary of Operating Results

(millions)	*2008*	*% Change*	*2007*	*% Change*	*2006*
Revenues	**$688.4**	14.8	$599.7	3.8	$577.6
Cost of gas sold	**476.6**	22.2	389.9	6.7	365.3
Operating expenses	**150.3**	(0.4)	150.9	1.6	148.5
Operating income	**61.5**	4.4	58.9	(7.7)	63.8
Net income	**27.1**	2.3	26.5	(10.8)	29.7

Therms sold – by customer segment					
Residential	**74.4**	6.1	70.1	(4.0)	73.0
Commercial	**375.9**	1.3	370.9	(1.3)	375.7
Industrial	**513.3**	4.8	489.8	7.3	456.6
Power generation	**455.6**	(3.4)	471.7	19.2	395.7
Total	**1,419.2**	1.2	1,402.5	7.8	1,301.0
Therms sold – by sales type					
System supply	**457.8**	4.6	437.8	11.9	391.1
Transportation	**961.4**	(0.3)	964.7	6.0	909.9
Total	**1,419.2**	1.2	1,402.5	7.8	1,301.0
Customer (thousands) – average	**335.1**	0.2	334.3	1.6	329.0

In Florida, natural gas service is unbundled for non-residential customers that elect this option, affording these customers the opportunity to purchase gas from any provider. The net result of unbundling is a shift from bundled transportation and commodity sales to transportation sales. Because the commodity portion of bundled sales is included in operating revenues at the cost of the gas on a pass-through basis, there is no net earnings impact to the company when a customer shifts to transportation-only sales. PGS markets its unbundled gas delivery services to customers through its "NaturalChoice" program. At year end 2008, approximately 46% of PGS' non-residential customers had elected to take service under this program.

Customer growth and therm sales growth have been increasingly difficult to forecast, due to the state of the national and Florida economies and the uncertainty of the timing of a recovery in the Florida housing market. In 2008, PGS had forecast customer growth of approximately 1.0%; however, actual customer growth was 0.2%, which is significantly lower than the average customer growth experienced for the past five years. PGS provides service in areas of Florida that experienced some of the most rapid growth in 2005 and 2006, including the Miami, Ft. Myers and Naples areas. These areas are now experiencing the most significant impacts of the slowdown in the housing market.

In 2009, customer growth and therm sales growth at PGS will be impacted by the uncertain timing of economic and housing market recoveries. Operation, maintenance and depreciation expenses are also expected to increase. Interim base rate relief was granted in 2008, which amounts to approximately $2.4 million on an annualized basis.

Since its acquisition by TECO Energy in 1997, PGS has expanded its gas distribution system through system extensions into areas of Florida not previously served by natural gas, such as the lower southwest coast in the Ft. Myers and Naples areas and the northeast coast in the Jacksonville area. In 2009, PGS expects its capital spending to support modest system expansion in anticipation that the Florida housing market will start to recover in 2010. Over time, PGS expects customer additions and related revenues, assuming an economic and housing market recovery throughout the state of Florida, and other factors (see the **Risk Factors** section).

Gas Supplies

PGS purchases gas from various suppliers depending on the needs of its customers. The gas is delivered to the PGS distribution system through three interstate pipelines on which PGS has reserved firm transportation capacity for delivery by PGS to its customers.

Gas is delivered by the Florida Gas Transmission Company (FGT) through more than 59 interconnections (gate stations) serving PGS' operating divisions. In addition, PGS' Jacksonville Division receives gas delivered by the South Georgia Natural Gas Company pipeline through two gate stations located northwest of Jacksonville. PGS also receives gas delivered by Gulfstream Natural Gas Pipeline through seven gate stations.

PGS procures natural gas supplies using baseload and swing-supply contracts with various suppliers along with spot market purchases. Pricing generally takes the form of either a variable price based on published indices, or a fixed price for the contract term.

TECO COAL

TECO Coal recorded net income of $18.0 million in 2008, compared to $90.9 million in 2007. TECO Coal's 2007 Non-GAAP Results Excluding Synthetic Fuel, which excluded the $52.6 million benefit associated with the production of synthetic fuel, were $38.3 million (see the **2007 Reconciliation of GAAP net income from continuing operations to non-GAAP results** table).

In 2008, total sales were 9.3 million tons, compared to 9.2 million tons, which included 6.0 million tons of synthetic fuel in 2007. Results in 2008 reflect an average net selling price per ton across all products, which excluded transportation allowances, almost 7% higher than 2007. Due to the signing of steam coal contracts for 2008 delivery during periods of lower prices in 2006 and 2007 and its 2008 metallurgical coal contracts early in the renewal cycle in late 2007, TECO Coal realized lower average prices per ton in 2008 than other coal producers realized from contracts signed during the period of very strong coal markets in 2008.

The cash cost of production increased 14% in 2008 compared to 2007, driven by diesel oil prices that were 42% higher than 2007 prices, higher per-ton costs for steel products used in underground mining, higher costs for explosives used in surface mining operations and higher costs associated with contract miners. The cost of production in 2008 also reflects the industry-wide issues of a shortage of qualified miners and lost productivity due to increased safety inspections, and difficult geology at several TECO Coal mines at various times during the year. Results also reflect a $2.6 million benefit from a contract settlement related to future coal sales, and a $0.6 million benefit from the true-up of the 2007 synthetic fuel tax credit rate, compared to a $1.6 million benefit in 2007 for the true-up of the 2006 rate.

TECO Coal recorded net income of $90.9 million in 2007, compared to $78.8 million in 2006. TECO Coal's 2007 Non-GAAP Results Excluding Synthetic Fuel, which excluded the $52.6 million of benefits associated with the production of synthetic fuel, were $38.3 million, compared to $46.7 million in 2006, which excluded $32.1 million of synthetic fuel benefits (see the **2007 and 2006 Reconciliation of GAAP net income from continuing operations to non-GAAP results** table).

Total sales were 9.2 million tons in 2007, including 6.0 million tons of synthetic fuel. Total sales were 9.8 million tons in 2006, including 5.3 million tons of synthetic fuel when synthetic fuel production was curtailed for approximately six weeks due to high oil prices. Lower sales were planned for 2007 in response to market weakness that developed in the second half of 2006. Results in 2007 reflect an average net selling price per ton across all products, which excluded transportation allowances, that was about 1% lower than 2006. The cash cost of production increased less than 0.5% in 2007 compared to 2006 reflecting the benefits of actions taken in 2006 and 2007 to close higher cost of production mines and to optimize mining plans. Results also reflect a $1.6 million benefit in 2007 from the true-up of the 2006 synthetic fuel tax credit rate, compared to a $2.7 million benefit in 2006 for the true-up of the 2005 synthetic fuel tax credit rate.

The $52.6 million of benefits from the production of synthetic fuel in 2007 reflect a $91.1 million reduction in earnings benefits due to the estimated 67% phase-out of the tax credit due to high oil prices, compared to the $36.7 million reduction due to a 35% phase-out in 2006. The results for synthetic fuel production also reflect a $53.8 million benefit from adjusting to market the valuation of the oil price hedges placed to protect the 2007 synthetic fuel benefits against high oil prices. In 2006, results included a $1.7 million mark-to-market charge.

Net income in 2006 and 2007 reflected the prior sale by TECO Synfuel Holdings, LLC of 98% of its ownership interest to three third party investors, along with associated percentage rights to benefits in the business that adjusted from time to time. Under these third-party ownership transactions, TECO Coal was paid to provide feedstock, operate the synthetic fuel production facilities and sell the output; TECO Coal also recognized a gain on the sale of the ownership interests in the facilities for each ton of synthetic fuel sold. The purchasers had the risks and rewards of ownership and were allocated 98% of the tax credits and operating costs.

TECO Coal Outlook

We expect TECO Coal's net income to increase in 2009 over 2008 from higher contract selling prices. Total sales are expected to be in a range between 9.8 million and 10.3 million tons in 2009, compared to 9.3 million tons in 2008. As of February 2009, approximately 9.6 million tons of expected sales were contracted at an average selling price of approximately $73 per ton. As of February 2009, the metallurgical and PCI coal normally sold to European customers had not been contracted due to the significant slowdown in the world-wide steel industry in response to the economic slowdown. In a normal contract year, these contracts would be expected to be signed by the end of March. The fully-loaded, all-in cost of production is expected to be in a range between $63 and $66 per ton in 2009. Diesel fuel prices have been hedged for those contracts that do not have diesel price adjustments in the contract.

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 have 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. 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.

TECO Coal sells almost all of its annual production under either multi-year contracts or contracts that recently have been finalized late in the previous year or early in the delivery year. For 2010, TECO Coal currently has approximately 50% of its expected sales contracted, primarily utility steam coal under contracts signed in 2008 at average prices similar to those in 2009.

Coal Markets

Beginning in the fall of 2007, prices for Central Appalachian coal, especially metallurgical coal, increased significantly. Continued strong demand for coal in China and India, bottlenecks in Australian ports, high oceangoing freight rates and the temporary closures of several major U.S. metallurgical coal mines caused prices for coal sold in international markets to increase dramatically in the first half of 2008. In addition, industry-wide expectations for increased exports of U.S. coal, declining domestic inventories and the potential for lower supplies from Central Appalachia due to rising safety costs and delays in issuance of required environmental permits for new mines caused coal prices to rise sharply. At times in 2008, spot prices for Central Appalachian steam and metallurgical coals approached $150 and $200 per ton, respectively.

In the third quarter of 2008, in response to the U.S. economic recession, the prices for many commodities, which had previously experienced very strong and very volatile prices in 2008, started to drop. The decline in commodity prices, including coal, accelerated in the fourth quarter of 2008 due to the spread of the U.S. economic recession to many other economies around the world.

The significant factors that could influence TECO Coal's results in 2009 are cost of production and the price and quantity for the unsold metallurgical and PCI coal tons. Longer-term factors that could influence results include inventories at steam coal users, weather, general economic conditions, the level of oil and natural gas prices, commodity price changes which impact the cost of production and CO_2 reductions if required (see the **Environmental Compliance** and **Risk Factors** sections).

TECO GUATEMALA

Our TECO Guatemala operations consist of two power plants operating in Guatemala under long-term contracts and an ownership interest in DECA II, which has an ownership interest in Guatemala's largest distribution utility, Empresa Eléctrica de Guatemala (EEGSA) and affiliated energy-related companies which provide, among other things, electricity transmission services, wholesale power sales to unregulated electric customers, engineering services and telecommunication services. The San José and Alborada power stations in Guatemala both have long-term power sales contracts. TECO Guatemala's effective 24% ownership interest in EEGSA is held jointly with partners Iberdrola and Electricidad of Portugal (EDP). Together, TECO Guatemala, Iberdrola, and EDP own an 81% controlling interest in EEGSA. TECO Guatemala has a 30% interest in the affiliated companies.

The Guatemalan operations are utility-like in nature due to the regulated nature of the EEGSA investment and the existence of long-term power sales contracts for the power generating facilities. The San José Power Station is a baseload coal-fired station that has had high capacity and availability factors.

The Alborada Power Station, which consists of oil-fired, simple-cycle combustion turbines, is a peak-load facility with high availability, but operates at a low capacity factor by design. Guatemala is heavily dependent on hydro-electric sources for baseload power generation. The Alborada Power Station is under contract to EEGSA but it is designated to be operating reserve status for the country of Guatemala by the country's power dispatcher. The plant runs at peak times or in times of loss of a major generating unit or transmission circuit in the country.

In our 2007 Annual Report on Form 10-K, we reported that our TECO Guatemala subsidiary expected the VAD charges applicable in the tariffs charged by EEGSA to be reset for a new five-year term in the summer of 2008. The VAD was expected to be reset in a manner similar to the process utilized in 2003, in accordance with applicable Guatemalan law.

On Jul. 25, 2008, the National Electric Energy Commission (CNEE), the Guatemalan regulatory body, issued a communication unilaterally disbanding the panel of experts appointed under existing regulations to review and approve the new VAD. EEGSA expected that the panel's action was going to result in increased rates. On Jul. 31, 2008, CNEE issued resolutions setting new tariff rates for EEGSA, which deviated significantly from the rates calculated consistent with the panel of experts' guidance. The new lower VAD set by CNEE was, on average, 50% below the prior level, essentially putting all of EEGSA's earnings, which had previously averaged about $10 million annually, at risk during the time this tariff remains in effect.

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 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. During this 90-day period, the parties may attempt to resolve the dispute amicably through consultation or negotiation (see the **Risk Factors** section). 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 (see **Footnote 12** to the **TECO Energy Consolidated Financial Statements**).

EEGSA, Iberdrola (EEGSA's managing partner), and EEGSA's other investors have actively pursued legal and other efforts in Guatemala to remedy CNEE's actions. Similarly, TGH engaged in discussions with Guatemalan officials in an attempt to resolve the dispute. Through Dec. 31, 2008, these efforts had not resolved the dispute and TGH proceeded with the initiation of a claim under the DR-CAFTA. Iberdrola had initiated similar proceedings under the bilateral trade treaty in place between the Republic of Guatemala and the Kingdom of Spain.

In 2008, net income was $36.9 million, compared to $44.7 million in 2007. In December, TECO Guatemala repatriated $71.7 million of cash and investments to TECO Energy, resulting in additional taxes of $9.6 million. TECO Guatemala's full-year 2008 non-GAAP results, which exclude $9.6 million of taxes related to the December repatriation of cash, were $46.5 million. The San José Power Station realized increased revenues in 2008 from significantly higher prices for spot energy sales. Revenues from contract energy sales increased due to a scheduled price escalation. Higher operating expenses and lower interest income on lower cash balances were essentially offset by lower interest on project debt. EEGSA had 3.9% customer growth in 2008, increasing its customer base by 37,000 to over 877,000 at year-end. The reduction in the VAD tariff at EEGSA starting in August 2008 reduced earnings at TECO Guatemala approximately $5.0 million. The year-to-date results for EEGSA and affiliated companies also included a $3.1 million benefit related to an adjustment to previously estimated 2007 income and year-end equity balances, compared to a similar $1.9 million benefit in 2007.

In 2007, net income was $44.7 million, compared to $37.6 million in 2006. DECA II earnings increased due to customer growth and higher energy sales at EEGSA and increased earnings from the affiliated companies. EEGSA had 3.8% customer growth in 2007, increasing its customer base by 31,000 to over 840,000 at year-end. Net income for DECA II reflected a $1.9 million benefit related to an adjustment to previously estimated year-end results. The San José Power Station realized increased revenues in 2007 from both contract and spot sales with volumes up 2% and 5%, respectively, and prices up 3% for both. Higher energy sales were a result of high availability. The Alborada Power Station benefited from higher capacity payments as scheduled under its contract and a 99.9% availability as calculated under its power sales agreement. Interest expense decreased due to lower interest rates and lower project debt balances, and interest income increased on higher offshore cash balances.

TECO Guatemala Outlook

At TECO Guatemala, we expect 2009 net income to decrease from 2008 levels, primarily due to the VAD tariff decision in 2008, and lower generation from the San José Power Station. In 2008, there was a five-month reduction in earnings from the VAD decision, but if the situation remains unresolved there would be a full year reduction in earnings in 2009. The San José Power Station went off-line in mid-January due to an equipment failure and is not expected to return to service until approximately mid-March. After its return to service, the economic dispatch of the San José Power Station will be dependent on the price of fuel for other generators. Currently, the dispatch price for some of the diesel generating resources in Guatemala, which use residual oil, is below the dispatch price of the coal-fired San José Power Station. If this relationship persists, generation from the San José Power Station would continue to be limited, thus reducing non-fuel energy sales revenues. However, the station has a 65% minimum take provision under its power sales agreement, which could be reduced if the plant does not meet an 85% availability rating. Results in 2009 will also be impacted by expected much lower spot energy sales and margins from the San José Power Station driven by the same oil/coal price differential condition, lower interest income on lower cash balances after the repatriation of cash in 2008, lower operator fees associated with the DECA II companies, and the absence of 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.

PARENT/OTHER

Parent/other cost was $55.2 million in 2008, compared to net income of $52.5 million in 2007. In 2008 the non-GAAP cost was $45.8 million, compared to the non-GAAP cost of $60.4 million in 2007. Non-GAAP costs in 2008 exclude $12.0 million of non-cash income taxes on the December 2008 repatriation of cash and investments from TECO Guatemala and a $2.6 million net benefit from adjustments to income taxes and previously estimated costs related to the sale of TECO Transport. Non-GAAP costs in 2007 exclude the $146.1 million net gain on the sale of TECO Transport, $13.0 million of charges related to the sale of TECO Transport, and the $20.2 million charge related to the debt extinguishment/exchanges completed in December (see the **2008** and **2007 Reconciliation of GAAP net income from continuing operations to non-GAAP results** tables). In 2008, interest expense at TECO Energy Parent and TECO Finance, combined, declined $18.5 million reflecting debt retirement actions.

In 2007, Parent/other net income was $52.5 million, compared to a cost of $60.4 million in 2006. In 2007, the non-GAAP cost was $60.4 million, compared to $74.2 million in 2006. Non-GAAP costs in 2006 exclude a $5.7 million gain on unused steam turbines and a $8.1 million gain on the sale of the remaining assets of the unfinished McAdams Power Station, which had been previously impaired. In 2007, parent interest expense declined $18.1 million reflecting parent debt retirement, which more than offset the $11.0 million lower parent interest income due to lower cash balances (see the **2006 Reconciliation of GAAP net income from continuing operations to non-GAAP results** table).

TECO TRANSPORT

We completed the sale of TECO Transport to an investment group for gross proceeds of $405 million in December 2007. The sale resulted in a net book gain of $149.4 million, before $16.3 million of transaction related costs recorded at TECO Energy parent. Proceeds from the sale of TECO Transport were used to pay down parent level debt on an accelerated basis.

Because of the Assets Held for Sale classification of TECO Transport, the recording of depreciation was discontinued as of Apr. 1, 2007. Net income through Dec. 3, 2007 was $34.0 million and non-GAAP results were $24.3 million in 2007, including the $9.7 million of depreciation expense that was not recorded in GAAP net income. Non-GAAP results were $25.8 million for the full-year period in 2006. Non-GAAP results in 2006 excluded $3.0 million of direct costs associated with damage from Hurricane Katrina, net of insurance recovery (see the **2007** and **2006 Reconciliation of GAAP net income from continuing operations to non-GAAP results** tables).

OTHER ITEMS IMPACTING NET INCOME

Other Income (Expense)

In 2008, Other income or (Expense) of $100.7 million reflected $72.5 million of pretax income from the Guatemalan operations, which are accounted for as equity investments; $7.2 million of pretax interest income on invested cash balances; and $6.7 million of pretax income from the sale of right-of-way easements and a contract settlement related to future coal sales at TECO Coal.

In 2007, Other income or (Expense) of $152.1 million reflected $84.5 million of mark-to-market gains on the oil price hedges on synthetic fuel production at TECO Coal; $68.6 million of pretax income from the Guatemalan operations, which are accounted for as equity investments; $19.4 million of pretax interest income on invested cash balances; and a $32.9 million pretax charge related to the debt extinguishment and exchange completed in 2007.

AFUDC equity at Tampa Electric, which is included in Other Income (expense), was $6.3 million and $4.5 million in 2008 and 2007, respectively. AFUDC is expected to increase in 2009 due to the installation of combustion turbines to meet peak load capacity needs, increased spending on qualified transmission projects, rail unloading facilities at Tampa Electric's Big Bend Power Station and for NO_x control also at Big Bend Power Station (see the **Environmental Compliance** and **Liquidity, Capital Resources** sections).

Interest Expense

Total interest expense was $228.9 million in 2008 compared to $257.8 million in 2007 and $278.3 million in 2006. In 2008, interest expense was reduced by the December 2007 retirement of $297 million of TECO Energy debt and the full-year benefit of other debt retirement in 2007. Interest expense declined in 2007 due to the 2006 retirement of the remaining 8.5% trust preferred securities (TruPS) outstanding, the repayment in January 2007 of $57 million of 5.93% junior subordinated notes, the repayment of $300 million of 6.125% notes in May 2007, and the repayment of $111 million of 5% Dock and Wharf bonds in September 2007. Interest expense also reflects Tampa Electric Company's issuance of $150 million of 6.10% notes in May 2008 and the impact of Tampa Electric Company's repurchase and remarketing of tax-exempt auction rate bonds in March 2008 (see the **Financing Activity** section).

Interest expense is expected to increase in 2009 due to Tampa Electric Company's increased borrowings to support its capital spending program (see the **Liquidity, Capital Resources** section).

Income Taxes

The provision for income taxes decreased in 2008 primarily due to lower operating income, partially offset by the taxes on the repatriation of cash and investments from Guatemala, the termination of the synthetic fuel operations tax credit program and its related investor income, and the gain recognized on the sale of TECO Transport in December 2007. The provision for income taxes increased in 2007 due to higher operating income, the gain recognized on the sale of TECO Transport, and the hedge settlement at TECO Coal. Income tax expense as a percentage of income from continuing operations before taxes was 36.8% in 2008, 34.9% in 2007 and 32.7% in 2006. For 2009, we expect the effective tax rate to be in the range of 30% to 35%.

The cash payments for income taxes, as required by the federal Alternative Minimum Tax rules (AMT), state income taxes and payments (refunds) related to prior years' audits totaled $6.0 million, ($10.5) million and $10.4 million in 2008, 2007 and 2006, respectively. The 2007 refund was a result of a 2003 and 2004 foreign tax-credit carryback claim.

Due to the generation of deferred income tax assets related to the net operating loss (NOL) carry-forward from disposition of the generating assets formerly held by TWG Merchant, our unregulated power generation subsidiary that is no longer in that business, in recent years cash tax payments for income taxes were limited to approximately 10% of the AMT rate and we expect future cash tax payments to be limited to a similar level, reduced by AMT foreign tax credits and various state taxes. We currently expect to utilize these NOLs through 2012. Beyond 2012, we expect to use more than $190 million of AMT carry-forward to limit future cash tax payments for federal income taxes to the level of AMT. We currently project a cash tax refund in 2009 of approximately $0.3 million. For the 2010-2012 period, we estimate tax payments to be in the range of $1 million to $3 million annually.

The tax credit for the production of synthetic fuel existed through the end of 2007. The credit was determined annually and was $0.4103 per million Btu for 2007 after phase-out ($1.2509 per million Btu with no phase-out), and was $0.8138 per million Btu in 2006 ($1.2121 per million Btu with no phase-out).

The income tax effect of gains and losses from discontinued operations is shown as a component of results from discontinued operations.

DISCONTINUED OPERATIONS

In 2007, net income from discontinued operations reflects a $14.3 million tax benefit recorded in discontinued operations in the second quarter as a result of reaching a favorable conclusion with taxing authorities related to the 2005 disposition of the Union and Gila River merchant power plants. TECO Transport was not classified as a discontinued operation due to the ongoing contractual relationship with Tampa Electric for solid fuel waterborne transportation services. In 2006, net income from discontinued operations was $1.9 million, reflecting primarily the recovery of receivables and adjustments for estimates for businesses that had been previously written off.

LIQUIDITY, CAPITAL RESOURCES

The table below sets forth the Dec. 31, 2008 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 credit facilities.

Balances as of Dec. 31, 2008

(millions)	Consolidated	Tampa Electric Company	Other Operating Companies	Parent/TECO Finance
Credit facilities	$ 675.0	$ 475.0	$ —	$ 200.0
Drawn amounts/LCs	101.5	30.4	—	71.1
Available credit facilities	573.5	444.6	—	128.9
Cash and short-term investments	14.6	3.6	10.8	0.2
Total liquidity	$ 588.1	$ 448.2	$ 10.8	$ 129.1

Consolidated other cash and short-term investments includes $10.8 million of cash at the unregulated operating companies for normal operations. Essentially all of the cash and investments at TECO Guatemala held offshore due to the tax deferral strategy associated with EEGSA was repatriated in December 2008 (see **Note 4** to the **TECO Energy Consolidated Financial Statements**). In addition to consolidated cash, as of Dec. 31, 2008, unconsolidated affiliates owned by TECO Guatemala, CGESJ (San José) and TCAE (Alborada) had unrestricted cash and short-term investment balances of $25.9 million, which are not included in the table above.

In 2008, we met our cash needs primarily from a mix of internal sources and cash on hand at the beginning of the year, including cash held offshore which was repatriated in December 2008. We supplemented this with net borrowings of $102 million, of which $68 million represented borrowings under bank credit facilities. Cash from operations was $388 million in 2008. Other sources of cash included net proceeds of $79 million in January associated with the settlement of 2007 oil price hedges related to TECO Coal's synthetic fuel program, and $22 million in common stock proceeds. We paid dividends in 2008 of $169 million, and our capital expenditures for the year were $590 million.

In 2007, we met our cash needs from a mix of internal sources, cash on hand at the beginning of the year, and long-term notes issued at Tampa Electric Company. We received cash from the sale of TECO Transport and used those proceeds primarily to accelerate the retirement of parent debt. Cash from operations was $554 million in 2007. Other sources of cash in 2007 included $405 million from the sale of TECO Transport, $78 million of proceeds from third-party investors for ownership interests in TECO Coal's synthetic fuel production facilities, $37 million repatriated from TECO Guatemala, and $250 million from the issuance of long-term debt at Tampa Electric Company. We used cash to retire

$357 million of TECO Energy parent debt at maturity, $111 million of TECO Energy parent-guaranteed TECO Transport Dock and Wharf bonds at maturity, and $297 million of TECO Energy parent debt prior to maturity, and the regulated companies reduced short-term borrowings $23 million and repaid $150 million of long-term debt at maturity. We paid dividends in 2007 of $163 million on TECO Energy common stock. Our capital expenditures for the year were $494 million.

Cash from Operations

In 2008, consolidated cash flow from operations was $388 million, which was negatively impacted by $116 million associated with net under-recoveries, primarily fuel and purchased power, under FPSC-approved recovery clauses. Cash from operations reflects a $12 million contribution to the pension plan in 2008.

We expect cash from operations in 2009 to be above the 2008 level. In November 2008, the FPSC approved recovery clause rates that provide for recovery of estimated 2008 under-recoveries over 12 months beginning Jan. 1, 2009.

Cash from Investing Activities

Our investing activities in 2008 resulted in a net use of cash of $493 million, including capital expenditures totaling $590 million. We received in January 2008 $79 million representing the remaining net hedge settlement of 2007 oil price hedges associated with TECO Coal's synthetic fuel program. Investing activity in 2008 also included $13 million received primarily from the unconsolidated Guatemalan affiliates, in addition to cash of $58 million repatriated from TECO Guatemala in December.

We expect capital spending for the next several years to be higher, primarily at Tampa Electric due to spending on combustion turbines to meet peak load needs, the completion of the third NO_x control project, transmission and distribution system reliability improvements, rail unloading facilities for the delivery of coal and improvements to coal-fired unit reliability (see the **Tampa Electric** and **Capital Expenditures** sections).

Cash from Financing Activities

Our financing activities in 2008 resulted in net use of cash of $45 million. Major items included Tampa Electric's net reduction of $95 million in outstanding auction rate bonds, the issuance of $150 million of 10-year notes for Tampa Electric and PGS, and the payment of $12 million in settlement of interest rate swaps associated with the 10-year note issuance (see the **Financing Activity** section). In addition, net borrowings under the bank credit facilities of Tampa Electric Company and TECO Finance in 2008 increased $68 million. We paid $169 million in common stock dividends, and we received $22 million in proceeds from our dividend reinvestment program and exercises of stock options.

In 2009, Tampa Electric Company expects to utilize equity contributions from TECO Energy, short-term borrowings under its credit facilities and a planned long-term debt issuance to support its capital spending program and for normal working capital fluctuations. We have no significant debt maturities in 2009. See the **Cash and Liquidity Outlook** section below for a discussion of financing expectations beyond 2009.

Cash and Liquidity Outlook

In general, we target to maintain consolidated liquidity (unrestricted cash on hand plus undrawn credit facilities) of at least $500 million. At Dec. 31, 2008 our consolidated liquidity was $588 million, consisting of $448 million at Tampa Electric Company, $129 million at TECO Energy parent and $11 million at the other consolidated operating companies. In addition, there was $26 million of unrestricted cash at the unconsolidated TECO Guatemala operating companies.

We expect our sources of cash in 2009 to include cash from operations at levels substantially higher than in 2008, due in large part to expected collection in 2009 of under-recovered fuel balances from 2008 as described above, supplemented by an expected issuance of long-term debt by Tampa Electric Company. We plan to use cash in 2009 for capital spending estimated at $740 million 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 of approximately $150 million to support its capital spending program, and expects to utilize its credit facilities for normal working capital fluctuations. Our credit facilities contain certain financial covenants (see **Covenants in Financing Agreements** section). Although we expect the normal utilization of our credit facilities to be low, we estimate that we could fully utilize the total available capacity under our facilities in 2009 and remain within the covenant restrictions.

Beyond 2009, our long-term debt maturities are very moderate until 2011. The $100 million variable rate notes of TECO Energy parent mature in 2010, and we plan to retire those notes without issuing replacement debt. Maturing debt of TECO Energy parent and TECO Finance totals $364 million in 2011 and $336 million in 2012. Although we plan to retire a significant amount of these maturities with cash generated internally, we will need to access the debt capital markets to fund a portion of the maturing debt. Tampa Electric Company has two series of notes totaling $650 million maturing in 2012 and will need to issue replacement debt to fund those maturities. The existing bank credit facilities for both Tampa Electric Company and TECO Energy/TECO Finance expire in 2012.

Our expected cash flow could be affected by variables discussed in the individual operating company sections, such as customer growth and usage changes at our regulated businesses, the outcomes of the Tampa Electric and PGS base rate proceedings, coal production levels and coal sales prices for the limited volumes not yet committed under fixed price contracts. In addition, actual fuel and other regulatory clause net recoveries will typically vary from those forecasted; however, the differences are generally recovered within the next calendar year. It is possible, however, that unforeseen cash requirements and/or shortfalls, or higher capital spending requirements could cause us to fall short of our liquidity target (see the **Risk Factors** section).

The higher capital expenditures expected at Tampa Electric over the next several years will require additional equity contributions from TECO Energy in order to support the capital structure and financial integrity of the utility. Tampa Electric funds its capital needs with a combination of internally generated cash, external borrowing and equity contributions from TECO Energy parent. The 2007 sale of TECO Transport allowed us to use proceeds for the early implementation of parent debt retirement plans and positioned us to redeploy part of the cash planned for parent debt retirement in future years to Tampa Electric in the form of parent equity contributions. In addition, through 2012, we expect to realize significant cash benefits from the utilization of net operating loss carryforwards generated in 2004 and 2005 upon the disposition of merchant power assets to reduce federal and certain state income taxes and expect that our cash payment of income taxes in those years will be less than $3 million.

As a result of our significant debt retirements in 2007 and reduced business risk, we have improved our debt credit ratings and ratings outlooks (see **Credit Ratings of Senior Unsecured Debt at Dec. 31, 2008** section). It is our intention to continue to improve our financial profile, with a goal of achieving additional ratings improvements. In the unlikely event Tampa Electric Company's ratings were downgraded to below investment grade, counterparties to our derivative instruments could request immediate payment or full collateralization of net liability positions. If the credit risk related contingent features underlying these derivative instruments were triggered as of Dec. 31, 2008, we could have been required to post additional collateral or settle existing positions with counterparties totaling $148 million, including Tampa Electric Company positions of $134 million. In addition, credit provisions in long-term gas transportation agreements of Tampa Electric and PGS would give the transportation providers the right to demand collateral which we estimate to be approximately $43 million. None of our credit facilities or financing agreements has ratings downgrade covenants which would require immediate repayment or collateralization; however in the event of a downgrade our interest expense could be higher.

Impact of Financial Market Conditions

The current disruption in the capital and credit markets could adversely impact the availability and associated cost of externally sourced capital. Although we do not expect either TECO Finance or TECO Energy parent to access the capital markets in the near-term, Tampa Electric Company expects to issue long-term debt in 2009 to support its capital spending program. We also expect to utilize credit facilities for normal working capital fluctuations.

The $200 million TECO Finance credit facility, which is guaranteed by us, and Tampa Electric Company's $325 million credit facility each has a May 2012 maturity. All of the banks participating in the credit facilities are performing their obligations under these facilities and meeting our funding requests. Tampa Electric Company's $150 million accounts receivable collateralized credit facility is scheduled for renewal in December 2009. We renewed this facility in December 2008, at a higher cost, but cannot be assured that we can renew the facility in December 2009 if market conditions are unfavorable at that time.

TECO Energy has minimal floating interest rate exposure. The TECO Energy floating rate notes ($100 million) are based on three-month LIBOR, and the bank credit facilities have a one-month LIBOR mode, with other modes also available. Tampa Electric Company can also borrow under its accounts receivable backed facility at conduit commercial paper rates. Regulated utilities had some challenges accessing the capital markets at the time of the financial uncertainty that existed in September and October of 2008 but were generally able to access the market for long-term debt issuance before and after the crisis time, although the rates increased significantly in late 2008. If current market conditions worsen, Tampa Electric Company's expected 2009 debt issue could be adversely impacted.

Our exposure to the Lehman bankruptcy was minimal as Tampa Electric had open positions with Lehman at Dec. 31, 2008 related to natural gas hedges that were out of the money. TECO Energy's overall financial commodity trading activities are confined to natural gas hedges at the utilities and diesel fuel oil and natural gas hedges at TECO Coal.

Our defined benefit pension assets were negatively impacted by unfavorable market conditions in 2008. At Jan. 1, 2008 our plan was more than 100% funded under calculation requirements of the Pension Protection Act (PPA) in effect at that time. We estimate the funded position at Jan. 1, 2009 to be approximately 90%, which assumes adoption of asset smoothing within a 10% corridor of market value and includes an additional contribution of approximately $11 million we expect to make in 2009 related to the 2008 plan year. We contributed $12 million to the plan in 2008, so the $11 million additional contribution will bring our total cash contribution for the 2008 plan year to $23 million. Asset smoothing was among the changes and technical corrections to PPA included in the Worker, Retiree and Employer Recovery Act of 2008 enacted in December 2008. We currently estimate the minimum contribution for the 2009 plan year, which would be paid no later than Sep. 15, 2010, to be $25 million; in addition, because our plan was less than 100% funded at Jan. 1, 2009, we will be required in 2010 to make quarterly contributions for the 2010 plan year estimated at $15 million.

We estimate that pension expense in 2009 will be approximately $6 million (pretax) higher than in 2008, due in large part to the asset value decline. For purposes of determining the expected asset return and gain/loss amortization components of pension expense under Statement of Financial Accounting Standard (SFAS) 87, *Employer's Accounting for Pensions*, our market-related value of plan assets is a calculated value that recognizes changes in asset value in a systematic manner over 5 years. Actuarial gains and losses that exceed a certain threshold are amortized over the remaining service lives of active plan participants. These actuarial methods have the effect of smoothing the impact of significant asset changes on pension expense in any one year.

At Dec. 31, 2008, separate from the pension plan, stemming from the investments we made of cash at DECA II we had non-current investments in student loan auction rate securities (SLARS) having a par value of $15 million. We recorded a temporary impairment of $2 million at Dec. 31, 2008 (see **Note 22** to the **TECO Energy Consolidated Financial Statements**). If current market conditions persist or deteriorate, it could lead to a future determination that an other-than-temporary impairment has occurred and reduce our net income.

Credit Facilities

At Dec. 31, 2008 and 2007, the following credit facilities and related borrowings existed:

		Dec. 31, 2008			*Dec. 31, 2007*		
(millions)		*Credit Facilities*	*Borrowings Outstanding*(2)	*Letters of Credit Outstanding*	*Credit Facilities*	*Borrowings Outstanding*(2)	*Letters of Credit Outstanding*
Tampa Electric	5-year facility	$325.0	$ —	$ 1.4	$325.0	$ —	$ —
	1-year accounts receivable facility	150.0	29.0	—	150.0	25.0	—
TECO Finance(1)	5-year facility	200.0	64.0	7.1	200.0	—	9.5
Total		$675.0	$93.0	$8.5	$675.0	$25.0	$9.5

(1) Prior to May 2007, TECO Energy was borrower under this facility.
(2) 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 notes payable under the credit facilities at Dec. 31, 2008 and 2007 were 2.65% and 4.76%, respectively.

At Dec. 31, 2008, TECO Finance had a $200 million bank credit facility in place guaranteed by TECO Energy with a maturity date of May 2012. Tampa Electric Company had a bank credit facility totaling $325 million, also maturing in May 2012. In addition, Tampa Electric Company had a $150 million accounts receivable securitized borrowing facility with a maturity date of December 2009. The TECO Finance and Tampa Electric Company bank credit facilities include sub-limits for letters of credit of $200 million and $50 million, respectively. At Dec. 31, 2008, $64 million was drawn on the TECO Finance credit facilities and $7.1 million in letters of credit were outstanding. At Dec. 31, 2008, $29 million was drawn on the Tampa Electric Company credit facilities and $1.4 million in letters of credit were outstanding. These credit facilities have financial covenants as identified in the **Covenants in Financing Agreements** section.

At current ratings, TECO Finance's and Tampa Electric Company's bank credit facilities require commitment fees of 12.5 basis points and 9.0 basis points, respectively, and drawn amounts are charged interest at LIBOR plus 55.0 – 60.0 basis points and 45.0 – 50.0 basis points, respectively. At Dec. 31, 2008, the LIBOR interest rate was 0.44%.

In January 2005, Tampa Electric Company and TEC Receivables Corp. (TRC), a wholly-owned subsidiary of Tampa Electric Company, entered into a $150 million accounts receivable collateralized borrowing facility. Under this facility, Tampa Electric Company sells and/or contributes to TRC all of its receivables for the sale of electricity or gas to its customers and related rights. The receivables are sold by Tampa Electric Company to TRC at a discount, which was initially 2%. The discount is subject to adjustment for future sales to reflect changes in prevailing interest rates and collection experience. TRC is consolidated in the financial statements of Tampa Electric Company and TECO Energy.

Under a Loan and Servicing Agreement, TRC may borrow up to $150 million to fund its acquisition of the receivables under the facility, and TRC secures such borrowings with a pledge of all of its assets, including the receivables. Tampa Electric Company acts as the servicer to service the collection of the receivables. TRC pays program and liquidity fees based on Tampa Electric Company's credit ratings, which total 175 basis points at its current ratings. Interest rates on the borrowings are based on prevailing asset-backed commercial paper rates, unless such rates are not available from conduit lenders, or under certain circumstances upon a change of accounting rules applicable to the lenders, in which case the rates will be at an interest rate equal to, at Tampa Electric Company's option, either Citibank's prime rate (or the federal funds rate plus 50 basis points, if higher) or a rate based on the London interbank deposit rate (if available) plus a margin. The facility includes the following financial covenants: (1) at each quarter-end, Tampa Electric Company's debt-to-capital ratio, as defined in the agreement, must not exceed 65%; and (2) certain dilution and delinquency ratios with respect to the receivables (see the **Covenants in Financing Agreements** section). At Dec. 31, 2008, the interest rate for borrowings under the Tampa Electric Company accounts receivable facility was 2.87%.

Covenants in Financing Agreements

In order to utilize their respective bank credit facilities, TECO Energy/Finance and Tampa Electric Company must meet certain financial tests as defined in the applicable agreements (see the **Credit Facilities** section). In addition, TECO Energy, TECO Finance, Tampa Electric Company, and other operating companies have certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2008, TECO Energy, TECO Finance, Tampa Electric Company, and the other operating companies were in compliance with all required financial covenants. The table that follows lists the significant financial covenants and the performance relative to them at Dec. 31, 2008. Reference is made to the specific agreements and instruments for more details.

TECO Energy Significant Financial Covenants

(millions, unless otherwise indicated)			
Instrument	*Financial Covenant*[1]	*Requirement/Restriction*	*Calculation at Dec. 31, 2008*
Tampa Electric Company			
PGS senior notes	EBIT/interest[2] Restricted payments Funded debt/capital Sale of assets	Minimum of 2.0 times Shareholder equity at least $500 Cannot exceed 65% Less than 20% of total assets	2.9 times $2,091 48.7% 0%
Credit facility	Debt/capital	Cannot exceed 65%	48.0%
Accounts receivable credit facility[3]	Debt/capital	Cannot exceed 65%	48.0%
6.25% senior notes	Debt/capital Limit on liens[5]	Cannot exceed 60% Cannot exceed $700	48.0% $0 liens outstanding
Insurance agreement relating to certain pollution bonds	Limit on liens[5]	Cannot exceed $400 (7.5% of net assets)	$0 liens outstanding
TECO Energy/TECO Finance			
Credit facility	Debt/EBITDA[2] EBITDA/interest[2] Limit on additional indebtedness Dividend restriction[4]	Cannot exceed 5.0 times Minimum of 2.6 times Cannot exceed $1,082 Cannot exceed $51 per quarter	4.4 times 3.5 times $0 $43
TECO Energy 7.5% notes	Limit on liens[5]	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	(6)	(6)
TECO Diversified			
Coal supply agreement guarantee	Dividend restriction	Net worth not less than $299 (40% of tangible net assets)	$534

(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 the Tampa Electric Company accounts receivable credit facilities (see **Note 6** to the **TECO Energy Consolidated Financial Statements**).
(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. This limitation would not include first mortgage bonds of Tampa Electric if any were outstanding.
(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. These limitations would not include first mortgage bonds of Tampa Electric if any were outstanding.

Credit Ratings of Senior Unsecured Debt at Dec. 31, 2008

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

On Jun. 9, 2008, Standard & Poor's Rating Services changed its outlook on TECO Energy, TECO Finance and Tampa Electric Company to positive from stable. At the same time, Standard & Poor's affirmed the senior unsecured ratings on all three entities.

In March 2008, Fitch upgraded the ratings on TECO Energy and TECO Finance senior unsecured debt to investment grade at BBB-. In addition, Fitch removed TECO Energy, TECO Finance and Tampa Electric Company from ratings watch positive and placed stable outlooks on the ratings.

Fitch's ratings upgrade of TECO Energy and TECO Finance reflected the leverage reduction resulting from the use of TECO Transport sale proceeds to reduce debt and from earlier debt reduction efforts. Fitch also cited TECO Energy's reduced business risk resulting from sales of non-regulated operations and focus on utility operations as factors considered in the upgrade. Moody's has assigned a positive outlook to Tampa Electric Company's rating and a stable outlook to TECO Energy and TECO Finance.

Standard & Poor's, Moody's and Fitch describe credit ratings in the BBB or Baa category as representing adequate capacity for payment of financial obligations. The lowest investment grade credit ratings for Standard & Poor's is BBB-, for Moody's is Baa3 and for Fitch is BBB-; thus all three credit rating agencies assign Tampa Electric Company's senior unsecured debt investment grade ratings. The ratings assigned to senior unsecured debt of TECO Energy and TECO Finance by Moody's and Fitch are investment grade and by Standard & Poor's are below investment grade.

A credit rating agency rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency. Any future downgrades in credit ratings may affect our ability to borrow and may increase financing costs, which may decrease earnings (see the **Risk Factors** section).

Summary of Contractual Obligations

The following table lists the obligations of TECO Energy and its subsidiaries for cash payments to repay debt, lease payments, contributions to the pension plan and unconditional commitments related to capital expenditures. This table does not include contingent obligations, which are discussed in a subsequent table.

Contractual Cash Obligations at Dec. 31, 2008

(millions)	**Payments Due by Period**					
	Total	**2009**	**2010**	**2011**	**2012-2013**	**After 2013**
Long-term debt(1)						
Recourse	$3,207.6	$ 5.5	$106.5	$366.9	$1,050.5	$1,678.2
Non-recourse(2)	9.1	1.4	1.4	1.5	3.1	1.7
Operating leases/rentals(3)	49.1	6.9	6.2	4.2	5.3	26.5
Net purchase obligations/commitments(4)	403.6	236.9	65.6	31.1	69.7	0.3
Interest payment obligations(5)	1,967.6	207.1	203.8	187.7	292.1	1,076.9
Pension plans (6)	141.5	10.9	40.5	25.3	64.8	--
Total contractual obligations	$5,778.5	$468.7	$424.0	$616.7	$1,485.5	$2,783.6

(1) Includes debt at TECO Energy, TECO Finance, Tampa Electric, PGS and the other operating companies (see **Note 7** to the **TECO Energy Consolidated Financial Statements** for a list of long-term debt and the respective due dates). Does not include debt at the deconsolidated Guatemalan affiliates.

(2) Reflects an intercompany loan at TECO Guatemala between its consolidated Cayman Island entity and an unconsolidated Guatemalan affiliate.

(3) The table above excludes payment obligations under contractual agreements of Tampa Electric and PGS for fuel, fuel transportation and power purchases, which are recovered under regulatory clauses approved by the FPSC annually (see the **Regulation** section). One of these agreements, in accordance with EITF 01-08 "*Determining Whether and Arrangement Contains a Lease*," has been determined to contain a lease (see **Note 12** to the **TECO Energy Consolidated Financial Statements**).

(4) Reflects those contractual obligations and commitments considered material to the respective operating companies, individually. At the end of 2008, these commitments include Tampa Electric's outstanding commitments for materials and installation related to the NO_x control equipment or other major projects such as combustion turbines for peaking capacity and long-term capitalized maintenance agreements for its combustion turbines.

(5) Includes variable rate notes at interest rates as of Dec. 31, 2008.

(6) The total includes the estimated minimum required contributions to the qualified pension plan as of the measurement date. Future contributions through 2013 are included, but they are subject to annual valuation reviews, which may vary significantly due to changes in interest rates, discount rate assumptions, and plan asset performance, which is affected by stock market performance, and other factors (see the **Liquidity, Capital Resources** section and **Note 5** to the **TECO Energy Consolidated Financial Statements**).

Summary of Contingent Obligations

The following table summarizes the letters of credit and guarantees outstanding that are not included in the Summary of Contractual Obligations table above and not otherwise included in our Consolidated Financial Statements. These amounts represent guarantees by TECO Energy on behalf of consolidated subsidiaries. TECO Energy has no guarantees outstanding on behalf of unconsolidated or unrelated parties.

Contingent Obligations at Dec. 31, 2008 *(millions)*			**Commitment Expiration**				
		Total[2]	**2009**	**2010**	**2011**	**2012 - 2013**	**After 2013[1]**
Letters of credit		$ 7.1	$ —	$ —	$ —	$ —	$ 7.1
Guarantees	Fuel purchase/energy management [2]	92.7	69.8	—	—	—	22.9
	Other	1.4	—	—	—	—	1.4
Total contingent obligations		$ 101.2	$ 69.8	$ —	$ —	$ —	$ 31.4

(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.

Capital Expenditures

	Actual	**Forecast**			
(millions)	**2008**	**2009**	**2010**	**2011 – 2013**	**2009 – 2013 Total**
Tampa Electric					
Transmission	$ 35	$ 95	$ 75	$ 185	$355
Distribution	110	110	110	340	560
Generation	115	215	120	285	620
Committed generation expansion	109	90	--	--	90
Proposed generation expansion[1]	--	--	10	630	640
Other	35	45	35	110	190
NO_X control projects	65	55	15	--	70
Other environmental	17	10	5	20	35
Tampa Electric total	486	620	370	1,570	2,560
Net cash effect of accruals and retentions	(15)	--	--	--	--
Tampa Electric net	471	620	370	1,570	2,560
Peoples Gas	69	60	60	170	290
Unregulated companies[2]	42	60	80	120	260
Total	$582	$740	$510	$1,860	$3,110

(1) See **Tampa Electric Generating Capacity Additions** discussion below.
(2) Represents the capital expenditures of TECO Coal, Seacoast LLC and the consolidated operations of TECO Guatemala. Under FIN 46R the major operations of TECO Guatemala are unconsolidated, and the related capital expenditures are not included in this table.

TECO Energy's 2008 cash capital expenditures of $582 million included $486 million, excluding AFUDC – debt and equity and amounts incurred but not paid, for Tampa Electric and $69 million for PGS. Tampa Electric's capital expenditures in 2008 were primarily for equipment and facilities to meet limited customer growth, generating equipment maintenance, capital expenditures required for construction of additional generating capacity in the form of five peaking units, environmental compliance, and NO_x control projects (see the **Environmental Compliance** section). Capital expenditures for PGS were approximately $46 million for system expansion and approximately $23 million for maintenance of the existing system. TECO Coal's capital expenditures included $16 million primarily for normal mining equipment replacement, and $24 million for new mine development.

TECO Energy estimates capital spending for ongoing operations to be $740 million for 2009 and approximately $2,370 million during the 2010 – 2013 period. The five-year capital expenditure forecast for the 2009 – 2013 period is approximately 10% lower than the previous five-year capital expenditure forecast for the 2008-2012 period.

For 2009, Tampa Electric expects to spend $620 million. For the transmission and distribution systems Tampa Electric expects to spend $205 million in 2009, including $20 million for transmission and distribution system storm hardening, $40 million for new high-voltage transmission system improvements and to meet reliability requirements, and $55 million for its pro-rata portion of upgrades to the central Florida transmission system to meet NERC reliability guidelines. Capital expenditures for the existing generating facilities of $215 million includes $60 million for the construction of coal unloading facilities for delivery of solid fuel by rail, and $150 million for generating system reliability, including approximately $95 million in major improvements to coal-fired units at Big Bend Power Station to take advantage of the extended outages to install NO_x control equipment. In addition, Tampa Electric expects to spend $90 million for the addition of five combustion turbines, $55 million for the addition of SCR equipment at the Big Bend Power Station for NO_x control, and $10 million for other environmental compliance programs in 2009. The five combustion turbines, one at the Big Bend Power Station and four at the Bayside Power Station, will meet peaking generation capacity needs and provide "black start" capability to meet NERC reliability requirements.

Tampa Electric expects to spend approximately $270 million annually to support normal system growth and reliability in the 2010 – 2013 period. This level of ongoing capital expenditures reflects the costs for materials and contractors, long-term regulatory requirements for storm hardening, and an active program of transmission and distribution system upgrades which will occur over the forecast period. These new programs and requirements include: approximately $30 million annually for repair and refurbishments of combustion turbines under long-term agreements with equipment manufacturers; average annual expenditures of more than $19 million for transmission and distribution system storm hardening; approximately $35 million annually for transmission and distribution system reliability and capacity improvements; and an average of about $35 million annually for its pro-rata portion of state-wide high-voltage transmission system improvements in Florida and to meet NERC reliability requirements. In addition to the ongoing annual capital expenditures, Tampa Electric expects to spend $15 million for compliance with the Environmental Consent Decree for the remaining SCR equipment and $25 million for other required environmental capital expenditures in the 2010 – 2013 period. The Environmental Consent Decree compliance expenditures are eligible for recovery of depreciation and a return on investment through the ECRC (see the **Environmental Compliance** section).

Capital expenditures for PGS are expected to be about $60 million in 2009 and $230 million during the 2010 – 2013 period. Included in these amounts is an average of approximately $40 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing renewal, replacement and system safety.

The unregulated companies expect to invest $60 million in 2009 and $200 million during the 2010 – 2013 period. Included in these amounts are expenditures for coal mine development to maintain production, compliance with new safety requirements under the MINER Act, and for normal coal mining equipment renewal and replacement at TECO Coal. Included in the forecast period are the capital expenditures associated with the construction of the 21-mile Seacoast LLC natural gas pipeline in northeast Florida.

Tampa Electric – Generating Capacity Additions

Tampa Electric has committed to completing the construction of five peaking capacity combustion turbines in 2009 at the Bayside and Big Bend power stations, with an expected total project cost of $236 million, excluding AFUDC. These units will meet the expected peak demand requirements in 2009 and 2010, and several will be configured to meet the NERC black start requirements for system reliability.

Due to the dramatic slowdown in the Florida and national economies and the Florida housing market, Tampa Electric is reassessing its forecast of long-term energy demand and sales growth. Tampa Electric had previously identified a need for new baseload capacity in early 2013; however, the current capital forecast reflects a deferral of construction of new baseload capacity beyond this forecast period. This forecast for proposed new generation includes additional combustion turbines in service in the 2012 time frame; however, Tampa Electric may seek to purchase power rather than build additional capacity based on the economics (see the **Tampa Electric** and **Regulation** sections).

Pending action by the Florida Legislature on a Florida RPS, the need for additional capital spending for renewable generating resources to meet the requirements of a RPS is likely but not yet defined (see the **Environmental Compliance** section). Depending on the final rules, which the Florida legislature is expected to enact in the 2009 legislative session, Tampa Electric may need to invest capital to develop additional sources of renewable power generation.

The forecasted capital expenditures shown above are based on our current estimates and assumptions for normal maintenance capital at the operating companies; capital expenditures to support normal system growth and new generating capacity at Tampa Electric and PGS; the programs for transmission and distribution system storm hardening and transmission system reliability requirements; and incremental investments above normal maintenance capital to expand the PGS system, the Seacoast LLC pipeline construction and capacity at TECO Coal. Actual capital expenditures could vary materially from these estimates due to changes in costs for materials or labor or changes in plans (see the **Risk Factors** section).

Financing Activity

Our 2008 consolidated year-end capital structure was 62% senior debt and 38% common equity. The debt-to-total-capital ratio has improved significantly over the past two years, primarily due to the repayment of $765 million of parent and parent guaranteed debt in 2007, as well as the increase in retained earnings due to the gain on the sale of TECO Transport in 2007. At Dec. 31, 2008 Tampa Electric's year-end capital structure was 48% debt and 52% common equity.

In 2008, we issued no new long-term debt at the TECO Energy parent level or at TECO Finance. We raised $3.6 million of equity through our dividend reinvestment plan.

In May 2008, Tampa Electric Company issued $150 million aggregate principal amount of 6.10% Notes due May 15, 2018 (the "6.10% Notes"). The 6.10% Notes were sold at par. The offering resulted in net proceeds (after deducting underwriting discounts and commissions and estimated offering expenses) of approximately $148.7 million. Net proceeds were used for general corporate purposes. In connection with this debt offering, Tampa Electric Company settled interest rate swaps entered into in 2007 for $11.8 million. These amounts will be reclassified to interest expense over the 10-year term of the related debt, resulting in an effective interest rate of 6.89%.

In March 2008, in response to the turmoil in the auction rate securities market, the Hillsborough County Industrial Development Authority (HCIDA) remarketed $86.0 million Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2006, in a fixed-rate mode. The bonds, which previously had been in auction rate mode, bear interest at 5.00% per annum and are subject to mandatory tender for purchase on Mar. 15, 2012 from the proceeds of a remarketing of the bonds. Tampa Electric Company is responsible for payment of the interest and principal associated with the bonds. Regularly scheduled principal and interest, when due, are insured by Ambac Assurance.

Also in March, Tampa Electric Company purchased in lieu of redemption $75.0 million Polk County Industrial Development Authority (PCIDA) Solid Waste Disposal Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 and $125.8 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007A, B and C (collectively, the "2007 Bonds"). Also on that date, the Insurance Agreement with Financial Guaranty Insurance Company (FGIC), pursuant to which FGIC issued a financial guaranty insurance policy for the 2007 HCIDA Bonds, was terminated. Tampa Electric Company also entered into a corresponding First Supplemental Loan and Trust Agreement regarding the removal of the bond insurance on the 2007 HCIDA Bonds. After these changes to the 2007 HCIDA Bonds, Tampa Electric Company remarketed the $54.2 million 2007 Series A and the $51.6 million 2007 Series B Bonds in long term interest rate modes. The $54.2 million 2007 Series A bonds, which previously had been in auction rate mode, bear interest at 5.65% per annum until maturity on Mar. 15, 2018. The $51.6 million 2007 Series B bonds, which previously had been in auction rate mode, bear interest at 5.15% per annum and will be subject to mandatory tender on Sep. 1, 2013 from the proceeds of a remarketing of the bonds. Tampa Electric Company is responsible for payment of the interest and principal associated with the 2007 Bonds.

As a result of these transactions, $95.0 million of the bonds purchased in lieu of redemption were held by the trustee at the direction of Tampa Electric Company as of Dec. 31, 2008 (the "Held Bonds") to provide an opportunity to evaluate refinancing alternatives. The Held Bonds effectively offset the outstanding debt balances and are presented net on the balance sheet. The Held Bonds continued in that status through the date of this report.

The following table provides details of financings beginning in 2006.

Date	*Security*	*Company*	*Net proceeds (millions)*	*Coupon*	*Use*
May 2008	Note due 2018	Tampa Electric Company	$149	6.10%	General corporate purposes
Mar. 2008	Tax exempt bonds due 2034	Tampa Electric	$86(1)	5.00%	Remarket auction rate securities in a fixed rate mode to 2012
Mar. 2008	Tax exempt bonds due 2025	Tampa Electric	$52(1)	5.15%	Remarket auction rate securities in a fixed rate mode to 2013
Mar. 2008	Tax exempt bonds due 2018	Tampa Electric	$54(1)	5.65%	Remarket auction rate securities in a fixed rate mode to maturity
Dec. 2007	Notes due 2017	TECO Finance(2)	$300(1)	6.572%	Debt for debt exchange of existing TECO Energy notes extending maturity
Dec. 2007	Notes due 2015	TECO Finance(2)	$191(1)	6.75%	Debt for debt exchange of existing TECO Energy notes
Dec. 2007	Notes due 2012	TECO Finance(2)	$236(1)	7.00%	Debt for debt exchange of existing TECO Energy notes
Dec. 2007	Notes due 2011	TECO Finance(2)	$172(1)	7.20%	Debt for debt exchange of existing TECO Energy notes
Jul. 2007	Tax-exempt bonds due 2018, 2020 and 2025	Tampa Electric	$126(1)	Auction rate mode	Refinance existing bonds
May 2007	30-year notes	Tampa Electric Company	$250	6.15%	Repay maturing notes, repay short-term debt and general corporate purposes
May 2007	Tax-exempt bonds due 2030	Tampa Electric	$75(1)	Auction rate mode	Refinance existing bonds
May 2006	30-year notes	Tampa Electric Company	$250	6.55%	Repay short-term debt and general corporate purposes
Jan. 2006	Tax-exempt bonds due 2034	Tampa Electric	$ 86 (1)	Auction rate mode	Refinance existing bonds

(1) These financing actions resulted in no new cash to the respective companies.

(2) These notes are guaranteed by TECO Energy.

Off-Balance Sheet Debt at Dec. 31, 2008

Unconsolidated affiliates have project debt balances as follows at Dec. 31, 2008. The two power plant financings are non-recourse project loans, and the debt associated with DECA II is general corporate debt at DECA II; all of this debt is held at the project entity level. Although we are not directly obligated on the debt, our equity interest in those unconsolidated affiliates and its commitments with respect to those projects are at risk if interest and principal payments on these loans are not made timely. Our equity investment in TECO Guatemala was $356.7 million at Dec. 31, 2008.

(millions)	*Long-term Debt*	*TECO Guatemala's Ownership Interest*
San José Power Station	$ 63.5	100%
Alborada Power Station	$ 4.3	96%
DECA II	$ 209.9	30%

The equity method of accounting is used to account for investments in partnership and corporate entities in which we, or our subsidiary companies, do not have either a majority ownership or exercise control.

We deconsolidated the project entities for the San José and Alborada power stations listed above in 2004 as a result of implementing FIN 46R. These projects were partially financed with non-recourse debt, which following the deconsolidation is considered to be off-balance sheet financing.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of consolidated financial statements requires management to make various estimates and assumptions that affect revenues, expenses, assets, liabilities, and the disclosure of contingencies. The policies and estimates identified below are, in the view of management, the more significant accounting policies and estimates used in the preparation of our consolidated financial statements. These estimates and assumptions are based on historical experience and on various other factors that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and judgments under different assumptions or conditions. See **Note 1** to the **TECO Energy Consolidated Financial Statements** for a description of our significant accounting policies and the estimates and assumptions used in the preparation of the consolidated financial statements.

Deferred Income Taxes

We use the liability method in the measurement of deferred income taxes. Under the liability method, we estimate our current tax exposure and assess the temporary differences resulting from differing treatment of items, such as depreciation for financial statement and tax purposes. These differences are reported as deferred taxes measured at current rates in the consolidated financial statements. Management reviews all reasonably available current and historical information, including forward-looking information, to determine if it is more likely than not that some or all of the deferred tax asset will not be realized. If we determine that it is likely that some or all of a deferred tax asset will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized.

At Dec. 31, 2008, we had net deferred income tax assets of $333.8 million, attributable primarily to property-related items and alternative minimum tax credit, operating loss carry-forwards and a valuation allowance. Based primarily on historical income levels and the steady growth expectations for future earnings of the company's core utility operations, management has determined that the net deferred tax assets recorded at Dec. 31, 2008 will be realized in future periods.

We believe that the accounting estimate related to deferred income taxes, and any related valuation allowance, is a critical estimate for the following reasons: 1) realization of the deferred tax asset is dependent upon the generation of sufficient taxable income in future periods; 2) a change in the estimated valuation reserves could have a material impact on reported assets and results of operations; and 3) administrative actions of the IRS or the U.S. Treasury or changes in law or regulation could change our deferred tax levels, including the potential for elimination or reduction of our ability to utilize the deferred tax assets (see **Note 4** to the **TECO Energy Consolidated Financial Statements**).

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109* (FIN 48). FIN 48 prescribes a recognition threshold and measurement attribute for financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return, and also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. See further discussion of FIN 48 in **Note 4** to the **TECO Energy Consolidated Financial Statements.**

Employee Postretirement Benefits

We sponsor a defined benefit pension plan (pension plan) that covers substantially all of our employees. In addition, we have unfunded non-qualified, non-contributory supplemental executive retirement benefit plans available to certain senior management. Several statistical and other factors, which attempt to anticipate future events, are used in calculating the expense and liability related to these plans. Key factors include assumptions about the expected rates of return on plan assets, salary increases and discount rates. These factors are determined by us within certain guidelines and with the help of external consultants. We consider market conditions, including changes in investment returns and interest rates, in making these assumptions.

Pension plan assets (plan assets) are invested in a mix of equity and fixed income securities. The assumptions for the expected return on plan assets are developed based on an analysis of historical market returns, the pension plan's actual past experience, and current market conditions. The expected return on assets assumption was based on expectations of long-term inflation, real growth in the economy, fixed income spreads and equity premiums consistent with our portfolio, with provision for active management and expenses paid from the trust. The discount rate assumption is based on a cash flow matching technique developed by our outside actuaries and current economic conditions. This technique matches the yields from high-quality (AA-rated, non-callable) corporate bonds to the company's projected cash flows for the pension plan to develop a present value that is converted to a discount rate assumption, which is subject to change each year. The salary increase assumption was based on the same underlying expectation of long-term inflation together with assumptions regarding real growth in wages and company-specific merit and promotion increases. Holding all other assumptions constant, a 1% increase or decrease in the assumed rate of return on plan assets would increase or decrease 2009 net income by approximately $2.8 million, respectively. Likewise, a 1.0% increase or decrease in the discount rate assumption would result in an approximately $2.5 million increase in 2009 net income or a $2.8 million decrease in net income, respectively.

Unrecognized actuarial gains and losses are being recognized over approximately a 15-year period, which represents the expected remaining service life of the employee group. Unrecognized actuarial gains and losses arise from several factors including experience and assumption changes in the obligations and from the difference between expected return and actual returns on plan assets. These unrecognized gains and losses will be systematically recognized in future net periodic pension expense in accordance with SFAS 87. Our policy is to fund the plan based on the required contribution determined by our actuaries within the guidelines set by the Employee Retirement Income Security Act of 1974 (ERISA), as amended.

In addition, we currently provide certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 who meet certain service requirements. The key assumptions used in determining the amount of obligation and expense recorded for postretirement benefits other than pension (OPEB), under SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, include the assumed discount rate and the assumed rate of increases in future health care costs. The discount rate used to determine the obligation for these benefits has matched the discount rate used in determining our pension obligation in each year presented. In estimating the health care cost trend rate, we consider our actual health care cost experience, future benefit structures, industry trends, and advice from our outside actuaries. We assume that the relative increase in health care cost will trend downward over the next several years, reflecting assumed increases in efficiency in the health care system and industry-wide cost containment initiatives. In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) was enacted. The Act established a prescription drug benefit under Medicare, known as Medicare Part D, and a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription benefit, which is at least actuarially equivalent to Medicare Part D. In May 2004, the FASB issued FASB Staff Position No. FSP 106-2 which required 1) that the effects of the federal subsidy be considered an actuarial gain and recognized in the same manner as other actuarial gains and losses and 2) certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits.

We adopted FSP 106-2 retroactive to the second quarter of 2004 for benefits provided that we believe to be actuarially equivalent to Medicare Part D. The expected subsidy reduced the accumulated postretirement benefit obligations (APBO) at Dec. 31, 2008 by $30.2 million and increased net income for 2008 by $1.9 million. In 2008, we filed for and received a Part D subsidy of $0.8 million.

The assumed health care cost trend rate for medical costs was 9.25% in 2008 and decreases to 5.25% in 2016 and thereafter. A 1% increase in the health care trend rates would have produced a 5.0% increase in the aggregate service and interest cost for 2008, which would have decreased net income $0.5 million, and a 2.2% increase in the accumulated postretirement benefit obligation as of Dec. 31, 2008.

A 1% decrease in the health care trend rates would have produced a 3.9% decrease in the aggregate service and interest cost for 2008, which would have increased net income $0.4 million, and a 1.9% decrease in the accumulated postretirement benefit obligation as of Dec. 31, 2008.

The actuarial assumptions we used in determining our pension and OPEB retirement benefits may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, or longer or shorter life spans of participants. While we believe that the assumptions used are appropriate, differences in actual experience or changes in assumptions may materially affect our financial position or results of operations.

See the discussion of Employee Postretirement Benefits in **Note 5** to the **TECO Energy Consolidated Financial Statements.**

Evaluation of Assets for Impairment

Long-Lived Assets

In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long- Lived Assets* (FAS 144), we assess whether there has been an other-than-temporary impairment of our long-lived assets and certain intangibles held and used by us when such indicators exist. We annually review all long-lived assets in the last quarter of each year to ensure that any gradual change over the year and the seasonality of the markets are considered when determining which assets require an impairment analysis. We believe the accounting estimates related to asset impairments are critical estimates for the following reasons: 1) the estimates are highly susceptible to change, as management is required to make assumptions based on expectations of the results of operations for significant/indefinite future periods and/or the then current market conditions in such periods; 2) markets can experience significant uncertainties; 3) the estimates are based on the ongoing expectations of management regarding probable future uses and holding periods of assets; and 4) the impact of an impairment on reported assets and earnings could be material. Our assumptions relating to future results of operations or other recoverable amounts are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. Our expectations regarding uses and holding periods of assets are based on internal long-term budgets and projections, which give consideration to external factors and market forces, as of the end of each reporting period. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities.

At Dec. 31, 2008, impairment tests were conducted on our long-lived assets. At the conclusion of the analyses, it was determined that all asset carrying values were recoverable based on the reasonable estimates used and that no impairment adjustments were necessary.

Goodwill and Other Intangible Assets

Under SFAS No. 142, *Goodwill and Other Intangible Assets*, goodwill is not subject to amortization. Rather, goodwill and intangible assets with an indefinite life are subject to an annual (or more frequently if events and circumstances indicate a possible impairment) assessment for impairment at the reporting unit level. Reporting units are generally determined as one level below the operating segment level; reporting units with similar characteristics are grouped for the purpose of determining the impairment, if any, of goodwill and other intangible assets. We estimate the fair value of goodwill using discounted cash flows generated from the underlying assets of the entity or projects. Intangible assets with a measurable useful life are required to be amortized over the estimated remaining life of the assets.

During the year ended Dec. 31, 2008, impairment tests were conducted on our goodwill assets. At the conclusion of the analyses, it was determined that all asset carrying values were recoverable based on the reasonable estimates used and that no impairment adjustments were necessary (see **Notes 17** and **18** to the **TECO Energy Consolidated Financial Statements**).

Equity Investments

Equity investments and any potential impairment are tested under Accounting Principles Board Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stock* (APB 18) which provides the accounting requirements for these investments. The standard for determining whether an impairment must be recorded under APB No. 18 is whether the investment has experienced a loss in value that is considered an "other than a temporary" decline in value.

The evaluation and measurement of impairments under the APB No. 18 standard involves the same uncertainties as described above for long-lived assets that we own directly and account for in accordance with FAS 144. Similarly, the estimates that we make with respect to our equity investments are subject to variation, and the impact of such variations could be material. Additionally, if the entities in which we hold these investments recognize an impairment under the provisions of FAS 144, we would record our proportionate share of that impairment loss and would evaluate our investment for an other than temporary decline in value under APB No. 18 (see **Note 18** to the **TECO Energy Consolidated Financial Statements**).

Regulatory Accounting

Tampa Electric's and PGS' retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by the Federal Energy Regulatory Commission (FERC). As a result, the regulated utilities qualify for the application of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*. This statement recognizes that the actions of a regulator can provide reasonable assurance of the existence of an asset or liability. Regulatory assets and liabilities arise as a result of a difference between generally accepted accounting principles and the accounting principles imposed by the regulatory authorities. Regulatory assets generally represent incurred costs that have been deferred, as their future recovery in customer rates is probable. Regulatory liabilities generally represent obligations to make refunds to customers from previous collections for costs that are not likely to be incurred.

As a result of regulatory treatment and corresponding accounting treatment, we expect that the impact on utility costs and required investment associated with future changes in environmental regulations would create regulatory assets. Current regulation in Florida allows utility companies to recover from customers prudently incurred costs (including, for required capital investments, depreciation and a return on invested capital) for compliance with new environmental regulations through the ECRC (see the **Environmental Compliance** and **Regulation** sections).

We periodically assess the probability of recovery of the regulatory assets by considering factors such as regulatory environment changes, recent rate orders to other regulated entities in the same jurisdiction, the current political climate in the state, and the status of any pending or potential deregulation legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate earned on invested capital and the timing and amount of assets to be recovered by rates. A change in these assumptions may result in a material impact on reported assets and the results of operations (see the **Regulation** section and **Notes 1** and **3** to the **TECO Energy Consolidated Financial Statements**).

RECENTLY ISSUED ACCOUNTING STANDARDS

Employers' Disclosures about Postretirement Benefit Plan Assets

In December 2008, the FASB issued FASB Staff Position (FSP) No. Financial Accounting Standard (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 our results of operations, statement of position or cash flows.

Disclosures by Public Entities about Transfers of Financial Assets and Interests in Variable Interest Entities

In December 2008, the FASB issued FSP No. FAS 140-4 and FASB Interpretation (FIN) 46(R)-8, *Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities* (FSP FAS 140-4 and FIN 46(R)-8). This FSP requires additional disclosures regarding transfers of financial assets and interests in variable interest entities. The guidance in FSP FAS 140-4 and FIN 46(R)-8 was effective for reporting periods ending after Dec. 15, 2008. We have adopted this FSP and included the additional disclosures required in this report. These additional required disclosures have no effect on our results of operations, statement of position or cash flows.

Fair Value of a Financial Asset When the Market for That Asset Is Not Active

In October 2008, the FASB issued FSP No. FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active* (FSP FAS 157-3). This FSP clarifies the definition of fair value by stating that a transaction price is not necessarily indicative of fair value in a market that is not active or in a forced liquidation or distressed sale. Rather, if we have the ability and intent to hold the asset, we may use our assumptions about future cash flows and appropriately adjusted discount rates in measuring fair value of the asset. The guidance in FSP FAS 157-3 was effective immediately upon issuance on Oct. 10, 2008, including prior periods for which financial statements have not been issued. The adoption of FSP FAS 157-3 was not material to our 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.

Additionally, in April 2008, the FASB revised Statement 133 Implementation Issues Nos. I1 and K4 to reflect the enhanced disclosures required by FAS 161. We do not believe these revisions or FAS 161 will be material to our results of operations, statement of position or cash flows, but will be significant to our financial statement disclosures.

Noncontrolling Interests in Consolidated Financial Statements

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements* (FAS 160). FAS 160 was issued to improve the relevance, comparability and transparency of the financial information provided by requiring: ownership interests be presented in the consolidated statement of financial position separate from parent equity; the amount of net income attributable to the parent and the noncontrolling interest be identified and presented on the face of the consolidated statement of income; changes in the parent's ownership interest be accounted for consistently; when deconsolidating, that any retained equity interest be measured at fair value; and that sufficient disclosures identify and distinguish between the interests of the parent and noncontrolling owners. The guidance in FAS 160 is effective for fiscal years beginning on or after Dec. 15, 2008. We do not believe FAS 160 will be material to our results of operations, statement of position or cash flows.

Business Combinations (Revised)

In December 2007, the FASB issued SFAS No. 141R, *Business Combinations* (FAS 141R). FAS 141R was issued to improve the relevance, representational faithfulness, and comparability of information disclosed in financial statements about business combinations. FAS 141R establishes principles and requirements for how the acquirer: 1) recognizes and measures the assets acquired, liabilities assumed and any noncontrolling interest in the acquiree; 2) recognizes and measures the goodwill acquired; and 3) determines what information to disclose for users of financial statements to evaluate the effects of the business combination. The guidance in FAS 141R is effective prospectively for any business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after Dec. 15, 2008. We will assess the impact of FAS 141R in the event we enter into a business combination for which the expected acquisition date is subsequent to the required effective date.

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.

FAS 157, among other things, requires the company to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value, and specifies a hierarchy of valuation techniques based on whether the inputs to those valuation techniques are observable or unobservable. FAS 157 defines the following fair value hierarchy, based on these two types of inputs:

- Level 1 – Quoted prices for identical instruments in active markets.
- Level 2 – Quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model derived valuations in which all significant inputs and significant value drivers are observable in active markets.
- Level 3 – Model derived valuations in which one or more significant inputs or significant value drivers are unobservable.

The effective date was for fiscal years beginning after Nov. 15, 2007. In November 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 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.

Additionally, the FASB issued FSP 157-1 in February 2008 to exclude SFAS 13, *Accounting for Leases*, and related pronouncements addressing lease fair value measurements from the scope of FAS 157. Assets and liabilities assumed in a business combination are not covered under this scope exception. The effective date of this FSP coincides with the adoption of FAS 157.

We do not believe applying FAS 157 to the remaining non-financial assets and liabilities will be material to our results of operations, statement of position or cash flows.

INFLATION

The effects of general inflation on our results have not been significant for the past several years. The annual average rate of inflation, as measured by the Consumer Price Index (CPI-U), all items, all urban consumers as reported by the U.S. Department of Labor, was 3.8%, 2.8% and 3.2% in 2008, 2007 and 2006, respectively. The current economic crisis and the rapid drop in commodity prices in the second half of 2008 are causing forecasts for 2009 to vary widely. Forecasts published in December 2008 by Morgan Stanley and the Wall Street Journal for 2009 inflation range from annual inflation of 1.2% to deflation of 1.3%.

Prices for certain products and services used by TECO Energy's operating companies continued to increase at rates above the CPI in the first half of 2008, including prices for concrete, steel and copper products and petroleum-based products used extensively in all of our operating companies, and for subcontracted services used by Tampa Electric and subcontracted mining services used by TECO Coal. With the rapid slowing of economies world wide in the second half of 2008 and the dramatic declines in commodity prices, especially petroleum based products, inflation dropped to almost zero in December 2008. Tampa Electric and PGS are eligible to recover the cost of commodity fuel through the respective FPSC-approved fuel-adjustment clauses. In those cases where the higher costs can not be similarly recovered, higher costs could reduce the profit margins at the operating companies.

ENVIRONMENTAL COMPLIANCE

Environmental Matters

Among our companies, Tampa Electric has a number of significant stationary sources with air emissions impacted by the Clean Air Act and material Clean Water Act implications. Tampa Electric has undertaken major steps to dramatically reduce its air emissions through a series of voluntary actions, including technology selection (e.g., IGCC and conversion of coal-fired units to natural-gas fired combined cycle); implementing a responsible fuel mix taking into account price and reliability impacts to its customers; a substantial capital expenditure program to add Best Available Control Technology (BACT) emissions controls; implementation of additional controls to accomplish earlier reductions of certain emissions allowing for lower emission rates when BACT was ultimately installed; and enhanced controls and monitoring systems for certain pollutants. All of these improvements represent an investment in excess of $2 billion since 1994.

Through these actions, Tampa Electric has achieved significant reductions of all air pollutants, including CO_2, while maintaining a reasonable fuel mix through the clean use of coal for the economic benefit of its customers.

Air Quality Control

Consent Decree

Tampa Electric, through voluntary negotiations with the U.S. Environmental Protection Agency (EPA), the U.S. Department of Justice (DOJ) and the Florida Department of Environmental Protection (FDEP), signed a Consent Decree, which became effective Feb. 29, 2000, and a Consent Final Judgment, which became effective Dec. 6, 1999, as settlement of federal and state litigation. Pursuant to these agreements, allegations of violations of New Source Review requirements of the Clean Air Act were resolved, provision was made for environmental controls and pollution reductions, and Tampa Electric began implementing a comprehensive program to dramatically decrease emissions from its power plants.

The emission reduction requirements included specific detail with respect to the availability of flue gas desulfurization systems (scrubbers) to help reduce SO_2, projects for NO_x reduction on Big Bend Units 1 through 4, and the repowering of the coal-fired Gannon Power Station to natural gas, which was renamed as the H. L. Culbreath Bayside Power Station (Bayside Power Station), in 2003 and 2004. The completed station has total station capacity of about 1,800 megawatts (nominal) of natural gas-fueled, combined-cycle electric generation. The repowering has reduced the facility's NO_x and SO_2 emissions by approximately 99% and particulate matter (PM) emissions by approximately 92% from 1998 levels.

In 2004, Tampa Electric made its NO_x reduction technology selection and decided to install SCR systems for NO_x control on Big Bend Unit 4, which was completed in May 2007. Tampa Electric is installing SCR technology on the remaining Big Bend units. Unit 3 went in service in May 2008, and Units 1 and 2 are expected to be in service by May 1, 2009 and May 1, 2010, respectively. The engineering and design is complete and construction of the remaining SCR systems is currently in progress. Tampa Electric's capital investment forecast includes amounts in the 2009 through 2011 period for compliance with the NO_x, SO_2 and PM reduction requirements (see the **Capital Expenditures** section).

The FPSC has determined that it is appropriate for Tampa Electric to recover the operating costs of and earn a return on the investment in the SCRs to be installed on all four of the units at the Big Bend Power Station and pre-SCR projects on Big Bend Units 1–3 (which are early plant improvements to reduce NO_x emissions prior to installing the SCRs) through the ECRC (see the **Regulation** section). The first SCR (Big Bend Unit 4) entered service in May 2007 and cost recovery for the capital investment started in 2007. The second SCR unit (Big Bend Unit 3) entered service in June 2008 and cost recovery started in 2008. In November 2008 the FPSC approved cost recovery for the capital investment on the Big Bend Unit 2 SCR to start in 2009.

In November 2007, Tampa Electric entered into an agreement with the EPA and DOJ for a Second Amendment to the Consent Decree. The Second Amendment: 1) establishes a 0.12 lb/MMBtu NO_x limit on a 30-day rolling average for Big Bend Units 1 through 3, which is lower than the original Consent Decree that had a provision for a limit as high as 0.15 lb/MMBtu depending on certain conditions; 2) allows for the sale of NO_x allowances gained as a result of surpassing the emission limit goals of the Consent Decree; and 3) calls for Tampa Electric to install a second PM Continuous Emissions Monitoring System and potentially replace the originally installed system if the new system is successful.

Emission Reductions

Projects committed to under the Consent Decree and Consent Final Judgment have resulted in significant reductions in emissions. Since 1998, Tampa Electric has reduced annual SO_2, NO_x and PM from its facilities by 162,000 tons, 42,000 tons, and 4,000 tons, respectively.

Reductions in SO_2 emissions were accomplished through the installation of scrubber systems on Big Bend Units 1 and 2 in 1999. Big Bend Unit 4 was originally constructed with a scrubber. The Big Bend Unit 4 scrubber system was modified in 1994 to allow it to scrub emissions from Big Bend Unit 3 as well. Currently the scrubbers at Big Bend Power Station remove more than 95% of the SO_2 emissions from the flue gas streams.

The repowering of the Gannon Power Station to the Bayside Power Station has resulted in a significant reduction in emissions of all pollutant types. We expect that Tampa Electric's actions to install additional NO_x emissions controls on all Big Bend Power Station units will result in the further reduction of emissions and that by 2010, the SCR projects will result in a total phased reduction of NO_x by 62,000 tons per year from 1998 levels.

In total, we expect that Tampa Electric's emission reduction initiatives will result in the reduction of SO_2, NO_x and PM emissions by 90%, 90% and 72%, respectively, below 1998 levels by 2010. With these state-of-the-art improvements in place, Tampa Electric's activities have helped to significantly enhance the quality of the air in the community. As a result of all its already completed emission reduction actions, and upon completion of the SCR projects, we expect that Tampa Electric will have achieved emission reduction levels called for in Phase I of the Clean Air Interstate Rule (CAIR) upon implementation in 2009.

Due to pollution control benefits from the environmental improvements, reductions in mercury emissions have occurred due to the repowering of Gannon Power Station to Bayside Power Station. At the Bayside Power Station, where mercury levels have decreased 99% below 1998 levels, there are virtually zero mercury emissions. Additional mercury reductions are also anticipated from the installation of NO_x controls at Big Bend Power Station, which are expected to lead to a reduction of mercury emissions of more than 70% from 1998 levels by 2010. The Clean Air Mercury Rule (CAMR) Phase I requirements were scheduled for implementation in 2010. CAMR was vacated by the U. S. Court of Appeals for the District of Columbia Circuit on Feb. 8, 2008. Prior to the court's decision Tampa Electric expected that it would have been in compliance with CAMR Phase I without additional capital investment.

In 2007 the EPA modified the 24-hour coarse and fine PM ambient air standards. Based on the reduced emissions of PM, sulfates and nitrates resulting from projects associated with compliance with the Consent Decree, as well as local ambient air quality data, the Tampa Electric service area is expected to be in compliance with the proposed new PM standards without additional expenditures by Tampa Electric.

Carbon Reductions

Tampa Electric has historically supported voluntary efforts to reduce carbon emissions and has taken significant steps to reduce overall emissions at Tampa Electric's facilities. Since 1998, Tampa Electric has reduced its system-wide emissions of CO_2 by approximately 20%, bringing emissions to near 1990 levels. Tampa Electric expects emissions of CO_2 to remain near 1990 levels until the addition of the next baseload unit, which is expected after 2013. Tampa Electric estimates that the repowering to natural gas and the shut-down of the Gannon Station coal-fired units resulted in a decrease in CO_2 emissions of approximately 4.8 million tons below 1998 levels. During this same timeframe, the numbers of retail customers and retail energy sales have risen by approximately 25%.

Tampa Electric's voluntary activities to reduce carbon emissions also include membership in the U.S. Department of Energy's Climate Challenge (now Power Partners) program since 1994, voluntary annual reporting of greenhouse gas (GHG) emissions through the Energy Information Agency (EIA) EIA-1605(b) Report since 1995 and participation in the Chicago Climate Exchange (CCX), a voluntary but legally binding cap and trade program dedicated to reducing GHG emissions since 2003. Because of Tampa Electric's membership in the CCX, its reported CO_2 emissions are audited annually by the Financial Industry Regulatory Authority (formerly National Association of Securities Dealers), which has certified the results thus far. In January 2008, the CCX recognized Tampa Electric for achieving its Phase I GHG participation targets for CO_2 reduction. While the commitment required in Phase I was a reduction of 4% below the average of the year 1998 – 2001, Tampa Electric surpassed this level with an actual reduction of approximately 20%.

There are pending initiatives on the federal and state levels to adopt climate legislation that would require reductions in GHG emissions. At the federal level, there are several legislative proposals that would limit CO_2 emissions. Most of these bills contain some type of cap-and-trade system with various allocation scenarios to regulated utilities, including credit for early action. While the timing of passage of any federal legislation into law remains uncertain, we will participate in the debate in an effort to ensure a comprehensive environmental approach to carbon emission reductions maintains a reliable energy supply at affordable prices. In order to meet the reduction contemplated, Tampa Electric could be required to make significant additional capital investments in technologies to reduce GHG that are not yet commercially viable.

At the state level, the Governor signed three Executive Orders in July 2007 aimed at reducing Florida's emissions of GHG. The three orders include directives for reducing GHG emissions by electric utilities to 2000 levels by 2017; to 1990 levels by 2025; and by 80 percent of 1990 levels by 2050; and the creation of the Governor's Action Team on Energy and Climate Change to develop a plan to achieve the targets contained in the Executive Orders including any necessary legislative initiatives required. The Action Team submitted its Phase One report to the Governor on Nov. 1, 2007. The final report was completed by the October 2008 deadline and included recommendations incorporating GHG emission reduction targets and strategies into Florida's energy future as well as energy efficiency and conservation targets.

Also in 2008, the state legislature passed broad energy and climate legislation that, among other items, affirmed the FDEP's authority to establish a utility carbon reduction schedule and a carbon dioxide cap and trade system by rule, but added a requirement for legislative ratification of the rule no sooner than January 2010. The FDEP has initiated the rule development process, but until the final rules are developed, the impact on Tampa Electric and its customers can not be determined.

The company is examining various options relating to its carbon emissions. In the fall of 2007, Tampa Electric announced that it would not move forward with its previously announced coal-fired IGCC unit, because of the continued uncertainty related to carbon reduction regulations, particularly capture and sequestration issues. At this time, Tampa Electric expects to meet its needs for its next baseload generating capacity with natural gas fired combined-cycle technology, as well as energy efficiency programs and renewable resources (see the **Tampa Electric** section). While natural gas has lower carbon emissions than coal, fuel prices can make natural gas generating facilities less economic than coal-fired facilities. Fuel switching from coal to natural gas, absent additional sources of supply, would increase natural gas prices, further reducing the economic efficiency of natural gas generation facilities. Increased costs for electricity may cause customers to change usage patterns, which would impact Tampa Electric's sales.

Tampa Electric currently emits approximately 16.6 million tons of CO_2 per year. Assuming a projected long-term average annual load growth of about 2.0%, Tampa Electric may emit approximately 19.8 million tons of CO_2 (an increase of approximately 19%) by 2020 if natural gas-fired peaking and combined-cycle generation additions are used to meet growing customer needs.

Tampa Electric expects that the costs to comply with new environmental regulations would be eligible for recovery through the ECRC. If approved as prudent, the costs required to comply with CO_2 emissions reductions would be reflected in customers' bills. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the ECRC, Tampa Electric could seek to recover those costs through a base-rate proceeding, but can not predict whether the FPSC would grant such recovery. Although Tampa Electric's current coal-based generation has declined to less than 60% of its output in 2008 from 95% of its output in 2002, due primarily to the conversion of the coal-fired Gannon Power Station into the natural gas-fired Bayside Power Station, coal fired facilities remain a significant part of Tampa Electric's generation fleet and additional coal units could be used in the future.

In the case of TECO Guatemala, the coal-fired San José Power Station in Guatemala is in compliance with current World Bank and Guatemalan Environmental Guidelines. While there are no known plans for legislation mandating GHG reductions in Guatemala, new rules or regulations could require additional capital investments or increase operating costs.

In the case of TECO Coal, it is unclear if the requirements for CO_2 emissions reductions would directly impact it as a carbon-based fuel provider or the user. In either case, it could make the use of coal more expensive or less desirable, which could impact TECO Coal's margins and profitability.

Renewable Energy

Renewables are a component of Tampa Electric's environmental portfolio. Tampa Electric's renewable energy program offers to sell renewable energy as an option to customers and utilizes energy generated in the state from renewable sources (e.g. biomass and solar). To date, 24 million kWh of renewable energy have been produced to support participating customer requirements.

Tampa Electric has installed almost 40,000 watts of solar panels to generate electricity from the sun at three schools and the Museum of Science and Industry in Tampa, and continues to evaluate opportunities for additional solar panel installations. In the area of biomass, which is organic plant material from yard clippings and other vegetation, Tampa Electric has tested bahia grass as a fuel to generate electricity at the Polk Power Station where it was ground and mixed with the pulverized coal slurry used in the plant's gasifier.

Despite the emphasis on the use of renewable energy sources to reduce GHG in the Governor's Executive Orders, the recently completed FPSC study conducted by Navigant Consulting indicates that only under the most favorable conditions of high customer incentives, a mature Renewable Energy Credit (REC) market and a high revenue rate cap would utilities hope to achieve the Governor's renewable energy target. The Navigant study also found that solar photovoltaic power generation and biomass were the most viable sources of renewable energy and that Florida was a poor location for either significant land based wind generation or concentrating solar generation. While support for tax incentives for renewable energy development specific to regional disparities may facilitate the development of new sources, mandates for renewable portfolios at high percentages create concerns that RECs will have to be purchased to meet the mandate, rates for customers will grow rapidly and such mandates are not likely to result in significant quantities of renewable energy sources to be developed in the state. A mandatory renewable energy portfolio standard could add to Tampa Electric's costs and adversely affect its operating results.

In Florida, the executive orders tasked the FPSC with evaluating a renewable portfolio target of 20% by 2020. The 2008 Energy Bill directed the FPSC to draft a rule for a RPS to be presented to the Florida Legislature by Feb. 1, 2009, but did not specify targets and timeframes. Under this direction, the FPSC's recommendation to the legislature is that the RPS percentage and timing be 7% by Jan. 1, 2013, 12% by Jan. 1, 2016, 18% by Jan. 1, 2019 and 20% by Jan. 1, 2021. In addition, a 2% of retail revenue cost cap was proposed, and a new clause for the recovery of costs associated with meeting the RPS standard was also proposed. A three-year review strategy was included in the draft rule to allow the Commission to adjust the goals and cost cap over time and as more experience is gained. The Legislature is expected to take up the issue in the upcoming legislative session and it must ratify the rule before it can be put into effect. Ratification can include approval of the rule as adopted by the FPSC, rejection of the rule entirely, or amendment to one or more elements of the rule. While prospects in the Legislature are uncertain, nothing can become final until further action of the FPSC after the 2009 legislative session.

Although the U.S. Congress has considered, but to date has not passed, a federal RPS standard, there is likely to be an increased emphasis on the passage of a federal RPS under the new Obama administration. Tampa Electric could incur significant costs to comply with a high percentage renewable energy portfolio standard, as proposed, and its operating results could be adversely affected if the company was not permitted to recover these costs from customers, or if customers change usage patterns in response to increased rates.

Water Supply and Quality

The EPA's final Clean Water Act Section 316(b) rule became effective Jul. 9, 2004. The rule established aquatic protection requirements for existing facilities that withdraw 50 million gallons or more of water per day from rivers, streams, lakes, reservoirs, estuaries, oceans, or other U.S. waters for cooling purposes. Tampa Electric uses water from Tampa Bay at its Bayside and Big Bend facilities for cooling water. Both plants use mesh screens to reduce the adverse impacts to aquatic organisms and Big Bend units 3 and 4 use proprietary fine-mesh screens, the best available technology, to further reduce impacts to aquatic organisms. Subsequent to promulgation of the rule, a number of states, environmental groups and others sought judicial review of the rule. On Jan. 25, 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule to the EPA for revisions. Among other things, the court rejected the EPA's use of "cost-benefit" analysis and suggested some ways to incorporate cost considerations. The Supreme Court agreed to review the Second Circuit's decision and heard arguments in December 2008. The full impact of these regulations will depend on subsequent legal proceedings, further rulemaking by the EPA, the results of studies and analyses performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies and, therefore, cannot now be determined.

The Big Bend Power Station also consumes a significant amount of water on a daily basis to generate electricity with steam and to operate its scrubbers to reduce SO_2 emissions. Water recycling and beneficial reuse programs are widely employed in the fresh water systems at both the Big Bend and Polk power stations to reduce demand on higher-cost municipal water systems and to control costs.

Conservation

Energy conservation is becoming increasingly important in a period of volatile energy prices and in the GHG emissions reduction debate. In 2007, the Governor signed three Executive Orders aimed at reducing Florida's emissions of GHG, which included a directive for the development of new policies to enhance energy efficiency and conservation statewide. The Climate Action Team described above completed a final report by the October 2008 deadline and included policy recommendations on energy efficiency and conservation targets which may either be used in the development of new legislation or in the augmentation of existing FPSC regulation.

Tampa Electric offers customers 27 comprehensive programs to conserve energy. These programs are designed to reduce peak energy demand which allows Tampa Electric to delay construction of future generation facilities. Since their inception, these conservation programs have reduced the summer peak demand by 220 megawatts, and the winter peak demand by 616 megawatts. These programs and their costs are approved annually by the FPSC with the costs recovered through a clause on the customer's bill.

In 2007, the FPSC approved the modification of nine existing programs and the addition of 13 new conservation programs. Following a two-year pilot program, the FPSC approved the Energy Planner program, which is a program aimed at residential customers that is expected to reduce summer peak demand by 22 megawatts, winter demand by 28 megawatts and annual energy consumption by almost 10,000 megawatt hours. In addition, PGS offers programs that enable customers to reduce their energy consumption, with the costs recovered through customers' bills.

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 Dec. 31, 2008, Tampa Electric Company has estimated its ultimate financial liability to be approximately $10.7 million (primarily related to PGS), and this amount has been reflected 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 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 credit worthy.

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 or changes in laws or regulations that could require additional remediation. Under current regulation, these additional costs would be eligible for recovery through customer rates.

Coal Ash Ponds

Over 98% of Tampa Electric's byproducts from the combustion of coal to generate power that were produced in 2008 were marketed to customers for beneficial use. For fly ash, over 99% was sold for reuse in concrete products. The Big Bend Power Station produces about 300,000 tons of fly ash annually. The fly ash is piped pneumatically from the power station to an onsite beneficiation facility and stored dry in silos until shipped to customers.

There are two other types of ash byproducts that are formed at different points in the boiler system during combustion. The first, called "economizer ash", is a heavier, more granular type of ash which is collected from the boiler exhaust duct. Tampa Electric's Big Bend Power Station produces a small amount of this, approximately 10,000 tons annually. Water is added and the material is sluiced to two small onsite (12 acres total area), lined ponds. Although there is no market for this material to date, Tampa Electric continues to evaluate beneficial reuse opportunities and intends to recycle it eventually. The second is "bottom ash", a glassy form of molten ash which is collected at the bottom of the boiler and then transferred to two additional onsite ponds (13 acres total area) for reclaiming. All of this material is reclaimed within thirty days of production and approximately 30,000 tons per year are sold to the cement industry. All of Tampa Electric's ash storage areas are lined and have groundwater monitoring systems in place, in accordance with state requirements.

REGULATION

The retail operations of Tampa Electric and PGS are regulated by the FPSC, which has jurisdiction over retail rates, quality of service and reliability, issuances of securities, planning, siting and construction of facilities, accounting and depreciation practices and other matters.

In general, the FPSC's pricing objective is to set rates at a level that allows the utility to collect total revenues (revenue requirements) equal to its cost of providing service, plus a reasonable return on invested capital.

For both Tampa Electric and PGS, the costs of owning, operating and maintaining the utility system, other than fuel, purchased power, conservation and certain environmental costs, are recovered through base rates. These costs include operation and maintenance expenses, depreciation and taxes, as well as a return on investment in assets used and useful in providing electric and natural gas distribution services (rate base). The rate of return on rate base, which is intended to approximate the individual company's weighted cost of capital, primarily includes its costs for debt, deferred income taxes at a zero cost rate and an allowed return on common equity. Base rates are determined in FPSC rate setting hearings which occur at irregular intervals at the initiative of Tampa Electric, PGS, the FPSC or other parties.

Tampa Electric is also subject to regulation by the Federal Energy Regulatory Commission (FERC) in various respects, including wholesale power sales, certain wholesale power purchases, transmission services, and accounting practices.

Federal, state and local environmental laws and regulations cover air quality, water quality, land use, power plant, substation and transmission line siting, noise and aesthetics, solid waste and other environmental matters (see the **Environmental Compliance** section).

Tampa Electric - Base Rates

Tampa Electric's rates and allowed return on equity (ROE) range of 10.75% to 12.75%, with a midpoint of 11.75%, are 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.

Before August 2008, Tampa Electric had not sought a base rate increase since 1992. Since that last rate proceeding, it had earned within its allowed ROE range while adding more than 200,000 customers and making significant investments in facilities and infrastructure. These facilities include baseload, intermediate and peaking generating capacity additions, to reliably serve the growing customer base. Tampa Electric expects a continued high level of capital investment, and higher levels of non-fuel operation and maintenance expenditures. As a result of lower customer growth, lower energy sales growth, and ongoing high levels of capital investment, Tampa Electric's 13-month average regulatory ROE was 8.7% at the end of 2008.

Recognizing the significant decline in ROE, Tampa Electric filed for a $228.2 million base rate increase in August 2008. The major factors in the filing included a request for an ROE mid-point of 12%, 55.3% equity in the capital structure, and rate base of $3.7 billion. The formal hearings before the FPSC were held in late January and the FPSC is scheduled to make its final decision on the requested increase in mid-March, with final rates effective in May 2009.

Tampa Electric-Cost Recovery Clauses

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 cost recovery 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 include the cost for natural gas and coal expected in 2009, the net recovery of $132.9 million of fuel and purchased power expenses, which were not collected in 2008 and underestimated in 2007, the net over-recovery of $4.7 million of costs recovered through the ECRC for the 2007 and 2008 periods, and the operating cost for and a return on the capital invested in the third SCR project to enter service at the Big Bend Power Station as well as the operation and maintenance expense associated with the projects as required by the EPA Consent Decree and FDEP Consent Final Judgment (see the **Environmental Compliance** section). The rates also reflect an additional disallowance of $1.9 million to settle all outstanding issues associated with the 2004 fuel transportation contract (see the **Tampa Electric** section and the **2008 Reconciliation of GAAP net income from continuing operations to non-GAAP results** reconciliation table). 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. Accordingly, Tampa Electric's residential customer rate per 1,000 kilowatt-hours increased $14.06 from $114.38 in 2008 to $128.44 in 2009.

The FPSC determined 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 Unit 4 and Big Bend Units 1-3 in October 2004 and May 2005, respectively, for NO_x control in compliance with the environmental consent decree. The SCR for Big Bend Unit 4 entered service in May 2007 and cost recovery started in 2007. The SCR for Big Bend Unit 3 entered service in May 2008 and cost recovery started in 2008. The SCRs for Big Bend Units 2 and 1 are scheduled to enter service by May 1, 2009 and 2010, respectively. Cost recovery for the capital investment for each unit, which is dependent on filings made in the year each SCR enters service, is expected to start in 2009 and 2010, respectively.

Coal Transportation Contract

In 2003, following a request for proposal process, Tampa Electric executed a new five-year contract with TECO Transport, (at the time an affiliated company, now United Maritime, an unaffiliated company) effective Jan. 1, 2004, for waterborne coal transportation and storage services at market rates. Hearings regarding the prudence of the RFP process and final contract were held and a final order on the matter was issued in October 2004, which reduced the annual amount Tampa Electric could recover from its customers through the fuel adjustment clause for the water transportation services for coal and petroleum coke provided by TECO Transport. The annual disallowance was $8 million to $10 million, depending on the volumes and origination points of the coal shipments, which is reflected in our results. To settle a dispute with the FPSC that arose in 2008 over the calculation of the waterborne transportation disallowance over its five-year life, Tampa Electric recorded a $1.9 million charge in 2008 (see the **Tampa Electric** section).

Tampa Electric issued a RFP for solid fuel transportation services in October 2007. Tampa Electric structured the RFP to comply with the FPSC order issued in October 2004. New contracts for solid fuel deliveries were executed with United Maritime, AEP Memco and CSX Railroad prior to the expiration of the then existing contract with United Maritime on Dec. 31, 2008. The rail service contract will provide Tampa Electric with bimodal capability for solid fuel transportation, which the FPSC had encouraged Tampa Electric to pursue, following the completion of construction of rail unloading facilities at Big Bend Power Station (see the **Liquidity, Capital Resources** section). In its November 2008 fuel hearings the FPSC approved the full recovery of rates for 2009 that included the costs associated with the new contracts.

Hardening of Transmission and Distribution Facilities

Due to extensive storm damage to utility facilities during the 2004 and 2005 hurricane seasons and the resulting outages utility customers experienced throughout the state, the FPSC initiated a proceeding to explore methods of designing and building transmission and distribution systems that would minimize long-term outages and restoration costs.

The FPSC subsequently issued an order requiring all investor owned utilities (IOUs) to implement a 10-point storm preparedness plan designed to improve the statewide electric infrastructure to better withstand severe storms and expedite recovery from future storms. Tampa Electric has implemented its plan and estimates the average incremental non-fuel operation and maintenance expense of this plan to be approximately $20 million annually. The FPSC also modified its rule regarding the design standards for new and replacement transmission and distribution line construction, including certain critical circuits in a utility's system. Future capital expenditures required under the storm hardening program are expected to average approximately $19 million annually for the foreseeable future.

Florida's Energy Plan

The FDEP has produced an energy plan for the state that, among other initiatives, encourages fuel diversity for electric generation, streamlining of the power plant siting review process, conservation by state agencies and consumers, educational programs for residential and business customers regarding energy conservation, expansion of the use of hydrogen and additional grants to study alternative energy supplies (see the **Environmental Compliance** section).

Utility Competition – Electric

Tampa Electric's retail electric business is substantially free from direct competition with other electric utilities, municipalities and public agencies. At the present time, the principal form of competition at the retail level consists of self-generation available to larger users of electric energy. Such users may seek to expand their alternatives through various initiatives, including legislative and/or regulatory changes that would permit competition at the retail level. Tampa Electric intends to retain and expand its retail business by managing costs and providing high quality service to retail customers.

Presently there is competition in Florida's wholesale power markets, largely as a result of the Energy Policy Act of 1992 and related federal initiatives. However, the state's Power Plant Siting Act, which sets the state's electric energy and environmental policy and governs the building of new generation involving steam capacity of 75 megawatts or more, requires that applicants demonstrate that a plant is needed prior to receiving construction and operating permits.

In 2003, the FPSC modified rules from 1994 that required IOUs to issue RFPs prior to filing a petition for Determination of Need for construction of a power plant with a steam cycle greater than 75 megawatts. The modified rules provide a mechanism for expedited dispute resolution, allow bidders to submit new bids whenever the IOU revises its cost estimates for its self-build option, require IOUs to disclose the methodology and criteria to be used to evaluate the bids, and provide more stringent standards for the IOUs to recover cost overruns in the event the self-build option is deemed the most cost-effective. These rules became effective prospectively for RFPs for applicable capacity additions.

PGS Rates

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. At the end of 2007, PGS' 13-month average regulatory ROE was below the bottom of its allowed range as a result of higher operating costs, continued investment in the distribution system and higher costs associated with required safety requirements, such as transmission and distribution pipeline integrity management.

Recognizing the significant decline in ROE, PGS filed for a $26.5 million base rate increase in August 2008. The major factors in the filing included a request for an ROE mid-point of 11.5%, 54.7% equity in the capital structure, and rate base of $564 million. The formal hearings before the FPSC are scheduled to be held in March and the FPSC is scheduled to make its final decision on the requested increase in May, with final rates effective in June 2009.

PGS Cost Recovery Clauses

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 its 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.

Utility Competition – Gas

Although PGS is not in direct competition with any other regulated distributors of natural gas for customers within its service areas, there are other forms of competition. At the present time, the principal form of competition for residential and small commercial customers is from companies providing other sources of energy, including electricity, propane and fuel oil. PGS has taken actions to retain and expand its natural gas distribution business, including managing costs and providing high quality service to customers.

In Florida, gas service is unbundled for all non-residential customers. In 2000, PGS implemented its "NaturalChoice" program, offering unbundled transportation service to all eligible customers and allowing non-residential customers to purchase commodity gas from a third party but continue to pay PGS for the transportation. As a result, PGS receives its base rate for distribution regardless of whether a customer decides to opt for transportation-only service or continue bundled service. PGS had approximately 13,600 transportation customers as of Dec. 31, 2008 out of approximately 29,500 eligible customers.

Competition is most prevalent in the large commercial and industrial markets. In recent years, these classes of customers have been targeted by companies seeking to sell gas directly by transporting gas through other facilities and thereby bypassing PGS facilities. In response to this competition, PGS has developed various programs, including the provision of transportation services at discounted rates.

CORPORATE GOVERNANCE

CEO and CFO Certifications

The most recent certifications by our Chief Executive Officer and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 are filed as exhibits to TECO Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2008. The certification of TECO Energy's Chief Executive Officer regarding compliance with the New York Stock Exchange (NYSE) corporate governance listing standards required by NYSE will be filed with NYSE following the 2009 Annual Meeting of Shareholders. Last year, we filed this certification with the NYSE after the 2008 Annual Meeting of Shareholders, in compliance with NYSE rules.

Item 7A Quantitative and Qualitative Disclosures about Market Risk

Risk Management Infrastructure

We are subject to various types of market risk in the course of daily operations, as discussed below. We have adopted an enterprise-wide approach to the management and control of market and credit risk. Middle Office risk management functions, including credit risk management and risk control, are independent of each transacting entity (Front Office).

Our Risk Management Policy (Policy) governs all energy transacting activity at the TECO Energy group of companies. The Policy is approved by our Board of Directors and administered by a Risk Authorizing Committee (RAC) that is comprised of senior management. Within the bounds of the Policy, the RAC approves specific hedging strategies, new transaction types or products, limits, and transacting authorities. Transaction activity is reported daily and measured against limits. For all commodity risk management activities, derivative transaction volumes are limited to the anticipated volume for customer sales or supplier procurement activities.

The RAC administers the Policy with respect to interest rate risk exposures. Under the Policy , the RAC operates and oversees transaction activity. Interest rate derivative transaction activity is directly correlated to borrowing activities.

Risk Management Objectives

The Front Office is responsible for reducing and mitigating the market risk exposures which arise from the ownership of physical assets and contractual obligations, such as debt instruments and firm customer sales contracts. The primary objectives of the risk management organization, the Middle Office, are to quantify, measure, and monitor the market risk exposures arising from the activities of the Front Office and the ownership of physical assets. In addition, the Middle Office is responsible for enforcing the limits and procedures established under the approved risk management policies. Based on the policies approved by the company's Board of Directors and the procedures established by the RAC, from time to time, members of the TECO Energy group of companies enter into futures, forwards, swaps and option contracts 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;
- Interest rate fluctuations on debt at TECO Energy and its affiliates; and
- Price fluctuations for physical purchases of fuel and explosives at TECO Coal;

The TECO Energy companies use derivatives only to reduce normal operating and market risks, not for speculative purposes. Our primary objective in using derivative instruments for regulated operations is to reduce the impact of market price volatility on ratepayers. For unregulated operations, the companies use derivative instruments primarily to mitigate the price uncertainty related to commodity inputs, such as diesel fuel.

Derivatives and Hedge Accounting

FAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as subsequently amended and interpreted, requires us and our affiliates 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 components of other comprehensive income or net income, depending on the designation of those instruments.

Designation of a hedging relationship requires management to make assumptions about the future probability of the timing and amount of the hedged transaction and the future effectiveness of the derivative instrument in offsetting the change in fair value or cash flows of the hedged item or transaction. The determination of fair value is dependent upon certain assumptions and judgments, as described more fully below (see **Note 22** to the **TECO Energy Consolidated Financial Statements**).

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.

Most 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.

Interest rate derivatives at the regulated utilities were entered into in 2007 as a cash flow hedge to reduce exposure to interest rate changes for a debt issuance during the second quarter of 2008. The $11.8 million settlement of these instruments in May of 2008 was recorded in accumulated other comprehensive income and will be amortized to earnings over the life of the related debt which matures on May 15, 2018. The remaining balance at Dec. 31, 2008 is $11.1 million.

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.

The valuation methods we used to determine fair value are described in **Note 22** to the **TECO Energy Consolidated Financial Statements**.

Credit Risk

We have a rigorous process for the establishment of new trading counterparties. This process includes an evaluation of each counterparty's financial statements, with particular attention paid to liquidity and capital resources; establishment of counterparty specific credit limits; optimization of credit terms; and execution of standardized enabling agreements. Our Credit Guidelines require transactions with counterparties below investment grade to be collateralized.

Contracts with different legal entities affiliated with the same counterparty are consolidated for credit purposes and managed as appropriate, considering the legal structure and any netting agreements in place. Credit exposures are calculated, compared to limits and reported to management on a daily basis. The Credit Guidelines are administered and monitored within the Middle Office, independent of the Front Office.

We have implemented procedures to monitor the creditworthiness of our counterparties and to consider nonperformance in valuing counterparty positions. Net liability positions are generally not adjusted as we use our derivative transactions as hedges and we have the ability and intent to perform under each of our contracts. In the instance of net asset positions, we consider 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 of our derivative instruments contain provisions that require our 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 our debt ratings, including Tampa Electric 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 aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on Dec. 31, 2008, was $161.1 million, including Tampa Electric Company positions of $134.8 million, for which we have posted collateral of $9.7 million in the normal course of business. If the credit-risk-related contingent features underlying these agreements were triggered as of Dec. 31, 2008, we could have been required to post additional collateral or settle existing positions with counterparties totaling $151.4 million. In the unlikely event that this situation would occur, we believe we maintain adequate lines of credit to meet these obligations.

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. As of Dec. 31, 2008 and 2007, a hypothetical 10% increase in the consolidated group's weighted average interest rate on its variable rate debt during the subsequent year, would not result in a material impact on pretax earnings. This is driven by the low amounts of variable rate debt at either TECO Energy or our subsidiaries.

These amounts were determined based on the variable rate obligations existing on the indicated dates at TECO Energy and its subsidiaries. A hypothetical 10% decrease in interest rates would increase the fair market value of our long-term debt by approximately 4.0% at Dec. 31, 2008 and 3.2% at Dec. 31, 2007 (see the **Financing Activity** section and **Notes 6** and **7** to the **TECO Energy Consolidated Financial Statements**). The above sensitivities assume no changes to our financial structure and could be affected by changes in our credit ratings, changes in general economic conditions or other external factors (see the **Risk Factors** section).

Commodity Risk

We and our affiliates 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. We assess and monitor risk using a variety of measurement tools. Management uses different risk measurement and monitoring tools based on the degree of exposure of each operating company to commodity risks.

Regulated Utilities

Historically, Tampa Electric's fuel costs used for generation were affected primarily by the price of coal and, to a lesser degree, the cost of natural gas and fuel oil. With the repowering of the Bayside Power Station, the use of natural gas, with its more volatile pricing, has increased substantially. PGS has exposure related to the price of purchased gas and pipeline capacity.

Currently, Tampa Electric's and PGS' commodity price risk is largely mitigated by the fact that increases in the price of fuel and purchased power are recovered through cost recovery clauses, with no anticipated effect on earnings. However, increasing fuel cost recovery has the potential to affect total energy usage and the relative attractiveness of electricity and natural gas to consumers. To moderate the impacts of fuel price changes on customers, both Tampa Electric and PGS manage commodity price risk by entering into long-term fuel supply agreements, prudently operating plant facilities to optimize cost, and entering into derivative transactions designated as cash flow hedges of anticipated purchases of wholesale natural gas. At Dec. 31, 2008 and 2007, a change in commodity prices would not have had a material impact on earnings for Tampa Electric or PGS, but could have had an impact on the timing of the cash recovery of the cost of fuel (see the **Tampa Electric** and **Regulation** sections).

Unregulated Operating Companies

Our unregulated operating companies, TECO Coal and TECO Guatemala, are subject to significant commodity risk. The operating companies do not speculate using derivative instruments. However, all derivative instruments may not receive hedge accounting treatment due to the strict requirements and narrow applicability of the accounting rules to dynamic transactions.

TECO Coal is exposed to commodity price risk through coal sales as a part of its daily operations. Where possible and economical, TECO Coal enters into fixed price sales transactions to mitigate variability in coal prices. TECO Coal is also exposed to variability in operating costs as a result of periodic purchases of diesel oil in its operations. At Dec. 31, 2008, TECO Coal had derivative instruments in place to reduce the price variability for its anticipated 2009 diesel oil purchases for all coal production volumes sold under contracts that did not include a fuel price component. Accordingly, a change in the average annual price for diesel oil is not expected to change TECO Coal's cost of production.

Like Tampa Electric and PGS, TECO Guatemala has commodity price risk that is largely mitigated by the fact that increases in the price of fuel are passed through to the power purchasing distribution utility. However, changes in the relative cost of coal-fired and oil-fired generation in Guatemala can have a substantial impact on the dispatch frequency of TECO Guatemala's units and its ability to achieve incremental spot market sales.

The following tables summarize the changes in and the fair value balances of derivative assets (liabilities) for the year ended Dec. 31, 2008:

Changes in Fair Value of Derivatives

(millions)	
Net fair value of derivatives as of Dec. 31, 2007	$ (23.9)
Additions and net changes in unrealized fair value of derivatives	(134.0)
Changes in valuation techniques and assumptions	—
Realized net settlement of derivatives	6.5
Net fair value of derivatives as of Dec. 31, 2008	$ (151.4)

Roll-Forward of Derivative Net Assets (Liabilities)

(millions)	
Total derivative net assets (liabilities) as of Dec. 31, 2007	$ (23.9)
Change in fair value of net derivative assets (liabilities):	
Recorded as regulatory assets and liabilities or other comprehensive income	(134.0)
Recorded in earnings	—
Realized net settlement of derivatives	6.5
Net option premium payments	—
Net fair value of derivatives at Dec. 31, 2008	$ (151.4)

At Dec. 31, 2008 the majority of the company's open positions consisted of standard over the counter (OTC) natural gas or heating oil swaps; therefore, the primary pricing inputs used to determine the fair value for the bulk of our derivative contracts were quoted market prices. However, in all instances prices, inputs, assumptions and the results of valuation techniques are validated by the Middle Office, independently of the Front Office.

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

The following is a summary table of sources of fair value, by maturity period, for derivative contracts at Dec. 31, 2008.

Maturity and Source of Derivative Contracts Net Assets (Liabilities) at Dec. 31, 2008

(millions)	*Current*	*Non-current*	*Total Fair Value*
Source of fair value			
Actively quoted prices	$ —	$ —	$ —
Other external sources(1)	(132.1)	(19.3)	(151.4)
Model prices (2)	—	—	—
Total	$(132.1)	$(19.3)	$(151.4)

(1) Reflects over-the-counter natural gas 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 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.

THIS
PAGE
INTENTIONALLY
LEFT
BLANK

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

TECO ENERGY, INC.

All other financial statement schedules have been omitted since they are not required, are inapplicable or the required information is presented in the financial statements or notes thereto.

Report of Independent Registered Certified Public Accounting Firm

To the Board of Directors and Shareholders of TECO Energy, Inc.:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of TECO Energy, Inc. and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the accompanying index present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 5 to the financial statements, the Company changed its method of accounting for its defined benefit pension and other postretirement plans as of December 31, 2006. Further, as discussed in Note 1 to the financial statements, the Company changed its method of accounting for stock-based compensation as of January 1, 2006.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Tampa, Florida
February 23, 2009

TECO ENERGY, INC.
Consolidated Balance Sheets

Assets *(millions)*	*Dec. 31, 2008*	*Dec. 31, 2007*
Current assets		
Cash and cash equivalents	$ 12.2	$ 162.6
Short-term investments	2.4	-
Receivables, less allowance for uncollectibles of $3.5 and $3.3 at Dec. 31, 2008 and 2007, respectively	285.9	295.9
Crude oil options receivable, net	-	78.5
Inventories, at average cost		
Fuel	90.2	85.8
Materials and supplies	72.8	68.2
Current regulatory assets	272.6	67.4
Current derivative assets	-	0.3
Income tax receivables	3.5	0.7
Prepayments and other current assets	25.8	23.0
Total current assets	765.4	782.4
Property, plant and equipment		
Utility plant in service		
Electric	5,528.3	5,275.2
Gas	964.4	917.4
Construction work in progress	463.5	364.8
Other property	354.8	336.4
Property, plant and equipment	7,311.0	6,893.8
Accumulated depreciation	(2,089.7)	(2,005.6)
Total property, plant and equipment, net	5,221.3	4,888.2
Other assets		
Deferred income taxes	333.8	424.9
Other investments	21.3	22.9
Long-term regulatory assets	325.3	186.8
Long-term derivative assets	0.1	1.9
Investment in unconsolidated affiliates	284.0	275.5
Goodwill	59.4	59.4
Deferred charges and other assets	136.8	123.2
Total other assets	1,160.7	1,094.6
Total assets	$ 7,147.4	$ 6,765.2

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

TECO ENERGY, INC.
Consolidated Balance Sheets – continued

Liabilities and Capital *(millions)*	*Dec. 31, 2008*	*Dec. 31, 2007*
Current liabilities		
Long-term debt due within one year		
Recourse	$ 5.5	$ 5.7
Non-recourse	1.4	1.4
Notes payable	93.0	25.0
Accounts payable	304.4	302.1
Customer deposits	144.6	138.1
Current regulatory liabilities	21.7	35.4
Current derivative liabilities	132.1	26.0
Interest accrued	45.1	32.7
Taxes accrued	21.2	33.2
Other current liabilites	15.3	18.0
Total current liabilities	784.3	617.6
Other liabilities		
Investment tax credits	11.2	12.2
Long-term regulatory liabilities	588.2	582.7
Long-term derivative liabilities	19.4	0.1
Deferred credits and other liabilities	530.0	377.2
Long-term debt, less amount due within one year		
Recourse	3,199.0	3,149.4
Non-recourse	7.6	9.0
Total other liabilities	4,355.4	4,130.6
Commitments and contingencies (see **Note 12**)		
Capital		
Common equity (400.0 million shares authorized; par value $1; 212.9 million shares and 210.9 million shares outstanding at Dec. 31, 2008 and 2007, respectively)	212.9	210.9
Additional paid in capital	1,518.2	1,489.2
Retained earnings	322.6	334.1
Accumulated other comprehensive loss	(46.0)	(17.2)
Total capital	2,007.7	2,017.0
Total liabilities and capital	$ 7,147.4	$ 6,765.2

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

TECO ENERGY, INC.
Consolidated Statements of Income

(millions, except per share amounts) *For the years ended Dec. 31,*		*2008*	*2007*	*2006*
Revenues				
Regulated electric and gas (includes franchise fees and gross receipts taxes of $109.2 in 2008, $111.2 in 2007 and $104.2 in 2006)		$ 2,778.2	$ 2,786.3	$ 2,660.3
Unregulated		597.1	749.8	787.8
Total revenues		3,375.3	3,536.1	3,448.1
Expenses				
Regulated operations				
Fuel		819.4	854.7	803.4
Purchased power		305.4	271.9	221.3
Cost of natural gas sold		476.6	389.9	365.3
Other		277.7	280.4	294.0
Operation other expense				
Mining related costs		440.6	435.4	450.2
Waterborne transportation costs		-	206.4	217.8
Other		18.2	16.6	15.6
Maintenance		173.9	183.5	183.3
Depreciation and amortization		266.1	263.7	282.2
Loss (gain) on sale, net of transaction related costs		0.9	(221.3)	-
Taxes, other than income		211.5	218.3	217.5
Sale of previously impaired assets / asset impairments		-	-	(20.7)
Total expenses		2,990.3	2,899.5	3,029.9
Income from operations		385.0	636.6	418.2
Other income (expense)				
Allowance for other funds used during construction		6.3	4.5	2.7
Other income		21.5	112.0	94.5
Loss on debt exchange/extinguishment		-	(32.9)	(2.5)
Income from equity investments		72.9	68.5	58.9
Total other income		100.7	152.1	153.6
Interest charges				
Interest expense		231.3	259.5	279.4
Allowance for borrowed funds used during construction		(2.4)	(1.7)	(1.1)
Total interest charges		228.9	257.8	278.3
Income before provision for income taxes		256.8	530.9	293.5
Provision for income taxes		94.4	214.2	118.7
Income from continuing operations before minority interest		162.4	316.7	174.8
Minority interest		-	82.2	69.6
Income from continuing operations		162.4	398.9	244.4
Discontinued operations				
Income from discontinued operations		-	-	2.3
Income tax (benefit) provision		-	(14.3)	0.4
Total discontinued operations		-	14.3	1.9
Net income		$ 162.4	$ 413.2	$ 246.3
Average common shares outstanding	– Basic	210.6	209.1	207.9
	– Diluted	211.4	209.9	208.7
Earnings per share from continuing operations	– Basic	$ 0.77	$ 1.91	$ 1.18
	– Diluted	$ 0.77	$ 1.90	$ 1.17
Earnings per share from discontinued operations	– Basic	$ -	$ 0.07	$ 0.01
	– Diluted	$ -	$ 0.07	$ 0.01
Earnings per share	– Basic	$ 0.77	$ 1.98	$ 1.19
	– Diluted	$ 0.77	$ 1.97	$ 1.18
Dividends declared and paid per common share outstanding		$ 0.795	$ 0.775	$ 0.760

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

TECO ENERGY, INC.
Consolidated Statements of Comprehensive Income

(millions) *For the years ended Dec. 31,*	*2008*	*2007*	*2006*
Net income	$ 162.4	$ 413.2	$ 246.3
Other comprehensive income (loss), net of tax			
Net unrealized losses on cash flow hedges	(18.9)	(6.3)	(0.3)
Amortization of unrecognized benefit costs	2.6	2.4	—
Recognized benefit costs due to curtailment	—	8.7	—
Change in benefit obligation due to annual remeasurement	(10.8)	8.5	42.7
Unrealized loss on available-for-sale securities	(1.7)	—	—
Other comprehensive (loss) income, net of tax	(28.8)	13.3	42.4
Comprehensive income	$ 133.6	$ 426.5	$ 288.7

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

TECO ENERGY, INC.
Consolidated Statements of Cash Flows

(millions) *For the years ended Dec. 31,*	*2008*	*2007*	*2006*
Cash flows from operating activities			
Net income	$ 162.4	$ 413.2	$ 246.3
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	266.1	263.7	282.2
Deferred income taxes	95.4	184.8	112.5
Investment tax credits, net	(1.0)	(2.5)	(2.6)
Allowance for other funds used during construction	(6.3)	(4.5)	(2.7)
Non-cash stock compensation	9.7	11.6	11.5
Gain on sales of business / assets, pretax	(1.7)	(246.1)	(67.0)
Equity in earnings of unconsolidated affiliates, net of cash distributions on earnings	(22.8)	(18.0)	(3.4)
Minority interest	-	(82.2)	(69.6)
Non-cash debt extinguishment / exchange	-	2.6	2.5
Derivatives marked to market	-	(82.7)	2.0
Deferred recovery clause	(115.8)	123.7	53.4
Receivables, less allowance for uncollectibles	10.0	8.7	(26.0)
Inventories	(9.0)	(9.6)	(5.8)
Prepayments and other deposits	(2.8)	3.2	11.4
Taxes accrued	(14.8)	26.6	(17.0)
Interest accrued	12.4	(17.8)	0.5
Accounts payable	(8.3)	(29.6)	(18.0)
Other	14.3	8.9	56.7
Cash flows from operating activities	387.8	554.0	566.9
Cash flows from investing activities			
Capital expenditures	(589.5)	(494.4)	(455.7)
Allowance for other funds used during construction	6.3	4.5	2.7
Net proceeds from sales of business / assets	0.6	405.2	100.4
Restricted cash	(0.1)	29.9	0.3
Distributions from unconsolidated affiliates	13.2	27.5	7.3
Other investments	76.1	(0.4)	(6.7)
Cash flows used in investing activities	(493.4)	(27.7)	(351.7)
Cash flows from financing activities			
Dividends	(168.6)	(163.0)	(158.7)
Proceeds from sale of common stock	21.8	14.0	12.5
Proceeds from long-term debt	327.8	444.1	327.5
Repayment of long-term debt	(293.8)	(1,137.5)	(199.3)
Contributions from minority interests	-	81.3	65.7
Debt exchange premiums	-	(21.2)	-
Net increase (decrease) in short-term debt	68.0	(23.0)	(167.0)
Cash flows used in financing activities	(44.8)	(805.3)	(119.3)
Net (decrease) increase in cash and cash equivalents	(150.4)	(279.0)	95.9
Cash and cash equivalents at beginning of the year	162.6	441.6	345.7
Cash and cash equivalents at end of the year	$ 12.2	$ 162.6	$ 441.6
Supplemental disclosure of cash flow information			
Cash paid during the year for:			
Interest (net of amounts capitalized)	$ 203.0	$ 262.1	$ 259.4
Income taxes paid (refund)	$ 6.0	$ (10.5)	$ 10.4

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

TECO ENERGY, INC.
Consolidated Statements of Capital

(millions)	Shares[1]	Common Stock	Additional Paid-in Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Unearned Compensation	Total Capital
Balance, Dec. 31, 2005	208.2	$ 208.2	$ 1,527.0	$ (83.1)	$ (51.1)	$ (9.3)	$ 1,591.7
Net income				246.3			246.3
Other comprehensive income, after tax					42.4		42.4
Common stock issued	1.3	1.3	9.4				10.7
Cash dividends declared			(79.2)	(79.5)			(158.7)
Stock compensation expense			11.5				11.5
Adoption FAS 123R			(9.3)			9.3	-
Tax benefits — stock options			1.4				1.4
Adoption FAS 158					(21.8)		(21.8)
Performance shares			5.5				5.5
Balance, Dec. 31, 2006	209.5	$ 209.5	$ 1,466.3	$ 83.7	$ (30.5)	$ -	$ 1,729.0
Net income				413.2			413.2
Other comprehensive income, after tax					13.3		13.3
Common stock issued	1.4	1.4	10.9				12.3
Cash dividends declared				(163.0)			(163.0)
Stock compensation expense			11.6				11.6
Implementation of FIN 48				0.2			0.2
Tax benefits — stock options			0.4				0.4
Balance, Dec. 31, 2007	210.9	$ 210.9	$ 1,489.2	$ 334.1	$ (17.2)	$ -	$ 2,017.0
Net income				162.4			162.4
Other comprehensive loss, after tax					(28.8)		(28.8)
Common stock issued	2.0	2.0	19.3				21.3
Cash dividends declared				(168.6)			(168.6)
Stock compensation expense			9.7				9.7
FAS 158-15-month transition impact				(5.3)			(5.3)
Balance, Dec. 31, 2008	212.9	$ 212.9	$ 1,518.2	$ 322.6	$ (46.0)	$ -	$ 2,007.7

(1) TECO Energy had a maximum of 400 million shares of $1 par value common stock authorized as of Dec.31, 2008, 2007, 2006 and 2005.

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

TECO ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Significant Accounting Policies

The significant accounting policies for both utility and diversified operations are as follows:

Principles of Consolidation

The consolidated financial statements include the accounts of TECO Energy, Inc. and its majority-owned subsidiaries (TECO Energy or the company). All significant inter-company balances and inter-company 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 or its subsidiary companies do not have majority ownership or exercise control.

For entities that are determined to meet the definition of a variable interest entity (VIE), the company obtains information, where possible, to determine if it is the primary beneficiary of the VIE. If the company is determined to be the primary beneficiary, then the VIE is consolidated and a minority interest is recognized for any other third-party interests. If the company is not the primary beneficiary, then the VIE is accounted for using the equity or cost method of accounting. In certain circumstances this can result in the company consolidating entities in which it has less than a 50% equity investment and deconsolidating entities in which it has a majority equity interest. (See **Note 19, Variable Interest Entities.**)

Use of Estimates

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.

Cash Equivalents

Cash equivalents are highly liquid, high-quality investments purchased with an original maturity of three months or less. The carrying amount of cash equivalents approximated fair market value because of the short maturity of these instruments.

Restricted Cash

Restricted cash included in "Deferred charges and other assets" at Dec. 31, 2008 and 2007 included $7.3 million of cash held in escrow related to the 2003 sale of Hardee Power Partners (HPP). The $7.3 million will be released from escrow in 2012, upon maturity of debt financing currently held by the purchaser of HPP.

Cost Capitalization

Debt issuance costs – The company capitalizes the external costs of obtaining debt financing and includes them in "Deferred charges and other assets" on TECO Energy's Consolidated Balance Sheet and amortizes such costs over the life of the related debt on a straight-line basis that approximates the effective interest method. These amounts are reflected in "Interest expense" on TECO Energy's Consolidated Statements of Income.

As discussed in **Note 7, Long-term Debt**, in December 2007, TECO Energy completed a debt exchange offer where $899.3 million principal amount of outstanding TECO Energy notes were exchanged for TECO Finance notes with substantially the same terms. Fees paid to the note holders in connection with these transactions of $21.2 million were capitalized and will be amortized over the lives of the related TECO Finance notes. The payment of these fees is reflected as "Debt exchange premiums" in the Financing section of the Consolidated Statement of Cash Flows for the year ended Dec. 31, 2007.

Planned Major Maintenance

TECO Energy accounts for planned maintenance projects by expensing the costs as incurred. Planned major maintenance projects that do not increase the overall life or value of the related assets are expensed. When the major maintenance materially increases the life or value of the underlying asset, the cost is capitalized. While normal maintenance outages covering various components of the plants generally occur on at least a yearly basis, major overhauls occur less frequently.

Tampa Electric and Peoples Gas System (PGS) expense major maintenance costs as incurred. For Tampa Electric and PGS, concurrent with a planned major maintenance outage, the cost of adding or replacing retirement units-of-property is capitalized in conformity with Florida Public Service Commission (FPSC) and Federal Energy Regulatory Commission (FERC) regulations.

The San José and Alborada plants in Guatemala each have a long-term power purchase agreement (PPA) with EEGSA. A major maintenance revenue recovery component is explicit in the capacity payment portion of the PPA for each plant. Accordingly, a portion of each monthly fixed capacity payment is deferred to recognize the portion that reflects recovery of future planned major maintenance expenses. Actual maintenance costs are expensed when incurred with a like amount of deferred recovery revenue recognized at the same time.

Depreciation

TECO Energy subsidiaries compute depreciation primarily by the straight-line method at annual rates that amortize the original cost, less net salvage value, of depreciable property over its estimated service life. TECO Coal subsidiaries depreciate certain mining assets by the units of production method that assigns a rate per unit produced by dividing the original cost over the estimated amount of units.

Total depreciation expense for the years ended Dec. 31, 2008, 2007 and 2006 was $257.3 million, $254.0 million and $270.3 million, respectively. The provision for total regulated utility plant in service, expressed as a percentage of the original cost of depreciable property was 3.6%, 3.7% and 3.9% for 2008, 2007 and 2006, respectively.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is a non-cash credit to income with a corresponding charge to utility plant which represents the cost of borrowed funds and a reasonable return on other funds used for construction. AFUDC is recorded in years when the capital expenditures on eligible projects exceed approximately $36 million. The base on which AFUDC is calculated excludes construction work-in-progress which has been included in rate base. The rate used to calculate AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. The rate was 7.79% for 2008, 2007 and 2006. Total AFUDC for 2008, 2007 and 2006 was $8.7 million, $6.2 million and $3.8 million, respectively.

Other Investments

As of Dec. 31, 2008, the company had a total of $13.3 million invested in two auction rate securities, including a $4.1 million security maturing on Jun. 15, 2032 and a $9.2 million security maturing on Jun. 1, 2041. These securities earn an interest rate set in an auction every 28 days or, in the event of a failed auction, a default rate determined in accordance with the respective agreements. Both the carrying amount and interest received are included under the caption "Other investments", on TECO Energy's Consolidated Balance Sheet and Consolidated Statement of Cash Flows, respectively.

As required by Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 115, *Accounting for Certain Investments in Debt and Equity Securities,* any unrealized change in fair value of available-for-sale securities is reflected in other comprehensive income.

As a result of market conditions leading to failed auctions, an impairment of $1.7 million was recorded in other comprehensive income during 2008. Because the company has the ability and intent to hold these investments until a recovery of its original investment value, it considers the investment to be temporarily impaired. These securities are backed by pools of student loans and it is expected that the investments will not be settled at a price less than their $15.0 million par value.

Inventory

TECO Energy subsidiaries value materials, supplies and fossil fuel inventory (coal, oil and natural gas) using a weighted-average cost method. These materials, supplies, and fuel inventories are carried at the lower of weighted-average cost or market, unless evidence indicates that the weighted-average cost (even if in excess of market) will be recovered with a normal profit upon sale in the ordinary course of business.

Investments in Unconsolidated Affiliates

Investments in unconsolidated affiliates are accounted for using the equity method of accounting. The percentage ownership interests for each investment at Dec. 31, 2008 and 2007 are presented in the following table:

TECO Energy's Percent Ownership in Unconsolidated Affiliates [1]

Dec. 31,	*2008*	*2007*
TECO Guatemala		
Distribucion Electrica CentroAmericana II, S.A.(DECA II)	30%	30%
Central Generadora Electrica San José, Limitada (San José or CGESJ)	100%	100%
Tampa Centro Americana de Electricidad, Limitada (Alborada or TCAE)	96%	96%
Other		
Walden Woods Business Center, Ltd.	-	50%

(1) TECO Energy, Inc. received $63.3 million, $63.2 million and $56.6 million during the years ended Dec. 31, 2008, 2007 and 2006, respectively, as dividends from unconsolidated affiliates.

Regulatory Assets and Liabilities

Tampa Electric and PGS are subject to the provisions of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation* (FAS 71) (see **Note 3** for additional details).

Deferred Income Taxes

TECO Energy uses the asset and liability method to determine deferred income taxes. Under the asset and liability method, the company estimates its current tax exposure and assesses the temporary differences resulting from differences in the treatment of items, such as depreciation, for financial statement and tax purposes. These differences are reported as deferred taxes, measured at current rates, in the consolidated financial statements. Management reviews all reasonably available current and historical information, including forward-looking information, to determine if it is more likely than not that some or all of the deferred tax asset will not be realized. If management determines that it is likely that some or all of a deferred tax asset will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized.

Investment Tax Credits

Investment tax credits have been recorded as deferred credits and are being amortized as reductions to income tax expense over the service lives of the related property.

Revenue Recognition

TECO Energy recognizes revenues consistent with the Securities and Exchange Commission's (SEC) Staff Accounting Bulletin (SAB) 104, *Revenue Recognition in Financial Statements.* Except as discussed below, TECO Energy and its subsidiaries recognize revenues on a gross basis when earned for the physical delivery of products or services and the risks and rewards of ownership have transferred to the buyer. Revenues for any financial or hedge transactions that do not result in physical delivery are reported on a net basis.

The regulated utilities' (Tampa Electric and PGS) retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by FERC. See **Note 3** for a discussion of significant regulatory matters and the applicability of FAS 71 to the company.

Revenues for TECO Coal shipments via rail are recognized when title and risk of loss transfer to the customer when the rail car is loaded. For coal shipments via ocean vessel, revenue is recognized under international shipping standards as defined by Incoterms 2000 when title and risk of loss transfer to the customer.

Revenues for certain transportation services at TECO Transport, prior to its sale in December 2007, were recognized using the percentage of completion method, which included estimates of the distance traveled and/or the time elapsed, compared to the total estimated contract.

Revenues for energy marketing operations at TECO Gas Services are presented on a net basis in accordance with Emerging Issues Task Force No. (EITF) 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent*, and EITF 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under Issues No. 98-10 and 00-17*, to reflect the nature of the contractual relationships with customers and suppliers. As a result, costs netted against revenues for the years ended Dec. 31, 2008, 2007 and 2006 were $17.3 million, $2.1 million and $0.8 million, respectively.

Shipping and Handling

TECO Coal includes the costs to ship product to customers in "Operation other expense - Mining related costs" on the Consolidated Statements of Income for the periods ended Dec. 31, 2008, 2007 and 2006 of $30.1 million, $25.9 million, and $20.6 million, respectively.

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 that are used to mitigate the fluctuations in the price of diesel fuel, the cash inflows and outflows are included in the operations section. Settlements for crude oil options that protected the cash flows related to the sales of investor interests in the synthetic fuel production facilities are included in the investing section.

Other Income and Minority Interest

Prior to 2008, TECO Energy earned a significant portion of its income indirectly through the synthetic fuel operations at TECO Coal. At the end of 2007 and 2006, TECO Coal had sold ownership interests in the synthetic fuel facilities to unrelated third-party investors equal to 98%. These investors paid for the purchase of the ownership interests as synthetic fuel was produced. The payments were based on the amount of production and sales of synthetic fuel and the related underlying value of the tax credit, which was subject to potential limitation based on the price of domestic crude oil. These payments are recorded in "Other income" in the Consolidated Statements of Income. The program that provided federal income tax credits for the production of synthetic fuel expired Dec. 31, 2007.

Additionally, the outside investors made payments towards the cost of producing synthetic fuel. These payments are reflected as a benefit under "Minority interest" in TECO Energy's Consolidated Statements of Income and these benefits comprise the majority of that line item.

For the year ended Dec. 31, 2007, "Other income" reflected a phase-out of approximately 67%, or $140.2 million, of the benefit of the underlying value of any 2007 tax credits based on an estimate of the average annual price of domestic crude oil during 2007. The cash payments and the benefits recognized in "Other income" and "Minority interest" were adjusted in the first quarter of 2008 for the final adjustment of $0.9 million to the 2007 inflation factor applied to the tax credit available on the production of synthetic fuel in 2007. A phase-out of approximately 35%, or $61.1 million after-tax, was recognized in 2006.

To protect the cash proceeds derived from the sale of ownership interests, TECO Energy had in place crude oil options to hedge against the risk of high oil prices reducing the value of the tax credits related to the production of synthetic fuel. These instruments were marked-to-market with fair value gains and losses recognized in "Other income" on the Consolidated Statements of Income. For the years ended Dec. 31, 2007 and 2006, the company recognized gains on marked-to-market derivatives of $82.7 million and $2.9 million, respectively. The increase in the gain from 2006 to 2007 was reflective of the increase in oil prices and the total volume of barrels hedged, which was 2.8 million barrels in 2006 compared to 25.1 million barrels in 2007.

Revenues and Cost Recovery

Revenues include amounts resulting from cost recovery clauses which provide for monthly billing charges to reflect increases or decreases in fuel, purchased power, conservation and environmental costs for Tampa Electric and purchased gas, interstate pipeline capacity and conservation costs for PGS. These adjustment factors are based on costs incurred and projected for a specific recovery period. Any over- or under-recovery of costs plus an interest factor are taken into account in the process of setting adjustment factors for subsequent recovery periods. Over-recoveries of costs are recorded as regulatory liabilities, and under-recoveries of costs are recorded as regulatory assets.

Certain other costs incurred by the regulated utilities are allowed to be recovered from customers through prices approved in the regulatory process. These costs are recognized as the associated revenues are billed. The regulated utilities accrue base revenues for services rendered but unbilled to provide a closer matching of revenues and expenses (see **Note 3**). As of Dec. 31, 2008 and 2007, unbilled revenues of $47.4 million and $46.6 million, respectively, are included in the "Receivables" line item on TECO Energy's Consolidated Balance Sheets.

Tampa Electric purchases power on a regular basis primarily to meet the needs of its retail customers. Tampa Electric purchased power from non-TECO Energy affiliates at a cost of $305.4 million, $271.9 million and $221.3 million, for the years ended Dec. 31, 2008, 2007 and 2006, respectively. The prudently incurred purchased power costs at Tampa Electric have historically been recovered through an FPSC-approved cost recovery clause.

Accounting for Excise Taxes, Franchise Fees and Gross Receipts

TECO Coal incurs most of TECO Energy's total excise taxes, which are accrued as an expense and reconciled to the actual cash payment of excise taxes. As general expenses, they are not specifically recovered through revenues. Excise taxes paid by the regulated utilities are not material and are expensed when incurred.

The regulated utilities are allowed to recover certain costs incurred from customers through prices approved by the FPSC. The amounts included in customers' bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Statements of Income. These amounts totaled $109.2 million, $111.2 million and $104.2 million for the years ended Dec. 31, 2008, 2007 and 2006, respectively. Franchise fees and gross receipt taxes payable by the regulated utilities are included as an expense on the Consolidated Statements of Income in "Taxes, other than income". For the years ended Dec. 31, 2008, 2007 and 2006, these totaled $109.0 million, $110.9 million and $104.0 million, respectively.

Asset Impairments

TECO Energy and its subsidiaries apply the provisions of FAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (FAS 144). FAS 144 addresses accounting and reporting for the impairment or disposal of long-lived assets, including the disposal of a component of a business.

In accordance with FAS 144, the company assesses whether there has been an impairment of its long-lived assets and certain intangibles held and used by the company when such impairment indicators exist. Indicators of impairment existed for certain asset groups, triggering a requirement to ascertain the recoverability of these assets using undiscounted cash flows. See **Note 18** for specific details regarding the results of these assessments.

Deferred Charges and Other Assets

Deferred charges and other assets consist primarily of mining development costs amortized on a per ton basis and offering costs associated with various debt offerings that are being amortized over the related obligation period as an increase in interest expense.

Deferred Credits and Other Liabilities

Other deferred credits primarily include the accrued post-retirement and pension liabilities, and medical and general liability claims incurred but not reported. The company and its subsidiaries have a self-insurance program supplemented by excess insurance coverage for the cost of claims whose ultimate value exceeds the company's retention amounts. The company estimates its liabilities for auto, general, marine protection and indemnity, and workers' compensation using discount rates mandated by statute or otherwise deemed appropriate for the circumstances. Discount rates used in estimating these liabilities at both Dec. 31, 2008 and 2007 ranged from 4.00% to 4.75%.

Stock-based Compensation

Effective Jan. 1, 2006, TECO Energy accounts for its stock-based compensation in accordance with FAS No. 123 (revised 2004), *Share-Based Payment* (FAS 123R). Under the provisions of FAS 123R, share-based compensation cost is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the employee's or director's requisite service period (generally the vesting period of the equity grant). Prior to this, the company accounted for its share-based payments under Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees* and its related interpretations and the disclosure requirements of FAS 123, *Accounting for Stock-Based Compensation*, as amended by FAS 148, *Accounting for Stock-Based Compensation – Transition and Disclosure*. The company elected to adopt the modified-prospective transition method as provided under FAS 123R and, accordingly, results for prior periods have not been restated. See **Note 9**, Common Stock, for more information on share-based payments.

Restrictions on Dividend Payments and Transfer of Assets

Dividends on TECO Energy's common stock are declared and paid at the discretion of its Board of Directors. The primary sources of funds to pay dividends on TECO Energy's common stock are dividends and other distributions from its operating companies. TECO Energy's credit facility contains a covenant that could limit the payment of dividends exceeding a calculated amount (initially $50 million) in any quarter under certain circumstances. Certain long-term debt at PGS contains restrictions that limit the payment of dividends and distributions on the common stock of Tampa Electric Company.

In addition, TECO Diversified, Inc., a wholly-owned subsidiary of TECO Energy and the holding company for TECO Coal, has a guarantee related to a coal supply agreement that limits the payment of dividends to its common shareholder, TECO Energy, but does not limit loans or advances. See **Notes 6, 7** and **12** for additional information on significant financial covenants.

Foreign Operations

The functional currency of the company's foreign investments is primarily the U.S. dollar. Transactions in the local currency are re-measured to the U.S. dollar for financial reporting purposes. The aggregate re-measurement gains or losses included in net income in 2008, 2007 and 2006 were not material. The foreign investments are generally protected from any significant currency gains or losses by the terms of the Guatemalan power sales agreements and other related contracts, in which payments are defined in U.S. dollars.

2. New Accounting Pronouncements

Employers' Disclosures about Postretirement Benefit Plan Assets

In December 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. Financial Accounting Standard (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 by Public Entities about Transfers of Financial Assets and Interests in Variable Interest Entities

In December 2008, the FASB issued FSP No. FAS 140-4 and FASB Interpretation (FIN) 46(R)-8, *Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities* (FSP FAS 140-4 and FIN 46(R)-8). This FSP requires additional disclosures regarding transfers of financial assets and interests in variable interest entities. The guidance in FSP FAS 140-4 and FIN 46(R)-8 was effective for reporting periods ending after Dec. 15, 2008. The company has adopted this FSP and included the additional disclosures required in this Form 10-K. These additional required disclosures have no effect on the company's results of operations, statement of position or cash flows.

Fair Value of a Financial Asset When the Market for That Asset Is Not Active

In October 2008, the FASB issued FSP No. FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active* (FSP FAS 157-3). This FSP clarifies the definition of fair value by stating that a transaction price is not necessarily indicative of fair value in a market that is not active or in a forced liquidation or distressed sale. Rather, if the company has the ability and intent to hold the asset, the company may use its assumptions about future cash flows and appropriately adjusted discount rates in measuring the fair value of the asset. The guidance in FSP FAS 157-3 was effective immediately upon issuance on Oct. 10, 2008, including prior periods for which financial statements have not been issued. The adoption of FSP FAS 157-3 was not material to the company's results of operations, statement of position or cash flows.

Disclosures about Credit Derivatives and Certain Guarantees

In September 2008, the FASB issued FSP No. FAS 133-1 and FASB Interpretation (FIN) 45-4, *Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161* (FSP FAS 133-1 and FIN 45-4). This FSP requires more detailed disclosures about credit derivatives and more detailed disclosures by sellers of credit derivatives. The guidance in FSP FAS 133-1 and FIN 45-4 is effective for reporting periods ending after Nov. 15, 2008. The additional required disclosures of FSP FAS 133-1 and FIN 45-4 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 does not believe FSP EITF 03-6-1 will be material to its results of operations, statement of position or cash flows.

Disclosures about Derivative Instruments and Hedging Activities

In March 2008, the FASB issued Statement of Financial Accounting Standards (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. The company believes that FAS 161 will be significant to its financial statement disclosures and will continue to evaluate the impact through its adoption.

Additionally, in April 2008, the FASB revised Statement 133 Implementation Issues Nos. I1 and K4 to reflect the enhanced disclosures required by FAS 161. The company does not believe these revisions will be material to its results of operations, statement of position or cash flows, but will be significant to its financial statement disclosures and will continue to evaluate the impact through its adoption.

Statement 133 Implementation Issue E23

In January 2008, the FASB cleared Implementation Issue *Hedging – General: Issues Involving the Application of the Shortcut Method under Paragraph 68* (Issue E23). Issue E23 amends FAS 133, paragraph 68 to include hedged items with trade dates differing from their settlement dates due to generally established conventions in the marketplace. This allows companies to assume these commitments have no ineffectiveness in a hedging relationship, thus allowing use of the shortcut method for accounting purposes assuming all other conditions within the paragraph are met.

Issue E23 also allows use of the shortcut method if the fair value of an interest rate swap is not zero at inception of the hedge as long as the swap was entered into at the relationship's inception, there was no transaction price of the swap in the company's principal or most advantageous market, and the difference between the swap's fair value and transaction price is due to differing prices within the bid-ask spread between the entry transaction and a hypothetical exit transaction.

The effective date for Issue E23 is for hedging relationships entered into on or after Jan. 1, 2008. Issue E23 is not material to the company's results of operations, statement of position or cash flows.

Noncontrolling Interests in Consolidated Financial Statements

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements* (FAS 160). FAS 160 was issued to improve the relevance, comparability and transparency of the financial information provided by requiring: ownership interests be presented in the consolidated statement of financial position separate from parent equity; the amount of net income attributable to the parent and the noncontrolling interest be identified and presented on the face of the consolidated statement of income; changes in the parent's ownership interest be accounted for consistently; when deconsolidating, that any retained equity interest be measured at fair value; and that sufficient disclosures identify and distinguish between the interests of the parent and noncontrolling owners. The guidance in FAS 160 is effective for fiscal years beginning on or after Dec. 15, 2008. The company is currently assessing the impact of FAS 160, but does not believe it will be material to its results of operations, statement of position or cash flows.

Business Combinations (Revised)

In December 2007, the FASB issued SFAS No. 141R, *Business Combinations* (FAS 141R). FAS 141R was issued to improve the relevance, representational faithfulness, and comparability of information disclosed in financial statements about business combinations. FAS 141R establishes principles and requirements for how the acquirer: 1) recognizes and measures the assets acquired, liabilities assumed and any noncontrolling interest in the acquiree; 2) recognizes and measures the goodwill acquired; and 3) determines what information to disclose for users of financial statements to evaluate the effects of the business combination. The guidance in FAS 141R is effective prospectively for any business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after Dec. 15, 2008. The company will assess the impact of FAS 141R in the event it enters into a business combination for which the expected acquisition date is subsequent to the required effective date.

Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards

In June 2007, the EITF issued EITF Issue No. 06-11, *Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards* (EITF 06-11). EITF 06-11 states that realized tax benefits resulting from share-based payment awards that entitle employees to dividends or dividend equivalents on non-vested equity shares or to payments equal to the dividends paid on the underlying shares while the equity option is outstanding and the dividends or dividend equivalents should be recorded as additional paid-in capital. Further, the amount recorded as additional paid-in capital should be included in the pool of excess tax benefits available to absorb tax deficiencies on share-based payment awards in accordance with FAS 123(R), *Accounting for Stock-Based Compensation*. EITF 06-11 is applied prospectively to the income tax benefits that result from dividends on equity-classified employee share-based payment awards that are declared in fiscal years beginning after Dec. 15, 2007, and interim periods within those fiscal years. The company has adopted EITF 06-11, but does not believe it is material to its results of operations, statement of position or cash flows.

Offsetting Amounts Related to Certain Contracts

In April 2007, the FASB issued FSP FIN 39-1. This FSP amends FASB Interpretation No. 39, *Offsetting of Amounts Related to Certain Contracts* by allowing an entity to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. The guidance in this FSP is effective for fiscal years beginning after Nov. 15, 2007. The company adopted this FSP effective Jan. 1, 2008 and set a policy to offset fair value amounts recognized with cash collateral received or cash collateral paid under master netting agreements. At Dec. 31, 2008, the company had paid cash collateral and offset the value of derivative positions in the amount of $9.7 million on the consolidated balance sheet.

Fair Value Option For Financial Assets and Financial Liabilities

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities - Including an amendment of FASB Statement No. 115* (FAS 159). FAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The objective of FAS 159 is to provide opportunities to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply hedge accounting provisions. FAS 159 is effective for fiscal years beginning after Nov. 15, 2007. The company adopted FAS 159 effective Jan. 1, 2008, but did not elect to measure any financial instruments at fair value. Accordingly, its adoption did not have any effect on its results of operations, statement of position or cash flows.

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.

FAS 157, among other things, requires the company to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value, and specifies a hierarchy of valuation techniques based on whether the inputs to those valuation techniques are observable or unobservable. FAS 157 defines the following fair value hierarchy, based on these two types of inputs:

- _Level 1_ – Quoted prices for identical instruments in active markets.
- _Level 2_ – Quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model derived valuations in which all significant inputs and significant value drivers are observable in active markets.
- _Level 3_ – Model derived valuations in which one or more significant inputs or significant value drivers are unobservable.

The effective date was for fiscal years beginning after Nov. 15, 2007. In November 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 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. See **Note 22, Fair Value**.

Additionally, the FASB issued FSP 157-1 in February 2008 to exclude SFAS 13, *Accounting for Leases*, and related pronouncements addressing lease fair value measurements from the scope of FAS 157. Assets and liabilities assumed in a business combination are not covered under this scope exception. The effective date of this FSP coincides with the adoption of FAS 157.

The company does not believe applying FAS 157 to the remaining non-financial assets and liabilities effective Jan. 1, 2009 will be material to 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 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 and PGS

Tampa Electric's rates and allowed return on equity (ROE) range of 10.75% to 12.75%, with a midpoint of 11.75%, are 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.

Tampa Electric had not sought a base rate increase since 1992. Since that last rate proceeding, it had earned within its allowed ROE range while adding more than 200,000 customers and making significant investments in facilities and infrastructure. These facilities include baseload, intermediate and peaking generating capacity additions to reliably serve the growing customer base. Tampa Electric expects a continued high level of capital investment, and higher levels of non-fuel operations and maintenance expenditures. As a result of lower customer growth, lower energy sales growth, and ongoing high levels of capital investment, Tampa Electric's 13-month average regulatory ROE was 8.7% at the end of 2008.

Recognizing the significant decline in ROE, Tampa Electric filed for a $228 million base rate increase in August 2008. The major factors in the filing included a request for an ROE mid-point of 12%, 55% equity in the capital structure, and a rate base of $3.657 billion. The formal hearings before the FPSC were held in late January and the FPSC is scheduled to make its final decision on the requested increase in mid-March, with final rates effective in May 2009.

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.

At the end of 2007, PGS' 13-month average regulatory ROE was below the bottom of its allowed range as a result of higher operating costs, continued investment in the distribution system and higher costs associated with required safety requirements, such as transmission and distribution pipeline integrity management.

Recognizing the significant decline in ROE, PGS filed for a $26.5 million base rate increase in August 2008. 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 are scheduled to be held in March and the FPSC is scheduled to make its final decision on the requested increase in May, with final rates effective in June 2009.

Cost Recovery – Tampa Electric and PGS

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 cost recovery 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 include the cost for natural gas and coal expected in 2009, the net recovery of $132.9 million of fuel and purchased power expenses, which were not collected in 2008 and underestimated in 2007, the net over-recovery of $4.7 million of costs recovered through the ECRC for the 2007 and 2008 periods, and the operating cost for and a return on the capital invested in the third SCR project to enter service at the Big Bend Station as well as the operations and maintenance expense associated with the projects as required by the EPA Consent Decree and FDEP Consent Final Judgment. The rates also reflect an additional disallowance of $3.0 million to settle all outstanding issues associated with the 2004 fuel transportation contract. 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. Accordingly, Tampa Electric's residential customer rate per 1,000 kilowatt-hours increased $14.06 from $114.38 in 2008 to $128.44 in 2009.

The FPSC determined 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 Unit 4 and Big Bend Units 1-3 in October 2004 and May 2005, respectively, for NOx control in compliance with the environmental consent decree. The SCR for Big Bend Unit 4 entered service in May 2007 and cost recovery started in 2007. The SCR for Big Bend Unit 3 entered service in May 2008 and cost recovery started in 2008. The SCRs for Big Bend Units 2 and 1 are scheduled to enter service by May 1, 2009 and 2010, respectively. Cost recovery for the capital investment for each unit, which is dependent on filings made in the year each SCR enters service, is expected to start in 2009 and 2010, respectively.

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 its 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.

SO_2 Emission Allowances

The Clean Air Act established SO_2 allowances to manage the achievement of SO_2 emissions requirements. The legislation also established a market-based SO_2 allowance trading component.

An allowance authorizes a utility to emit one ton of SO_2 during a given year. The EPA allocates allowances to utilities based on mandated emissions reductions. Allowances may not be used for compliance prior to the calendar year for which they are allocated. At the end of each year, a utility must hold an amount of allowances at least equal to its annual emissions. Tampa Electric accounts for the allocated allowances using an inventory model with a zero basis, since they are granted to the company at no cost.

Allowances are fully marketable and, once allocated, may be bought, sold, traded or banked for use in current or future years. In addition, the EPA withholds a small percentage of the annual SO_2 allowances it allocates to utilities for auction sales. Any resulting auction proceeds are then forwarded to the respective utilities.

Over the years, Tampa Electric has acquired allowances through EPA allocations and has sold unneeded allowances based on compliance and allowances available. The SO_2 allowances unneeded and sold resulted from lower emissions at Tampa Electric brought about by environmental actions taken by the company under the Clean Air Act.

For the year ended Dec. 31, 2008, Tampa Electric received $11.9 million in allowance proceeds, $11.2 million resulting from the sale of approximately 119,000 allowances and EPA auction proceeds of $0.7 million. In the year ended Dec. 31, 2007 Tampa Electric received $90.5 million in allowance proceeds, $89.7 million resulting from the sale of approximately 168,000 allowances and EPA auction proceeds of $0.8 million. In the year ended Dec 31, 2006 Tampa Electric received $44.8 million in allowance proceeds, $43.4 million resulting from the sale of approximately 44,500 allowances and auction proceeds of $1.4 million

Tampa Electric recognizes a gain at the time of sale, approximately 95% of which accrues to retail customers through the environmental cost recovery clause. These gains are reflected in Revenues on the Consolidated Statements of Income.

Other Items

Storm Damage Cost Recovery

Tampa Electric accrues $4 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. During 2008, $1.6 million in net costs related to Tropical Storm Fay were charged to the reserve. Tampa Electric's storm reserve was $22.7 million and $20.3 million as of Dec. 31, 2008 and 2007, respectively.

Coal Transportation Contract

In September 2004, the FPSC voted to disallow a portion of the costs that Tampa Electric could recover from its customers for water transportation services under a five year transportation agreement ending Dec. 31, 2008. This agreement was with an affiliate prior to its sale in December 2007. The amounts disallowed, and excluded from the recovery under the fuel adjustment clause, were $17.4 million, $15.1 million and $15.3 million for the years ended Dec. 31, 2008, 2007 and 2006, respectively. The 2008 amount includes $3.0 million to settle a dispute arising in 2008 regarding the calculation of the disallowance over the entire five year period.

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. 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. Details of the regulatory assets and liabilities as of Dec. 31, 2008 and 2007 are presented in the following table:

Regulatory Assets and Liabilities

(millions)	*Dec. 31, 2008*	*Dec. 31, 2007*
Regulatory assets:		
Regulatory tax asset [1]	$ 65.1	$ 62.5
Other:		
Cost recovery clauses	266.8	47.2
Post-retirement benefit asset	220.3	97.5
Deferred bond refinancing costs [2]	21.7	25.5
Environmental remediation	10.8	11.4
Competitive rate adjustment	4.7	5.4
Other	8.5	4.7
Total other regulatory assets	532.8	191.7
Total regulatory assets	597.9	254.2
Less: Current portion	272.6	67.4
Long-term regulatory assets	$ 325.3	$ 186.8
Regulatory liabilities:		
Regulatory tax liability [1]	$ 17.5	$ 18.8
Other:		
Deferred allowance auction credits	-	0.1
Cost recovery clauses	3.4	18.9
Environmental remediation	10.6	11.4
Transmission and delivery storm reserve	22.7	20.3
Deferred gain on property sales [3]	4.1	4.7
Accumulated reserve-cost of removal	551.2	543.5
Other	0.4	0.4
Total other regulatory liabilities	592.4	599.3
Total regulatory liabilities	609.9	618.1
Less: Current portion	21.7	35.4
Long-term regulatory liabilities	$ 588.2	$ 582.7

(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) Dec. 31,	*2008*	*2007*
Clause recoverable [1]	$ 271.5	$ 52.6
Components of rate base [2]	227.7	101.7
Regulatory tax assets [3]	65.1	62.5
Capital structure and other [3]	33.6	37.4
Total	$ 597.9	$ 254.2

(1) To be recovered through cost recovery clauses approved by the FPSC on a dollar for dollar basis in the next year. The increase between years is principally due to higher 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 bond refinancing costs which are amortized over the life of the related debt instruments. See footnotes 1 and 2 in the prior table for additional information.

4. Income Tax Expense

Income tax expense consists of the following components:

Income Tax Expense (Benefit)

(millions)	*Federal*	*Foreign*	*State*	*Total*
2008				
Continuing operations				
Current payable	$ —	$ 0.5	$ (0.6)	$ (0.1)
Deferred	90.9	0.1	4.4	95.4
Amortization of investment tax credits	(0.9)	—	—	(0.9)
Income tax expense from continuing operations	90.0	0.6	3.8	94.4
Total income tax expense	$ 90.0	$ 0.6	$ 3.8	$ 94.4
2007				
Continuing operations				
Current payable	$ 2.8	$ 0.7	$ 14.1	$ 17.6
Deferred	178.6	—	20.5	199.1
Amortization of investment tax credits	(2.5)	—	—	(2.5)
Income tax expense from continuing operations	178.9	0.7	34.6	214.2
Discontinued operations				
Deferred	(14.3)	—	—	(14.3)
Income tax benefit from discontinued operations	(14.3)	—	—	(14.3)
Total income tax expense	$ 164.6	$ 0.7	$ 34.6	$ 199.9
2006				
Continuing operations				
Current payable	$ 1.0	$ 2.8	$ 5.4	$ 9.2
Deferred	87.2	0.2	24.7	112.1
Amortization of investment tax credits	(2.6)	—	—	(2.6)
Income tax expense from continuing operations	85.6	3.0	30.1	118.7
Discontinued operations				
Deferred	8.5	—	(8.1)	0.4
Income tax expense (benefit) from discontinued operations	8.5	—	(8.1)	0.4
Total income tax expense	$ 94.1	$ 3.0	$ 22.0	$ 119.1

As discussed in **Note 1**, TECO Energy uses the liability method to determine deferred income taxes. Based primarily on the reversal of deferred income tax liabilities and future earnings of the company's core utility operations, management has determined that the net deferred tax assets recorded at Dec. 31, 2008 will be realized in future periods.

The principal components of the company's deferred tax assets and liabilities recognized in the balance sheet are as follows:

Deferred Income Tax Assets and Liabilities

(millions) Dec. 31,	*2008*	*2007*
Deferred income tax assets [1]		
Alternative minimum tax credit carryforward	$ 197.0	$ 196.6
Investment in partnership	—	61.8
Net operating loss carryforward	547.5	508.2
Other	168.8	164.2
Gross deferred income tax assets	913.3	930.8
Valuation allowance	(12.0)	(4.1)
Total deferred income tax assets	901.3	926.7
Deferred income tax liabilities [1]		
Property related	(514.5)	(487.2)
Deferred fuel	(53.0)	(14.6)
Total deferred income tax liabilities	(567.5)	(501.8)
Net deferred income tax assets	$ 333.8	$ 424.9

(1) Certain property related assets and liabilities have been netted.

At Dec. 31, 2008, the company has cumulative unused federal and state (Florida) net operating losses (NOLs) of $1,389.9 million and $832.4 million, respectively, expiring at various times between 2025 and 2028. In addition, the company has unused general business credits of $3.5 million expiring between 2026 and 2027 and unused foreign tax credits of $43.1 million expiring between 2015 and 2018. The company also has available alternative minimum tax credit carryforwards for tax purposes of $197.0 million which may be used indefinitely to reduce federal income taxes.

The company establishes valuation allowances on its deferred tax assets, including NOLs and tax credits, when the amount of expected future taxable income is not likely to support the use of the deduction or credit. Our valuation allowance, which reduces our deferred tax assets to an amount that will more likely than not be realized, was $12.0 million at Dec. 31, 2008. During 2008, our valuation allowance increased $7.9 million due to a $12.0 million valuation allowance recorded against foreign tax credits generated in 2008 and the reclassification of a $4.1 million state valuation allowance to current income taxes payable for unused capital losses.

Effective Income Tax Rate

(millions) *For the years ended Dec. 31,*	*2008*	*2007*	*2006*
Net income from continuing operations before minority interest	$ 162.4	$ 316.7	$ 174.8
Plus: minority interest	—	82.2	69.6
Net income from continuing operations	162.4	398.9	244.4
Total income tax provision	94.4	214.2	118.7
Income from continuing operations before income taxes	256.8	613.1	363.1
Income taxes on above at federal statutory rate of 35%	89.9	214.6	127.1
Increase (decrease) due to			
State income tax, net of federal income tax	2.5	22.5	18.7
Foreign income taxed at different rates	(18.6)	(17.5)	(14.4)
Non-conventional fuels tax credit	—	(1.4)	(2.1)
AFUDC equity	(2.2)	(1.6)	(1.0)
Tax on repatriation of foreign earnings	14.8	5.4	4.4
State rate change	—	—	2.7
Valuation allowance	12.0	2.0	2.1
Depletion	(4.6)	(7.8)	(9.8)
Other	0.6	(2.0)	(9.0)
Total income tax provision from continuing operations	$ 94.4	$ 214.2	$ 118.7
Provision for income taxes as a percent of income from continuing operations, before income taxes	36.8%	34.9%	32.7%

For the three years presented, we experienced a number of events that have impacted the overall effective tax rate on continuing operations. These events included permanent reinvestment of foreign income under APB Opinion No. 23, *Accounting for Taxes – Special Areas* (APB 23), adjustment of deferred tax assets for the effect of an enacted change in state tax rates, depletion, repatriation of foreign earnings to the United States and reduction of income tax expense under the "tonnage tax" regime. The increase in the company's 2008 effective tax rate compared to 2007 is principally due to the tax on repatriation of foreign earnings and the valuation allowance on foreign tax credits offset primarily by the increase of consolidated profitability in lower foreign tax jurisdictions and the decrease of state income taxes as compared to a year ago.

U.S. income taxes and foreign withholding taxes have not been provided on $50.0 million of undistributed earnings of certain foreign subsidiaries at Dec. 31, 2008, since these earnings are considered indefinitely reinvested based on our projected income and cash flow streams for the foreseeable future which show that such funds will be utilized offshore. Applicable U.S. income and foreign withholding taxes are provided on these earnings in the periods in which they are no longer considered indefinitely reinvested. It is not practicable to determine the income tax liability that might be incurred if these earnings were to be distributed.

During 2008, the company repatriated $98.2 million of foreign earnings resulting in $14.7 million additional tax expense net of foreign tax credits. Of this amount $71.7 million represented a one-time repatriation from certain foreign subsidiaries whose remaining earnings at the end of the year are considered indefinitely reinvested.

The actual cash paid (refunded) for income taxes as required for the alternative minimum tax, state income taxes and prior year audits in 2008, 2007 and 2006 was $6.0 million, ($10.5) million and $10.4 million, respectively.

In June 2006, the FASB issued FASB Interpretation Number 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109, Accounting for Income Taxes* (FIN 48). FIN 48 addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, the company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods, and requires increased disclosures.

One Jan. 1, 2007, the company adopted the provisions of FIN 48. As a result of the implementation of FIN 48, the company recognized a $0.1 million decrease in the deferred tax liability for uncertain tax benefits with a corresponding increase to the Jan. 1, 2007 balance of retained earnings. Subsequent to the implementation of FIN 48, during 2007, the company recognized in the second quarter $14.3 million of tax benefits in discontinued operations as a result of reaching favorable conclusions with taxing authorities, and in the fourth quarter, $1.9 million of current tax expense from an uncertain tax position that did not meet the more likely than not criteria. The company has had on-going discussions with state tax authorities related to tax issues addressed prior to the adoption of FIN 48. The principal remaining issues relate to how a state taxes the sale of various revenue components and how it treats the nature of the sale of various partnership interests. Due to the fact that the company did not have sufficient information to determine whether these issues would be resolved favorably, a full valuation allowance had already been recorded as the most probable outcome. During 2008, there were no further resolutions of these issues and the company is in the appeal process. If these matters are positively settled, they would increase earnings in the period of settlement. If unfavorably resolved, they would have no impact on earnings, but they would result in a decrease in operating cash flows. The gross cash exposure on this issue as of Dec. 31, 2008 was $12.7 million.

The following table provides a reconciliation of Unrecognized Tax Benefits at the beginning and end of 2008:

Unrecognized Tax Benefits		
(in millions)		
Balance, Jan. 1, 2008	$	14.9
Addition for tax positions of the current year		-
Additions for tax posititions of prior years		-
Reductions for tax positions of prior years for:		
Changes in judgement		-
Settlements during the period		-
Lapses of applicable statute of limitation		-
Balance, Dec. 31, 2008	$	14.9

The company recognizes interest and penalties associated with uncertain tax positions in "Operation other expense – Other" in the Consolidated Statements of Income. In 2008 and 2007, the company recorded $1.4 million and $0.9 million, respectively, of pre- tax charges for interest only. Additionally, the company has recorded $3.3 million of interest on the balance sheet as of Dec. 31, 2008. No amounts have been recorded for penalties.

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 returns 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 for the 2008 tax year. 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 taxing authorities in major state and foreign jurisdictions include 2003 and forward.

5. Employee Postretirement Benefits

In September 2006, the FASB issued SFAS No.158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)* (FAS 158). The company adopted FAS 158 on Dec. 31, 2006. This standard requires the recognition in the statement of financial position the over-funded or under-funded status of a defined benefit postretirement plan, measured as the difference between the fair value of plan assets and the projected benefit obligation (PBO) in the case of a defined benefit plan, or the accumulated postretirement benefit obligation (APBO) in the case of other postretirement benefit plans. As a result of this standard, the company increased its benefit liabilities on the balance sheet and accumulated other comprehensive loss, net of estimated tax benefits. In addition, as a result of the application of FAS 71 to the impacts of FAS 158, Tampa Electric Company increased both benefit liabilities and regulatory assets. This standard did not affect the results of operations.

Pension Benefits

TECO Energy has a non-contributory defined benefit retirement plan that covers substantially all employees. Benefits are based on employees' age, years of service and final average earnings.

Amounts disclosed for pension benefits also include the unfunded obligations for the supplemental executive retirement plan. This is a non-qualified, non-contributory defined benefit retirement plan available to certain members of senior management.

The Pension Protection Act of 2006 (PPA), became effective Jan. 1, 2008 and requires companies to, among other things, maintain certain defined minimum funding thresholds (or face plan benefit restrictions), pay higher premiums to the Pension Benefit Guaranty Corporation if they sponsor defined benefit plans, amend plan documents and provide additional plan disclosures in regulatory filings and to plan participants.

The Worker, Retiree, and Employer Recovery Act of 2008 (WRERA) was signed into law on Dec. 23, 2008. WRERA grants plan sponsors relief from certain funding requirements and benefit restrictions, and also provides some technical corrections to the PPA. There are two primary provisions that impact funding results for TECO Energy. First, for plans funded less than 100%, required shortfall contributions will be based on a percentage of the funding target until 2011, rather than the funding target of 100%. These percentages are 92%, 94% and 96% in 2008, 2009 and 2010, respectively. Second, one of the technical corrections, referred to as asset smoothing, allows the use of asset averaging subject to certain limitations in the determination of funding requirements. The Jan. 1, 2009 estimate assumes adoption of the asset smoothing methodology under WRERA and includes an additional 2008 plan year contribution expected to be made in 2009.

For the year ended Dec. 31, 2008, TECO Energy's pension plan experienced actual negative asset returns of approximately 22%. These negative returns during 2008 were a primary driver in causing significant actuarial losses for the year ended Dec. 31, 2008. The qualified pension plan's actuarial value of assets, including credit balance, was 105.6% of the PPA funded target as of Jan. 1, 2008 and is estimated at 90% of the PPA funded target as of Jan. 1, 2009.

Other Postretirement Benefits

TECO Energy and its subsidiaries currently provide certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 meeting certain service requirements. The company contribution toward health care coverage for most employees who retired after the age of 55 between Jan. 1, 1990 and Jun. 30, 2001 is limited to a defined dollar benefit based on service. The company contribution toward pre-65 and post-65 health care coverage for most employees retiring on or after Jul. 1, 2001 is limited to a defined dollar benefit based on an age and service schedule. In 2009, the company expects to make a contribution of about $12.3 million to this program. Postretirement benefit levels are substantially unrelated to salary. The company reserves the right to terminate or modify the plans in whole or in part at any time.

On Dec. 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the MMA) was signed into law. Beginning in 2006, the new law added prescription drug coverage to Medicare, with a 28% tax-free subsidy to encourage employers to retain their prescription drug programs for retirees, along with other key provisions. TECO Energy's current retiree medical program for those eligible for Medicare (generally over age 65) includes coverage for prescription drugs. The company has determined that prescription drug benefits available to certain Medicare-eligible participants under its defined-dollar-benefit postretirement health care plan are at least "actuarially equivalent" to the standard drug benefits that are offered under Medicare Part D.

On May 19, 2004, the FASB issued FASB Staff Position No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* (FSP 106-2). The guidance in FSP 106-2 requires (a) that the effects of the federal subsidy be considered an actuarial gain and recognized in the same manner as other actuarial gains and losses and (b) certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits. TECO Energy adopted FSP 106-2 retroactive for the second quarter of 2004.

The company received subsidy payments under Part D for the 2006 and 2007 plan years. Its 2008 Part D subsidy application with the Centers for Medicare and Medicaid Services (CMS) was approved in February 2009 and the company expects to receive the payment later this year.

Obligations and Funded Status *(millions)*	**Pension Benefits 2008**	**Pension Benefits 2007**	**Other Benefits 2008**	**Other Benefits 2007**
Change in benefit obligation				
Net benefit obligation at prior measurement date (1)	$ 557.2	$ 569.9	$ 195.7	$ 202.8
Effect of eliminating early measurement date	4.8	-	1.4	-
Service cost	15.4	16.0	4.1	5.3
Interest cost	31.9	33.0	12.0	12.2
Plan participants' contributions	-	-	3.8	3.6
Actuarial (gain) loss	3.3	(21.9)	(5.7)	(8.4)
Plan amendments	-	0.3	(9.4)	(3.8)
Curtailment	-	(6.1)	-	(2.1)
Special termination benefits	-	0.6	-	-
Gross benefits paid	(54.5)	(34.6)	(13.8)	(14.8)
Settlements	(2.7)	-	-	-
Federal subsidy on benefits paid	n/a	n/a	0.8	0.9
Net benefit obligation at measurement date (1)	$ 555.4	$ 557.2	$ 188.9	$ 195.7
Change in plan assets				
Fair value of plan assets at prior measurement date (1)	$ 492.7	$ 435.2	$ -	$ -
Effect of eliminating early measurement date	28.4	-	-	-
Actual return on plan assets (2)	(119.1)	56.6	-	-
Employer contributions	15.9	35.5	10.0	11.2
Plan participants' contributions	-	-	3.8	3.6
Settlements	(2.7)	-	-	-
Gross benefits paid	(54.5)	(34.6)	(13.8)	(14.8)
Fair value of plan assets at measurement date (1)	$ 360.7	$ 492.7	$ -	$ -
Funded status				
Fair value of plan assets (3)	$ 360.7	$ 492.7	$ -	$ -
Benefit obligation (PBO/APBO)	555.4	557.2	188.9	195.7
Funded status at measurement date (1)	(194.7)	(64.5)	(188.9)	(195.7)
Net contributions after measurement date	-	26.1	-	2.6
Unrecognized net actuarial loss	237.2	81.9	1.0	5.9
Unrecognized prior service (benefit) cost	(2.7)	(3.2)	7.3	18.9
Unrecognized net transition (asset) obligation	-	-	8.8	11.7
Accrued liability at end of year	$ 39.8	$ 40.3	$ (171.8)	$ (156.6)
Amounts Recognized in Balance Sheet				
Long-term regulatory assets	$ 186.3	$ 57.2	$ 34.0	$ 40.3
Accrued benefit costs and other current liabilities	(1.8)	(4.5)	(13.6)	(13.6)
Deferred credits and other liabilities	(193.0)	(34.0)	(175.3)	(179.5)
Accumulated other comprehensive loss (income) (pretax)	48.3	21.6	(16.9)	(3.8)
Net amount recognized at end of year	$ 39.8	$ 40.3	$ (171.8)	$ (156.6)

(1) The measurement dates were Dec. 31, 2008 and Sep. 30, 2007. In accordance with FAS 158, the company moved to a year-end measurement date effective Dec. 31, 2008 under the 15-month transition approach.

(2) The actual return on plan assets differed from expectations due to the general market decline.

(3) The Market Related Value (MRV) of plan assets is used as the basis for calculating the expected return on plan assets (EROA) component of periodic pension expense. MRV reflects the fair value of plan assets adjusted for experience gains and losses (i.e. the differences between actual investment returns and expected returns) spread over five years.

Amounts recognized in accumulated other comprehensive income

(millions)	Pension Benefits 2008	Pension Benefits 2007	Other Benefits 2008	Other Benefits 2007
Net actuarial loss (gain)	$ 47.8	$ 20.4	$ (17.4)	$ (15.0)
Prior service cost (credit)	0.5	1.2	(1.4)	8.6
Transition obligation (asset)	-	-	1.9	2.6
	$ 48.3	$ 21.6	$ (16.9)	$ (3.8)

The accumulated benefit obligation for all defined benefit pension plans was $504.9 million at Dec. 31, 2008 and $493.0 million at Sep. 30, 2007.

Assumptions used to determine benefit obligations at Dec. 31 for 2008 and Sep. 30 for 2007:

	Pension Benefits 2008	Pension Benefits 2007	Other Benefits 2008	Other Benefits 2007
Discount rate	6.05%	6.20%	6.05%	6.20%
Rate of compensation increase	4.25%	4.25%	4.25%	4.25%
Healthcare cost trend rate				
Initial rate	n/a	n/a	8.50%	9.25%
Ultimate rate	n/a	n/a	5.00%	5.25%
Year rate reaches ultimate	n/a	n/a	2015	2015

A one-percentage-point change in assumed health care cost trend rates would have the following effect on the benefit obligation:

(millions)	Increase	Decrease
Effect on postretirement benefit obligation	$ 4.2	$ (3.6)

Net periodic benefit cost

(millions)	Pension Benefits 2008 [(1)]	Pension Benefits 2007 [(2)]	Pension Benefits 2006 [(2)]	Other Benefits 2008 [(1)]	Other Benefits 2007 [(2)]	Other Benefits 2006 [(2)]
Service cost	$ 15.4	$ 16.0	$ 15.8	$ 4.1	$ 5.3	$ 6.0
Interest cost	31.9	33.0	30.7	12.0	12.2	11.3
Expected return on plan assets	(39.0)	(36.3)	(35.7)	-	-	-
Amortization of:						
Actuarial loss	4.0	9.1	8.8	-	-	0.5
Prior service (benefit) cost	(0.4)	(0.5)	(0.5)	1.8	2.8	3.0
Transition (asset) obligation	-	-	-	2.3	2.5	2.7
Curtailment loss	-	(0.4)	-	-	6.4	-
Settlement loss	0.9	-	-	-	-	-
Net periodic benefit cost	$ 12.8	$ 20.9	$ 19.1	$ 20.2	$ 29.2	$ 23.5

(1) Benefit Cost was measured for the twelve months ended Dec. 31, 2008. The company elected a 15-month transition approach allowed by FAS 158 to move from an early measurement date of Sep. 30, 2007 to a year end measurement date of Dec. 31, 2008. In connection with this election, the company recorded after-tax charges to Retained Earnings of $2.2 million for Pensions and $3.1 million for Other Postretirement Benefits in the fourth quarter of 2008.
(2) Benefit Cost was measured for the twelve months ended Sep. 30.

In addition to the costs shown above, $0.6 million of special termination benefit costs were recognized in 2007 related to pension benefits.

The estimated net loss and prior service net cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are $1.6 million and $0.1 million, respectively. The estimated prior service credit and transition obligation for the other postretirement benefit plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are $0.2 million and $0.5 million, respectively.

In addition, the estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from regulatory assets into net periodic benefit cost over the next fiscal year total $5.3 million. The estimated prior service cost and transition obligation for the other postretirement benefit plan that will be amortized from regulatory asset into net periodic benefit cost over the next fiscal year totals $2.8 million.

Assumptions used to determine net periodic benefit cost for years ended Dec. 31,

	Pension Benefits			Other Benefits		
	2008	2007	2006	2008	2007	2006
Discount rate	6.20%	5.85%	5.50%	6.20%	5.85%	5.50%
Expected long-term return on plan assets	8.25%	8.25%	8.50%	n/a	n/a	n/a
Rate of compensation increase	4.25%	4.00%	3.75%	4.25%	4.00%	3.75%
Healthcare cost trend rate						
Initial rate	n/a	n/a	n/a	9.25%	9.50%	9.50%
Ultimate rate	n/a	n/a	n/a	5.25%	5.25%	5.00%
Year rate reaches ultimate	n/a	n/a	n/a	2015	2015	2013

The discount rate assumption was based on a cash flow matching technique developed by our outside actuaries and a review of current economic conditions. This technique matches the yields from high-quality (Aa-graded, non-callable) corporate bonds to the company's projected cash flows for the benefit plans to develop a present value that is converted to a discount rate.

The expected return on assets assumption was based on expectations of long-term inflation, real growth in the economy, fixed income spreads, and equity premiums consistent with our portfolio, with provision for active management and expenses paid.

The compensation increase assumption was based on the same underlying expectation of long-term inflation together with assumptions regarding real growth in wages and company-specific merit and promotion increases.

A one-percentage-point change in assumed health care cost trend rates would have the following effect on expense:

(millions)	1% Increase	1% Decrease
Effect on periodic cost	$ 0.8	$ (0.6)

Asset Allocation

Pension plan assets (plan assets) are invested in a mix of equity and fixed income securities. The company's investment objective is to obtain above-average returns while minimizing volatility of expected returns over the long term. The target equities/fixed income mix is designed to meet investment objectives. The company's strategy is to hire proven managers and allocate assets to reflect a mix of investment styles, emphasize preservation of principal to minimize the impact of declining markets, and stay fully invested except for cash to meet benefit payment obligations and plan expenses.

Pension Plan Assets	**Target Allocation**	**Actual Allocation, End of Year**	
Asset Category		**2008**	**2007**
Equity securities	55-65%	56%	64%
Fixed income securities	35-45%	44%	36%
Total		100%	100%

The company reviews the plan's asset allocation periodically and re-balances the investment mix to maximize asset returns, optimize the matching of investment yields with the plan's expected benefit obligations, and minimize pension cost.

Other Postretirement Benefit Plan Assets

There are no assets associated with TECO Energy's other postretirement benefits plan.

Contributions

TECO Energy's policy is to fund the qualified pension plan at or above amounts determined by its actuaries to meet ERISA guidelines for minimum annual contributions and minimize PBGC premiums paid by the plan. TECO Energy contributed $11.7 million to this plan in 2008 and $30.0 million in 2007, which met the minimum funding requirements for both 2008 and 2007. TECO Energy expects to make an $11 million contribution to the qualified pension plan in 2009 and estimates annual minimum contributions to range from $25 - $40 million per year in 2010 to 2013 based on current assumptions.

The supplemental executive retirement plan is funded annually to meet the benefit obligations. The company made contributions of $4.2 million and $1.3 million to this plan in 2008 and 2007, respectively. In 2009, the company expects to make a contribution of about $2.3 million to this plan.

Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Expected Benefit Payments - TECO Energy (including projected service and net of employee contributions)	**Pension Benefits**	**Other Postretirement Benefits**	
		Gross	Expected Federal Subsidy
Expected benefit payments *(millions)*:			
2009	$ 44.8	$ 13.4	$ (1.1)
2010	$ 46.3	$ 14.3	$ (1.2)
2011	$ 47.6	$ 15.1	$ (1.4)
2012	$ 48.7	$ 15.5	$ (1.5)
2013	$ 49.8	$ 15.6	$ (1.7)
2014-2018	$ 269.2	$ 78.2	$ (10.3)

Defined Contribution Plan

The company has a defined contribution savings plan covering substantially all employees of TECO Energy and its subsidiaries (the Employers) that enables participants to save a portion of their compensation up to the limits allowed by IRS guidelines. The company and its subsidiaries match up to 6% of the participant's payroll savings deductions. Effective in July 2004, employer matching contributions were 30% of eligible participant contributions with additional incentive match of up to 70% of eligible participant contributions based on the achievement of certain operating company financial goals. In April 2007, the employer matching contributions were changed to 50% of eligible participant contributions, with an additional incentive match of up to 50%. For the years ended Dec. 31, 2008, 2007 and 2006, the company and its subsidiaries recognized expense totaling $7.1 million, $8.6 million and $9.0 million, respectively, related to the matching contributions made to this plan.

6. Short-Term Debt

At Dec. 31, 2008 and 2007, the following credit facilities and related borrowings existed:

Credit Facilities	*Dec. 31, 2008*			*Dec. 31, 2007*		
(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-year accounts receivable facility	150.0	29.0	—	150.0	25.0	—
TECO Energy/TECO Finance:						
5-year facility	200.0	64.0	7.1	200.0	—	9.5
Total	$ 675.0	$ 93.0	$ 8.5	$ 675.0	$ 25.0	$ 9.5

(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 notes payable at Dec. 31, 2008 and 2007 was 2.65% and 4.76%, respectively.

Tampa Electric Company Accounts Receivable Facility

On Dec. 18, 2008, Tampa Electric Company and TEC Receivables Corp. (TRC), a wholly-owned subsidiary of Tampa Electric Company, amended their $150 million accounts receivable collateralized borrowing facility, entering into Amendment No. 6 to the Loan and Servicing Agreement with certain lenders named therein and Citicorp North America, Inc. as Program Agent. The amendment (i) extends the maturity date to Dec. 17, 2009, (ii) provides that TRC will continue to pay program and liquidity fees based on Tampa Electric Company's credit ratings, which pursuant to the amendment, will total 175 basis points at Tampa Electric Company's current ratings, (iii) provides that the interest rates on the borrowings will be based on prevailing asset-backed commercial paper rates, unless such rates are not available from conduit lenders, or under certain circumstances upon a change of accounting rules applicable to the lenders, in which case the rates will be at an interest rate equal to, at Tampa Electric Company's option, either Citibank's prime rate (or the federal funds rate plus 50 basis points, if higher) or a rate based on the London interbank offer rate (if available) plus a margin and (iv) makes other technical changes.

7. Long-Term Debt

At Dec. 31, 2008, total long-term debt had a carrying amount of $3,216.7 million and an estimated fair market value of $2,987.5 million. At Dec. 31, 2007, total long-term debt had a carrying amount of $3,168.7 million and an estimated fair market value of $3,270.1 million. (See **Note 22, Fair Value** for further discussion.)

A substantial part of the tangible assets of Tampa Electric are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under Tampa Electric's first mortgage bond indenture.

TECO Energy's maturities and annual sinking fund requirements of long-term debt for 2009 through 2013 and thereafter are as follows:

Long-Term Debt Maturities

Dec. 31, 2008 (millions)	*2009*	*2010*	*2011*	*2012*	*2013*	*Thereafter*	*Total Long-Term Debt*
TECO Energy	$ -	$ 102.8	$ 191.7	$ 100.2	$ -	$ 8.8	$ 403.5
TECO Finance	-	-	171.8	236.2	-	491.2	899.2
Tampa Electric	-	-	-	540.0	60.7	1,068.2	1,668.9
Peoples Gas	5.5	3.7	3.4	113.4	-	110.0	236.0
TECO Guatemala	1.4	1.4	1.5	1.5	1.6	1.7	9.1
Total long-term debt maturities	$ 6.9	$ 107.9	$ 368.4	$ 991.3	$ 62.3	$ 1,679.9	$ 3,216.7

Debt Securities

Issuance of Tampa Electric Company 6.10% Notes due 2018

On May 16, 2008, Tampa Electric Company issued $150 million aggregate principal amount of 6.10% Notes due May 15, 2018 (6.10% Notes). The 6.10% Notes were sold at par. The offering resulted in net proceeds to the Company (after deducting underwriting discounts and commissions and estimated offering expenses) of approximately $148.7 million. Net proceeds were used for general corporate purposes. Tampa Electric Company may redeem all or any part of the 6.10% Notes at its option at any time and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of the 6.10% Notes to be redeemed or (ii) the present value of the remaining payments of principal and interest on the 6.10% Notes to be redeemed, discounted at an applicable treasury rate (as defined in the applicable indenture) plus 35 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date.

On May 15, 2008, in connection with this debt offering, Tampa Electric Company settled interest rate swaps entered into in 2007 for $11.8 million. The cash outflows related to this settlement are netted with the proceeds from the debt offering in the financing section of the Consolidated Statement of Cash Flows and are recorded in "Accumulated other comprehensive loss" on the Consolidated Balance Sheet. These amounts will be reclassified to interest expense over the 10-year term of the related debt, resulting in an effective interest rate of 6.89%.

Remarketing and Repurchase in Lieu of Redemption of Tampa Electric Company's Tax-Exempt Auction Rate Bonds

On Mar. 19, 2008, the Hillsborough County Industrial Development Authority (HCIDA) remarketed $86.0 million Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2006, in a fixed-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. The bonds, which previously had been in auction rate mode, bear interest at 5.00% per annum and are subject to mandatory tender for purchase on Mar. 15, 2012 from the proceeds of a remarketing of the bonds. Tampa Electric Company is responsible for payment of the interest and principal associated with the bonds. Regularly scheduled principal and interest when due are insured by Ambac Assurance Corporation, as more fully described in Amendment No. 1 to the company's Annual Report on Form 10-K for the year ended Dec. 31, 2007.

On Mar. 26, 2008, Tampa Electric Company purchased in lieu of redemption $75.0 million Polk County Industrial Development Authority (PCIDA) Solid Waste Disposal Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 and $125.8 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007A, B and C (collectively, the "2007 Bonds"). Also on that date, the Insurance Agreement dated as of Jul. 25, 2007 with Financial Guaranty

Insurance Company, pursuant to which Financial Guaranty Insurance Company issued a financial guaranty insurance policy for the HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007A, B and C (the "2007 HCIDA Bonds"), was terminated. There was no financial statement impact related to the termination of this agreement. Tampa Electric Company also entered into a corresponding First Supplemental Loan and Trust Agreement regarding the removal of the bond insurance on the 2007 HCIDA Bonds. After these changes to the 2007 HCIDA Bonds, the company remarketed the $54.2 million 2007 Series A and the $51.6 million 2007 Series B Bonds in long term interest rate modes. The $54.2 million 2007 Series A bonds, which previously had been in auction rate mode, bear interest at 5.65% per annum until maturity on Mar. 15, 2018. The $51.6 million 2007 Series B bonds, which previously had been in auction rate mode, bear interest at 5.15% per annum and will be subject to mandatory tender on Sep. 1, 2013 from the proceeds of a remarketing of the bonds. Tampa Electric Company is responsible for payment of the interest and principal associated with the 2007 Bonds.

As a result of these transactions, $95.0 million of the bonds purchased in lieu of redemption were held by the trustee at the direction of Tampa Electric Company as of Dec. 31, 2008 (the "Held Bonds") to provide an opportunity to evaluate refinancing alternatives. The Held Bonds effectively offset the outstanding debt balances and are presented net on the balance sheet.

At Dec. 31, 2008 and 2007, TECO Energy had the following long-term debt outstanding:

Long-term Debt *(millions) Dec. 31,*		*Due*	*2008*	*2007*
TECO Energy	Notes[1]:			
	Floating rate 5.2% (effective rate 5.4%) for 2008 and 7.23% for 2007[2][6]	2010	100.0	100.0
	7.5% (effective rate of 7.8%)[2]	2010	2.8	2.8
	7.2% (effective rate of 7.4%)	2011	191.7	191.7
	7.0% (effective rate of 7.1%)	2012	100.2	100.2
	6.75% (effective rate of 6.9%)[2]	2015	8.8	8.8
			403.5	403.5
TECO Finance	Notes[1][3]:7.2% (effective rate of 7.4%)	2011	171.8	171.8
	7.0% (effective rate of 7.1%)	2012	236.2	236.2
	6.75% (effective rate of 6.9%)[2]	2015	191.2	191.2
	6.572% (effective rate of 7.3%)	2017	300.0	300.0
			899.2	899.2
Tampa Electric	Installment contracts payable[4] :			
	5.1% Refunding bonds (effective rate of 5.7%)	2013	60.7	60.7
	5.65% Refunding bonds (effective rate of 6.3%) and 4.4% variable rate for 2007[5][6]	2018	54.2	54.2
	Variable rate bonds repurchased in 2008, 4.6% variable rate for 2007[6][7]	2020	—	20.0
	5.5% Refunding bonds (effective rate of 6.3%)	2023	86.4	86.4
	5.15% Refunding bonds (effective rate of 5.9%) and 4.7% variable rate for 2007[6][8]	2025	51.6	51.6
	Variable rate bonds repurchased in 2008, 5.3% variable rate for 2007[6][7]	2030	—	75.0
	5.0% Refunding bonds (effective rate of 6.1%) and 4.6% variable rate for 2007 [6][9]	2034	86.0	86.0
	Notes[1]: 6.875% (effective rate of 7.0%)	2012	210.0	210.0
	6.375% (effective rate of 7.4%)	2012	330.0	330.0
	6.25% (effective rate of 6.3%) [2]	2014-2016	250.0	250.0
	6.10% (effective rate of 7.1%)	2018	100.0	—
	6.55% (effective rate of 6.6%)	2036	250.0	250.0
	6.15% (effective rate of 6.2%)	2037	190.0	190.0
			1,668.9	1,663.9
Peoples Gas System	Senior Notes[1][2]: 10.33%	2008	—	1.0
	10.30%	2008-2009	1.8	2.8
	9.93%	2008-2010	2.0	3.0
	8.00%	2008-2012	12.2	14.9
	Notes[1] 6.875% (effective rate of 7.0%)	2012	40.0	40.0
	6.375% (effective rate of 7.4%)	2012	70.0	70.0
	6.10% (effective rate of 7.1%)	2018	50.0	—
	6.15% (effective rate of 6.2%)	2037	60.0	60.0
			236.0	191.7
TECO Guatemala	Note: 3.00% Fixed rate	2008-2014	9.1	10.4
Unamortized debt discount, net			(3.2)	(3.2)
			3,213.5	3,165.5
Less amount due within one year			6.9	7.1
Total long-term debt			$ 3,206.6	$ 3,158.4

(1) These securities are subject to redemption in whole or in part, at any time, at the option of the company.
(2) These long-term debt agreements contain various restrictive financial covenants.
(3) Guaranteed by TECO Energy.
(4) Tax-exempt securities.
(5) These bonds were converted in March 2008 from an auction rate mode to a fixed rate mode through maturity on May 15, 2018.
(6) Composite year-end interest rate.
(7) In March 2008 these bonds, which were in auction rate mode, were purchased in lieu of redemption by Tampa Electric Company.
(8) These bonds were converted in March 2008 from an auction rate mode to a fixed rate mode for the term ending Sep. 1, 2013.
(9) These bonds were converted in March 2008 from an auction rate mode to a fixed rate mode for the term ending Mar. 15, 2012.

8. Preferred Stock

Preferred stock of TECO Energy – $1 par
10 million shares authorized, none outstanding.
Preference stock (subordinated preferred stock) of Tampa Electric – no par
2.5 million shares authorized, none outstanding.
Preferred stock of Tampa Electric – no par
2.5 million shares authorized, none outstanding.
Preferred stock of Tampa Electric – $100 par
1.5 million shares authorized, none outstanding.

9. Common Stock

Stock-Based Compensation

On Jan. 1, 2006, TECO Energy adopted FAS 123R, requiring the company to recognize expense related to the fair value of its stock-based compensation awards. Prior to this, the company accounted for its share-based payments under APB 25 and related interpretations. The company adopted FAS 123R using the modified-prospective transition method. Under this transition method, compensation cost recognized beginning Jan. 1, 2006 includes compensation cost for all share-based payments granted prior to, but not yet vested as of Dec. 31, 2005 (based on the grant-date fair market value estimated in accordance with the original provisions of FAS 123), and compensation cost for all share-based payments granted on or after Jan. 1, 2006 (based on the grant date fair market value estimated in accordance with the provisions of FAS 123R).

TECO Energy has two share-based compensation plans, the Equity Plan and the Director Equity Plan (Plans), which are described below. The types of awards granted under these Plans include stock options, stock grants, time-vested restricted stock and performance-based restricted stock. Stock options have been granted with an exercise price greater than or equal to the fair market value of the common stock on the date of grant and have a 10-year contractual term. Stock options for the Director Equity Plan vest immediately and stock options for the Equity Plan have graded vesting over a three-year period, with the first 33% becoming exercisable one year after the date of grant. Stock options were last awarded in 2006. Stock grants and time-vested restricted stock are valued at the fair market value on the date of grant, with expense recognized over the vesting period, which is normally three years. Beginning in 2006, the company granted time-vested restricted stock to directors that vests one-third each year. Performance-based restricted stock has been granted to officers and employees, with shares potentially vesting after three years. The total awards for performance-based restricted stock vest based on the total return of TECO Energy common stock compared to a peer group of utility stocks. The 2006 grant can vest between 0% to 200% of the original grant and the 2007 and 2008 grants can vest between 0% to 150% of the original grant. Dividends are paid on all time-vested and performance-based restricted stock awards during the vesting period.

TECO Energy recognized total stock compensation expense for 2008, 2007 and 2006 of $9.8 million, $11.6 million and $11.5 million, respectively. Total stock compensation expense is reflected in "Operation other expense-Other" on the Consolidated Statements of Income. Cash received from option exercises under all share-based payment arrangements was $18.2 million, $9.2 million and $7.3 million for the periods ended Dec. 31, 2008, 2007 and 2006, respectively. The aggregate intrinsic value of stock options exercised was $8.4 million, $3.6 million and $2.7 million for the periods ended Dec. 31, 2008, 2007 and 2006, respectively. The total fair market value of awards vesting during 2008 was $2.6 million, which includes stock grants, time-vested restricted stock and performance-based restricted stock. As of Dec. 31, 2008, there was $10.3 million of unrecognized compensation cost related to all non-vested awards that is expected to be recognized over a weighted average period of two years. In accordance with FAS 123R, the cash flows resulting from excess tax deductions on share-based payments are classified as financing cash flows.

The fair market value of stock options is determined using the Black-Scholes valuation model, and the company uses the following methods to determine its underlying assumptions: expected volatilities are based on the historical volatilities; the expected term of options granted is based on the Staff Accounting Bulletin No. 107 (SAB 107) simplified method of averaging the vesting term and the original contractual term; the risk-free interest rate is based on the U.S. Treasury implied yield on zero-coupon issues (with a remaining term equal to the expected term of the option); and the expected dividend yield is based on the current annual dividend amount divided by the stock price on the date of grant.

The fair market value of performance-based restricted stock awards is determined using the Monte-Carlo valuation model, and the company uses the following methods to determine its underlying assumptions: expected volatilities are based on the historical volatilities; the expected term of the awards is based on the performance measurement period (which is generally three years); the risk-free interest rate is based on the U.S. Treasury implied yield on zero-coupon issues (with a remaining term equal to the expected term of the award); and the expected dividend yield is based on the current annual dividend amount divided by the stock price on the date of grant, with continuous compounding.

The value of time-vested restricted stock and stock grants are based on the fair market value of TECO Energy common stock at the time of grant.

Stock-based compensation expense reduced the company's results of operations as follows:

(millions, except per share amounts) For the years ended Dec. 31,	2008	2007	2006
Income before income taxes	$ 9.8	$ 11.6	$ 11.5
Net income	$ 6.0	$ 7.1	$ 7.1
EPS - Basic	$ 0.03	$ 0.03	$ 0.03
EPS - Diluted	$ 0.03	$ 0.03	$ 0.03

Assumptions	*2008*	*2007*	*2006*
Assumptions applicable to stock options			
Risk-free interest rate	-	-	4.92%
Expected lives (in years)	-	-	6
Expected stock volatility	-	-	27.00%
Dividend yield	-	-	4.66%
Assumptions applicable to performance-based restricted stock			
Risk-free interest rate	2.46%	4.53%	4.92%
Expected lives (in years)	3	3	3
Expected stock volatility	18.38%	16.71%	18.22%
Dividend yield	4.80%	4.25%	4.64%

Equity Plan

In April 2004, the company's shareholders approved the 2004 Equity Incentive Plan (2004 Plan). The 2004 Plan superseded the 1996 Equity Incentive Plan (1996 Plan), and no additional grants will be made under the 1996 Plan. Under the 2004 Plan, the Compensation Committee of the Board of Directors authorized 10 million shares of TECO Energy common stock that may be awarded as stock grants, stock options and/or stock equivalents to officers, key employees and consultants of TECO Energy and its subsidiaries. The Compensation Committee has discretion to determine the terms and conditions of each award, which may be subject to conditions relating to continued employment, restrictions on transfer or performance criteria.

Under the 2004 Plan and the 1996 Plan (collectively referred to as the "Equity Plans"), 1.1 million options were granted to employees in 2006 with a weighted average fair value of $3.26. (No stock options were granted in 2008 or 2007.) In addition, 0.7 million, 0.6 million and 0.5 million shares of restricted stock were granted in 2008, 2007 and 2006, respectively, with weighted average fair values of $16.85, $18.14 and $16.85, respectively. In 2006, 17,962 shares of unrestricted common stock were granted with a weighted average fair value of $17.54.

Director Equity Plan

In April 1997, the company's shareholders approved the 1997 Director Equity Plan (1997 Plan), as an amendment and restatement of the 1991 Director Stock Option Plan (1991 Plan). The 1997 Plan superseded the 1991 Plan, and no additional grants will be made under the 1991 Plan. The purpose of the 1997 Plan is to attract and retain highly qualified non-employee directors of the company and to encourage them to own shares of TECO Energy common stock. The 1997 Plan, administered by the Board of Directors, authorized 250,000 shares of TECO Energy common stock to be awarded as stock grants, stock options and/or stock equivalents.

No stock options were granted in 2008, 2007 or 2006. Under the 1997 Plan, 22,500 shares of restricted stock were awarded in 2008, with a weighted average fair value of $16.66.

A summary of non-vested shares of restricted stock and stock options for 2008 under all of the Equity Plans are shown as follows:

Nonvested Restricted Stock and Stock Options

	Time Based Restricted Stock[1]		Performance Based Restricted Stock[1]		Nonvested Stock Options [2]	
	Number of Shares (thousands)	*Weighted Avg. Grant Date Fair Value (per share)*	*Number of Shares (thousands)*	*Weighted Avg. Grant Date Fair Value (per share)*	*Number of Shares (thousands)*	*Weighted Avg. Grant Date Fair Value (per share)*
Nonvested balance at Dec. 31, 2007	399	$ 17.47	825	$ 19.52	867	$ 3.45
Granted	231	16.61	445	16.97	-	-
Vested	(149)	16.38	(240)	24.07	(563)	3.56
Forfeited	(3)	17.54	(9)	17.37	(5)	3.26
Nonvested balance at Dec. 31, 2008	478	$ 17.39	1,021	$ 17.36	299	$ 3.26

(1) The weighted average remaining contractual term of restricted stock is 2 years.
(2) All nonvested stock options are expected to vest.

Stock option transactions during 2008 under all of the Equity Plans are summarized as follows:

Stock Options

	Number of Shares (thousands)	*Weighted Avg. Option Price (per share)*	*Weighted Avg. Remaining Contractual Term (years)*	*Aggregate Intrinsic Value (millions)*
Outstanding balance at Dec. 31, 2007	8,901	$ 20.78		
Granted	-	-		
Exercised	(1,365)	13.35		
Cancelled	(700)	16.30		
Outstanding balance at Dec. 31, 2008[1]	6,836	$ 21.60	4	$ 0.4
Exercisable at Dec. 31, 2008[1]	6,537	$ 21.84	4	$ 0.4
Available for future grant at Dec. 31, 2008	2,110			

(1) Option prices range from $11.09 to $31.58.

As of Dec. 31, 2008, the options outstanding under the Equity Plans are summarized below:

	Stock Options Outstanding			Stock Options Exercisable		
Range of Option Prices	Option Shares (thousands)	Weighted Avg. Option Price	Weighted Avg. Remaining Contractual Life	Option Shares (thousands)	Weighted Avg. Option Price	Weighted Avg. Remaining Contractual Life
$11.09 - $13.64	1,196	$12.77	5 Years	1,196	$12.77	5 Years
$16.21 - $19.05	1,584	$16.31	7 Years	1,285	$16.31	7 Years
$21.25 - $22.48	1,566	$21.36	1 Year	1,566	$21.36	1 Year
$23.55 - $25.97	67	$24.27	1 Year	67	$24.27	1 Year
$27.97 - $31.58	2,423	$29.50	3 Years	2,423	$29.50	3 Years
Total	6,836	$21.60	4 Years	6,537	$21.84	4 Years

Dividend Reinvestment Plan

In 1992, TECO Energy implemented a Dividend Reinvestment and Common Stock Purchase Plan. TECO Energy raised $3.6 million, $3.9 million and $4.4 million of common equity from this plan in 2008, 2007 and 2006, respectively.

Shareholder Rights Plan

In accordance with the company's Shareholder Rights Plan, a Right to purchase one additional share of the company's common stock at a price of $90 per share is attached to each outstanding share of the company's common stock. The Rights Plan will expire according to its terms in May 2009. The Rights will become exercisable 10 business days after a person acquires 10% or more of the company's outstanding common stock or commences a tender offer that would result in such person owning 10% or more of such stock. If any person acquires 10% or more of the outstanding common stock, the rights of holders, other than the acquiring person, become rights to buy shares of common stock of the company (or of the acquiring company if the company is involved in a merger or other business combination and is not the surviving corporation) having a market value of twice the exercise price of each Right.

The company may redeem the Rights at a nominal price per Right until 10 business days after a person acquires 10% or more of the outstanding common stock.

Other

In February 2009, the Compensation Committee of TECO Energy's Board of Directors awarded eight senior officers time-vested restricted common stock in-lieu of cash for 50% of their annual incentive award; the remaining balances of these 2008 incentive awards were paid in cash. The full cost of these incentives were reflected in the 2008 income statement under the caption "Operation other expense-Other." In connection with these restricted stock awards, 72,342 shares were issued at a grant-date value of $12.15. These awards will vest one year from the date of grant.

10. Other Comprehensive Income

TECO Energy reported the following other comprehensive income (loss) (OCI) for the years ended Dec. 31, 2008, 2007 and 2006, related to changes in the fair value of cash flow hedges and amortization of unrecognized benefit costs associated with the company's pension plans:

Other comprehensive income (loss) *(millions)*	*Gross*	*Tax*	*Net*
2008			
Unrealized loss on cash flow hedges	$ (25.2)	$ 9.4	$ (15.8)
Plus: Loss reclassified to net income	(4.9)	1.8	(3.1)
Loss on cash flow hedges	(30.1)	11.2	(18.9)
Amortization of unrecognized benefit costs	4.2	(1.6)	2.6
Unrecognized loss on available-for-sale securities	(1.7)	-	(1.7)
Unrecognized benefits due to remeasurement	(17.7)	6.9	(10.8)
Total other comprehensive (loss) income	$ (45.3)	$ 16.5	$ (28.8)
2007			
Unrealized loss on cash flow hedges	$ (3.7)	$ 1.4	$ (2.3)
Less: Gain reclassified to net income	(6.5)	2.5	(4.0)
Loss on cash flow hedges	(10.2)	3.9	(6.3)
Amortization of unrecognized benefit costs	4.3	(1.9)	2.4
Recognized benefit costs due to curtailment	14.2	(5.5)	8.7
Unrecognized benefits due to remeasurement	13.7	(5.2)	8.5
Total other comprehensive income (loss)	$ 22.0	$ (8.7)	$ 13.3
2006			
Unrealized gain on cash flow hedges	$ —	$ —	$ —
Less: Gain reclassified to net income	(0.5)	0.2	(0.3)
Gain (loss) on cash flow hedges	(0.5)	0.2	(0.3)
Additional minimum pension liability	69.5	(26.8)	42.7
Total other comprehensive income (loss)	$ 69.0	$ (26.6)	$ 42.4

Accumulated other comprehensive loss *(millions) Dec. 31,*	*2008*	*2007*
Unrecognized pension losses and prior service costs (1)	$ (29.9)	$ (13.3)
Unrecognized other benefit losses, prior service costs and transition obligations (2)	10.6	2.3
Unrecognized loss on available-for-sale securities	(1.7)	—
Net unrealized (losses) gains from cash flow hedges (3)	(25.1)	(6.2)
Total accumulated other comprehensive loss	$ (46.0)	$ (17.2)

(1) Net of tax benefit of $18.4 million and $8.3 million as of Dec. 31, 2008 and 2007, respectively.
(2) Net of tax expense of $6.3 million and $1.5 million as of Dec. 31, 2008 and 2007, respectively.
(3) Net of tax benefit of $15.0 million and $3.8 million as of Dec. 31, 2008 and 2007, respectively.

11. Earnings Per Share

For the years ended Dec. 31, 2008, 2007 and 2006, stock options for 4.3 million shares, 5.8 million shares and 7.0 million shares, respectively, were excluded from the computation of diluted earnings per share due to their anti-dilutive effect.

Earnings per Share *(millions, except per share amounts)* *For the years ended Dec. 31,*		*2008*	*2007*	*2006*
Numerator				
Net income from continuing operations, basic and diluted		$ 162.4	$ 398.9	$ 244.4
Discontinued operations, net of tax		—	14.3	1.9
Net income, diluted		$ 162.4	$ 413.2	$ 246.3
Denominator				
Average number of shares outstanding – basic		210.6	209.1	207.9
Plus: Incremental shares for unvested restricted stock and assumed conversions: Stock options at end of period, unvested unrestricted stock and contingent performance shares		4.3	3.6	3.3
Less: Treasury shares which could be purchased		(3.5)	(2.8)	(2.5)
Average number of shares outstanding – diluted		211.4	209.9	208.7
Earnings per share from continuing operations	Basic	$ 0.77	$ 1.91	$ 1.18
	Diluted	$ 0.77	$ 1.90	$ 1.17
Earnings per share from discontinued operations, net	Basic	$ —	$ 0.07	$ 0.01
	Diluted	$ —	$ 0.07	$ 0.01
Earnings per share	Basic	$ 0.77	$ 1.98	$ 1.19
	Diluted	$ 0.77	$ 1.97	$ 1.18

12. 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.

Investment in Empresa Eléctrica de Guatemala

TECO Guatemala has a 24% ownership interest in EEGSA through a joint venture (DECA II) with Iberdrola, S.A. and Electricidade de Portugal, S.A. The Value Added Distribution (VAD) charges applicable in the tariffs charged by EEGSA are reset every five years. The VAD was expected to be reset for a new five-year term in the third quarter of 2008 in a manner similar to the process utilized in 2003, in accordance with applicable Guatemalan law.

On Jul. 25, 2008, the National Commission of Electrical Energy (CNEE), the Guatemalan regulatory body responsible for establishing tariff rates, issued a communication unilaterally disbanding the panel of experts appointed under existing regulations to review and approve the new tariff rates. On Jul. 31, 2008, CNEE issued resolutions setting new tariff rates for EEGSA, which deviated from the rates calculated consistent with the panel of experts' guidance. The new lower VAD set by CNEE is significantly below the prior period level. The results from Aug. 1, 2008 forward reflect the lower tariff rates.

TECO Energy and EEGSA's other investors are actively pursuing legal and other efforts to facilitate reconsideration of the VAD through procedures consistent with EEGSA's interpretation of Guatemala's Electricity Law. On Jan. 13, 2009, TECO Guatemala Holdings, LLC, a subsidiary of the company, delivered a Notice of Intent to the Guatemalan government indicating that it intends to file an arbitration claim against the Republic of Guatemala under the Dominican-Republic-Central America-United States Free Trade Agreement (DR-CAFTA). The 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. During this 90-day period, the parties may attempt to resolve the dispute amicably through consultation or negotiation.

TECO Guatemala evaluated its $150.3 million investment in DECA II, including associated goodwill of $3.9 million, at Dec. 31, 2008 and determined that the value was not impaired. (See **Note 18, Asset Impairments**.) In the event the activities described above are unsuccessful and no reasonable mitigation strategies are available such that lower revenues could be expected to continue indefinitely and make the returns we anticipated on this investment unachievable, we will need to reevaluate our strategy related to this investment and an impairment would be likely.

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 Dec. 31, 2008, Tampa Electric Company has estimated its ultimate financial liability to be approximately $10.7 million, primarily at PGS, 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 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 or changes in laws or regulations that could require additional remediation. These costs are recoverable through customer rates established in subsequent base rate proceedings.

Long-Term Commitments

TECO Energy has commitments under long-term leases, primarily for building space, capacity payments, office equipment and heavy equipment.

Total rental expense for these leases, included in "Operation other expense - Other" on the Consolidated Statements of Income for the years ended Dec. 31, 2008, 2007 and 2006, was $9.9 million, $29.8 million and $30.0 million, respectively. 2007 and 2006 include leases of marine equipment at TECO Transport, which was sold on Dec. 4, 2007.

The following is a schedule of future minimum lease payments at Dec. 31, 2008 for all leases with non-cancelable lease terms in excess of one year:

Future Minimum Lease Payments

(millions)	*Capacity Payments* (1)	*Operating Leases*	*Total*
Year ended Dec. 31:			
2009	$ 8.4	$ 6.8	$ 15.2
2010	8.6	6.2	14.8
2011	8.8	4.2	13.0
2012	8.9	3.1	12.0
2013	9.1	2.4	11.5
Thereafter	48.5	26.5	75.0
Total future minimum lease payments	$ 92.3	$ 49.2	$ 141.5

(1) This schedule includes the fixed capacity payments required under a capacity and tolling agreement of Tampa Electric which commenced Jan. 1, 2009. In accordance with the provisions of EITF 01-08, *Determining Whether an Arrangement Contains a Lease*, the company evaluated the agreement and concluded based on the criteria that the agreement met the

lease definition. Prudently incurred capacity payments are recoverable under an FPSC-approved cost recovery clause (See **Note 3**).

Guarantees and Letters of Credit

TECO Energy accounts for guarantees in accordance with FASB Interpretation No. (FIN) 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others (an interpretation of FASB Statements No. 5, 57 and 107 and rescission of FASB Interpretation No. 34)*. Upon issuance or modification of a guarantee the company determines if the obligation is subject to either or both of the following:

- Initial recognition and initial measurement of a liability; and/or
- Disclosure of specific details of the guarantee.

Generally, guarantees of the performance of a third party or guarantees that are based on an underlying (where such a guarantee is not a derivative subject to FAS 133) are likely to be subject to the recognition and measurement, as well as the disclosure provisions, of FIN 45. Such guarantees must initially be recorded at fair value, as determined in accordance with the interpretation.

Alternatively, guarantees between and on behalf of entities under common control or that are similar to product warranties are subject only to the disclosure provisions of the interpretation. The company must disclose information as to the term of the guarantee and the maximum potential amount of future gross payments (undiscounted) under the guarantee, even if the likelihood of a claim is remote.

A summary of the face amount or maximum theoretical obligation under TECO Energy's letters of credit and guarantees as of Dec. 31, 2008 are as follows:

Letters of Credit and Guarantees

(millions)	*Maturing*				
Letters of Credit and Guarantees for the Benefit of:	*2009*	*2010-2013*	*After[1] 2013*	*Total*	*Liabilities Recognized at Dec. 31, 2008*
Tampa Electric					
Letters of credit	$ –	$ –	$ 0.3	$ 0.3	$ –
Guarantees:					
Fuel purchase/energy management [2]	–	–	20.0	20.0	4.7
	–	–	20.3	20.3	4.7
TECO Coal					
Letters of credit	–	–	6.8	6.8	–
Guarantees: Fuel purchase related [2]	–	–	1.4	1.4	1.2
	–	–	8.2	8.2	1.2
Other subsidiaries					
Guarantees:					
Fuel purchase/energy management [2]	69.8	–	2.9	72.7	26.2
Total	$ 69.8	$ –	$ 31.4	$101.2	$ 32.1

(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 amount guaranteed under current agreements. Liabilities recognized represent the associated obligation of TECO Energy under these agreements at Dec. 31, 2008. 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 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. At Dec. 31, 2008, TECO Energy, TECO Finance, Tampa Electric Company and the other operating companies were in compliance with all required financial covenants.

13. Related Parties

The company and its subsidiaries had certain transactions, in the ordinary course of business, with entities in which directors of the company had interests. The company paid legal fees of $1.9 million, $1.3 million and $1.2 million for the years ended Dec. 31, 2008, 2007 and 2006, respectively, to Ausley McMullen, P.A. of which Mr. Ausley (a director of TECO Energy) is an employee. Other transactions were not material for the years ended Dec. 31, 2008, 2007 and 2006. No material balances were payable as of Dec. 31, 2008 or 2007.

14. 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 FAS 131, *Disclosures about Segments of an Enterprise and Related Information*. All significant intercompany transactions are eliminated in the consolidated financial statements of TECO Energy, but are included in determining reportable segments.

The information presented in the following table excludes all discontinued operations. See **Note 20** for additional details of the components of discontinued operations.

Segment Information

(millions)	Tampa Electric	Peoples Gas	TECO Coal	TECO Transport[3]	TECO Guatemala	Other & Eliminations	Total TECO Energy
2008							
Revenues - outsiders	$ 2,089.8	$ 688.4	$ 588.4	$ -	$ 8.4 [5]	$ 0.3	$ 3,375.3
Revenues - affiliates	1.4	-	-	-	-	(1.4)	-
Total revenues	2,091.2	688.4	588.4	-	8.4	(1.1)	3,375.3
Earnings from unconsol. affiliates	-	-	-	-	72.5	0.4	72.9
Depreciation and amortization	185.6	41.9	37.6	-	0.8	0.2	266.1
Total interest charges [1]	114.7	18.2	8.1	-	15.4	72.5	228.9
Internally allocated interest [1]	-	-	6.7	-	15.1	(21.8)	-
Provision (benefit) for taxes	81.9	17.3	2.3	-	14.8	(21.9) [9]	94.4
Net income from continuing operations [1]	$ 135.6	$ 27.1	$ 18.0	$ -	$ 36.9 [7]	$ (55.2) [2]	$ 162.4
Goodwill, net	$ -	$ -	$ -	$ -	$ 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 [4]	-	383.1 [8]	38.4	7,147.4
Capital expenditures	$ 479.7	$ 69.0	$ 40.3	$ -	$ 0.5	$ -	$ 589.5
2007							
Revenues - outsiders	$ 2,186.6	$ 599.7	$ 544.5	$ 197.1	$ 8.0 [5]	$ 0.2	$ 3,536.1
Revenues - affiliates	1.8	-	-	93.2	-	(95.0)	-
Total revenues	2,188.4	599.7	544.5	290.3	8.0	(94.8)	3,536.1
Earnings from unconsol. affiliates	-	-	-		68.5	-	68.5
Depreciation and amortization	178.6	40.1	38.4	5.6	0.5	0.5	263.7
Total interest charges [1]	112.2	17.1	12.5	4.8	15.2	96.0	257.8
Internally allocated interest [1]	-	-	11.6	0.8	14.9	(27.3)	-
Provision (benefit) for taxes	85.2	16.4	46.3	13.5	7.8	45.0	214.2
Net income from continuing operations [1]	$ 150.3	$ 26.5	$ 90.9	$ 34.0	$ 44.7	$ 52.5 [2]	$ 398.9
Goodwill, net	$ -	$ -	$ -	$ -	$ 59.4	$ -	$ 59.4
Investment in unconsolidated affiliates	-	-	-	-	275.5	-	275.5
Other non-current investments	-	-	-	-	15.0	8.0	23.0
Total assets	4,838.3	761.4	501.2 [4]	-	435.3 [8]	229.0	6,765.2
Capital expenditures	$ 373.8	$ 49.2	$ 43.8	$ 25.1	$ 2.3	$ 0.2	$ 494.4
2006							
Revenues - outsiders	$ 2,082.7	$ 577.6	$ 574.9	$ 205.1	$ 7.6 [5]	$ 0.2	$ 3,448.1
Revenues - affiliates	2.2	-	-	103.4	-	(105.6)	-
Total revenues	2,084.9	577.6	574.9	308.5	7.6	(105.4)	3,448.1
Earnings from unconsol. affiliates	-	-	-	(0.3)	58.7	0.5	58.9
Depreciation and amortization	186.3	36.5	36.4	22.1	0.6	0.3	282.2
Total interest charges [1]	107.4	15.2	10.6	4.5	15.0	125.6	278.3
Internally allocated interest [1]	-	-	9.9	(1.4)	14.6	(23.1)	-
Provision (benefit) for taxes	80.3	18.8	35.6	10.9	8.7	(35.6)	118.7
Net income from continuing operations [1]	$ 135.9	$ 29.7	$ 78.8	$ 22.8	$ 37.6	$ (60.4) [2]	$ 244.4
Goodwill, net	$ -	$ -	$ -	$ -	$ 59.4	$ -	$ 59.4
Investment in unconsolidated affiliates	-	-	-	2.9	276.0	14.0	292.9
Other non-current investments	-	-	-	-	-	8.0	8.0
Total assets	4,813.7	765.2	389.4 [4]	333.9	424.6 [8]	635.0	7,361.8
Capital expenditures	$ 366.4 [6]	$ 54.0	$ 40.2	$ 16.5	$ 0.7	$ (22.1) [6]	$ 455.7

(1) Segment net income is reported on a basis that includes internally allocated financing costs. Internally allocated costs were at pretax rates of 7.15% for September through December 2008, 7.25% for January through August 2008, and 7.5% for 2007 and 2006. Rates were based on the average of each subsidiary's equity and indebtedness to TECO Energy assuming a 50/50 debt/equity capital structure. Internally allocated interest charges are a component of total interest charges.

(2) Results for 2008 include $0.6 million of after-tax transaction costs and a $3.2 million tax benefit related to the sale of TECO Transport. Results for 2007 include $16.4 million of these transaction costs, the $149.4 million after-tax gain on the sale of TECO Transport and $20.2 million of after-tax debt extinguishment costs. Results for 2006 include after-tax gains of $8.1 million from the sale of McAdams and $5.7 million from the sale of two steam turbines.

(3) 2007 results for TECO Transport are through Dec. 3, 2007.

(4) The carrying value of mineral rights as of Dec. 31, 2008, 2007 and 2006 was $18.1 million, $18.9 million and $20.6 million, respectively.

(5) Revenues for 2008, 2007 and 2006 are exclusive of entities deconsolidated as a result of FIN 46R and include only revenues for the consolidated Guatemalan entities. See **Note 19** for further details.

(6) Included in other capital expenditures is a cash offset of $22.1 million, related to the sale of two combustion turbines by TPS McAdams to Tampa Electric. The corresponding capital expenditure is included in Tampa Electric's capital expenditures for 2006.

(7) Net income includes $9.6 million in taxes related to the cash and investments repatriated from Guatemala in December 2008.

(8) Total assets represent primarily equity and advances invested in unconsolidated affiliates. As of Dec. 31, 2008, 2007 and 2006, the equity and advances balance due TECO Energy totaled $356.8 million, $413.5 million and $401.9 million, respectively.

(9) Benefit includes a $12.0 million valuation allowance in consolidated income taxes related to the cash and investments repatriated from Guatemala in December 2008.

Tampa Electric provides retail electric utility services to more than 667,000 customers in West Central Florida. PGS is engaged in the purchase and distribution of natural gas for more than 335,000 residential, commercial, industrial and electric power generation customers in the state of Florida.

TECO Coal, through its wholly-owned subsidiaries, owns mineral rights and owns or operates surface and underground mines and coal processing and loading facilities in Kentucky, Tennessee and Virginia. TECO Coal acquired and began operating two synthetic fuel facilities in 2000, whose production qualified for the non-conventional fuels tax credit through the expiration of the tax credit program on Dec. 31, 2007.

TECO Transport, through its wholly-owned subsidiaries, transported, stored and transferred coal and other dry bulk commodities for third parties and Tampa Electric. TECO Transport's subsidiaries operated on the Mississippi, Ohio and Illinois rivers, in the Gulf of Mexico and worldwide. TECO Transport was sold on Dec. 4, 2007.

TECO Guatemala includes the equity investments in the San José and Alborada power plants, the equity investment in DECA II, and the TECO Guatemala parent company.

15. Asset Retirement Obligations

TECO Energy accounts for asset retirement obligations under FAS 143, "Accounting for Asset Retirement Obligations" (FAS 143) and FIN 47 *Accounting for Conditional Asset Retirement Obligations*. An asset retirement obligation (ARO) for a long-lived asset is recognized at fair value at inception of the obligation if there is a legal obligation under an existing or enacted law or statute, a written or oral contract, or by legal construction under the doctrine of promissory estoppel. Retirement obligations are recognized only if the legal obligation exists in connection with or as a result of the permanent retirement, abandonment or sale of a long-lived asset.

When the liability is initially recorded, the carrying amount of the related long-lived asset is correspondingly increased. Over time, the liability is accreted to its estimated future value. The corresponding amount capitalized at inception is depreciated over the remaining useful life of the asset. The liability must be revalued each period based on current market prices.

TECO Energy has recognized asset retirement obligations for reclamation and site restoration obligations principally associated with coal mining, storage and transfer facilities. The majority of obligations arise from environmental remediation and restoration activities for coal-related operations. Prior to the adoption of FAS 143, TECO Coal accrued reclamation costs for such activities. For TECO Coal, the adoption of FAS 143 modified the valuation and accrual methods used to estimate the fair value of asset retirement obligations.

For the years ended Dec. 31, 2008, 2007 and 2006, TECO Energy recognized $1.4 million, $1.4 million and $1.5 million of accretion expense, respectively, associated with asset retirement obligations in "Depreciation and amortization" on the Consolidated Statements of Income. For the year ended Dec. 31, 2008, increased cost of removal of materials used in the generation and transmission of electricity resulted in a $2.9 million estimated cash flow revision at Tampa Electric.

Reconciliation of beginning and ending carrying amount of asset retirement obligations:

(millions)	Dec. 31, 2008	2007
Beginning balance	$ 47.8	$ 52.7
Additional liabilities	2.4	0.1
Liabilities settled	(1.6)	(7.0)
Accretion expense	1.4	1.4
Revisions to estimated cash flows	2.9	-
Other[1]	-	0.6
Ending balance	$ 52.9	$ 47.8

(1) Accretion reclassed as a deferred regulatory asset.

As regulated utilities, Tampa Electric and PGS must file depreciation and dismantlement studies periodically and receive approval from the FPSC before implementing new depreciation rates. Included in approved depreciation rates is either an implicit net salvage factor or a cost of removal factor, expressed as a percentage. The net salvage factor is principally comprised of two components—a salvage factor and a cost of removal or dismantlement factor. The company uses current cost of removal or dismantlement factors as part of the estimation method to approximate the amount of cost of removal in accumulated depreciation.

For Tampa Electric and PGS, the original cost of utility plant retired or otherwise disposed of and the cost of removal, or dismantlement, less salvage value is charged to accumulated depreciation and the accumulated cost of removal reserve reported as a regulatory liability, respectively.

16. Mergers, Acquisitions and Dispositions

Sale of TECO Transport

On Dec. 4, 2007, TECO Diversified, Inc., a wholly-owned subsidiary of the company, sold its entire interest in TECO Transport Corporation for cash to an unaffiliated investment group. The selling price was $405 million, subject to a working capital adjustment, and resulted in a pretax gain of $221.3 million, which is net of transaction-related costs. In accordance with the provisions of FAS 144, as a result of its significant continuing involvement with Tampa Electric related to the waterborne transportation of solid fuel, the results of TECO Transport were reflected in continuing operations for 2007.

On Feb. 19, 2008, TECO Energy, through TECO Diversified, Inc., paid $3.7 million to adjust the working capital estimated at Dec. 31, 2007 related to the sale of TECO Transport to an unaffiliated investment group.

Sale of Properties

During the year ended Dec. 31, 2006, the company sold two lots adjacent to the corporate office in downtown Tampa, Florida to third party real estate developers. The sales included total proceeds of $15.0 million and resulted in pretax gains of $6.4 million. Included in each sale agreement was the ability to lease the properties until construction commenced and options to repurchase the properties after a certain period of time in the event the lots were not developed. As a result of this continuing involvement, the total gain was being deferred until such time as the continuing involvement terminates. During 2007, the option to repurchase one of the lots expired and construction commenced. As a result, $0.4 million related to that sale was recognized in "Other income" on the Consolidated Statement of Income.

Sale of Steam Turbines

In July 2006, the company sold a steam turbine generator located in Maricopa County, Arizona to a third party for a net after-tax gain of $2.6 million. In December 2006, the company sold a second steam turbine generator also located in Maricopa County, Arizona to a third party for a net after-tax gain of $3.1 million.

Sale of TPS McAdams, LLC

On Jun. 23, 2006, TPS McAdams, LLC, an indirect subsidiary of TECO Energy, was sold to Von Boyett Corporation for $1.2 million in cash. The assets of TPS McAdams, LLC had been impaired in 2004 to an estimate of salvage value, which included allowances for potential future site restoration costs. In the first quarter of 2006, TPS McAdams, LLC sold the combustion turbines at the site to Tampa Electric at the book value contemplated in the salvage estimate. The sale and transfer of TPS McAdams, LLC, including its remaining assets and any potential site restoration costs at terms better than contemplated in the salvage estimate, resulted in a pretax gain of $10.7 million ($8.1 million after-tax) being recognized in continuing operations.

Sale of TECO Thermal

In May 2006, the company sold the assets of TECO Thermal, an indirect subsidiary of TECO Energy, to a third party. Total proceeds on the sale were $8.1 million and resulted in an after-tax gain of $0.5 million.

Synthetic Fuel Facilities

Effective Apr. 1, 2003, TECO Coal sold a 49.5% indirect interest in Pike Letcher Synfuel, LLC (PLS), which owns synthetic fuel production facilities located at TECO Coal's operations in eastern Kentucky. In May 2004, TECO Coal sold an additional 40.5% of its membership interest in the synthetic fuel facilities and another 8% in July 2005, under similar terms as the first transaction. Generally, revenue was recognized as the monthly installments were received. Because the purchase price for this sale, as well as the other sales of ownership interests, was related to the value of tax credits generated through December 2007, it was subject to a reduction to the extent the credit was limited due to the average domestic oil price for a particular year exceeding the benchmark designated for that year by the Department of Energy. In addition to retaining a 2% membership interest in the facilities, TECO Coal continued to supply the feedstock and operate the facilities through the expiration of the agreement on Dec. 31, 2007.

17. Goodwill and Other Intangible Assets

SFAS 141, *Business Combinations*, requires all business combinations be accounted for using the purchase method of accounting. Under SFAS 142, *Goodwill and Other Intangible Assets* (FAS 142), goodwill is not subject to amortization. Rather, goodwill and intangible assets with an indefinite life are subject to an annual assessment for impairment at the reporting unit level. Reporting units are generally determined as one level below the operating segment level; reporting units with similar characteristics are grouped for the purpose of determining the impairment, if any, of goodwill and other intangible assets. Intangible assets with a measurable useful life are required to be amortized.

At Dec. 31, 2008, the company had $59.4 million of goodwill on its balance sheet, which is reflected in the TECO Guatemala segment. The balance of goodwill arose from the purchase of multiple entities as a result of the company's investments in its San José and Alborada power plants ($52.4 million and $3.1 million, respectively), and its equity investment in DECA II ($3.9 million). Since these three investments are one level below the operating segment level, discrete cash flow information is available, and management regularly reviews their operating results separately, this is the reporting unit level at which potential impairment is tested. Additionally, since San José and Alborada are deconsolidated as a result of FIN46 (R), these are considered equity investments and any potential impairment is tested under Accounting Principles Board Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stock* (APB 18), along with TECO Guatemala's investment at DECA II. See **Note 18, Asset Impairments** for further discussion.

18. Asset Impairments

The company accounts for long-lived asset impairments in accordance with FAS 144, which requires that long-lived assets be tested for recoverability whenever events or changes in circumstances indicate that its carrying value may not be recoverable. An asset is considered not recoverable if its carrying value exceeds the sum of its undiscounted expected cash flows. If it is determined that the carrying value is not recoverable and its carrying value exceeds its fair value, an impairment charge is made and the value of the asset is reduced to its fair value. When the impaired asset is disposed of, if the consideration received is in excess of the reduced carrying value, a gain would then be recorded. In accordance with FAS 144, the company assesses whether there has been an impairment of its long-lived assets and certain intangibles held and used by the company when such impairment indicators exist. No such indicators of impairment existed as of Dec. 31, 2008, 2007 or 2006.

The company accounts for equity investments in accordance with APB 18. APB 18 requires that equity investments be tested for impairment if there is an indication that the investment may have a loss in value that is other than temporary. An indication may include a fair value of an investment that is less than its carrying amount. The fair value for an equity investment is generally determined using discounted cash flows appropriate for the business model of the equity investment. The models incorporate assumptions relating to future results of operations that are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. Management periodically reviews and adjusts the assumptions, as necessary, to reflect current market conditions and observable activity. If a sale is expected in the near term or a similar transaction can be readily observed in the marketplace, then this information is used by management to estimate the fair value of the equity investment. As stated in **Note 17, Goodwill and Other Intangible Assets**, the company has three equity investments reflected in its TECO Guatemala segment. During 2008, there was an indication that the company's investment in DECA II may have had a loss in value that is other than temporary.

While quoted prices in active markets provide the best evidence of fair value, these are not available since TECO Guatemala has not received any offers for the purchase of its investment in DECA II. Additionally, multiples of earnings or another performance measure to determine fair value is not available since there are no comparable entities in Guatemala that have recently been sold. While there have been similar sales in Central America, these sales are not comparable to TECO Guatemala's investment due to the differing regulatory, economic and growth environments throughout Central America. Therefore, in conducting the impairment assessment for the company's investment in DECA II, the company used discounted cash flows of the business model of each of DECA II's significant group of assets.

The models incorporate assumptions relating to future results of operations that are based on a combination of historical experience, fundamental economic analysis, observable market activity, independent market studies and probabilities weighted for management's estimate of the most likely outcomes. Cash flows through 2015 were based on detailed operating forecasts provided by EEGSA. A growth factor of 5% was applied to predict subsequent year cash flows through 2048, when EEGSA's franchise to transmit and distribute electricity in Guatemala expires. The growth factor was determined based on past trends and management's expectations for both growth and inflation. The cash flows were discounted to a present value using the company's cost of capital, adjusted for an additional risk premium, as determined by management, for an investment in Guatemala. The additional risk premium was determined by reviewing the macro and micro economic, political and regulatory environment in Guatemala. Management tested the model valuation using discount rates ranging from 11% to 15%. The resulting calculations did not alter the conclusion of the tests.

The company determined the fair value of its investment in DECA II supports the investment and related goodwill carrying amounts at Dec. 31, 2008, resulting in no impairment charge. The company will continue to monitor its investment in DECA II as events and/or circumstances change or resolve. (See **Note 12, Commitments and Contingencies** for more information.)

19. Variable Interest Entities

TECO Energy accounts for VIEs under FIN 46(R), *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51* (FIN 46(R)). In accordance with FIN 46(R), the company evaluates for consolidation all long-term agreements with VIEs in which contractual, ownership or other pecuniary interests in that entity change with changes in the fair value of the entity's net assets. A party to an agreement that absorbs a majority of the entity's expected losses, receives a majority of its expected residual returns, or both, is considered to be the primary beneficiary and is required to consolidate that entity. In addition to these quantitative factors, the company evaluates qualitative factors that would indicate that a transfer of risk from the entity to the company has occurred. The transfer of substantial risk from the entity to the company could result in a determination that the company is the primary beneficiary of the entity. While the company reviews each contract individually, for purposes of analyzing PPA's, the determining factors are generally the length of the agreement and which entity absorbs the fuel risk.

The company formed TCAE to own and construct the Alborada Power Station and the company formed CGESJ to own and construct the San José Power Station. Both power stations are located in Guatemala and both projects obtained long-term PPAs with EEGSA, a distribution utility in Guatemala. The terms of the two separate PPAs include EEGSA's right to the full capacity of the plants for 15 years, U.S. dollar based capacity payments, certain terms for providing fuel, and certain other terms including the right to extend the Alborada and San José contracts. Management believes that EEGSA is the primary beneficiary of the variable interests in TCAE and CGESJ due to the terms of the PPAs. Accordingly, both entities were deconsolidated as of Jan. 1, 2004. The TCAE deconsolidation resulted in the initial removal of $25 million of debt and $15.1 million of net assets from TECO Energy's Consolidated Balance Sheet. The San José deconsolidation resulted in the initial removal of $65.5 million of debt and $106.6 million of net assets from TECO Energy's Consolidated Balance Sheet. The results of operations for the two projects are classified as "Income from equity investments" on TECO Energy's Consolidated Statements of Income since the date of deconsolidation. TECO Energy's estimated maximum loss exposure is its equity investment of approximately $198.5 million in these entities. See **Note 24** for summary financial information related to these entities.

Pike Letcher Synfuel, LLC was established as part of the Apr. 1, 2003, sale of TECO Coal's synthetic fuel production facilities. While TECO Energy's maximum loss exposure in this entity was its investment of approximately $8.2 million, the company could have lost potential earnings and incurred losses related to the production costs for synthetic fuel, in the event that such production created non-conventional fuel tax credits in excess of TECO Energy's or the other buyers' capacity to generate sufficient taxable income to use such credits or fuel tax credits were reduced or eliminated due to high oil prices. Management believed that the company was the primary beneficiary of this VIE and continued to consolidate the entity under the guidance of FIN 46(R) through the expiration of synfuel production on Dec. 31, 2007.

Tampa Electric has entered into multiple PPAs with wholesale energy providers in Florida to ensure the ability to meet customer energy demand and to provide lower cost options in the meeting of this demand. These agreements are with similar entities and contain similar provisions. They range in size from 125 to 370 MW of available capacity. Some of these provisions provide for the transfer or sharing of a number of risks inherent in the generation of energy. Some of these risks include: operating and maintenance; regulatory; credit; commodity/fuel; and energy market risk. In most instances, the company has reviewed these risks and has determined that the owners of these entities have retained the majority of these risks over the expected life of the underlying generating assets and are the primary beneficiaries. As a result, the company is not required to consolidate any of these entities. The company purchased $167.2 million, $109.7 million, and $88.0 million under these PPAs for the years ended Dec. 31, 2008, 2007, and 2006, respectively.

In one instance the company's agreement with the entity for 370 MW of capacity was entered into prior to Dec. 31, 2003, the effective date of FIN 46(R). Under FIN 46(R), the company is required to make an exhaustive effort to obtain sufficient information to determine if this entity is a VIE and which holder of the variable interests is the primary beneficiary. The owners of this entity are not willing to provide the information necessary to make these determinations, have no obligation to do so and the information is not available publicly. As a result, the company is unable to determine if this entity is a VIE and if so, which variable interest holder, if any, is the primary beneficiary. The company has no obligation to this entity beyond the purchase of capacity; therefore, the maximum exposure for the company is the obligation to pay for such capacity under terms of the PPA at rates that could be unfavorable to the wholesale market. The company purchased $71.6 million, $54.5 million, and $50.7 million under this PPA for the years ended Dec. 31, 2008, 2007, and 2006, respectively.

The company does not provide any material financial or other support to any of the VIEs it is involved with, nor is the company under any obligation to absorb losses associated with these VIEs. Other than the Guatemalan projects previously mentioned, in the normal course of business, our involvement with the remaining VIEs does not affect our Consolidated Balance Sheets, Statements of Income or Cash Flows.

20. Discontinued Operations and Assets Held for Sale

Union and Gila River Project Companies (TPGC)

Net income from discontinued operations in 2007 was $14.3 million, after-tax, reflecting a favorable conclusion reached in the second quarter with taxing authorities for the 2005 disposition of the Union and Gila River merchant power plants.

TECO Thermal

For fiscal year ended Dec. 31, 2006, the results from operations of TECO Thermal (sold in 2006) are presented as discontinued operations on the income statement. See **Note 16** for additional details related to this sale.

The following table provides the selected components of discontinued operations for TECO Thermal:

Components of income from discontinued operations – TECO Thermal

(millions) *For the years ended Dec. 31,*	*2008*	*2007*	*2006*
Revenues	$ –	$ –	$ 0.8
Income from operations	–	–	1.5
Gain on sale	–	–	0.8
Income before provision for income taxes	–	–	2.3
Provision for income taxes	–	–	0.4
Net income from discontinued operations	$ –	$ –	$ 1.9

21. Derivatives and Hedging

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;
- To limit the exposure to price fluctuations for physical purchases of fuel and explosives at TECO Coal; and
- To limit the exposure to synthetic fuel tax credits from TECO Coal's synthetic fuel produced as a result of changes to the reference price of domestically produced oil (prior to Dec. 31, 2007).

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 Activity* and SFAS 149, *Amendment on Statement 133 on Derivative Instruments and Hedging Activities.* 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 instruments' settlement. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the amount paid or received on the underlying physical transaction.

At Dec. 31, 2008 and 2007, respectively, TECO Energy and its affiliates had derivative assets (current and non-current) totaling $0.1 million and $2.2 million, and liabilities (current and non-current) totaling $151.5 million and $26.1 million. At Dec. 31, 2008, $26.0 million of liabilities are related to heating oil swaps. The remaining $0.1 million of assets and $125.5 million in liabilities are related to natural gas swaps. At Dec. 31, 2007, $8.2 million of liabilities are related to interest rate swaps and the remaining $2.2 million of assets and $17.9 million in liabilities are related to natural gas swaps.

At Dec. 31, 2008 and 2007, accumulated other comprehensive income (AOCI) included an after-tax $13.6 million unrealized loss and an after-tax $6.2 million unrealized loss, respectively, representing the fair value of cash flow hedges whose underlying transactions will occur within the next 12 months. Amounts recorded in AOCI reflect the estimated fair value based on market prices as of the balance sheet date of heating oil, natural gas and interest rate swap derivative instruments designated as cash flow hedges. These amounts are expected to fluctuate with movements in market prices and may or may not be realized as a loss upon future reclassification from OCI to earnings. The company does not currently have any cash flow hedges for transactions forecasted to take place in periods subsequent to 2011.

For the years ended Dec. 31, 2008, 2007 and 2006, TECO Energy and its affiliates reclassified amounts from OCI and recognized net pretax (losses) gains of $(4.9) million, $6.5 million and $0.5 million, respectively. (See **Note 10**) Amounts reclassified from OCI were primarily related to cash flow hedges for physical purchases of fuel oil at TECO Transport and TECO Coal. For these types of hedge relationships, the gain or loss on the derivative at settlement is reclassified from OCI to earnings, which is offset by the increased or decreased cost of spot purchases for fuel oil.

As a result of applying the provisions of FAS 71 in accordance with the FPSC, 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 fuel recovery clause on the risks of hedging activities. (See **Note 3**). Based on the fair value of cash flow hedges at Dec. 31, 2008, net pretax losses of $119.4 million are expected to be reclassified from regulatory assets or liabilities to the Consolidated Statement of Income within the next twelve months.

At Dec. 31, 2007, TECO Energy had a "Crude oil options receivable, net" asset totaling $78.5 million for transactions that were not designated as either a cash flow or fair value hedge. This balance includes the full settlement value of the crude oil options of $120.8 million, offset by the $42.3 million of margin call collateral collected. These derivatives were marked-to-market with fair value gains and losses recognized in "Other income" on the Consolidated Statements of Income. For the years ended Dec. 31, 2007 and 2006, the company recognized gains on marked-to-market derivatives of $82.7 million and $2.9 million, respectively. The increase in the gain from 2006 to 2007 is reflective of the increase in oil prices and the total volume of barrels hedged, 2.8 million barrels in 2006 compared to 25.1 million barrels in 2007.

22. Fair Value

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.

FAS 157, among other things, requires the company to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. It also requires recognition of trade-date gains related to certain derivative transactions whose fair value has been determined using unobservable market inputs. This guidance supersedes the guidance in EITF Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities* (EITF 02-3), which prohibited the recognition of trade-date gains for such derivative transactions when determining the fair value of instruments not traded in an active market.

On Nov. 14, 2007, the FASB reaffirmed its position that companies will be required to implement the standard for financial assets and liabilities, as well as for any other assets and liabilities that are carried at fair value on a recurring basis in financial statements. The FASB did, however, provide a one year deferral for the implementation of FAS 157 for other non-financial assets and liabilities. Effective Jan. 1, 2008, the company adopted FAS 157 for financial assets and liabilities that are carried at fair value on a recurring basis.

FAS 157 is applied prospectively as of the first interim period for the fiscal year in which it is initially adopted, except for limited retrospective adoption for the following three items:

- The valuation of financial instruments using blockage factors;
- Financial instruments that were measured at fair value using the transaction price (as indicated in EITF 02-3); and,

• The valuation of hybrid financial instruments that were measured at fair value using the transaction price (as indicated in FAS 155).

The impact of adoption in these areas would be applied as a cumulative-effect adjustment to opening retained earnings, measured as the difference between the carrying amounts and the fair values of relevant assets and liabilities at the date of adoption. TECO Energy does not have any of the three aforementioned items, and therefore no transition adjustment was recorded.

Fair Value Hierarchy

FAS 157 specifies a hierarchy of valuation techniques based on whether the inputs to those valuation techniques are observable or unobservable. In accordance with FAS 157, these two types of inputs have created the following fair value hierarchy:

- *Level 1* – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed equities and U.S. government treasury securities.
- *Level 2* – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as OTC forwards, options and repurchase agreements.
- *Level 3* – Pricing inputs include significant inputs that are generally not observable in the marketplace. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. At each balance sheet date, the company performs an analysis of all instruments subject to FAS 157 and includes in Level 3 all of those whose fair value is based on significant unobservable inputs.

This hierarchy requires the use of observable market data when available.

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.

Valuation Techniques

FAS 157 describes three main approaches to measuring the fair value of assets and liabilities:

1) *Market Approach* - The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities (including a business). The market approach includes the use of matrix pricing.

2) *Income Approach* - The income approach uses valuation techniques to convert future amounts (for example, cash flows or earnings) to a single present amount (discounted). The measurement is based on the value indicated by current market expectations about those future amounts.

3) *Cost Approach* -The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (often referred to as current replacement cost). The cost approach assumes that the fair value would not exceed what it would

cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

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 Dec. 31, 2008. 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 Dec. 31, 2008*			
(millions)	*Level 1*	*Level 2*	*Level 3*	*Total*
Assets				
Natural gas swaps	$ -	$ 0.1	$ -	$ 0.1
Other investments	-	-	13.3	13.3
Total	$ -	$ 0.1	$ 13.3	$ 13.4
Liabilities				
Natural gas swaps	$ -	$ 134.5	$ -	$ 134.5
Heating oil swaps	-	26.0	-	26.0
Total	$ -	$ 160.5	$ -	$ 160.5

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 $2.8 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 Balance Sheets.

The company considers the impact of nonperformance risk in determining the fair value of derivatives. The company considers the net position with each counterparty, past performance of both parties and the intent of the parties, measures of credit risk including credit default swaps and historical default probabilities, and whether the markets in which we transact have experienced dislocation. At Dec. 31, 2008 the fair value of derivatives was not materially affected by nonperformance risk. The company's net positions with substantially all counterparties were liability positions.

Other investments reflect two auction rate securities with a combined par value of $15.0 million. As a result of auction failures and the lack of an alternative active market, the company in 2008 changed the valuation technique for these securities to an income approach using a discounted cash flow model. Accordingly, these securities changed to Level 3 within FAS 157's three tier fair value hierarchy since initial valuation at Jan. 1, 2008. 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 $1.6 million decrease in value.

Based on the fair value determined from the discounted cash flow analysis, a temporary impairment was recorded in other comprehensive income. These are investment grade securities backed by pools of student loans. Therefore, it is expected that the investments will not be settled at a price less than par value. Because the company has the ability and intent to hold this investment until a recovery of its original investment value, it considers the investment to be temporarily impaired at Dec. 31, 2008.

In accordance with SFAS 107, *Disclosures about Fair Value of Financial Instruments*, TECO Energy has disclosed the fair value of its long-term debt to be $2,987.5 million. (See **Note 7, Long-term Debt**) The determination of fair value for these instruments includes obtaining prices from third party financial institutions and in some cases utilizing a model to discount the future cash flows produced by the instruments by a rate determined by applying a spread based on TECO Energy's or Tampa Electric Company's credit ratings (also provided by third party financial institutions) to U.S. Treasury rates.

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

(millions)	*Auction Rate Securities*	*Interest Rate Swaps*	*Total*
Balance at Jan. 1, 2008	$ -	$ (9.0)	$ (9.0)
Transfers to Level 3	14.0	-	14.0
Change in fair market value	-	(7.3)	(7.3)
Included in earnings	-	-	-
Balance at Mar. 31, 2008	14.0	(16.3)	(2.3)
Transfers to Level 3	-	-	-
Change in fair market value	-	4.5	4.5
Settled[1]	-	11.8	11.8
Included in earnings	-	-	-
Balance at Jun. 30, 2008	14.0	-	14.0
Transfers to Level 3	-	-	-
Change in fair market value	(0.9)	-	(0.9)
Settled	-	-	-
Included in earnings	-	-	-
Balance at Sep. 30, 2008	13.1	-	13.1
Transfers to Level 3	-	-	-
Change in fair market value	0.2	-	0.2
Settled	-	-	-
Included in earnings	-	-	-
Balance at Dec. 31, 2008	$ 13.3	$ -	$ 13.3

(1) $11.8 million of forward starting interest rate swaps were settled in the second quarter of 2008 and were related to Tampa Electric Company's May 2008 issuance of debt.

23. TECO Finance, Inc.

TECO Finance, Inc. (TECO Finance) is a wholly-owned subsidiary of TECO Energy, Inc. TECO Finance's sole purpose is to raise capital for TECO Energy's diversified businesses. TECO Energy is a full and unconditional guarantor of TECO Finance's securities. (See **Note 7**) TECO Finance meets the definition of a significant subsidiary by virtue of total assets exceeding 10 % of such income for TECO Energy consolidated. As required by Regulation S-X, condensed financial statements for TECO Finance are presented below:

TECO Finance, Inc.
Condensed Balance Sheets

(millions)	Dec. 31, 2008	Dec. 31, 2007
Assets		
Current assets		
Cash	$ -	$ 0.2
Advances-intercompany	769.7	737.6
Total current assets	769.7	737.8
Non-current assets		
Deferred tax asset	18.6	1.8
Unamortized debt expense	25.3	29.0
Total non-current assets	43.9	30.8
Total assets	$ 813.6	$ 768.6
Liabilities and Capital		
Current liabilities		
Notes payable	$ 64.0	$ -
Interest payable	9.9	1.8
Advances payable-intercompany	-	-
Total current liabilities	73.9	1.8
Non-current liabilities		
Long-term debt	900.3	900.5
Total liabilities	974.2	902.3
Capital		
Common stock and paid in capital	0.1	0.1
Retained deficit	(160.7)	(133.8)
Total capital	(160.6)	(133.7)
Total liabilities and capital	$ 813.6	$ 768.6

TECO Finance, Inc.
Condensed Statements of Operations

(millions) For the years ended Dec. 31,	2008	2007	2006
Revenues	$ -	$ -	$ -
Other income			
Interest expense	43.7	2.2	-
Loss before benefit from income taxes	(43.7)	(2.2)	-
Benefit from income taxes	16.8	0.8	-
Net loss	$ (26.9)	$ (1.4)	$ -

TECO Finance, Inc.
Condensed Statements of Cash Flows

(millions) *For the years ended Dec. 31,*	2008	2007	2006
Cash flows from operating activities			
Net loss	$ (26.9)	$ (1.4)	$ -
Adjustments to reconcile net loss to net cash from operating activities:			
Deferred taxes	(16.8)	(0.8)	-
Interest payable	8.1	1.8	-
Other assets	3.7	(1.7)	
Other liabilities	(0.2)	-	-
Cash flows used in operating activities	(32.1)	(2.1)	-
Cash flows from financing activities			
Advances	(32.1)	2.2	-
Short-term debt or notes	64.0	-	
Cash flows provided by financing activities	31.9	2.2	-
Net increase (decrease) in cash	(0.2)	0.1	-
Cash at the beginning of the year	0.2	0.1	0.1
Cash at end of the year	$ -	$ 0.2	$ 0.1

24. Central Generadora Eléctrica San José, Limitada (CGESJ)

The company formed CGESJ to own and construct the San José Power Station. It is located in Guatemala and obtained a long-term PPA with EEGSA, a distribution utility in Guatemala. CGESJ was deconsolidated as of Jan. 1, 2004 under FIN 46(R). (See **Note 19, Variable Interest Entities** for more information). In 2008, CGESJ's net income from continuing operations before income taxes, extraordinary items and cumulative effect of a change in accounting principle exceeded 10% of such income for TECO Energy consolidated. As a result, CGESJ meets the definition of a significant subsidiary in Regulation S-X. The summarized financial information required for subsidiaries not consolidated is presented in the table below:

Central Generadora Eléctrica San José, Limitada (CGESJ)
Summarized Assets and Liabilities

(millions)	*Dec. 31, 2008*	*Dec. 31, 2007*
Assets		
Total current assets	$ 53.8	$ 44.1
Total non-current assets	142.5	146.8
Total assets	$ 196.3	$ 190.9
Liabilities		
Total current liabilities	$ 17.1	$ 9.8
Total non-current liabilities	56.4	65.3
Total liabilities	$ 73.5	$ 75.1

Central Generadora Eléctrica San José, Limitada (CGESJ)
Summarized Results of Operations

(millions) *For the years ended Dec. 31,*		*2008*		*2007*		*2006*
Operating revenues	$	95.1	$	92.6	$	82.8
Operating expenses		51.6		50.2		45.2
Gross profit	$	43.5	$	42.4	$	37.6
Income from continuing operations before extraordinary items and cumulative effect of change in accounting principle		33.9		31.9		26.2
Net Income	$	33.9	$	31.9	$	26.2

25. Quarterly Data (unaudited)

Financial data by quarter is as follows:

(millions, except per share amounts) *Quarter ended*	*Dec. 31*	*Sep. 30*	*Jun. 30*	*Mar. 31*
2008				
Revenues	$ 770.3	$ 926.1	$ 887.2	$ 791.7
Income from operations	$ 88.5	$ 116.5	$ 102.4	$ 77.6
Net income				
Net income from continuing operations	$ 22.0	$ 58.2	$ 51.4	$ 30.8
Net income	$ 22.0	$ 58.2	$ 51.4	$ 30.8
Earnings per share (EPS) — basic				
EPS from continuing operations	$ 0.10	$ 0.28	$ 0.24	$ 0.15
EPS	$ 0.10	$ 0.28	$ 0.24	$ 0.15
Earnings per share (EPS) — diluted				
EPS from continuing operations	$ 0.10	$ 0.27	$ 0.24	$ 0.15
EPS	$ 0.10	$ 0.27	$ 0.24	$ 0.15
Dividends paid per common share	$ 0.20	$ 0.20	$ 0.20	$ 0.195
Stock price per common share (1)				
High	$ 16.05	$ 21.80	$ 21.99	$ 17.75
Low	$ 10.50	$ 15.36	$ 15.97	$ 14.48
Close	$ 12.35	$ 15.73	$ 21.49	$ 15.95

Quarter ended	*Dec. 31* (2)	*Sep. 30*	*Jun. 30*	*Mar. 31*
2007				
Revenues	$ 858.3	$ 990.0	$ 866.5	$ 821.3
Income from operations	$ 328.8	$ 141.7	$ 87.7	$ 78.4
Net income				
Net income from continuing operations	$ 173.9	$ 92.8	$ 59.4	$ 72.8
Net income	$ 173.9	$ 92.8	$ 73.7	$ 72.8
Earnings per share (EPS) — basic				
EPS from continuing operations	$ 0.83	$ 0.44	$ 0.28	$ 0.35
EPS	$ 0.83	$ 0.44	$ 0.35	$ 0.35
Earnings per share (EPS) — diluted				
EPS from continuing operations	$ 0.83	$ 0.44	$ 0.28	$ 0.35
EPS	$ 0.83	$ 0.44	$ 0.35	$ 0.35
Dividends paid per common share	$ 0.195	$ 0.195	$ 0.195	$ 0.19
Stock price per common share (1)				
High	$ 17.91	$ 17.71	$ 18.58	$ 17.49
Low	$ 15.58	$ 14.84	$ 16.40	$ 16.22
Close	$ 17.21	$ 16.43	$ 17.18	$ 17.21

(1) Trading prices for common shares

(2) Fourth quarter 2007 results include TECO Transport results through Dec. 3, 2007, the $149.4 million after-tax gain on the sale of TECO Transport and $20.2 million of after-tax debt extinguishment costs. See **Note 16** for more information regarding the sale of TECO Transport.

THIS
PAGE
INTENTIONALLY
LEFT
BLANK

TAMPA ELECTRIC COMPANY
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

All other financial statement schedules have been omitted since they are not required, are inapplicable or the required information is presented in the financial statements or notes thereto.

Report of Independent Registered Certified Public Accounting Firm

To the Board of Directors and Shareholders of Tampa Electric Company:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Tampa Electric Company and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 5 to the financial statements, the Company changed its method of accounting for its defined benefit pension and other post-retirement plans as of December 31, 2006.

/s/ PricewaterhouseCoopers LLP
Tampa, Florida
February 23, 2009

TAMPA ELECTRIC COMPANY
Consolidated Balance Sheets

Assets (millions)	*Dec. 31, 2008*	*Dec. 31, 2007*
Property, plant and equipment		
Utility plant in service		
Electric	$ 5,514.9	$ 5,262.0
Gas	964.4	917.4
Construction work in progress	462.4	363.6
Property, plant and equipment, at original costs	6,941.7	6,543.0
Accumulated depreciation	(1,868.5)	(1,808.6)
	5,073.2	4,734.4
Other property	4.5	4.5
Total property, plant and equipment (net)	5,077.7	4,738.9
Current assets		
Cash and cash equivalents	3.6	11.9
Receivables, less allowance for uncollectibles of $1.6 and $1.4 at Dec. 31, 2008 and 2007, respectively	236.1	238.8
Inventories, at average cost		
Fuel	76.8	66.2
Materials and supplies	61.8	58.0
Current regulatory assets	272.6	67.4
Current derivative assets	-	0.3
Taxes receivable	0.2	2.9
Prepayments and other current assets	14.1	11.6
Total current assets	665.2	457.1
Deferred debits		
Unamortized debt expense	22.3	22.9
Long-term regulatory assets	325.3	186.8
Long-term derivative assets	0.1	1.9
Other	18.0	11.7
Total deferred debits	365.7	223.3
Total assets	$ 6,108.6	$ 5,419.3

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

TAMPA ELECTRIC COMPANY
Consolidated Balance Sheets -continued

Liabilities and Capital (millions)	*Dec. 31, 2008*	*Dec. 31, 2007*
Capital		
Common stock	$ 1,802.4	$ 1,510.4
Accumulated other comprehensive loss	(6.8)	(5.0)
Retained earnings	295.0	295.6
Total capital	2,090.6	1,801.0
Long-term debt, less amount due within one year	1,894.8	1,844.8
Total capitalization	3,985.4	3,645.8
Current liabilities		
Long-term debt due within one year	5.5	5.7
Notes payable	29.0	25.0
Accounts payable	262.5	237.6
Customer deposits	144.6	138.1
Current regulatory liabilities	21.7	35.4
Current derivative liabilities	119.4	26.0
Current deferred income taxes	36.6	0.3
Interest accrued	27.1	23.5
Taxes accrued	20.1	16.8
Other	11.2	11.3
Total current liabilities	677.7	519.7
Deferred credits		
Non-current deferred income taxes	447.6	407.5
Investment tax credits	11.2	12.0
Long-term derivative liabilities	14.8	0.1
Long-term regulatory liabilities	588.2	582.7
Other	383.7	251.5
Total deferred credits	1,445.5	1,253.8
Total liabilities and capital	$ 6,108.6	$ 5,419.3

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

TAMPA ELECTRIC COMPANY
Consolidated Statements of Income and Comprehensive Income

(millions) *For the years ended Dec. 31,*	*2008*	*2007*	*2006*
Revenues			
Electric (includes franchise fees and gross receipts taxes of $85.0 in 2008, $87.4 in 2007 and $81.4 in 2006)	$ 2,091.2	$ 2,188.4	$ 2,084.9
Gas (includes franchise fees and gross receipts taxes of $24.2 in 2008, $23.8 in 2007 and $22.8 in 2006)	687.9	599.1	577.0
Total revenues	2,779.1	2,787.5	2,661.9
Expenses			
Operations			
Fuel	819.4	947.9	906.8
Purchased power	305.4	271.9	221.3
Cost of natural gas sold	476.6	389.9	365.3
Other	277.3	279.8	293.5
Maintenance	121.4	113.9	111.8
Depreciation and amortization	227.5	218.7	222.8
Taxes, federal and state	97.8	99.8	96.8
Taxes, other than income	171.2	174.6	172.4
Total expenses	2,496.6	2,496.5	2,390.7
Income from operations	282.5	291.0	271.2
Other income			
Allowance for other funds used during construction	6.3	4.5	2.7
Taxes, non-utility federal and state	(1.4)	(1.7)	(2.3)
Other income, net	8.0	12.2	16.6
Total other income	12.9	15.0	17.0
Interest charges			
Interest on long-term debt	124.5	118.3	106.7
Other interest	10.6	12.6	17.0
Allowance for borrowed funds used during construction	(2.4)	(1.7)	(1.1)
Total interest charges	132.7	129.2	122.6
Net income	162.7	176.8	165.6
Other comprehensive loss, net of tax			
Net unrealized losses on cash flow hedges	(1.8)	(5.0)	-
Other comprehensive loss, net of tax	(1.8)	(5.0)	-
Comprehensive income	$ 160.9	$ 171.8	$ 165.6

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

TAMPA ELECTRIC COMPANY
Consolidated Statements of Cash Flows

(millions) *For the years ended Dec. 31,*	*2008*	*2007*	*2006*
Cash flows from operating activities			
Net income	$ 162.7	$ 176.8	$ 165.6
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation	227.5	218.7	222.8
Deferred income taxes	75.8	(45.6)	(23.2)
Investment tax credits, net	(0.9)	(2.5)	(2.5)
Allowance for funds used during construction	(6.3)	(4.5)	(2.7)
Gain on sale of business/assets, pretax	(0.4)	(0.4)	-
Deferred recovery clause	(115.8)	123.7	53.4
Receivables, less allowance for uncollectibles	2.7	(3.9)	0.6
Inventories	(14.4)	(9.2)	(1.3)
Prepayments	(2.5)	(0.3)	(3.3)
Taxes accrued	6.0	9.5	24.5
Interest accrued	3.6	(3.1)	1.2
Accounts payable	7.0	(20.1)	(9.1)
Other	11.4	5.9	29.8
Cash flows from operating activities	356.4	445.0	455.8
Cash flows from investing activities			
Capital expenditures	(548.7)	(423.0)	(420.4)
Allowance for funds used during construction	6.3	4.5	2.7
Net proceeds from sale of assets	6.3	0.4	-
Purchase of a business	-	-	(1.4)
Cash flows used in investing activities	(536.1)	(418.1)	(419.1)
Cash flows from financing activities			
Common stock	292.0	81.8	51.8
Proceeds from long-term debt	327.8	444.1	327.5
Repayment of long-term debt/Purchase in-lieu-of redemption	(292.5)	(356.9)	(91.9)
Net increase (decrease) in short-term debt	4.0	(23.0)	(167.0)
Dividends	(159.9)	(166.1)	(169.4)
Cash flows from (used in) financing activities	171.4	(20.1)	(49.0)
Net (decrease) increase in cash and cash equivalents	(8.3)	6.8	(12.3)
Cash and cash equivalents at beginning of period	11.9	5.1	17.4
Cash and cash equivalents at end of period	$ 3.6	$ 11.9	$ 5.1
Supplemental disclosure of cash flow information			
Cash paid during the year for:			
Interest	$ 120.9	$ 123.3	$ 106.9
Income taxes	$ 18.4	$ 135.0	$ 100.1

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

TAMPA ELECTRIC COMPANY
Consolidated Statements of Retained Earnings

(millions) *For the years ended Dec. 31,*	*2008*	*2007*	*2006*
Balance, beginning of year	$ 295.6	$ 284.9	$ 288.7
Add: Net income	162.7	176.8	165.6
	458.3	461.7	454.3
Deduct:			
Implementation of FAS 158	3.4	—	—
Cash dividends on capital stock			
Common	159.9	166.1	169.4
Balance, end of year	$ 295.0	$ 295.6	$ 284.9

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

Consolidated Statements of Capitalization

		Capital Stock Outstanding Dec. 31,		*Cash Dividends Paid* [1]	
(millions, except share amounts)	*Current Redemption Price*	*Shares*	*Amount*	*Per Share*	*Amount*
Common stock — without par value					
25 million shares authorized					
2008	N/A	10	$ 1,802.4	[2]	$159.9
2007	N/A	10	$ 1,510.4	[2]	$166.1
Preferred stock — $100 par value					
1.5 million shares authorized, none outstanding.					
Preferred stock – no par					
2.5 million shares authorized, none outstanding.					
Preference stock – no par					
2.5 million shares authorized, none outstanding.					

(1) Quarterly dividends paid on Feb. 28, May 28, Aug. 28 and Nov. 28 during 2008 and 2007.
(2) Not meaningful.

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

TAMPA ELECTRIC COMPANY
Consolidated Statements of Capitalization -continued

Long-Term Debt (millions) Dec. 31,		*Due*	*2008*	*2007*
Tampa Electric	Installment contracts payable[1]:			
	5.1% Refunding bonds (effective rate of 5.7%)	2013	$ 60.7	$ 60.7
	5.65% Refunding bonds (effective rate of 6.3%) and 4.4% variable rate for 2007[2][3]	2018	54.2	54.2
	Variable rate bonds repurchased in 2008, 4.6% variable rate for 2007[2][6]	2020	—	20.0
	5.5% Refunding bonds (effective rate of 6.3%)	2023	86.4	86.4
	5.15% Refunding bonds (effective rate of 5.9%) and 4.7% variable rate for 2007[2][7]	2025	51.6	51.6
	Variable rate bonds repurchased in 2008, 5.3% variable rate for 2007[2][6]	2030	—	75.0
	5.0% Refunding bonds (effective rate of 6.1%) and 4.6% variable rate for 2007[2][8]	2034	86.0	86.0
	Notes[4]:6.875% (effective rate of 7.0%)	2012	210.0	210.0
	6.375% (effective rate of 7.4%)	2012	330.0	330.0
	6.25% (effective rate of 6.3%)[5]	2014-2016	250.0	250.0
	6.10% (effective rate of 7.1%)	2018	100.0	—
	6.55% (effective rate of 6.6%)	2036	250.0	250.0
	6.15% (effective rate of 6.2%)	2037	190.0	190.0
			1,668.9	1,663.9
Peoples Gas System	Senior Notes[4][5]:			
	10.33%	2008	—	1.0
	10.30%	2008-2009	1.8	2.8
	9.93%	2008-2010	2.0	3.0
	8.00%	2008-2012	12.2	14.9
	Notes[4]:6.875% (effective rate of 7.0%)	2012	40.0	40.0
	6.375% (effective rate of 7.4%)	2012	70.0	70.0
	6.10% (effective rate of 7.1%)	2018	50.0	—
	6.15% (effective rate of 6.2%)	2037	60.0	60.0
			236.0	191.7
			1,904.9	1,855.6
Unamortized debt premium (discount), net			(4.6)	(5.1)
			1,900.3	1,850.5
Less amount due within one year			5.5	5.7
Total long-term debt			1,894.8	1,844.8
Total capital			2,090.6	1,801.0
Total capitalization			$3,985.4	$3,645.8

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

(1) Tax-exempt securities.
(2) Composite year-end interest rate.
(3) These bonds were converted in March 2008 from an auction rate mode to a fixed rate mode through maturity on May 15, 2018.
(4) These securities are subject to redemption in whole or in part, at any time, at the option of the company.
(5) These long-term debt agreements contain various restrictive financial covenants.
(6) In March 2008 these bonds, which were in auction rate mode, were purchased in lieu of redemption by Tampa Electric Company.
(7) These bonds were converted in March 2008 from an auction rate mode to a fixed rate mode for the term ending Sep. 1, 2013.
(8) These bonds were converted in March 2008 from an auction rate mode to a fixed rate mode for the term ending Mar. 15, 2012.

TAMPA ELECTRIC COMPANY
Consolidated Statements of Capitalization -continued

At Dec. 31, 2008, total long-term debt had a carrying amount of $1,904.9 million and an estimated fair market value of $1,822.6 million. At Dec. 31, 2007, total long-term debt had a carrying amount of $1,855.6 million and an estimated fair market value of $1,932.1 million. The estimated fair market value of long-term debt was based on quoted market prices for the same or similar issues, on the current rates offered for debt of the same remaining maturities, or for long-term debt issues with variable rates that approximate market rates, at carrying amounts. The carrying amount of long-term debt due within one year approximated fair market value because of the short maturity of these instruments. (See **Note 13, Fair Value**)

A substantial part of the tangible assets of Tampa Electric is pledged as collateral for the first mortgage bonds issued under Tampa Electric's first mortgage bond indentures. There are currently no bonds outstanding under Tampa Electric's first mortgage bond indenture, and Tampa Electric could cause the lien associated with this indenture to be released at any time. Maturities and annual sinking fund requirements of long-term debt for the years 2009 through 2013 and thereafter are as follows:

Long-Term Debt Maturities

Dec. 31, (millions)	*2009*	*2010*	*2011*	*2012*	*2013*	*Thereafter*	*Total Long-term debt*
Tampa Electric	$ -	$ -	$ -	$ 540.0	$ 60.7	$ 1,068.2	$ 1,668.9
Peoples Gas	5.5	3.7	3.4	113.4	-	110.0	236.0
Total long-term debt maturities	$ 5.5	$ 3.7	$ 3.4	$ 653.4	$ 60.7	$ 1,178.2	$ 1,904.9

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

TAMPA ELECTRIC COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Significant Accounting Policies

The significant accounting policies are as follows:

Basis of Accounting

Tampa Electric Company maintains its accounts in accordance with recognized policies prescribed or permitted by the Florida Public Service Commission (FPSC) and the Federal Energy Regulatory Commission (FERC). These policies conform with generally accepted accounting principles in all material respects.

The impact of Statement of Financial Accounting Standard (FAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*, (FAS 71) has been minimal in the company's experience, but when cost recovery is ordered over a period longer than a fiscal year, costs are recognized in the period that the regulatory agency recognizes them in accordance with FAS 71.

The company's retail and wholesale businesses are regulated by the FPSC and related FERC, respectively. Prices allowed by both agencies are generally based on recovery of prudent costs incurred plus a reasonable return on invested capital.

Principles of Consolidation

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. 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.

For entities that are determined to meet the definition of a variable interest entity (VIE), Tampa Electric Company obtains information, where possible, to determine if it is the primary beneficiary of the VIE. If Tampa Electric Company is determined to be the primary beneficiary, then the VIE is consolidated and a minority interest is recognized for any other third-party interests. If Tampa Electric Company is not the primary beneficiary, then the VIE is accounted for using the equity or cost method of accounting. In certain circumstances this can result in Tampa Electric Company consolidating entities in which it has less than a 50% equity investment and deconsolidating entities in which it has a majority equity interest. (See **Note 14, Variable Interest Entities** for more information.)

Planned Major Maintenance

Tampa Electric and PGS expense major maintenance costs as incurred. Concurrent with a planned major maintenance outage, the cost of adding or replacing retirement units-of-property is capitalized in conformity with FPSC and FERC regulations.

Cash Equivalents

Cash equivalents are highly liquid, high-quality investments purchased with an original maturity of three months or less. The carrying amount of cash equivalents approximated fair market value because of the short maturity of these instruments.

Depreciation

Tampa Electric computes depreciation expense by applying composite, straight-line rates (approved by the state regulatory agency) to the investment in depreciable property. Total depreciation expense for the years ended Dec. 31, 2008, 2007 and 2006 was $224.3 million, $215.5 million and $217.4 million, respectively. There were no plant acquisition adjustments in 2008, 2007 or 2006. The provision for total regulated utility plant in service, expressed as a percentage of the original cost of depreciable property was 3.6%, 3.7% and 3.9% for 2008, 2007 and 2006, respectively. Construction work-in progress is not depreciated until the asset is completed or placed in service.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is a non-cash credit to income with a corresponding charge to utility plant which represents the cost of borrowed funds and a reasonable return on other funds used for construction. AFUDC is recorded in years when the capital expenditures on eligible projects exceed approximately $36 million. The base on which AFUDC is calculated excludes construction work-in-progress which has been included in rate base. The rate used to calculate AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. The rate was 7.79% for 2008, 2007 and 2006. Total AFUDC for 2008, 2007 and 2006 was $8.7 million, $6.2 million, and $3.8 million, respectively.

Deferred Income Taxes

Tampa Electric Company utilizes the liability method in the measurement of deferred income taxes. Under the liability method, the temporary differences between the financial statement and tax bases of assets and liabilities are reported as deferred taxes measured at current tax rates. Tampa Electric and PGS are regulated, and their books and records reflect approved regulatory treatment, including certain adjustments to accumulated deferred income taxes and the establishment of a corresponding regulatory tax liability reflecting the amount payable to customers through future rates.

Investment Tax Credits

Investment tax credits have been recorded as deferred credits and are being amortized as reductions to income tax expense over the service lives of the related property.

Inventory

Tampa Electric Company values materials, supplies and fossil fuel inventory (coal, oil and natural gas) using a weighted-average cost method. These materials, supplies, and fuel inventories are carried at the lower of weighted-average cost or market, unless evidence indicates that the weighted-average cost (even if in excess of market) will be recovered with a normal profit upon sale in the ordinary course of business.

Revenue Recognition

Tampa Electric Company recognizes revenues consistent with the Securities and Exchange Commission's Staff Accounting Bulletin (SAB) 104, *Revenue Recognition in Financial Statements*. Except as discussed below, Tampa Electric Company recognizes revenues on a gross basis when earned for the physical delivery of products or services and the risks and rewards of ownership have transferred to the buyer.

The regulated utilities' (Tampa Electric and PGS) retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by FERC. See **Note 3** for a discussion of significant regulatory matters and the applicability of FAS 71 to the company.

Revenues and Cost Recovery

Revenues include amounts resulting from cost recovery clauses which provide for monthly billing charges to reflect increases or decreases in fuel, purchased power, conservation and environmental costs for Tampa Electric and purchased gas, interstate pipeline capacity and conservation costs for PGS. These adjustment factors are based on costs incurred and projected for a specific recovery period. Any over- or under-recovery of costs plus an interest factor are taken into account in the process of setting adjustment factors for subsequent recovery periods. Over-recoveries of costs are recorded as regulatory liabilities, and under-recoveries of costs are recorded as regulatory assets.

Certain other costs incurred by the regulated utilities are allowed to be recovered from customers through prices approved in the regulatory process. These costs are recognized as the associated revenues are billed. The regulated utilities accrue base revenues for services rendered but unbilled to provide a closer matching of revenues and expenses (see **Note 3**). As of Dec. 31, 2008 and 2007, unbilled revenues of $47.4 million and $46.6 million, respectively, are included in the "Receivables" line item on Tampa Electric Company's Consolidated Balance Sheets.

Tampa Electric purchases power on a regular basis primarily to meet the needs of its retail customers. Tampa Electric purchased power from non-TECO Energy affiliates at a cost of $305.4 million, $271.9 million and $221.3 million, for the years ended Dec. 31, 2008, 2007 and 2006, respectively. The prudently incurred purchased power costs at Tampa Electric have historically been recovered through an FPSC-approved cost recovery clause.

Accounting for Excise Taxes, Franchise Fees and Gross Receipts

Tampa Electric Company is allowed to recover certain costs incurred from customers through prices approved by the FPSC. The amounts included in customers' bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Statements of Income. These amounts totaled $109.2 million, $111.2 million and $104.2 million, for the years ended Dec. 31, 2008, 2007 and 2006, respectively. Franchise fees and gross receipt taxes payable by the regulated utilities are included as an expense on the Consolidated Statements of Income in "Taxes, other than income". For the years ended Dec. 31, 2008, 2007 and 2006, these totaled $109.0 million, $110.9 million and $104.0 million, respectively. Excise taxes paid by the regulated utilities are not material and are expensed as incurred.

Asset Impairments

Tampa Electric Company accounts for long-lived assets in accordance with FAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which supersedes FAS 121, *Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of*. FAS 144 addresses accounting and reporting for the impairment or disposal of long-lived assets, including the disposal of a component of a business.

In accordance with FAS 144, the company assesses whether there has been impairment of its long-lived assets and certain intangibles held and used by the company when such impairment indicators exist. As of Dec. 31, 2008, the carrying value of all long-lived assets was determined to be recoverable. No adjustments for asset impairments were recorded.

Restrictions on Dividend Payments and Transfer of Assets

Certain long-term debt at PGS contains restrictions that limit the payment of dividends and distributions on the common stock of Tampa Electric Company. See **Note 8** for additional information on significant financial covenants.

Receivables and Allowance for Uncollectible Accounts

Receivables consist of services billed to residential, commercial, industrial and other customers. An allowance for doubtful accounts is established based on Tampa Electric's and PGS's collection experience. Circumstances that could affect Tampa Electric's and PGS's estimates of uncollectible receivables include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

2. New Accounting Pronouncements

Employers' Disclosures about Postretirement Benefit Plan Assets

In December 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. Financial Accounting Standard (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 by Public Entities about Transfers of Financial Assets and Interests in Variable Interest Entities

In December 2008, the FASB issued FSP No. FAS 140-4 and FASB Interpretation (FIN) 46(R)-8, *Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities* (FSP FAS 140-4 and FIN 46(R)-8). This FSP requires additional disclosures regarding transfers of financial assets and interests in variable interest entities. The guidance in FSP FAS 140-4 and FIN 46(R)-8 was effective for reporting periods ending after Dec. 15, 2008. The company has adopted this FSP and included the additional disclosures required in this Form 10-K. These additional required disclosures have no effect on the company's results of operations, statement of position or cash flows.

Fair Value of a Financial Asset When the Market for That Asset Is Not Active

In October 2008, the FASB issued FSP No. FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active* (FSP FAS 157-3). This FSP clarifies the definition of fair value by stating that a transaction price is not necessarily indicative of fair value in a market that is not active or in a forced liquidation or distressed sale. Rather, if the company has the ability and intent to hold the asset, the company may use its assumptions about future cash flows and appropriately adjusted discount rates in measuring the fair value of the asset. The guidance in FSP FAS 157-3 was effective immediately upon issuance on Oct. 10, 2008, including prior periods for which financial statements have not been issued. The adoption of FSP FAS 157-3 was not material to the company's results of operations, statement of position or cash flows.

Disclosures about Credit Derivatives and Certain Guarantees

In September 2008, the FASB issued FSP No. FAS 133-1 and FASB Interpretation (FIN) 45-4, *Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161* (FSP FAS 133-1 and FIN 45-4). This FSP requires more detailed disclosures about credit derivatives and more detailed disclosures by sellers of credit derivatives. The guidance in FSP FAS 133-1 and FIN 45-4 is effective for reporting periods ending after Nov. 15, 2008. The additional required disclosures of FSP FAS 133-1 and FIN 45-4 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 Statement of Financial Accounting Standards (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. The company believes that FAS 161 will be significant to its financial statement disclosures and will continue to evaluate the impact through its adoption.

Additionally, in April 2008, the FASB revised Statement 133 Implementation Issues Nos. I1 and K4 to reflect the enhanced disclosures required by FAS 161. The company does not believe these revisions will be material to its results of operations, statement of position or cash flows, but will be significant to its financial statement disclosures and will continue to evaluate the impact through its adoption.

Statement 133 Implementation Issue E23

In January 2008, the FASB cleared Implementation Issue *Hedging – General: Issues Involving the Application of the Shortcut Method under Paragraph 68* (Issue E23). Issue E23 amends FAS 133, paragraph 68 to include hedged items with trade dates differing from their settlement dates due to generally established conventions in the marketplace. This allows companies to assume these commitments have no ineffectiveness in a hedging relationship, thus allowing use of the shortcut method for accounting purposes assuming all other conditions within the paragraph are met.

Issue E23 also allows use of the shortcut method if the fair value of an interest rate swap is not zero at inception of the hedge as long as the swap was entered into at the relationship's inception, there was no transaction price of the swap in the company's principal or most advantageous market, and the difference between the swap's fair value and transaction price is due to differing prices within the bid-ask spread between the entry transaction and a hypothetical exit transaction.

The effective date for Issue E23 is for hedging relationships entered into on or after Jan. 1, 2008. Issue E23 is not material to the company's results of operations, statement of position or cash flows.

Noncontrolling Interests in Consolidated Financial Statements

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements* (FAS 160). FAS 160 was issued to improve the relevance, comparability and transparency of the financial information provided by requiring: ownership interests be presented in the consolidated statement of financial position separate from parent equity; the amount of net income attributable to the parent and the noncontrolling interest be identified and presented on the face of the consolidated statement of income; changes in the parent's ownership interest be accounted for consistently; when deconsolidating, that any retained equity interest be measured at fair value; and that sufficient disclosures identify and distinguish between the interests of the parent and noncontrolling owners. The guidance in FAS 160 is effective for fiscal years beginning on or after Dec. 15, 2008. The company is currently assessing the impact of FAS 160, but does not believe it will be material to its results of operations, statement of position or cash flows.

Business Combinations (Revised)

In December 2007, the FASB issued SFAS No. 141R, *Business Combinations* (FAS 141R). FAS 141R was issued to improve the relevance, representational faithfulness, and comparability of information disclosed in financial statements about business combinations. FAS 141R establishes principles and requirements for how the acquirer: 1) recognizes and measures the assets acquired, liabilities assumed and any noncontrolling interest in the acquiree; 2) recognizes and measures the goodwill acquired; and 3) determines what information to disclose for users of financial statements to evaluate the effects of the business combination. The guidance in FAS 141R is effective prospectively for any business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after Dec. 15, 2008. The company will assess the impact of FAS 141R in the event it enters into a business combination for which the expected acquisition date is subsequent to the required effective date.

Offsetting Amounts Related to Certain Contracts

In April 2007, the FASB issued FSP FIN 39-1. This FSP amends FASB Interpretation No. 39, *Offsetting of Amounts Related to Certain Contracts* by allowing an entity to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. The guidance in this FSP is effective for fiscal years beginning after Nov. 15, 2007. The company adopted this FSP effective Jan. 1, 2008 and set a policy to offset fair value amounts recognized with cash collateral received or cash collateral paid under master netting agreements. At Dec. 31, 2008, the company had paid cash collateral and offset the value of derivative positions in the amount of $0.7 million on the consolidated balance sheet.

Fair Value Option For Financial Assets and Financial Liabilities

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities - Including an amendment of FASB Statement No. 115* (FAS 159). FAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The objective of FAS 159 is to provide opportunities to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply hedge accounting provisions. FAS 159 is effective for fiscal years beginning after Nov. 15, 2007. The company adopted FAS 159 effective Jan. 1, 2008, but did not elect to measure any financial instruments at fair value. Accordingly, its adoption did not have any effect on its results of operations, statement of position or cash flows.

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.

FAS 157, among other things, requires the company to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value, and specifies a hierarchy of valuation techniques based on whether the inputs to those valuation techniques are observable or unobservable. FAS 157 defines the following fair value hierarchy, based on these two types of inputs:

- <u>Level 1</u> – Quoted prices for identical instruments in active markets.
- <u>Level 2</u> – Quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model derived valuations in which all significant inputs and significant value drivers are observable in active markets.
- <u>Level 3</u> – Model derived valuations in which one or more significant inputs or significant value drivers are unobservable.

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 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. See **Note 13, Fair Value Measurements.**

Additionally, the FASB issued FSP 157-1 in February 2008 to exclude SFAS 13, *Accounting for Leases*, and related pronouncements addressing lease fair value measurements from the scope of FAS 157. Assets and liabilities assumed in a business combination are not covered under this scope exception. The effective date of this FSP coincides with the adoption of FAS 157.

The company does not believe applying FAS 157 to the remaining non-financial assets and liabilities effective Jan. 1, 2009 will be material to 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 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 and PGS

Tampa Electric's rates and allowed return on equity (ROE) range of 10.75% to 12.75%, with a midpoint of 11.75%, are 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.

Tampa Electric had not sought a base rate increase since 1992. Since that last rate proceeding, it had earned within its allowed ROE range while adding more than 200,000 customers and making significant investments in facilities and infrastructure. These facilities include baseload, intermediate and peaking generating capacity additions to reliably serve the growing customer base. Tampa Electric expects a continued high level of capital investment, and higher levels of non-fuel operations and maintenance expenditures. As a result of lower customer growth, lower energy sales growth, and ongoing high levels of capital investment, Tampa Electric's 13-month average regulatory ROE was 8.7% at the end of 2008.

Recognizing the significant decline in ROE, Tampa Electric filed for a $228 million base rate increase in August 2008. The major factors in the filing included a request for an ROE mid-point of 12%, 55% equity in the capital structure, and a rate base of $3.657 billion. The formal hearings before the FPSC were held in late January and the FPSC is scheduled to make its final decision on the requested increase in mid-March, with final rates effective in May 2009.

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.

At the end of 2007, PGS' 13-month average regulatory ROE was below the bottom of its allowed range as a result of higher operating costs, continued investment in the distribution system and higher costs associated with required safety requirements, such as transmission and distribution pipeline integrity management.

Recognizing the significant decline in ROE, PGS filed for a $26.5 million base rate increase in August 2008. 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 are scheduled to be held in March and the FPSC is scheduled to make its final decision on the requested increase in May, with final rates effective in June 2009.

Cost Recovery – Tampa Electric and PGS

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 cost recovery 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 include the cost for natural gas and coal expected in 2009, the net recovery of $132.9 million of fuel and purchased power expenses, which were not collected in 2008 and underestimated in 2007, the net over-recovery of $4.7 million of costs recovered through the ECRC for the 2007 and 2008 periods, and the operating cost for and a return on the capital invested in the third SCR project to enter service at the Big Bend Station as well as the operations and maintenance expense associated with the projects as required by the EPA Consent Decree and FDEP Consent Final Judgment. The rates also reflect an additional disallowance of $3.0 million to settle all outstanding issues associated with the 2004 fuel transportation contract. 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. Accordingly, Tampa Electric's residential customer rate per 1,000 kilowatt-hours increased $14.06 from $114.38 in 2008 to $128.44 in 2009.

The FPSC determined 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 Unit 4 and Big Bend Units 1-3 in October 2004 and May 2005, respectively, for NOx control in compliance with the environmental consent decree. The SCR for Big Bend Unit 4 entered service in May 2007 and cost recovery started in 2007. The SCR for Big Bend Unit 3 entered service in May 2008 and cost recovery started in 2008. The SCRs for Big Bend Units 2 and 1 are scheduled to enter service by May 1, 2009 and 2010, respectively. Cost recovery for the capital investment for each unit, which is dependent on filings made in the year each SCR enters service, is expected to start in 2009 and 2010, respectively.

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 its 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.

SO_2 Emission Allowances

The Clean Air Act established SO_2 allowances to manage the achievement of SO_2 emissions requirements. The legislation also established a market-based SO_2 allowance trading component.

An allowance authorizes a utility to emit one ton of SO_2 during a given year. The EPA allocates allowances to utilities based on mandated emissions reductions. Allowances may not be used for compliance prior to the calendar year for which they are allocated. At the end of each year, a utility must hold an amount of allowances at least equal to its annual emissions. Tampa Electric accounts for the allocated allowances using an inventory model with a zero basis, since they are granted to the company at no cost.

Allowances are fully marketable and, once allocated, may be bought, sold, traded or banked for use in current or future years. In addition, the EPA withholds a small percentage of the annual SO_2 allowances it allocates to utilities for auction sales. Any resulting auction proceeds are then forwarded to the respective utilities.

Over the years, Tampa Electric has acquired allowances through EPA allocations and has sold unneeded allowances based on compliance and allowances available. The SO_2 allowances unneeded and sold resulted from lower emissions at Tampa Electric brought about by environmental actions taken by the company under the Clean Air Act.

For the year ended Dec. 31, 2008, Tampa Electric received $11.9 million in allowance proceeds, $11.2 million resulting from the sale of approximately 119,000 allowances and EPA auction proceeds of $0.7 million. In the year ended Dec. 31, 2007 Tampa Electric received $90.5 million in allowance proceeds, $89.7 million resulting from the sale of approximately 168,000 allowances and EPA auction proceeds of $0.8 million. In the year ended Dec 31, 2006 Tampa Electric received $44.8 million in allowance proceeds, $43.4 million resulting from the sale of approximately 44,500 allowances and auction proceeds of $1.4 million

Tampa Electric recognizes a gain at the time of sale, approximately 95% of which accrues to retail customers through the environmental cost recovery clause. These gains are reflected in Revenues on the Consolidated Statements of Income.

Other Items

Storm Damage Cost Recovery

Tampa Electric accrues $4 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. During 2008, $1.6 million in net costs related to Tropical Storm Fay were charged to the reserve. Tampa Electric's storm reserve was $22.7 million and $20.3 million as of Dec. 31, 2008 and 2007, respectively.

Coal Transportation Contract

In September 2004, the FPSC voted to disallow a portion of the costs that Tampa Electric could recover from its customers for water transportation services under a five year transportation agreement ending Dec. 31, 2008. This agreement was with an affiliate prior to its sale in December 2007. The amounts disallowed, and excluded from the recovery under the fuel adjustment clause, were $17.4 million, $15.1 million and $15.3 million for the years ended Dec. 31, 2008, 2007 and 2006, respectively. The 2008 amount includes $3.0 million to settle a dispute arising in 2008 regarding the calculation of the disallowance over the entire five year period.

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. 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. Details of the regulatory assets and liabilities as of Dec. 31, 2008 and 2007 are presented in the following table:

Regulatory Assets and Liabilities

(millions)	*Dec. 31, 2008*	*Dec. 31, 2007*
Regulatory assets:		
Regulatory tax asset (1)	$ 65.1	$ 62.5
Other:		
Cost recovery clauses	266.8	47.2
Post-retirement benefit asset	220.3	97.5
Deferred bond refinancing costs (2)	21.7	25.5
Environmental remediation	10.8	11.4
Competitive rate adjustment	4.7	5.4
Other	8.5	4.7
Total other regulatory assets	532.8	191.7
Total regulatory assets	597.9	254.2
Less: Current portion	272.6	67.4
Long-term regulatory assets	$ 325.3	$ 186.8
Regulatory liabilities:		
Regulatory tax liability (1)	$ 17.5	$ 18.8
Other:		
Deferred allowance auction credits	-	0.1
Cost recovery clauses	3.4	18.9
Environmental remediation	10.6	11.4
Transmission and delivery storm reserve	22.7	20.3
Deferred gain on property sales (3)	4.1	4.7
Accumulated reserve-cost of removal	551.2	543.5
Other	0.4	0.4
Total other regulatory liabilities	592.4	599.3
Total regulatory liabilities	609.9	618.1
Less: Current portion	21.7	35.4
Long-term regulatory liabilities	$ 588.2	$ 582.7

(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) Dec. 31,	*2008*	*2007*
Clause recoverable (1)	$ 271.5	$ 52.6
Components of rate base (2)	227.7	101.7
Regulatory tax assets (3)	65.1	62.5
Capital structure and other (3)	33.6	37.4
Total	$ 597.9	$ 254.2

(1) To be recovered through cost recovery clauses approved by the FPSC on a dollar-for-dollar basis in the next year. The increase between years is principally due to higher 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 bond refinancing costs which are amortized over the life of the related debt instruments. See footnotes (1) and (2) in the prior table for additional information.

4. Income Tax Expense

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 twelve months ended Dec. 31, 2008 and 2007 differ from the statutory rate principally due to state income taxes, amortization of investment tax credits and the domestic activity production deduction. The increase in the effective tax rate between the years is principally due to higher permanent differences including a decrease in the domestic activity production and lower investment tax credit.

In June 2006, the FASB issued FIN 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109, Accounting for Income Taxes*. FIN 48 addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, Tampa Electric Company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. FIN 48 provides that the tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures.

Tampa Electric Company adopted the provisions of FIN 48 effective Jan. 1, 2007 with no impact. Tampa Electric Company recognizes accrued interest and penalties associated with uncertain tax positions in "Operation other expense – other" in the Consolidated Statements of Income. For the twelve months ended Dec. 31, 2008, Tampa Electric Company did not record any amounts of interest or penalties.

The Internal Revenue Service (IRS) concluded its examination of federal income tax returns for the years 2007 during the year ended 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. 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 jurisdictions include 2005 and onward.

Tampa Electric 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 within the next twelve months.

Income tax expense consists of the following components:

Income Tax Expense

(millions)	*Federal*	*State*	*Total*
2008			
Currently payable	$ 18.8	$ 5.5	$ 24.3
Deferred	67.0	8.8	75.8
Amortization of investment tax credits	(0.9)	—	(0.9)
Total income tax expense	$ 84.9	$ 14.3	$ 99.2
Included in other income, net			(1.4)
Included in operating expenses			$ 97.8
2007			
Currently payable	$ 128.5	$ 21.2	$ 149.7
Deferred	(39.2)	(6.4)	(45.6)
Amortization of investment tax credits	(2.5)	—	(2.5)
Total income tax expense	$ 86.8	$ 14.8	$ 101.6
Included in other income, net			(1.8)
Included in operating expenses			$ 99.8
2006			
Currently payable	$ 107.4	$ 17.4	$ 124.8
Deferred	(20.3)	(2.9)	(23.2)
Amortization of investment tax credits	(2.5)	—	(2.5)
Total income tax expense	$ 84.6	$ 14.5	$ 99.1
Included in other income, net			(2.3)
Included in operating expenses			$ 96.8

Deferred taxes result from temporary differences in the recognition of certain liabilities or assets for tax and financial reporting purposes. The principal components of Tampa Electric Company's deferred tax assets and liabilities recognized in the balance sheet are as follows:

Deferred Income Tax Assets and Liabilities

(millions) As of Dec. 31,	*2008*	*2007*
Deferred income tax assets [(1)]		
Medical benefits	$ 47.6	$ 44.0
Insurance reserves	20.5	18.7
Investment tax credits	7.0	7.5
Hedging activities	4.3	3.2
Pension and post-retirement benefits	85.0	37.6
Other	10.7	27.3
Total deferred income tax assets	175.1	138.3
Deferred income tax liabilities [(1)]		
Property related	(521.4)	(494.0)
Deferred fuel	(52.9)	(14.6)
Pension and post-retirement benefits	(85.0)	(37.5)
Total deferred income tax liabilities	(659.3)	(546.1)
Net deferred income tax liability	$ (484.2)	$ (407.8)

(1) Certain property related assets and liabilities have been netted.

Deferred income tax assets and liabilities above are included in the balance sheet as follows:

(millions) As of Dec. 31,	***2008***	***2007***
Current deferred tax liabilities	$ (36.6)	$ (0.3)
Non-current deferred tax liabilities	(447.6)	(407.5)
Total	$ (484.2)	$ (407.8)

The total income tax provisions differ from amounts computed by applying the federal statutory tax rate to income before income taxes for the following reasons:

Effective Income Tax Rate

(millions)	***2008***	***2007***	***2006***
Net income	$ 162.7	$ 176.8	$ 165.6
Total income tax provision	99.2	101.6	99.1
Income before income taxes	$ 261.9	$ 278.4	$ 264.7
Income taxes on above at federal statutory rate of 35%	$ 91.7	$ 97.4	$ 92.7
Increase (decrease) due to			
State income tax, net of federal income tax	9.3	9.5	9.4
Equity portion of AFUDC	(2.2)	(1.5)	(1.0)
Domestic production deduction	—	(2.8)	(1.5)
Other	0.4	(1.0)	(0.5)
Total income tax provision	$ 99.2	$ 101.6	$ 99.1
Provision for income taxes as a percent of income from continuing operations, before income taxes	37.9%	36.5%	37.4%
Consolidated Statements of Cash Flows			
Cash paid during the year for income taxes	$ 18.4	$ 135.0	$ 100.1

5. Employee Postretirement Benefits

In September 2006, the FASB issued FAS No.158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R).* The company adopted FAS 158 on Dec. 31, 2006. This standard requires the recognition in the statement of financial position the over-funded or under-funded status of a defined benefit postretirement plan, measured as the difference between the fair value of plan assets and the projected benefit obligation (PBO) in the case of a defined benefit plan, or the accumulated postretirement benefit obligation (APBO) in the case of other postretirement benefit plans. As a result of the application of FAS 71 to the impacts of FAS 158, Tampa Electric Company increased both benefit liabilities and regulatory assets. This standard did not affect the results of operations.

Pension Benefits

Tampa Electric Company is a participant in the comprehensive retirement plans of TECO Energy, including a non-contributory defined benefit retirement plan which covers substantially all employees. Where appropriate and reasonably determinable, the portion of expenses, income, gains or losses allocable to Tampa Electric Company are presented. Otherwise, such amounts presented reflect the amount allocable to all participants of the TECO Energy retirement plans. Benefits are based on employees' age, years of service and final average earnings.

The Pension Protection Act of 2006 (PPA), became effective Jan. 1, 2008 and requires companies to, among other things, maintain certain defined minimum funding thresholds (or face plan benefit restrictions), pay higher premiums to the Pension Benefit Guaranty Corporation if they sponsor defined benefit plans, amend plan documents and provide additional plan disclosures in regulatory filings and to plan participants.

The Worker, Retiree, and Employer Recovery Act of 2008 (WRERA) was signed into law on Dec. 23, 2008. WRERA grants plan sponsors relief from certain funding requirements and benefit restrictions, and also provides some technical corrections to the PPA. There are two primary provisions that impact funding results for TECO Energy. First, for plans funded less than 100%, required shortfall contributions will be based on a percentage of the funding target until 2011, rather than the funding target of 100%. These percentages are 92%, 94% and 96% in 2008, 2009 and 2010, respectively. Second, one of the technical corrections, referred to as asset smoothing, allows the use of asset averaging subject to certain limitations in the determination of funding requirements. The Jan. 1, 2009 estimate assumes adoption of the asset smoothing methodology under WRERA and includes an additional 2008 plan year contribution expected to be made in 2009.

For the year ended Dec. 31, 2008, TECO Energy's pension plan experienced actual negative asset returns of approximately 22%. These negative returns during 2008 were a primary driver in causing significant actuarial losses for the year ended Dec. 31, 2008. The qualified pension plan's actuarial value of assets, including credit balance, was 105.6% of the PPA funded target as of Jan. 1, 2008 and is estimated at 90% of the PPA funded target as of Jan. 1, 2009.

Amounts disclosed for pension benefits also include the unfunded obligations for the supplemental executive retirement plans. These are non-qualified, non-contributory defined benefit retirement plans available to certain members of senior management. In 2008, Tampa Electric Company made a contribution of $1.0 million to these plans.

Reconciliations of the funded status and the accrued pension liability and components of net pension expense for TECO Energy, Inc. are presented below.

TECO Energy Consolidated	Pension Benefits	
Obligations and Funded Status		
(millions)	**2008**	**2007**
Change in benefit obligation		
Net benefit obligation at prior measurement date (1)	$ 557.2	$ 569.9
Effect of eliminating early measurement date	4.8	n/a
Service cost	15.4	16.0
Interest cost	31.9	33.0
Plan participants' contributions	-	-
Actuarial (gain) loss	3.3	(21.9)
Plan amendments	-	0.3
Curtailment	-	(6.1)
Special termination benefits	-	0.6
Gross benefits paid	(54.5)	(34.6)
Settlements	(2.7)	-
Federal subsidy on benefits paid	n/a	n/a
Net benefit obligation at measurement date (1)	$ 555.4	$ 557.2
Change in plan assets		
Fair value of plan assets at prior measurement date	$ 492.7	$ 435.2
Effect of eliminating early measurement date	28.4	n/a
Actual return on plan assets (2)	(119.1)	56.6
Employer contributions	15.9	35.5
Plan participants' contributions	-	-
Settlement	(2.7)	-
Gross benefits paid	(54.5)	(34.6)
Fair value of plan assets at measurement date (1)	$ 360.7	$ 492.7
Funded status		
Fair value of plan assets (3)	$ 360.7	$ 492.7
Benefit obligation (PBO)	555.4	557.2
Funded status at measurement date	(194.7)	(64.5)
Net contributions after measurement date	-	26.1
Unrecognized net actuarial loss	237.2	81.9
Unrecognized prior service (benefit) cost	(2.7)	(3.2)
Unrecognized net transition (asset) obligation	-	-
Accrued liability at end of year	$ 39.8	$ 40.3
Amounts Recognized In Balance Sheet		
Long-term regulatory assets	$ 186.3	$ 57.2
Accrued benefit costs and other current liabilities	(1.8)	(4.5)
Deferred credits and other liabilities	(193.0)	(34.0)
Accumulated other comprehensive (income) loss pretax	48.3	21.6
Net amount recognized at end of year	$ 39.8	$ 40.3

(1) The measurement dates were Dec. 31, 2008 and Sep. 30, 2007. In accordance with FAS 158, the company moved to a year-end measurement date effective Dec. 31, 2008 under the 15-month transition approach.
(2) The actual return on plan assets differed from expectations due to the general market decline.
(3) The Market Related Value (MRV) of plan assets is used as the basis for calculating the expected return on plan assets (EROA) component of periodic pension expense. MRV reflects the fair value of plan assets adjusted for experience gains and losses (i.e. the differences between actual investment returns and expected returns) spread over five years.

Tampa Electric Company	**Pension Benefits 2008**	**2007**
Amounts recognized in balance sheet *(millions)*		
Long-term regulatory assets	$ 186.3	$ 57.2
Accrued benefit costs and other current liabilities	(1.1)	(1.0)
Deferred credits and other liabilities	(152.0)	(22.8)
Net amount recognized at end of year	$ 33.2	$ 33.4

The accumulated benefit obligation for all defined benefit pension plans was $504.9 million at Dec. 31, 2008 and $493.0 million at Sep. 30, 2007 (the measurement dates), respectively.

Assumptions used to determine benefit obligations at Dec. 31 for 2008 and Sep. 30 for 2007:

	Pension Benefits 2008	**2007**
Discount rate	6.05%	6.20%
Rate of compensation increase	4.25%	4.25%

Components of TECO Energy consolidated Net Periodic Benefit Cost

Net periodic benefit cost: *(millions)*	**Pension Benefits 2008** (1)	**2007** (2)	**2006** (2)
Service cost	$ 15.4	$ 16.0	$ 15.8
Interest cost	31.9	33.0	30.7
Expected return on plan assets	(39.0)	(36.3)	(35.7)
Amortization of:			
Actuarial loss	4.0	9.1	8.8
Prior service (benefit) cost	(0.4)	(0.5)	(0.5)
Transition (asset) obligation	-	--	-
Curtailment (gain) loss	-	(0.4)	-
Settlement (gain) loss	0.9	-	-
Net periodic benefit cost	$ 12.8	$ 20.9	$ 19.1

(1) Benefit Cost was measured for the twelve months ended Dec. 31, 2008. The company elected a 15-month transition approach allowed by FAS 158 to move from an early measurement date of Sep. 30, 2007 to a year end measurement date of Dec. 31, 2008. In connection with this election, TECO Energy recorded after-tax charges to Retained Earnings of $2.2 million for Pensions in the fourth quarter of 2008; Tampa Electric's portion was $1.3 million.

(2) Benefit Cost was measured for the twelve months ended Sep. 30.

In addition to the costs shown above, $0.6 million of special termination benefit costs were recognized in 2007. Tampa Electric Company's portion of the net periodic benefit costs was $8.4 million, $14.1 million and $13.6 million for 2008, 2007 and 2006, respectively.

The estimated net loss and prior service net (benefits) for the defined benefit pension plans that will be amortized by Tampa Electric Company from regulatory assets into net periodic benefit cost over the next fiscal year total $5.3 million.

Assumptions used to determine net periodic benefit cost for years ended Dec. 31,

	Pension Benefits		
	2008	2007	2006
Discount rate	6.20%	5.85%	5.50%
Expected long-term return on plan assets	8.25%	8.25%	8.50%
Rate of compensation increase	4.25%	4.00%	3.75%

The discount rate assumption was based on a cash flow matching technique developed by our outside actuaries and a review of current economic conditions. This technique matches the yields from high-quality (Aa-graded, non-callable) corporate bonds to the company's projected cash flows for the pension plan to develop a present value that is converted to a discount rate.

The expected return on assets assumption was based on expectations of long-term inflation, real growth in the economy, fixed income spreads, and equity premiums consistent with our portfolio, with provision for active management and expenses paid.

The compensation increase assumption was based on the same underlying expectation of long-term inflation together with assumptions regarding real growth in wages and company-specific merit and promotion increases.

Asset Allocation

Pension plan assets (plan assets) are invested in a mix of equity and fixed income securities. The company's investment objective is to obtain above-average returns while minimizing volatility of expected returns over the long term. The target equities/fixed income mix is designed to meet investment objectives. The company's strategy is to hire proven managers and allocate assets to reflect a mix of investment styles, emphasize preservation of principal to minimize the impact of declining markets, and stay fully invested except for cash to meet benefit payment obligations and plan expenses.

Pension Plan Assets	**Target Allocation**	**Actual Allocation, End of Year**	
Asset Category		**2008**	**2007**
Equity securities	55-65%	56%	64%
Fixed income securities	35-45%	44%	36%
Total		100%	100%

The company reviews the plan's asset allocation periodically and re-balances the investment mix to maximize asset returns, optimize the matching of investment yields with the plan's expected benefit obligations, and minimize pension cost.

Contributions

TECO Energy's policy is to fund the qualified pension plan at or above amounts determined by its actuaries to meet ERISA guidelines for minimum annual contributions and minimize PBGC premiums paid by the plan. TECO Energy contributed $11.7 million to this plan in 2008 and $30.0 million in 2007, which met the minimum funding requirements for both 2008 and 2007. Tampa Electric's portion of the contribution made to this non-contributory defined benefit plan in 2008 was $9.5 million.

TECO Energy expects to make an $11 million contribution to the qualified pension plan in 2009 and estimates annual minimum contributions to range from $25 - $40 million per year in 2010 to 2013 based on current assumptions. Tampa Electric's portion of the contribution to the qualified pension plan to be made in 2009 is estimated at $8.8 million.

Other Postretirement Benefits

TECO Energy and its subsidiaries currently provide certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 meeting certain service requirements. Tampa Electric Company's contribution toward health care coverage for most employees who retired after the age of 55 between Jan. 1, 1990 and Jun. 30, 2001 is limited to a defined dollar benefit based on service. The company contribution toward pre-65 and post-65 health care coverage for most employees retiring on or after Jul. 1, 2001 is limited to a defined dollar benefit based on an age and service schedule. In 2009, the company expects to make a contribution of about $9.6 million to this program. Postretirement benefit levels are substantially unrelated to salary. The company reserves the right to terminate or modify the plans in whole or in part at any time.

In 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the MMA) was signed into law. Beginning in 2006, the new law added prescription drug coverage to Medicare, with a 28% tax-free subsidy to encourage employers to retain their prescription drug programs for retirees, along with other key provisions. TECO Energy's current retiree medical program for those eligible for Medicare (generally over age 65) includes coverage for prescription drugs. The company has determined that prescription drug benefits available to certain Medicare-eligible participants under its defined-dollar-benefit postretirement health care plan are at least "actuarially equivalent" to the standard drug benefits to be offered under Medicare Part D.

In 2004, the FASB issued FSP 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* (FSP 106-2). The guidance in FSP 106-2 requires (a) that the effects of the federal subsidy be considered an actuarial gain and recognized in the same manner as other actuarial gains and losses and (b) certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits. TECO Energy and its subsidiaries adopted FSP 106-2 retroactive for the second quarter of 2004.

The company received subsidy payments under Part D for the 2006 and 2007 plan years. Its 2008 Part D subsidy application with the Centers for Medicare and Medicaid Services (CMS) was approved in February 2009 and the company expects to receive the payment later this year.

The following charts summarize the balance sheet and income statement impacts for Tampa Electric Company, as well as the benefit obligations, assets and funded status.

Obligations and Funded Status-Other Postretirement Benefits

(millions)	2008	2007
Change in benefit obligation		
Net benefit obligation at prior measurement date (1)	$ 143.2	$ 145.6
Effect of eliminating early measurement date	0.5	n/a
Service cost	2.2	2.3
Interest cost	8.7	8.3
Plan participants' contributions	2.7	2.6
Actuarial (gain) loss	(3.1)	(3.4)
Curtailment	-	(1.5)
Gross benefits paid	(10.5)	(11.5)
Federal subsidy on benefits paid	0.7	0.8
Net benefit obligation at measurement date (1)	$ 144.4	$ 143.2
Change in plan assets		
Employer contributions	$ 7.8	$ 8.9
Plan participants' contributions	2.7	2.6
Gross benefits paid	(10.5)	(11.5)
Fair value of plan assets at measurement date (1)	$ -	$ -
Funded status		
Fair value of plan assets	$ -	$ -
Benefit obligation (APBO)	144.4	143.2
Funded status at measurement date (1)	(144.4)	(143.2)
Net contributions after measurement date	-	2.2
Unrecognized net actuarial loss	18.4	20.9
Unrecognized prior service (benefit) cost	8.7	10.3
Unrecognized net transition (asset) obligation	6.9	9.1
Accrued liability at end of year	$ (110.4)	$ (100.7)
Amounts Recognized in Balance Sheet		
Long-term regulatory assets	$ 34.0	$ 40.3
Current liabilities	(10.1)	(10.2)
Non-current liabilities	(134.3)	(130.8)
Accumulated other comprehensive income	n/a	n/a
Net amount recognized at end of year	$ (110.4)	$ (100.7)

(1) The measurement dates were Dec. 31, 2008 and Sep. 30, 2007.

Assumptions used to determine benefit obligations at Dec. 31 for 2008 and Sep. 30 for 2007:

	Other Benefits	
	2008	2007
Discount rate	6.05%	6.20%
Rate of compensation increase	4.25%	4.25%
Healthcare cost trend rate		
Initial rate	8.50%	9.25%
Ultimate rate	5.00%	5.25%
Year rate reaches ultimate	2015	2015

A one-percentage-point change in assumed health care cost trend rates would have the following effect on the benefit obligation:

(millions)	1% Increase	1% Decrease
Effect on postretirement benefit obligation	$ 3.1	$ (2.6)

The estimated prior service cost and transition obligation for the other postretirement benefit plans that will be amortized at Tampa Electric Company from regulatory assets into net periodic benefit cost over the next fiscal year is $2.8 million.

Components of Net Periodic Other Postretirement Benefit Cost

Net periodic benefit cost *(millions)*:	2008 (1)	2007 (2)	2006 (2)
Service cost	$ 2.2	$ 2.3	$ 2.3
Interest cost	8.7	8.3	7.7
Amortization of:			
Actuarial loss	-	-	0.4
Prior service (benefit) cost	1.2	1.7	1.7
Transition (asset) obligation	1.8	2.2	2.1
Net periodic benefit cost	$ 13.9	$ 14.5	$ 14.2

(1) Benefit Cost was measured for the twelve months ended Dec. 31, 2008. The company elected a 15-month transition approach allowed by FAS 158 to move from an early measurement date of Sep. 30, 2007 to a year end measurement date of Dec. 31, 2008. In connection with this election, the company recorded after-tax charges to Retained Earnings of $2.1 million for Other Postretirement Benefits in the fourth quarter of 2008.

(2) Benefit Cost was measured for the twelve months ended Sep. 30.

Assumptions used to determine net periodic benefit cost for years ended Dec. 31,

		Other Benefits	
	2008	2007	2006
Discount rate	6.20%	5.85%	5.50%
Expected long-term return on plan assets	n/a	n/a	n/a
Rate of compensation increase	4.25%	4.00%	3.75%
Healthcare cost trend rate			
Initial rate	9.25%	9.50%	9.50%
Ultimate rate	5.25%	5.25%	5.00%
Year rate reaches ultimate	2015	2015	2013

The discount rate assumption was based on a cash flow matching technique developed by our outside actuaries and a review of current economic conditions. This technique matches the yields from high-quality (Aa-graded, non-callable) corporate bonds to the company's projected cash flows for the benefit plans to develop a present value that is converted to a discount rate.

The compensation increase assumption was based on the same underlying expectation of long-term inflation together with assumptions regarding real growth in wages and company-specific merit and promotion increases.

A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(millions)	1% Increase	1% Decrease
Effect on periodic cost	$ 0.2	$ (0.2)

Other Postretirement Benefit Plan Assets

There are no assets associated with Tampa Electric Company's other postretirement benefits plan.

Benefit Payments

Information about TECO Energy's expected benefit payments for the pension and postretirement benefit plans follows:

Expected Benefit Payments - TECO Energy Consolidated (including projected service and net of employee contributions)	**Pension Benefits**	**Other Postretirement Benefits**	
Expected benefit payments *(millions)*:		Gross	Expected Federal Subsidy
2009	$ 44.8	$ 13.4	$ (1.1)
2010	$ 46.3	$ 14.3	$ (1.2)
2011	$ 47.6	$ 15.1	$ (1.4)
2012	$ 48.7	$ 15.5	$ (1.5)
2013	$ 49.8	$ 15.6	$ (1.7)
2014-2018	$ 269.2	$ 78.2	$ (10.3)

Defined Contribution Plan

The company has a defined contribution savings plan covering substantially all employees of TECO Energy and its subsidiaries (the Employers) that enables participants to save a portion of their compensation up to the limits allowed by IRS guidelines. The company and its subsidiaries match up to 6% of the participant's payroll savings deductions. Effective July 2004, employer matching contributions were 30% of eligible participant contributions with additional incentive match of up to 70% of eligible participant contributions based on the achievement of certain operating company financial goals. In April 2007, the employer matching contributions were changed to 50% of eligible participant contributions with an additional incentive match of up to 50%. For the years ended Dec. 31, 2008, 2007 and 2006, Tampa Electric Company recognized expense totaling $5.1 million, $5.8 million and $4.5 million, respectively, related to the matching contributions made to this plan.

6. Short-Term Debt

At Dec. 31, 2008 and 2007, the following credit facilities and related borrowings existed:

Credit Facilities	*Dec. 31, 2008*			*Dec. 31, 2007*		
(millions)	*Credit Facilities*	*Borrowings Outstanding*[1]	*Letters of Credit Outstanding*	*Credit Facilities*	*Borrowings Outstanding*	*Letters of Credit Outstanding*
Recourse:						
Tampa Electric Company:						
5-year facility	$ 325.0	$ —	$ 1.4	$ 325.0	$ —	$ —
1-year accounts receivable facility	150.0	29.0	—	150.0	25.0	—
Total	$ 475.0	$ 29.0	$ 1.4	$ 475.0	$ 25.0	$ —

(1)Borrowings outstanding are reported as notes payable.

These credit facilities require commitment fees ranging from 9.0 – 125.0 basis points. The weighted average interest rate on outstanding notes payable at Dec. 31, 2008 and 2007 was 2.13% and 4.76%, respectively.

Tampa Electric Company Accounts Receivable Facility

On Dec. 18, 2008, Tampa Electric Company and TEC Receivables Corp. (TRC), a wholly-owned subsidiary of Tampa Electric Company, amended their $150 million accounts receivable collateralized borrowing facility, entering into Amendment No. 6 to the Loan and Servicing Agreement with certain lenders named therein and Citicorp North America, Inc. as Program Agent. The amendment (i) extends the maturity date to Dec. 17, 2009, (ii) provides that TRC will continue to pay program and liquidity fees based on Tampa Electric Company's credit ratings, which pursuant to the amendment, will total 175 basis points at Tampa Electric Company's current ratings, (iii) provides that the interest rates on the borrowings will be based on prevailing asset-backed commercial paper rates, unless such rates are not available from conduit lenders, or under certain circumstances upon a change of accounting rules applicable to the lenders, in which case the rates will be at an interest rate equal to, at Tampa Electric Company's option, either Citibank's prime rate (or the federal funds rate plus 50 basis points, if higher) or a rate based on the London interbank offer rate (if available) plus a margin and (iv) makes other technical changes.

7. Common Stock

Tampa Electric Company is a wholly owned subsidiary of TECO Energy, Inc.

	Common Stock		*Issue*	
(millions, except shares)	*Shares*	*Amount*	*Expense*	*Total*
Balance Dec. 31, 2008 (1)	10	$ 1,802.4	$ —	$ 1,802.4
Balance Dec. 31, 2007 (1)	10	$ 1,510.4	$ —	$ 1,510.4

(1) TECO Energy, Inc. made equity contributions to Tampa Electric of $292.0 million and $81.8 million in 2008 and 2007, respectively, to support capital needs associated with generation expansion and environmental projects.

8. Commitments and Contingencies

Legal Contingencies

From time to time, Tampa Electric Company is involved in various other 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 Dec. 31, 2008, Tampa Electric Company has estimated its ultimate financial liability to be approximately $10.7 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 or changes in laws or regulations that could require additional remediation. These costs are recoverable through customer rates established in subsequent base rate proceedings.

Long-Term Commitments

Tampa Electric Company has commitments under long-term leases, primarily for building space, capacity payments, office equipment and heavy equipment. Total rental expense included in the Consolidated Statements of Income for the years ended Dec. 31, 2008, 2007 and 2006 was $2.0 million, $1.9 million and $4.2 million, respectively.

The following table is a schedule of future minimum lease payments at Dec. 31, 2008 for all leases with non-cancelable lease terms in excess of one year:

Future Minimum Lease Payments

(millions)	*Capacity Payments [1]*	*Operating Leases*	*Total*
Year ended Dec. 31:			
2009	$ 8.4	$ 2.2	$ 10.6
2010	8.6	2.1	10.7
2011	8.8	2.0	10.8
2012	8.9	2.1	11.0
2013	9.1	2.0	11.1
Thereafter	48.5	22.9	71.4
Total future minimum lease payments	$ 92.3	$ 33.3	$ 125.6

(1) This schedule includes the fixed capacity payments required under a capacity and tolling agreement of Tampa Electric which commenced Jan. 1, 2009. In accordance with the provisions of EITF 01-08, *Determining Whether an Arrangement Contains a Lease*, the company evaluated the agreement and concluded based on the criteria that the agreement met the lease definition. Prudently incurred capacity payments are recoverable under an FPSC-approved cost recovery clause (See **Note 3**).

Guarantees and Letters of Credit

On Jan. 1, 2003, Tampa Electric Company adopted the prospective initial measurement provisions for certain types of guarantees, in accordance with FASB Interpretation No. (FIN) 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others (an interpretation of FASB Statements No. 5, 57, and 107 and rescission of FASB Interpretation No. 34).* Upon issuance or modification of a guarantee after Jan. 1, 2003, Tampa Electric Company must determine if the obligation is subject to either or both of the following:

- Initial recognition and initial measurement of a liability; and/or
- Disclosure of specific details of the guarantee.

Generally, guarantees of the performance of a third party or guarantees that are based on an underlying (where such a guarantee is not a derivative subject to FAS 133) are likely to be subject to the recognition and measurement, as well as the disclosure provisions, of FIN 45. Such guarantees must initially be recorded at fair value, as determined in accordance with the interpretation.

Alternatively, guarantees between and on behalf of entities under common control or that are similar to product warranties are subject only to the disclosure provisions of the interpretation. The company must disclose information as to the term of the guarantee and the maximum potential amount of future gross payments (undiscounted) under the guarantee, even if the likelihood of a claim is remote. At Dec. 31, 2008, 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.

At Dec. 31, 2008, 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 Dec. 31, 2008*
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.

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 Dec. 31, 2008, Tampa Electric Company was in compliance with required financial covenants.

9. Related Party Transactions

In January 2006, Tampa Electric purchased two 150-megawatt combustion turbines and other ancillary equipment from TPS McAdams for $20.6 million. This has been included in capital expenditures on the Tampa Electric Company **Consolidated Statements of Cash Flows** for the period ended Dec. 31, 2006.

In October 2003, Tampa Electric signed a five-year contract renewal with an affiliate company, TECO Transport, for integrated waterborne fuel transportation services effective Jan. 1, 2004. The contract called for inland river and ocean transportation along with river terminal storage and blending services for up to 5.5 million tons of coal annually through 2008. In December 2007, TECO Energy sold TECO Transport to an unaffiliated party.

A summary of activities between Tampa Electric Company and its affiliates follows:

Net transactions with affiliates:			
(millions)	*2008*	*2007*	*2006*
Fuel and interchange related, net[2]	$ —	$ 93.2	$ 103.1
Administrative and general, net	$ 21.0	$ 19.6	$ 14.5
Amounts due from or to affiliates of the company at Dec. 31,			
(millions)	*2008*	*2007*	
Accounts receivable [1]	$ 1.5	$ 0.7	
Accounts payable [1]	$ 6.9	$ 5.5	

(1) Accounts receivable and accounts payable were incurred in the ordinary course of business and do not bear interest.
(2) Amounts related to the transportation, transfer and storage of coal by TECO Transport.

10. Segment Information

Tampa Electric Company is a public utility operating within the state of Florida. Through its Tampa Electric division, it is engaged in the generation, purchase, transmission, distribution and sale of electric energy to more than 667,000 customers in West Central Florida. Its Peoples Gas System division is engaged in the purchase, distribution and marketing of natural gas for more than 335,000 residential, commercial, industrial and electric power generation customers in the state of Florida.

Segment Information

(millions)	*Tampa Electric*	*Peoples Gas*	*Other & eliminations*	*Tampa Electric Company*
2008				
Revenues – outsiders	$2,089.8	$ 688.4	$ —	$2,778.2
Revenues – affiliates	1.4	—	(0.5)	0.9
Total revenues	2,091.2	688.4	(0.5)	2,779.1
Depreciation and amortization	185.6	41.9	—	227.5
Total interest charges	114.7	18.2	(0.2)	132.7
Provision for taxes	81.9	17.3	—	99.2
Net income	$ 135.6	$ 27.1	$ —	$ 162.7
Total assets	5,294.7	823.4	(9.5)	6,108.6
Capital expenditures	$ 479.7	$ 69.0	$ —	$ 548.7
2007				
Revenues – outsiders	$2,186.6	$ 599.7	$ —	$2,786.3
Revenues – affiliates	1.8	—	(0.6)	1.2
Total revenues	2,188.4	599.7	(0.6)	2,787.5
Depreciation and amortization	178.6	40.1	—	218.7
Total interest charges	112.2	17.1	(0.1)	129.2
Provision for taxes	85.2	16.4	—	101.6
Net income	$ 150.3	$ 26.5	$ —	$ 176.8
Total assets	4,672.5	754.3	(7.5)	5,419.3
Capital expenditures	$ 373.8	$ 49.2	$ —	$ 423.0
2006				
Revenues – outsiders	$2,082.7	$ 577.6	$ —	$2,660.3
Revenues – affiliates	2.2	—	(0.6)	1.6
Total revenues	2,084.9	577.6	(0.6)	2,661.9
Depreciation and amortization	186.3	36.5	—	222.8
Total interest charges	107.4	15.2	—	122.6
Provision for taxes	80.3	18.8	—	99.1
Net income	$ 135.9	$ 29.7	$ —	$ 165.6
Total assets	4,620.7	748.9	(4.5)	5,365.1
Capital expenditures	$ 366.4	$ 54.0	$ —	$ 420.4

11. Asset Retirement Obligations

Tampa Electric Company accounts for asset retirement obligations under FAS 143, *Accounting for Asset Retirement Obligations*. An asset retirement obligation (ARO) for a long-lived asset is recognized at fair value at inception of the obligation if there is a legal obligation under an existing or enacted law or statute, a written or oral contract, or by legal construction under the doctrine of promissory estoppel. Retirement obligations are recognized only if the legal obligation exists in connection with or as a result of the permanent retirement, abandonment or sale of a long-lived asset.

When the liability is initially recorded, the carrying amount of the related long-lived asset is correspondingly increased. Over time, the liability is accreted to its estimated future value. The corresponding amount capitalized at inception is depreciated over the remaining useful life of the asset. The liability must be revalued each period based on current market prices.

For the years ended Dec. 31, 2008, 2007 and 2006, accretion expense was immaterial. For the year ended Dec. 31, 2008, increased cost of removal of materials used in the generation and transmission of electricity resulted in a $2.9 million estimated cash flow revision at Tampa Electric Company.

Reconciliation of beginning and ending carrying amount of asset retirement obligations:

(millions)	*Dec. 31,* 2008	2007
Beginning Balance	$ 27.1	$ 26.5
Revisions to estimated cash flows	2.9	-
Other(1)	-	0.6
Ending Balance	$ 30.0	$ 27.1

(1) Accretion recorded as a deferred regulatory asset.

As regulated utilities, Tampa Electric and PGS must file depreciation and dismantlement studies periodically and receive approval from the FPSC before implementing new depreciation rates. Included in approved depreciation rates is either an implicit net salvage factor or a cost of removal factor, expressed as a percentage. The net salvage factor is principally comprised of two components – a salvage factor and a cost of removal or dismantlement factor. Tampa Electric Company uses current cost of removal or dismantlement factors as part of the estimation method to approximate the amount of cost of removal in accumulated depreciation.

12. Derivatives and Hedging

Tampa Electric Company enters into futures, forwards, swaps and option contracts to limit the exposure to interest rate changes for future debt issuance and price fluctuations for physical purchases and sales of natural gas in the course of normal operations. Tampa Electric Company uses derivatives only to reduce normal operating and market risks, not for speculative purposes. Tampa Electric Company's primary objective is to reduce the impact of market price volatility on ratepayers, and uses derivative instruments primarily to optimize the value of physical assets, including generation capacity and natural gas delivery. The risk management policies adopted by the 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 FAS 133, *Accounting for Derivative Instruments and Hedging Activities, as amended by FAS 138, Accounting for Certain Derivative Instruments and Certain Hedging Activity* and FAS 149, *Amendment on Statement 133 on Derivative Instruments and Hedging Activities*. 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 its reclassification. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the amount paid or received on the underlying physical transaction. Additionally, amounts deferred in OCI related to an effective designated cash flow hedge must be reclassified to current earnings if the anticipated hedged transaction is no longer probable of occurring.

At Dec. 31, 2008 and Dec. 31, 2007, Tampa Electric Company and its affiliates had derivative assets (current and non-current) totaling $0.1 million and $2.2 million, respectively, and liabilities (current and non-current) totaling $134.2 million and $26.1 million, respectively. At Dec. 31, 2008, all assets and liabilities were related to natural gas swaps. At Dec. 31, 2007, $8.2 million of liabilities were related to interest rate swaps. The remaining $2.2 million of assets and $17.9 million in liabilities were related to natural gas swaps

As a result of applying the provisions of FAS 71 in accordance with the FPSC, 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 fuel recovery clause on the risks of hedging activities. (See **Note 3**). Based on the fair value of cash flow hedges at Dec. 31, 2008, net pretax losses of $119.4 million are expected to be reclassified from regulatory assets or liabilities to the Consolidated Statement of Income within the next twelve months. Tampa Electric Company does not currently have any cash flow hedges for transactions forecasted to take place in periods subsequent to 2010.

13. Fair Value

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.

FAS 157, among other things, requires the company to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. It also requires recognition of trade-date gains related to certain derivative transactions whose fair value has been determined using unobservable market inputs. This guidance supersedes the guidance in Emerging Issues Task Force Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities* (EITF 02-3), which prohibited the recognition of trade-date gains for such derivative transactions when determining the fair value of instruments not traded in an active market.

On Nov. 14, 2007, the FASB reaffirmed its position that companies will be required to implement the standard for financial assets and liabilities, as well as for any other assets and liabilities that are carried at fair value on a recurring basis in financial statements. The FASB did, however, provide a one year deferral for the implementation of FAS 157 for other non-financial assets and liabilities. Effective Jan. 1, 2008, Tampa Electric Company adopted FAS 157 for financial assets and liabilities that are carried at fair value on a recurring basis.

FAS 157 is applied prospectively as of the first interim period for the fiscal year in which it is initially adopted, except for limited retrospective adoption for the following three items:

- The valuation of financial instruments using blockage factors;
- Financial instruments that were measured at fair value using the transaction price (as indicated in EITF 02-3); and,
- The valuation of hybrid financial instruments that were measured at fair value using the transaction price (as indicated in FAS 155).

The impact of adoption in these areas would be applied as a cumulative-effect adjustment to opening retained earnings, measured as the difference between the carrying amounts and the fair values of relevant assets and liabilities at the date of adoption. Tampa Electric Company does not have any of the three aforementioned items, and therefore no transition adjustment was recorded.

Fair Value Hierarchy

FAS 157 specifies a hierarchy of valuation techniques based on whether the inputs to those valuation techniques are observable or unobservable. In accordance with FAS 157, these two types of inputs have created the following fair value hierarchy:

- *Level 1* – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed equities and U.S. government treasury securities.
- *Level 2* – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as OTC forwards, options and repurchase agreements.
- *Level 3* – Pricing inputs include significant inputs that are generally not observable in the marketplace. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. At each balance sheet date, the company performs an analysis of all instruments subject to FAS 157 and includes in Level 3 all of those whose fair value is based on significant unobservable inputs.

This hierarchy requires the use of observable market data when available.

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, 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, Tampa Electric 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.

Valuation Techniques

FAS 157 describes three main approaches to measuring the fair value of assets and liabilities:

1) *Market Approach* - The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities (including a business). The market approach includes the use of matrix pricing.

2) *Income Approach* - The income approach uses valuation techniques to convert future amounts (for example, cash flows or earnings) to a single present amount (discounted). The measurement is based on the value indicated by current market expectations about those future amounts.

3) *Cost Approach* -The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (often referred to as current replacement cost). The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

Items Measured at Fair Value on a Recurring Basis

The following table sets forth by level within the fair value hierarchy Tampa Electric Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of Dec. 31, 2008. 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. Tampa Electric 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 Dec. 31, 2008*			
(millions)	*Level 1*	*Level 2*	*Level 3*	*Total*
Assets				
Natural gas swaps	$ -	$ 0.1	$ -	$ 0.1
Total	$ -	$ 0.1	$ -	$ 0.1
Liabilities				
Natural gas swaps	$ -	$ 134.2	$ -	$ 134.2
Total	$ -	$ 134.2	$ -	$ 134.2

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.

Tampa Electric Company considers the impact of nonperformance risk in determining the fair value of derivatives. Tampa Electric Company considers the net position with each counterparty, past performance of both parties and the intent of the parties, measures of credit risk including credit default swaps and historical default probabilities, and whether the markets in which we transact have experienced dislocation. At Dec. 31, 2008 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.

In accordance with SFAS 107, *Disclosures about Fair Value of Financial Instruments*, Tampa Electric Company has disclosed the fair value of its long-term debt to be $1,822.6.0 million. (See **Consolidated Statements of Capitalization**) The determination of fair value for these instruments includes obtaining prices from third party financial institutions and in some cases utilizing a model to discount the future cash flows produced by the instruments by a rate determined by applying a spread based on Tampa Electric Company's credit ratings (also provided by third party financial institutions) to U.S. Treasury rates.

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

(millions)	*Interest Rate Swaps*	*Total*
Balance at Jan. 1, 2008	$ (9.0)	$ (9.0)
Transfers to Level 3	-	-
Change in fair market value	(7.3)	(7.3)
Included in earnings	-	-
Balance at Mar. 31, 2008	(16.3)	(16.3)
Transfers to Level 3	-	-
Change in fair market value	4.5	4.5
Settled	11.8	11.8
Included in earnings	-	-
Balance at Jun. 30, 2008	-	-
Transfers to Level 3	-	-
Change in fair market value	-	-
Settled	-	-
Included in earnings	-	-
Balance at Sep. 30, 2008	-	-
Transfers to Level 3	-	-
Change in fair market value	-	-
Settled[(1)]	-	-
Included in earnings	-	-
Balance at Dec. 31, 2008	$ -	$ -

(1) $11.8 million of forward starting interest rate swaps were settled in the second quarter of 2008 and are related to Tampa Electric Company's May 2008 issuance of debt. 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 was used to determine the stream of cash flows over the life of the contract. The cash flows were then discounted using a spot discount rate to determine the fair value.

14. Variable Interest Entities

Tampa Electric Company accounts for VIEs under FIN 46(R), *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51* (FIN 46(R)). In accordance with FIN 46(R), the company evaluates for consolidation all long-term agreements with VIEs in which contractual, ownership or other pecuniary interests in that entity change with changes in the fair value of the entity's net assets. A party to an agreement that absorbs a majority of the entity's expected losses, receives a majority of its expected residual returns, or both, is considered to be the primary beneficiary and is required to consolidate that entity. In addition to these quantitative factors, the company evaluates qualitative factors that would indicate that a transfer of risk from the entity to the company has occurred. The transfer of substantial risk from the entity to the company could result in a determination that the company is the primary beneficiary of the entity. While we review each contract individually, for purposes of analyzing PPAs, the determining factors are generally the length of the agreement and which entity absorbs the fuel risk.

Tampa Electric has entered into multiple PPAs with wholesale energy providers in Florida to ensure the ability to meet customer energy demand and to provide lower cost options in the meeting of this demand. These agreements are with similar entities and contain similar provisions. They range in size from 125 to 370 MW of available capacity. Some of these provisions provide for the transfer or sharing of a number of risks inherent in the generation of energy. Some of these risks include: operating and maintenance; regulatory; credit; commodity/fuel; and energy market risk. In most instances, Tampa Electric has reviewed these risks and has determined that the owners of these entities have retained the majority of these risks over the expected life of the underlying generating assets and are the primary beneficiaries. As a result, Tampa Electric is not required to consolidate any of these entities. Tampa Electric purchased $167.2 million, $109.7 million, and $88.0 million under these PPAs for the years ended December 31, 2008, 2007, and 2006, respectively.

In one instance Tampa Electric's agreement with the entity for 370 MW of capacity was entered into prior to Dec. 31, 2003, the effective date of FIN 46(R). Under FIN 46(R), Tampa Electric is required to make an exhaustive effort to obtain sufficient information to determine if this entity is a VIE and which holder of the variable interests is the primary beneficiary. The owners of this entity are not willing to provide the information necessary to make these determinations, have no obligation to do so and the information is not available publicly. As a result, Tampa Electric is unable to determine if this entity is a VIE and if so, which variable interest holder, if any, is the primary beneficiary. Tampa Electric has no obligation to this entity beyond the purchase of capacity; therefore, the maximum exposure for Tampa Electric is the obligation to pay for such capacity under terms of the PPA at rates that could be unfavorable to the wholesale market. Tampa Electric purchased $71.6 million, $54.5 million, and $50.7 million under this PPA for the years ended Dec. 31, 2008, 2007, and 2006, respectively.

Tampa Electric Company does not provide any material financial or other support to any of the VIEs it is involved with, nor is Tampa Electric Company under any obligation to absorb losses associated with these VIEs. Tampa Electric Company's involvement with the remaining VIEs does not affect its Consolidated Balance Sheets, Statements of Income or Cash Flows.

15. Other Comprehensive Income

Tampa Electric Company reported the following other comprehensive income (loss) for the years ended Dec. 31, 2008, 2007 and 2006, related to changes in the fair value of cash flow hedges and amortization of unrecognized benefit costs associated with the company's pension plans:

Other comprehensive income (loss) *(millions)*	*Gross*	*Tax*	*Net*
2008			
Unrealized loss on cash flow hedges	$ (3.6)	$ 1.4	$ (2.2)
Less: Loss reclassified to net income	0.7	(0.3)	0.4
Loss on cash flow hedges	(2.9)	1.1	(1.8)
Total other comprehensive (loss) income	$ (2.9)	$ 1.1	$ (1.8)
2007			
Unrealized loss on cash flow hedges	$ (8.2)	$ 3.2	$ (5.0)
Less: Gain reclassified to net income	—	—	—
Loss on cash flow hedges	(8.2)	3.2	(5.0)
Total other comprehensive (loss) income	$ (8.2)	$ 3.2	$ (5.0)
2006			
Unrealized gain on cash flow hedges	$ —	$ —	$ —
Less: Gain reclassified to net income	—	—	—
Gain (loss) on cash flow hedges	—	—	—
Total other comprehensive income (loss)	$ —	$ —	$ —

Accumulated other comprehensive loss *(millions) Dec. 31,*	*2008*	*2007*
Net unrealized loss from cash flow hedges [1]	$ (6.8)	$ (5.0)
Total accumulated other comprehensive loss	$ (6.8)	$ (5.0)

(1) Net of tax benefit of $4.3 million and $3.2 million as of Dec. 31, 2008 and 2007, respectively.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

Item 9A. CONTROLS AND PROCEDURES.

TECO Energy, Inc.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) of the Securities Exchange Act of 1934, as amended. We conducted an evaluation of the effectiveness of TECO Energy, Inc.'s internal control over financial reporting as of Dec. 31, 2008 based on the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under this framework, our management concluded that TECO Energy, Inc.'s internal control over financial reporting was effective as of Dec. 31, 2008.

Conclusions Regarding Effectiveness 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 annual report, Dec. 31, 2008 (the "Evaluation Date"). Based on such evaluation, TECO Energy's principal executive officer and principal financial officer have concluded that, as of the Evaluation Date, TECO Energy's disclosure controls and procedures are effective.

Management's Report on Internal Control over Financial Reporting.

TECO Energy's internal control over financial reporting as of Dec. 31, 2008 has been audited by PricewaterhouseCoopers LLP, an independent registered certified public accounting firm, as stated in their report which is on page 75 of this report.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. A control system, no matter how well designed and operated, can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Changes in Internal Control over Financial Reporting.

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) of the Securities Exchange Act of 1934, as amended. We conducted an evaluation of the effectiveness of Tampa Electric Company's internal control over financial reporting as of Dec. 31, 2008 based on the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under this framework, our management concluded that Tampa Electric Company's internal control over financial reporting was effective as of Dec. 31, 2008.

Conclusions Regarding Effectiveness 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 Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this annual report, Dec. 31, 2008 (the "Evaluation Date"). Based on such evaluation, Tampa Electric Company's principal executive officer and principal financial officer have concluded that, as of the Evaluation Date, Tampa Electric Company's disclosure controls and procedures are effective.

Management's Report on Internal Control over Financial Reporting.

This annual report does not include an attestation report of PricewaterhouseCoopers, LLP regarding Tampa Electric Company's internal control over financial reporting. Management's report was not subject to attestation by

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

(a) The information required by Item 10 with respect to the directors of the registrant is included under the caption "Election of Directors" in TECO Energy's definitive proxy statement for its Annual Meeting of Shareholders to be held on Apr. 29, 2009 (Proxy Statement) and is incorporated herein by reference.

(b) The information required by Item 10 concerning executive officers of the registrant is included under the caption "Executive Officers of the Registrant" on page 33 of this report.

(c) The information required by Item 10 concerning Section 16(a) Beneficial Ownership Reporting Compliance is included under that caption in the Proxy Statement and is incorporated herein by reference.

(d) Information regarding TECO Energy's Audit Committee, including the committee's financial experts, is included under the caption "Committees of the Board" in the Proxy Statement, and is incorporated herein by reference.

(e) TECO Energy has adopted a code of ethics applicable to all of its employees, officers and directors. The text of the *Standards of Integrity* is available in the Investors section of the company's website at www.tecoenergy.com. Any amendments to or waivers of the *Standards of Integrity* for the benefit of any executive officer or director will also be posted on the website.

Item 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is included in the Proxy Statement beginning with the caption "Compensation Discussion and Analysis" and ending with "Post-Termination Benefits" just above the caption "Ratification of Appointment of Auditor", and under the caption "Compensation of Directors" and is incorporated herein by reference.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by Item 12 is included under the captions "Share Ownership", and "Equity Compensation Plan Information" in the Proxy Statement, and is incorporated herein by reference.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by Item 13 is included under the captions "Certain Relationships and Related Person Transactions" and "Director Independence" in the Proxy Statement, and is incorporated herein by reference.

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 for TECO Energy is included under the caption "Item 2 – Ratification of Appointment of Auditor" in the Proxy Statement and is incorporated herein by reference.

Tampa Electric Company incurred $0.8 million, $0.8 million and $0.9 million in audit-related fees rendered by PricewaterhouseCoopers for 2008, 2007 and 2006, respectively, including $0.3 related to Sarbanes-Oxley in each of the three years. No other fees were incurred at Tampa Electric Company in those years, for services rendered by PricewaterhouseCoopers.

PricewaterhouseCoopers pursuant to temporary rules of the Securities and Exchange Commission that permit the company to provide only management's report in this annual report.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. A control system, no matter how well designed and operated, can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Changes in Internal Control over Financial Reporting.

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.

Item 9B. OTHER INFORMATION.

None.

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) **Certain Documents Filed as Part of this Form 10-K**

1. Financial Statements
   TECO Energy, Inc. Financial Statements – See index on page 81
   Tampa Electric Company Financial Statements – See index on page 134
2. Financial Statement Schedules
   Condensed Parent Company Financial Statements Schedule I – pages 174-177
   TECO Energy, Inc. Schedule II – page 178
   Tampa Electric Company Schedule II – page 179
3. Exhibits – See index beginning on page 183

(b) The exhibits filed as part of this Form 10-K are listed on the Exhibit Index immediately preceding such Exhibits. The Exhibit Index is incorporated herein by reference.

(c) The financial statement schedules filed as part of this Form 10-K are listed in paragraph (a)(2) above, and follow immediately.

SCHEDULE I – CONDENSED PARENT COMPANY FINANCIAL STATEMENTS

TECO ENERGY, INC.
PARENT COMPANY ONLY
Condensed Balance Sheets

(millions) *Assets*	*Dec. 31, 2008*	*Dec. 31, 2007*
Current assets		
Cash and cash equivalents	$ 0.2	$ 99.8
Advances to affiliates	204.4	395.8
Accounts receivable from affiliates	7.4	4.4
Accounts receivable	0.2	—
Interest receivable from affiliates	1.8	2.3
Other current assets	1.1	1.2
Total current assets	215.1	503.5
Property, plant and equipment		
Property, plant and equipment	0.7	0.7
Accumulated depreciation	(0.2)	(0.1)
Total property, plant and equipment	0.5	0.6
Other assets		
Investment in subsidiaries	2,671.7	2,637.0
Deferred income taxes	732.5	782.2
Other assets	22.9	10.5
Total other assets	3,427.1	3,429.7
Total assets	$ 3,642.7	$ 3,933.8
Liabilities and capital		
Current liabilities		
Long-term debt, current	$ —	$ —
Accounts payable to affiliates	0.4	1.0
Accounts payable	4.9	11.4
Margin call collateral	—	42.3
Interest payable	4.5	5.0
Taxes accrued	0.2	3.8
Advances from affiliates	1,158.2	1,416.9
Other current liabilities	1.6	4.4
Total current liabilities	1,169.8	1,484.8
Other liabilities		
Long-term debt-others	403.9	404.1
Other liabilities	22.9	12.3
Total other liabilities	426.8	416.4
Capital		
Common equity	212.9	210.9
Additional paid in capital	1,518.2	1,489.2
Retained earnings	322.6	334.2
Accumulated other comprehensive loss	(7.6)	(1.7)
Common equity	2,046.1	2,032.6
Total capital	2,046.1	2,032.6
Total liabilities and capital	$ 3,642.7	$ 3,933.8

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

SCHEDULE I – CONDENSED PARENT COMPANY FINANCIAL STATEMENTS

TECO ENERGY, INC.
PARENT COMPANY ONLY
Condensed Statements of Income

For the years ended Dec. 31, (millions)	*2008*	*2007*	*2006*
Revenues	$ —	$ —	$ —
Expenses			
Administrative and general expenses	4.2	5.7	6.8
Other taxes	0.8	0.9	—
Transaction (gain) costs related to sale of business	(0.2)	27.1	—
Depreciation and amortization	0.2	0.4	—
Total expenses	5.0	34.1	6.8
Loss from operations	(5.0)	(34.1)	(6.8)
Loss on debt extinguishment	—	(32.9)	(2.5)
Other income	2.0	1.4	—
Earnings from investments in subsidiaries	192.1	504.6	319.4
Interest income (expense)			
Interest income			
Affiliates	—	27.3	23.1
Others	—	9.3	20.3
Interest expense			
Others	(28.1)	(121.3)	(148.7)
Total interest expense	(28.1)	(84.7)	(105.3)
Income before income taxes	161.0	354.3	204.8
Benefit for income taxes	(1.4)	(58.9)	(41.5)
Net income	$ 162.4	$ 413.2	$ 246.3

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

SCHEDULE I – CONDENSED PARENT COMPANY FINANCIAL STATEMENTS

TECO ENERGY, INC.
PARENT COMPANY ONLY
Condensed Statements of Cash Flows

For the years ended Dec. 31, (millions)	*2008*	*2007*	*2006*
Cash flows from operating activities	$ 19.6	$ 56.8	$ 10.2
Cash flows from investing activities			
Restricted cash	(0.1)	(0.2)	0.1
Capital expenditures	—	(0.1)	—
Investment in subsidiaries	(271.0)	(67.8)	(43.3)
Dividends from subsidiaries	408.4	338.7	282.3
Net change in affiliate advances	(67.4)	166.7	75.4
Other non-current investments	(42.3)	42.3	—
Cash flows from investing activities	27.6	479.6	314.5
Cash flows from financing activities			
Dividends to shareholders	(168.6)	(163.0)	(158.7)
Common stock	21.8	14.0	12.5
Repayment of long-term debt	—	(668.7)	(106.2)
Debt exchange premium	—	(21.2)	—
Cash flows used in financing activities	(146.8)	(838.9)	(252.4)
Net (decrease) increase in cash and cash equivalents	(99.6)	(302.5)	72.3
Cash and cash equivalents at beginning of period	99.8	402.3	330.0
Cash and cash equivalents at end of period	$ 0.2	$ 99.8	$ 402.3

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

SCHEDULE I – CONDENSED PARENT COMPANY FINANCIAL STATEMENTS

TECO ENERGY, INC.
PARENT COMPANY ONLY
Notes to Condensed Financial Statements

1. Basis of Presentation

TECO Energy, Inc., on a stand alone basis, (the parent company) has accounted for majority-owned subsidiaries using the equity basis of accounting. These financial statements are presented on a condensed basis. Additional disclosures relating to the parent company financial statements are included under the TECO Energy **Notes to Consolidated Financial Statements**, which information is hereby incorporated by reference. These parent company condensed financial statements are required under Regulation S-X when the net assets exceed 25% of consolidated net assets.

The use of estimates is inherent in the preparation of financial statements in accordance with generally accepted accounting principles. Actual results could differ from those estimates. Certain prior year amounts were reclassified to conform to the current year presentation.

2. Long-term Obligations

In connection with debt tender and exchange transactions, $32.9 million of premiums and fees were expensed and are included in "Loss on debt extinguishment" on the Condensed Parent Income Statement for the year ended Dec. 31, 2007. See **Note 7** to the TECO Energy **Consolidated Financial Statements** for a description and details of long-term debt obligations of the parent company.

3. Commitments and Contingencies

See **Note 12** to the TECO Energy **Consolidated Financial Statements** for a description of all material contingencies and guarantees outstanding of the parent company.

4. Derivatives and Hedging

At Dec. 31, 2007, TECO Energy had a "Crude oil options receivable, net" asset totaling $78.5 million for transactions that were not designated as either a cash flow or fair value hedge. This balance includes the full settlement value of the crude oil options of $120.8 million, offset by the $42.3 million of margin call collateral collected. (See **Note 2**, New Accounting Pronouncements – Offsetting Amounts Related to Certain Contracts and **Note 21**, Derivatives and Hedging, to the TECO Energy **Consolidated Financial Statements.**)

5. Sale of TECO Transport

On Dec. 4, 2007, TECO Diversified, Inc., a wholly-owned subsidiary of the company, sold its entire interest in TECO Transport Corporation for cash to an unaffiliated investment group. In connection with this sale, TECO Energy Parent Only incurred transaction-related charges of $27.1 million.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

TECO ENERGY, INC.
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
For the Years Ended Dec. 31, 2008, 2007 and 2006
(millions)

	Balance at Beginning of Period	Additions: Charged to Income	Additions: Other Charges	Payments & Deductions [1]	Balance at End of Period
Allowance for Uncollectible Accounts:					
2008	$ 3.3	$ 8.1	$ —	$ 7.9	$ 3.5
2007	$ 4.6	$ 6.8	$ —	$ 8.1	$ 3.3
2006	$ 6.9	$ 6.9	$ —	$ 9.2	$ 4.6

(1) Write-off of individual bad debt accounts

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

TAMPA ELECTRIC COMPANY
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
For the Years Ended Dec. 31, 2008, 2007 and 2006
(millions)

	Balance at Beginning of Period	Additions: Charged to Income	Additions: Other Charges	Payments & Deductions [1]	Balance at End of Period
Allowance for Uncollectible Accounts:					
2008	$ 1.4	$ 8.1	$ —	$ 7.9	$ 1.6
2007	$ 1.2	$ 6.8	$ —	$ 6.6	$ 1.4
2006	$ 1.3	$ 6.3	$ —	$ 6.4	$ 1.2

(1) Write-off of individual bad debt accounts

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

Dated: February 26, 2009

By: /s/ SHERRILL W. HUDSON
SHERRILL W. HUDSON, Chairman of the Board,
Director and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on February 26, 2009:

Signature	Title
/s/ SHERRILL W. HUDSON SHERRILL W. HUDSON	Chairman of the Board, Director and Chief Executive Officer (Principal Executive Officer)
/s/ GORDON L. GILLETTE GORDON L. GILLETTE	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ SANDRA W. CALLAHAN SANDRA W. CALLAHAN	Vice President-Treasury and Risk Management (Principal Accounting Officer)

Signature	Title	Signature	Title
/s/ C. DUBOSE AUSLEY C. DUBOSE AUSLEY	Director	/s/ TOM L. RANKIN TOM L. RANKIN	Director
/s/ JAMES L. FERMAN, JR. JAMES L. FERMAN, JR.	Director	/s/ WILLIAM D. ROCKFORD WILLIAM D. ROCKFORD	Director
/s/ LUIS GUINOT, JR. LUIS GUINOT, JR.	Director	/s/ J. THOMAS TOUCHTON J. THOMAS TOUCHTON	Director
/s/ JOSEPH P. LACHER JOSEPH P. LACHER	Director	/s/ PAUL L. WHITING PAUL L. WHITING	Director
/s/ LORETTA A. PENN LORETTA A. PENN	Director		
/s/ JOHN B. RAMIL JOHN B. RAMIL	Director		

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

TAMPA ELECTRIC COMPANY

Dated: February 26, 2009

By: /s/ SHERRILL W. HUDSON
SHERRILL W. HUDSON, Chairman of the Board, Director and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on February 26, 2009:

Signature	Title
/s/ SHERRILL W. HUDSON SHERRILL W. HUDSON	Chairman of the Board, Director and Chief Executive Officer (Principal Executive Officer)
/s/ GORDON L. GILLETTE GORDON L. GILLETTE	Senior Vice President-Finance and Chief Financial Officer (Principal Financial Officer)
/s/ PHIL L. BARRINGER PHIL L. BARRINGER	Chief Accounting Officer (Principal Accounting Officer)

Signature	Title	Signature	Title
/s/ C. DUBOSE AUSLEY C. DUBOSE AUSLEY	Director	/s/ TOM L. RANKIN TOM L. RANKIN	Director
/s/ JAMES L. FERMAN, JR. JAMES L. FERMAN, JR.	Director	/s/ WILLIAM D. ROCKFORD WILLIAM D. ROCKFORD	Director
/s/ LUIS GUINOT, JR. LUIS GUINOT, JR.	Director	s/ J. THOMAS TOUCHTON J. THOMAS TOUCHTON	Director
/s/ JOSEPH P. LACHER JOSEPH P. LACHER	Director	/s/ PAUL L. WHITING PAUL L. WHITING	Director
/s/ LORETTA A. PENN LORETTA A. PENN	Director		
/s/ JOHN B. RAMIL JOHN B. RAMIL	Director		

Supplemental Information to Be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act

No annual report or proxy material has been sent to Tampa Electric Company's security holders because all of its equity securities are held by TECO Energy, Inc.

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 through February 4, 2009 (Form 8-K dated Feb. 4, 2009 of TECO Energy, Inc. and Exhibit 3.1 thereto).	*
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)	*
4.1	Loan and Trust Agreement among Hillsborough County Industrial Development Authority, Tampa Electric Company and The Bank of New York Trust Company of Florida, N.A., as trustee, dated as of Jun. 1, 2002 (including the form of bond). (Exhibit 4.5, Amendment No. 1 to Form 10-K for 2004 of TECO Energy, Inc. and Tampa Electric Company).	*
4.2	Loan and Trust Agreement among Hillsborough County Industrial Development Authority, Tampa Electric Company and The Bank of New York Trust Company, N.A., as trustee, dated as of Jan. 5, 2006 (including the form of bond) (Exhibit 4.1, Form 8-K dated Jan. 19, 2006 of Tampa Electric Company).	*
4.3	Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of Jul. 1, 1998 (Exhibit 4.1, Registration Statement No. 333-55873 of Tampa Electric Company).	*
4.4	Third Supplemental Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of Jun. 15, 2001 (Exhibit 4.2, Form 8-K dated Jun. 25, 2001 of Tampa Electric Company).	*
4.5	Fourth Supplemental Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of Aug. 15, 2002 (Exhibit 4.2, Form 8-K dated Aug. 26, 2002 of Tampa Electric Company).	*
4.6	Fifth Supplemental Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of May 1, 2006 (Exhibit 4.16, Form 8-K dated May 12, 2006 of Tampa Electric Company).	*
4.7	Amended and Restated Note Agreement dated as of May 30, 1997 between Tampa Electric Company (successor by merger to Peoples Gas System, Inc.) and The Prudential Insurance Company of America (Exhibit 4.2, Form 8-K dated Dec. 15, 2004 of TECO Energy, Inc. and Tampa Electric Company).	*
4.8	Letter Amendment No. 1 dated as of Dec. 9, 2004 to the Amended and Restated Note Agreement dated as of May 30, 1997 between Tampa Electric Company (successor by merger to Peoples Gas System, Inc.) and The Prudential Insurance Company of America (Exhibit 4.1, Form 8-K dated Dec. 15, 2004 of TECO Energy, Inc., and Tampa Electric Company).	*
4.9	Note Purchase Agreement among Tampa Electric Company and the Purchasers party thereto, dated as of Apr. 11, 2003 (Exhibit 10.1, Form 8-K dated Apr. 14, 2003 of Tampa Electric Company).	*
4.10	Loan and Trust Agreement dated as of May 1, 2007 among Polk County Industrial Development Authority, Tampa Electric Company and The Bank of New York Trust Company, N.A., as trustee (including the form of Bond) (Exhibit 4.1, Form 8-K dated May 14, 2007 of Tampa Electric Company).	*
4.11	Sixth Supplemental Indenture dated as of May 25, 2007 between Tampa Electric Company and The Bank of New York, as trustee, supplementing the Indenture dated as of Jul. 1, 1998, as amended (Exhibit 4.18, Form 8-K dated May 25, 2007 of Tampa Electric Company).	*
4.12	6.15% Notes due 2037 (Exhibit 4.19, Form 8-K dated May 25, 2007 of Tampa Electric Company).	*
4.13	Seventh Supplemental Indenture dated as of May 1, 2008 between Tampa Electric Company and The Bank of New York, as trustee, supplementing the Indenture dated as of Jul. 1, 1998, as amended (Exhibit 4.20, Form 8-K dated May 16, 2008 of Tampa Electric Company).	*
4.14	6.10% Notes due 2018 (Exhibit 4.21, Form 8-K dated May 16, 2008 of Tampa Electric Company).	*
4.15	Loan and Trust Agreement dated as of Jul. 2, 2007 among Hillsborough County Industrial Development Authority, Tampa Electric Company and The Bank of New York Trust Company,	*

	N.A., as trustee (including the form of Bond) (Exhibit 4.1, Form 8-K dated Jul. 25, 2007 of Tampa Electric Company).	
4.16	First Supplemental Loan and Trust Agreement dated as of Mar. 26, 2008 among Hillsborough County Industrial Development Authority, Tampa Electric Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1, Form 8-K dated Mar. 26, 2008 of Tampa Electric Company).	*
4.17	Indenture between TECO Energy, Inc. and The Bank of New York, as trustee, dated as of Aug. 17, 1998 (Exhibit 4.1, Form 8-K dated Sep. 20, 2000 of TECO Energy, Inc.).	*
4.18	Third Supplemental Indenture dated as of Dec. 1, 2000 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.21, Form 8-K dated Dec. 21, 2000 of TECO Energy, Inc.).	*
4.19	Fourth Supplemental Indenture dated as of Apr. 30, 2001 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.28, Form 8-K dated May 1, 2001 of TECO Energy, Inc.).	*
4.20	Fifth Supplemental Indenture dated as of Sep. 10, 2001 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.16, Form 8-K dated Sep. 26, 2001 of TECO Energy, Inc.).	*
4.21.1	Sixth Supplemental Indenture dated as of Jan. 15, 2002 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.28, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.21.2	Amended and Restated Trust Agreement of TECO Capital Trust II among TECO Funding Company II, LLC, The Bank of New York and The Bank of New York (Delaware), dated as of Jan. 15, 2002 (Exhibit 4.31, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.21.3	Amended and Restated Limited Liability Agreement of TECO Funding Company II, LLC, dated as of Jan. 15, 2002 (Exhibit 4.33, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.21.4	Guarantee Agreement by and between TECO Energy, Inc., as Guarantor and The Bank of New York, dated as of Jan. 15, 2002 (Exhibit 4.35, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.	*
4.22	Seventh Supplemental Indenture dated as of May 1, 2002 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.15, Form 8-K dated May 13, 2002 of TECO Energy, Inc.).	*
4.23	Ninth Supplemental Indenture dated as of Jun. 10, 2003 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.15, Form 8-K dated Jun. 13, 2003 of TECO Energy, Inc.).	*
4.24	Tenth Supplemental Indenture dated as of May 26, 2005 between TECO Energy, Inc. and The Bank of New York, as trustee (including the form of 6.75% Note) (Exhibit 4.1, Form 8-K dated May 26, 2005 of TECO Energy, Inc.).	*
4.25	Eleventh Supplemental Indenture dated as of Jun. 7, 2005 between TECO Energy, Inc. and The Bank of New York, as trustee (including the form of Floating Rate Note) (Exhibit 4.1, Form 8-K dated Jun. 7, 2005 of TECO Energy, Inc.).	*
4.26	Renewed Rights Agreement between TECO Energy, Inc. and The Bank of New York., as Rights Agent, as amended and restated as of Feb. 2, 2004 (Exhibit 1, Form 8-A/A, of TECO Energy, Inc. filed on Feb. 23, 2004).	*
4.27	Indenture dated as of December 21, 2007 by and among TECO Finance, Inc., as issuer, TECO Energy, Inc., as guarantor, and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1, Form 8-K dated Dec. 21, 2007 of TECO Energy, Inc.).	*
4.28	First Supplemental Indenture dated as of December 21, 2007 by and among TECO Finance, Inc., as issuer, TECO Energy, Inc., as guarantor, and The Bank of New York Trust Company, N.A., as trustee, supplementing the Indenture dated as of December 21, 2007 (including the form of TECO Finance 7.20% notes due 2011, TECO Finance 7.00% notes due 2012 and TECO Finance 6.572% notes due 2017) (Exhibit 4.2, Form 8-K dated Dec. 21, 2007 of TECO Energy, Inc.).	*
4.29	Second Supplemental Indenture dated as of December 21, 2007 by and among TECO Finance, Inc., as issuer, TECO Energy, Inc., as guarantor, and The Bank of New York Trust Company, N.A., as trustee, supplementing the Indenture dated as of December 21, 2007 (including the form of TECO Finance 6.75% notes due 2015) (Exhibit 4.3, Form 8-K dated Dec. 21, 2007 of TECO Energy, Inc.).	*
10.1	TECO Energy Group Supplemental Executive Retirement Plan, as amended and restated as of Nov. 1, 2007 (Exhibit 10.1, Form 10-K for 2007 of TECO Energy, Inc. and Tampa Electric Company).	*
10.2	TECO Energy Group Supplemental Disability Income Plan, dated as of Mar. 20, 1989 (Exhibit 10.22, Form 10-K for 1988 of TECO Energy, Inc.).	*
10.3	TECO Energy Group Supplemental Retirement Benefits Trust Agreement, effective as of Nov. 17, 2008.	
10.4	Annual Incentive Compensation Plan for TECO Energy and subsidiaries, revised as of Feb. 4, 2009.	

10.5	Form of Change-in-Control Severance Agreement between TECO Energy, Inc. and Executive Officers. (Exhibit 10.1, Form 10-Q for the quarter ended September 30, 2008 of TECO Energy, Inc. and Tampa Electric Company)	*
10.6	TECO Energy Directors' Deferred Compensation Plan, as amended and restated effective as of Aug. 1, 2007 (Exhibit 10.3, Form 10-Q for the quarter ended Sep. 30, 2007 of TECO Energy, Inc. and Tampa Electric Company).	*
10.7	Form of Nonstatutory Stock Option under the TECO Energy, Inc. 1996 Equity Incentive Plan (and its successor plan) (Exhibit 10.5, Form 10-Q for the quarter ended Jun. 30, 1999 of TECO Energy, Inc.).	*
10.8	TECO Energy, Inc. 1997 Director Equity Plan (Exhibit 10.1, Form 8-K dated Apr. 16, 1997 of TECO Energy, Inc.).	*
10.9	Form of Nonstatutory Stock Option under the TECO Energy, Inc. 1997 Director Equity Plan, dated as of Jan. 29, 2003 (Exhibit 10.28, Form 10-K for 2002 of TECO Energy, Inc. and Tampa Electric Company).	*
10.10	Form of Restricted Stock Agreement under the TECO Energy, Inc. 1997 Director Equity Plan (Exhibit 10.3, Form 10-Q for the quarter ended Jun. 30, 2006 of TECO Energy, Inc. and Tampa Electric Company).	*
10.11	TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.2, Form 10-Q for the quarter ended Mar. 31, 2004 of TECO Energy, Inc. and Tampa Electric Company).	*
10.12	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.12, Form 10-K for 2006 of TECO Energy, Inc. and Tampa Electric Company).	*
10.13	Form of Performance Shares Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.2, Form 10-Q for the quarter ended Jun. 30, 2006 of TECO Energy, Inc. and Tampa Electric Company).	*
10.14	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2004 Equity Incentive Plan	
10.15	Form of Performance Shares Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.1, Form 10-Q for the quarter ended Jun. 30, 2008 of TECO Energy, Inc. and Tampa Electric Company).	*
10.16	Form of Restricted Stock Agreement between TECO Energy, Inc. and S. W. Hudson under the TECO Energy, Inc. 2004 Equity Incentive Plan. (Exhibit 10.3, Form 10-Q for the quarter ended Jun. 30, 2008 of TECO Energy, Inc. and Tampa Electric Company).	*
10.17	Nonstatutory Stock Option granted to S. W. Hudson, dated as of Jul. 6, 2004, under the TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.1, Form 10-Q for the quarter ended Jun. 30, 2004 of TECO Energy, Inc. and Tampa Electric Company).	*
10.18.1	Compensatory Arrangements with Executive Officers of TECO Energy, Inc.	
10.18.2	Compensatory Arrangements with Directors of TECO Energy, Inc. (Exhibit 10.10.2, Form 10-K for 2005 of TECO Energy, Inc. and Tampa Electric Company)	*
10.19	Insurance Agreement dated as of Jan. 5, 2006 between Tampa Electric Company and Ambac Assurance Corporation (Exhibit 10.1, Form 8-K dated Jan. 19, 2006 of Tampa Electric Company).	*
10.20	Second Amended and Restated Credit Agreement dated as of May 9, 2007, among TECO Finance, Inc., as Borrower, TECO Energy, Inc. as Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders and LC Issuing Banks party thereto (Exhibit 4.1, Form 8-K dated May 9, 2007 of TECO Energy, Inc.).	*
10.21	Second Amended and Restated Credit Agreement dated as of May 9, 2007, among Tampa Electric Company, as Borrower, Citibank, N.A., as Administrative Agent, and the Lenders and LC Issuing Banks party thereto (Exhibit 4.2, Form 8-K dated May 9, 2007 of Tampa Electric Company).	*
10.22	Purchase and Contribution Agreement dated as of Jan. 6, 2005, between Tampa Electric Company as the Originator and TEC Receivables Corporation as the Purchaser (Exhibit 4.1, Form 8-K dated Jan. 6, 2005 of TECO Energy, Inc. and Tampa Electric Company).	*
10.23	Loan and Servicing Agreement dated as of Jan. 6, 2005, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citicorp North America, Inc. as Program Agent (Exhibit 4.2, Form 8-K dated Jan. 6, 2005 of TECO Energy, Inc. and Tampa Electric Company).	*

10.23.1	Amendment No. 6 to Loan and Servicing Agreement dated as of December 18, 2008, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citicorp North America, Inc. as Program Agent (Exhibit 99.1, Form 8-K dated Dec.18, 2008 of TECO Energy, Inc. and Tampa Electric Company).	*
10.24	Insurance Agreement dated as of May 14, 2007 between Tampa Electric Company and Financial Guaranty Insurance Company (Exhibit 10.1, Form 8-K dated May 14, 2007 of 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	
21	Subsidiaries of the Registrant	
23.1	Consent of Independent Certified Public Accountants – TECO Energy, Inc.	
23.2	Consent of Independent Certified Public Accountants – Tampa Electric Company	
23.3	Consent of Marshall Miller & Associates	
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 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 Annual Report on Form 10-K and is not filed as part of it.
* Indicates exhibit previously filed with the Securities and Exchange Commission and incorporated herein by reference. Exhibits filed with periodic reports of TECO Energy, Inc. and Tampa Electric Company were filed under Commission File Nos. 1-8180 and 1-5007, respectively.

Certain instruments defining the rights of holders of long-term debt of TECO Energy, Inc. and its consolidated subsidiaries authorizing in each case a total amount of securities not exceeding 10% of total assets on a consolidated basis are not filed herewith. TECO Energy, Inc. will furnish copies of such instruments to the Securities and Exchange Commission upon request.

Certain instruments defining the rights of holders of long-term debt of Tampa Electric Company authorizing in each case a total amount of securities not exceeding 10% of total assets on a consolidated basis are not filed herewith. Tampa Electric Company will furnish copies of such instruments to the Securities and Exchange Commission upon request.

Executive Compensation Plans and Arrangements

Exhibits 10.1 through 10.18 above are management contracts or compensatory plans or arrangements in which executive officers or directors of TECO Energy, Inc. participate.

Exhibit A-2

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 June 30, 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.** (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	**59-2052286**
1-5007	**TAMPA ELECTRIC COMPANY** (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	**59-0475140**

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 Jul. 27, 2009 was 213,744,776. As of Jul. 27, 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 61.

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 Jun. 30, 2009 and Dec. 31, 2008, and the results of their operations and cash flows for the periods ended Jun. 30, 2009 and 2008. The results of operations for the three month and six month periods ended Jun. 30, 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/A for the year ended Dec. 31, 2008 and to the notes on pages 9 through 27 of this report.

INDEX TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS

TECO ENERGY, INC.
Consolidated Condensed Balance Sheets
Unaudited

Assets *(millions)*	*Jun. 30, 2009*	*Dec. 31, 2008*
Current assets		
Cash and cash equivalents	$ 28.0	$ 12.2
Short-term investments	-	2.4
Receivables, less allowance for uncollectibles of $4.6 and $3.5 at Jun. 30, 2009 and Dec. 31, 2008, respectively	309.7	285.9
Inventories, at average cost		
Fuel	142.9	90.2
Materials and supplies	67.5	72.8
Current regulatory assets	172.4	272.6
Current derivative assets	0.2	-
Income tax receivables	0.5	3.5
Prepayments and other current assets	25.1	25.8
Total current assets	746.3	765.4
Property, plant and equipment		
Utility plant in service		
Electric	5,743.5	5,528.3
Gas	993.3	964.4
Construction work in progress	460.7	463.5
Other property	366.9	354.8
Property, plant and equipment	7,564.4	7,311.0
Accumulated depreciation	(2,155.8)	(2,089.7)
Total property, plant and equipment, net	5,408.6	5,221.3
Other assets		
Deferred income taxes	278.5	333.8
Other investments	9.8	21.3
Long-term regulatory assets	319.2	325.3
Long-term derivative assets	0.6	0.1
Investment in unconsolidated affiliates	273.6	284.0
Goodwill	59.4	59.4
Deferred charges and other assets, including restricted cash of $7.3 and $7.5 at Jun. 30, 2009 and Dec. 31, 2008, respectively	134.1	136.8
Total other assets	1,075.2	1,160.7
Total assets	$ 7,230.1	$ 7,147.4

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

TECO ENERGY, INC.
Consolidated Condensed Balance Sheets – continued
Unaudited

Liabilities and Capital *(millions)*	*Jun. 30, 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	188.0	93.0
Accounts payable	264.5	304.4
Customer deposits	148.6	144.6
Current regulatory liabilities	26.9	21.7
Current derivative liabilities	113.7	132.1
Interest accrued	48.1	45.1
Taxes accrued	46.2	21.2
Other current liabilities	15.6	15.3
Total current liabilities	858.5	784.3
Other liabilities		
Investment tax credits	11.0	11.2
Long-term regulatory liabilities	579.8	588.2
Long-term derivative liabilities	10.3	19.4
Deferred credits and other liabilities	527.9	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	4,334.2	4,355.4
Commitments and contingencies (see **Note 9**)		
Capital		
Common equity (400.0 million shares authorized; par value $1; 213.7 and 212.9 shares outstanding at Jun. 30, 2009 and Dec. 31, 2008, respectively)	213.7	212.9
Additional paid in capital	1,523.9	1,518.2
Retained earnings	332.9	322.6
Accumulated other comprehensive loss	(33.1)	(46.0)
Total capital	2,037.4	2,007.7
Total liabilities and capital	$ 7,230.1	$ 7,147.4

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

TECO ENERGY, INC.
Consolidated Condensed Statements of Income
Unaudited

(millions, except per share amounts)	*Three months ended Jun. 30,* *2009*	*2008*
Revenues		
Regulated electric and gas (includes franchise fees and gross receipts taxes of $28.2 in 2009 and $27.6 in 2008)	$ 662.9	$ 730.0
Unregulated	162.3	157.2
Total revenues	825.2	887.2
Expenses		
Regulated operations		
Fuel	225.5	176.2
Purchased power	56.1	115.9
Cost of natural gas sold	50.9	133.8
Other	81.0	71.9
Operation other expense		
Mining related costs	110.9	116.8
Other	4.3	5.6
Maintenance	46.2	45.6
Depreciation and amortization	71.3	64.9
Taxes, other than income	55.9	54.1
Total expenses	702.1	784.8
Income from operations	123.1	102.4
Other income		
Allowance for other funds used during construction	2.5	1.7
Other income	6.1	4.0
Income from equity investments	12.9	21.6
Total other income	21.5	27.3
Interest charges		
Interest expense	57.4	56.6
Allowance for borrowed funds used during construction	(1.0)	(0.7)
Total interest charges	56.4	55.9
Income before provision for income taxes	88.2	73.8
Provision for income taxes	27.3	22.4
Net income	$ 60.9	$ 51.4
Average common shares outstanding – Basic	211.7	210.4
– Diluted	212.5	212.1
Earnings per share – Basic	$ 0.29	$ 0.24
– Diluted	$ 0.29	$ 0.24
Dividends paid per common share outstanding	$ 0.20	$ 0.20

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

TECO ENERGY, INC.
Consolidated Condensed Statements of Income
Unaudited

(millions, except per share amounts)	*Six months ended Jun. 30, 2009*	*2008*
Revenues		
Regulated electric and gas (includes franchise fees and gross receipts taxes of $58.3 in 2009 and $54.0 in 2008)	$ 1,316.7	$ 1,370.2
Unregulated	332.5	308.7
Total revenues	1,649.2	1,678.9
Expenses		
Regulated operations		
Fuel	454.2	339.8
Purchased power	98.3	197.8
Cost of natural gas sold	139.2	252.8
Other	158.0	143.2
Operation other expense		
Mining related costs	229.4	224.0
Other	8.4	9.9
Maintenance	98.6	91.6
Depreciation and amortization	141.0	129.9
Taxes, other than income	116.3	109.0
Transaction related costs	-	0.9
Total expenses	1,443.4	1,498.9
Income from operations	205.8	180.0
Other income		
Allowance for other funds used during construction	5.8	3.0
Other income	20.1	9.3
Income from equity investments	21.7	39.0
Total other income	47.6	51.3
Interest charges		
Interest expense	115.0	114.8
Allowance for borrowed funds used during construction	(2.3)	(1.2)
Total interest charges	112.7	113.6
Income before provision for income taxes	140.7	117.7
Provision for income taxes	45.1	35.5
Net income	$ 95.6	$ 82.2
Average common shares outstanding – Basic	211.6	210.1
– Diluted	212.3	211.6
Earnings per share – Basic	$ 0.45	$ 0.39
– Diluted	$ 0.45	$ 0.39
Dividends paid per common share outstanding	$ 0.40	$ 0.395

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

TECO ENERGY, INC.
Consolidated Condensed Statements of Comprehensive Income
Unaudited

(millions)	*Three months ended Jun. 30,* 2009	2008	*Six months ended Jun. 30,* 2009	2008
Net income	$ 60.9	$ 51.4	$ 95.6	$ 82.2
Other comprehensive income (loss), net of tax				
Net unrealized gain (loss) on cash flow hedges	8.1	3.9	10.5	(2.1)
Amortization of unrecognized benefit costs	0.4	(0.1)	0.7	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	8.5	3.8	12.9	(13.6)
Comprehensive income	$ 69.4	$ 55.2	$ 108.5	$ 68.6

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

TECO ENERGY, INC.
Consolidated Condensed Statements of Cash Flows
Unaudited

(millions)	*Six months ended Jun. 30, 2009*	*2008*
Cash flows from operating activities		
Net income	$ 95.6	$ 82.2
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	141.0	129.9
Deferred income taxes	45.5	39.7
Investment tax credits, net	(0.2)	(1.0)
Allowance for funds used during construction	(5.8)	(3.0)
Non-cash stock compensation	4.7	6.1
Gain on sale of business/assets, pretax	(18.6)	(1.1)
Equity in earnings of unconsolidated affiliates, net of cash distributions on earnings	0.3	(6.8)
Deferred recovery clauses	83.3	(92.4)
Receivables, less allowance for uncollectibles	(23.8)	(34.0)
Inventories	(47.4)	(7.9)
Prepayments and other current assets	0.7	(2.1)
Taxes accrued	27.2	15.7
Interest accrued	3.0	15.0
Accounts payable	(9.6)	76.9
Other	32.1	21.3
Cash flows from operating activities	328.0	238.5
Cash flows from investing activities		
Capital expenditures	(367.8)	(265.7)
Allowance for funds used during construction	5.8	3.0
Net proceeds (settlement) from sale of business/assets	29.2	(7.3)
Restricted cash	0.2	-
Distributions from unconsolidated affiliates	-	13.2
Other investments	9.7	76.2
Cash flows used in investing activities	(322.9)	(180.6)
Cash flows from financing activities		
Dividends	(85.3)	(83.5)
Proceeds from the sale of common stock	2.4	20.0
Proceeds from long-term debt	-	327.9
Repayment of long-term debt/Purchase in lieu of redemption	(1.4)	(288.1)
Net increase (decrease) in short-term debt	95.0	(25.0)
Cash flows from (used) in financing activities	10.7	(48.7)
Net increase in cash and cash equivalents	15.8	9.2
Cash and cash equivalents at beginning of period	12.2	162.6
Cash and cash equivalents at end of period	$ 28.0	$ 171.8

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

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 Jun. 30, 2009 and Dec. 31, 2008, and the results of operations and cash flows for the periods ended Jun. 30, 2009 and 2008. The results of operations for the three month and six month periods ended Jun. 30, 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 Jun. 30, 2009 and Dec. 31, 2008, unbilled revenues of $56.6 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 $56.1 million and $98.3 million for the three months and six months ended Jun. 30, 2009, respectively, compared to $115.9 million and $197.8 million for the three months and six months ended Jun. 30, 2008, respectively.

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 $28.2 million and $58.3 million, respectively, for the three months and six months ended Jun. 30, 2009, compared to $27.6 million and $54.0 million, respectively, for the three months and six months ended Jun. 30, 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 $28.2 million and $58.2 million, respectively, for the three months and six months ended Jun. 30, 2009, compared to $27.6 million and $53.8 million, respectively, for the three months and six months ended Jun. 30, 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 that 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 also typically 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

The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles

In June 2009, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard (SFAS) No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles* (FAS 168). FAS 168 replaces FAS 162, *The Hierarchy of Generally Accepted Accounting Principles* (FAS 162). It names the FASB Accounting Standards Codification (Codification) as the single source of authoritative U.S. Generally Accepted Accounting Principles (GAAP) for non-governmental entities recognized by the FASB. FAS 168 is effective for reporting periods ending after Sep. 15, 2009, and once effective, will supersede all U.S. GAAP accounting standards, aside from rules and interpretive releases issued by the Securities and Exchange Commission (SEC). The Codification is not intended to change GAAP; rather, it will change the referencing of U.S. GAAP. Therefore, it is not expected to have an impact on the company's results of operations, statement of position or cash flows.

Accounting for Transfers of Financial Assets

In June 2009, the FASB issued SFAS No. 166, *Accounting for Transfers of Financial Assets* (FAS 166). FAS 166 revises SFAS 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities-a replacement of FASB Statement No. 125* and requires companies to provide more information about sales of securitized financial assets. It is effective for fiscal periods beginning after Nov. 15, 2009. The new requirements will not have an impact on the company's results of operations, statement of position or cash flows.

Variable Interest Entities

In June 2009, the FASB issued SFAS No.167, *Amendments to FASB Interpretation No. 46(R)* (FAS 167). FAS 167 changes the way a company determines if a variable interest entity (VIE) should be consolidated. It is effective for fiscal years beginning after Nov. 15, 2009. TECO Energy is evaluating the effects of FAS 167 and believes that at the time of adoption it could have a significant effect on the company's statement of position or cash flows, but not a significant impact on the results of operations.

Subsequent Events

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events* (FAS 165). FAS 165 requires companies to disclose the date through which they evaluated subsequent events and whether that date corresponds with the filing of their financial statements. It is effective for fiscal periods ending after Jun. 15, 2009, and the adoption does not have an effect on the company's results of operations, statement of position or cash flows.

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 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 FAS 124-2), 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 FSP did not materially affect the company's results of operations, statement of position or cash flows. The company adopted this FSP effective Apr. 1, 2009.

FSP FAS 115-2 and FAS 124-2 is 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. The FSP did not materially affect the company's results of operations, statement of position or cash flows. The company adopted this FSP effective Apr. 1, 2009.

FSP FAS 107-1 and APB 28-1 requires 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 had no effect on the company's results of operations, statement of position or cash flows. The company adopted this FSP effective Apr. 1, 2009.

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. FSP FAS 132(R)-1 will be significant to the company's financial statement disclosures but 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 (see **Note 8**).

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' 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 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. On Mar. 17, 2009, the FPSC approved an increase to base rates, effective on May 7, 2009, of $104.2 million that reflects a return on equity of 11.25%, which is the middle of a range between 10.25% and 12.25%. Additionally, the FPSC approved a step increase of $33.6 million effective Jan. 1, 2010 for capital additions placed in service in 2009 bringing the total approved base rate increase to $137.8 million.

On May 15, 2009, Tampa Electric filed a Motion for Reconsideration regarding the calculation of the annual revenue requirements approved by the FPSC. On Jul. 14, 2009, the FPSC approved Tampa Electric's Motion resulting in an overall weighted cost of capital of 8.29%, compared to the 8.11% previously approved. This change will increase the previously approved $104.2 million to $113.6 million and the $33.6 million step increase to $34.1 million, bringing the total approved base rate increase to $147.7 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. In addition to several base rate design changes, residential base rates reflect a two-block structure which offers a lower rate for the first 1,000 kilowatt-hours of usage each month. 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.

Base Rates – PGS

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. On May 5, 2009, the FPSC approved a base rate increase of $19.2 million that became effective on Jun. 18, 2009 and reflects a return on equity of 10.75%, which is the middle of a range between 9.75% and 11.75%. The allowed equity in capital structure is 54.7% from all investor sources of capital on an allowed rate base of $560.8 million.

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 and 3) the operating cost for and a return on the capital invested in the third selective catalytic reduction (SCR) project at the Big Bend Station, which also includes 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 the refund by Tampa Electric of the 2008 final true-up amount of $35.4 million as part of the mid-course adjustment.

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, 3 and 2 entered service in 2007, 2008 and 2009, respectively, and cost recovery started in 2007, 2008 and 2009, respectively. 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' 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 $8.0 million annually effective May 2009, an increase of $4.0 million from the prior year, 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 $25.3 million and $22.7 million as of Jun. 30, 2009 and Dec. 31, 2008, respectively.

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.

Details of the regulatory assets and liabilities as of Jun. 30, 2009 and Dec. 31, 2008 are presented in the following table:

Regulatory Assets and Liabilities

(millions)	*Jun. 30, 2009*	*Dec. 31, 2008*
Regulatory assets:		
Regulatory tax asset [1]	$ 67.0	$ 65.1
Other:		
Cost recovery clauses	160.4	266.8
Postretirement benefit asset	215.7	220.3
Deferred bond refinancing costs [2]	19.8	21.7
Environmental remediation	11.1	10.8
Competitive rate adjustment	3.3	4.7
Other	14.3	8.5
Total other regulatory assets	424.6	532.8
Total regulatory assets	491.6	597.9
Less: Current portion	172.4	272.6
Long-term regulatory assets	$ 319.2	$ 325.3
Regulatory liabilities:		
Regulatory tax liability [1]	$ 15.7	$ 17.5
Other:		
Cost recovery clauses	2.4	3.4
Environmental remediation	10.4	10.6
Transmission and delivery storm reserve	25.3	22.7
Deferred gain on property sales [3]	3.8	4.1
Accumulated reserve-cost of removal	547.9	551.2
Other	1.2	0.4
Total other regulatory liabilities	591.0	592.4
Total regulatory liabilities	606.7	609.9
Less: Current portion	26.9	21.7
Long-term regulatory liabilities	$ 579.8	$ 588.2

(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 the regulatory assets and the related recovery periods:

Regulatory assets

(millions)	*Jun. 30, 2009*	*Dec. 31, 2008*
Clause recoverable [1]	$ 163.7	$ 271.5
Components of rate base [2]	223.9	227.7
Regulatory tax assets [3]	67.0	65.1
Capital structure and other [3]	37.0	33.6
Total	$ 491.6	$ 597.9

(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.

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 six month periods ended Jun. 30, 2009 and Jun. 30, 2008, the company recorded $0.5 million and $0.4 million, respectively, of pre-tax charges for interest only. No amounts have been recorded for penalties for the six month periods ended Jun. 30, 2009 and Jun. 30, 2008.

During the six month periods ended Jun. 30, 2009 and Jun. 30, 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. There have been no significant changes to these benefit plans during the current year.

Pension Expense

(millions)	*Pension Benefits*		*Other Postretirement Benefits*	
Three months ended Jun. 30,	*2009*	*2008*	*2009*	*2008*
Components of net periodic benefit expense				
Service cost	$ 3.9	$ 3.9	$ 0.7	$ 1.0
Interest cost on projected benefit obligations	8.5	8.0	2.8	3.0
Expected return on assets	(9.4)	(9.8)	-	-
Amortization of:				
Transition obligation	-	-	0.6	0.6
Prior service (benefit) cost	(0.1)	(0.1)	0.2	0.4
Actuarial loss	2.5	1.0	-	-
Net pension expense recognized in the TECO Energy Consolidated Condensed Statements of Income	$ 5.4	$ 3.0	$ 4.3	$ 5.0
Six months ended Jun. 30,				
Components of net periodic benefit expense				
Service cost	$ 7.8	$ 7.7	$ 1.5	$ 2.1
Interest cost on projected benefit obligations	16.8	15.9	5.6	6.0
Expected return on assets	(18.9)	(19.5)	-	-
Amortization of:				
Transition obligation	-	-	1.1	1.2
Prior service (benefit) cost	(0.2)	(0.2)	0.4	0.8
Actuarial loss	4.3	2.0	-	-
Pension expense	9.8	5.9	8.6	10.1
Settlement cost	-	0.9	-	-
Net pension expense recognized in the TECO Energy Consolidated Condensed Statements of Income	$ 9.8	$ 6.8	$ 8.6	$ 10.1

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. During the three months ended Jun. 30, 2009, the pension plan trust experienced a net gain on its invested assets, offsetting the net loss experienced by the trust during the first quarter of 2009.

Effective Dec. 31, 2006, in accordance with FAS 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans*, TECO Energy adjusted its postretirement benefit obligations and recorded other comprehensive income (loss) to reflect the unamortized transition obligation, prior service cost, and actuarial gains and losses of its postretirement benefit plans. The adjustment to other comprehensive income was net of amounts that, for regulatory purposes prescribed by FAS 71, were recorded as regulatory assets for Tampa Electric Company. For the three months and six months ended Jun. 30, 2009, TECO Energy and its subsidiaries reclassed \$0.6 million and \$1.1 million, respectively, 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 and six months ended Jun. 30, 2009, Tampa Electric Company reclassed \$2.6 million and \$4.6 million, respectively, of unamortized transition obligation, prior service cost and actuarial gains and losses from regulatory assets to net income as part of periodic benefit expense.

6. Short-Term Debt

At Jun. 30, 2009 and Dec. 31, 2008, the following credit facilities and related borrowings existed:

Credit Facilities

	Jun. 30, 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	$ 60.0	$ 6.3	$ 325.0	$ -	$ 1.4
1-year accounts receivable facility	150.0	99.0	-	150.0	29.0	-
TECO Energy/TECO Finance:						
5-year facility (2)	200.0	29.0	7.1	200.0	64.0	7.1
Total	$ 675.0	$ 188.0	$ 13.4	$ 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 7.0 to 125.0 basis points. The weighted-average interest rate on outstanding amounts payable under the credit facilities at Jun. 30, 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 and six months ended Jun. 30, 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 Jun. 30,*			*Six months ended Jun. 30,*		
(millions)	*Gross*	*Tax*	*Net*	*Gross*	*Tax*	*Net*
2009						
Unrealized gain on cash flow hedges	$ 6.3	$ (2.3)	$ 4.0	$ 3.2	$ (1.2)	$ 2.0
Add: Loss reclassified to net income	6.5	(2.4)	4.1	13.5	(5.0)	8.5
Gain on cash flow hedges	12.8	(4.7)	8.1	16.7	(6.2)	10.5
Amortization of unrecognized benefit costs	0.6	(0.2)	0.4	1.1	(0.4)	0.7
Reclassification to earnings loss on available-for-sale securitie	-	-	-	1.7	-	1.7
Total other comprehensive income	$ 13.4	$ (4.9)	$ 8.5	$ 19.5	$ (6.6)	$ 12.9
2008						
Unrealized gain (loss) on cash flow hedges	$ 5.7	$ (2.1)	$ 3.6	$ (4.0)	$ 1.5	$ (2.5)
Add: Loss reclassified to net income	0.5	(0.2)	0.3	0.6	(0.2)	0.4
Gain (loss) on cash flow hedges	6.2	(2.3)	3.9	(3.4)	1.3	(2.1)
Amortization of unrecognized benefit costs	0.5	(0.6)	(0.1)	1.1	(0.8)	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 income (loss)	$ 6.7	$ (2.9)	$ 3.8	$ (20.9)	$ 7.3	$ (13.6)

Accumulated Other Comprehensive Income (Loss)		
(millions)	*Jun. 30, 2009*	*Dec. 31, 2008*
Unrecognized pension losses and prior service costs[(2)]	$ (29.2)	$ (29.8)
Unrecognized other benefit losses, prior service costs and transition obligations[(3)]	10.7	10.6
Net unrealized losses from cash flow hedges [(4)]	(14.6)	(25.1)
Net unrecognized loss on available-for-sale securities	-	(1.7)
Total accumulated other comprehensive loss	$ (33.1)	$ (46.0)

(1) Amount relates to an off-shore investment not subject to U.S. Federal income tax.
(2) Net of tax benefit of $18.1 million and $18.4 million as of Jun. 30, 2009 and Dec. 31, 2008, respectively.
(3) Net of tax expense of $6.4 million and $6.3 million as of Jun. 30, 2009 and Dec. 31, 2008, respectively.
(4) Net of tax benefit of $8.8 million and $15.0 million as of Jun. 30, 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.

(millions, except per share amounts)	*Three months ended Jun. 30,* 2009	2008	*Six months ended Jun. 30,* 2009	2008
Basic earnings per share				
Net income	$ 60.9	$ 51.4	$ 95.6	$ 82.2
Amount allocated to nonvested participating shareholders	(0.6)	(0.3)	(0.8)	(0.5)
Income available to common shareholders - basic	$ 60.3	$ 51.1	$ 94.8	$ 81.7
Average shares outstanding common	211.7	210.4	211.6	210.1
Basic earnings per share	$ 0.29	$ 0.24	$ 0.45	$ 0.39
Diluted earnings per share				
Net income	$ 60.9	$ 51.4	$ 95.6	$ 82.2
Amount allocated to nonvested participating shareholders	(0.6)	(0.3)	(0.8)	(0.5)
Income available to common shareholders - diluted	$ 60.3	$ 51.1	$ 94.8	$ 81.7
Average shares outstanding common	211.7	210.4	211.6	210.1
Assumed conversions of stock options, unvested restricted stock and contingent performance shares, net	0.8	1.7	0.7	1.5
Adjusted average shares outstanding common - diluted	212.5	212.1	212.3	211.6
Diluted earnings per share	$ 0.29	$ 0.24	$ 0.45	$ 0.39
Anti-dilutive shares	5.9	4.2	6.5	4.5

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 Jun. 30, 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 consolidated condensed 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

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 Jun. 30, 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 Jun. 30, 2009*
Tampa Electric					
Letters of credit	$ -	$ -	$ 0.3	$ 0.3	$ -
Guarantees:					
Fuel purchase/energy management (2)	-	-	20.0	20.0	2.8
	-	-	20.3	20.3	2.8
TECO Coal					
Letters of credit	-	-	6.8	6.8	-
Guarantees: Fuel purchase related (2)	-	-	1.4	1.4	1.8
	-	-	8.2	8.2	1.8
Other subsidiaries					
Guarantees:					
Fuel purchase/energy management (2)	94.8	-	2.9	97.7	11.0
Total	$ 94.8	$ -	$ 31.4	$ 126.2	$ 15.6

Letters of Credit-Tampa Electric Company

(millions) *Letters of Credit for the Benefit of:*	*2009*	*2010-2013*	*After (1) 2013*	*Total*	*Liabilities Recognized at Jun. 30, 2009*
Tampa Electric					
Letters of credit	$ 4.9	$ -	$ 1.4	$ 6.3	$ 5.2
Total	$ 4.9	$ -	$ 1.4	$ 6.3	$ 5.2

(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 Jun. 30, 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 Jun. 30, 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.

Segment Information [1]

(millions) *Three months ended Jun. 30,*	*Tampa Electric*	*Peoples Gas*	*TECO Coal*	*TECO [2] Guatemala*	*Other & Eliminations*	*TECO Energy*
2009						
Revenues - external	$ 563.2	$ 99.7	$ 160.2	$ 2.0	$ 0.1	$ 825.2
Sales to affiliates	0.4	3.4	-	-	(3.8)	-
Total revenues	563.6	103.1	160.2	2.0	(3.7)	825.2
Equity earnings of unconsolidated affiliates	-	-	-	12.9	-	12.9
Depreciation	49.3	11.0	10.8	0.2	-	71.3
Total interest charges[1]	28.7	4.8	1.9	3.1	17.9	56.4
Internally allocated interest [1]	-	-	1.7	3.1	(4.8)	-
Provision (benefit) for taxes	27.8	2.9	1.7	-	(5.1)	27.3
Net income (loss) from continuing operations	$ 48.5	$ 4.6	$ 10.1	$ 7.9	$ (10.2)	$ 60.9
2008						
Revenues - external	$ 545.7	$ 184.3	$ 155.2	$ 2.0	$ -	$ 887.2
Sales to affiliates	0.4	-	-	-	(0.4)	-
Total revenues	546.1	184.3	155.2	2.0	(0.4)	887.2
Equity earnings of unconsolidated affiliates	-	-	-	21.6	-	21.6
Depreciation	45.0	10.3	9.3	0.2	0.1	64.9
Total interest charges[1]	27.9	4.5	2.0	3.7	17.8	55.9
Internally allocated interest [1]	-	-	1.5	3.6	(5.1)	-
Provision (benefit) for taxes	23.6	3.4	0.2	2.1	(6.9)	22.4
Net income (loss) from continuing operations	$ 40.2	$ 5.3	$ 4.2	$ 14.9	$ (13.2)	$ 51.4

(millions) *Six months ended Jun. 30,*	*Tampa Electric*	*Peoples Gas*	*TECO Coal*	*TECO [2] Guatemala*	*Other & Eliminations*	*TECO Energy*
2009						
Revenues - external	$ 1,070.5	$ 246.2	$ 328.3	$ 4.1	$ 0.1	$ 1,649.2
Sales to affiliates	0.7	9.9	-	-	(10.6)	-
Total revenues	1,071.2	256.1	328.3	4.1	(10.5)	1,649.2
Equity earnings of unconsolidated affiliates	-	-	-	21.7	-	21.7
Depreciation	97.3	21.8	21.4	0.4	0.1	141.0
Total interest charges[1]	56.9	9.5	3.7	6.3	36.3	112.7
Internally allocated interest [1]	-	-	3.2	6.2	(9.4)	-
Provision (benefit) for taxes	37.2	10.1	3.0	9.6	(14.8)	45.1
Net income (loss) from continuing operations	$ 66.8	$ 15.8	$ 18.1	$ 21.1	$ (26.2)	$ 95.6
2008						
Revenues - external	$ 1,006.9	$ 363.3	$ 304.3	$ 4.3	$ 0.1	$ 1,678.9
Sales to affiliates	0.7	-	-	-	(0.7)	-
Total revenues	1,007.6	363.3	304.3	4.3	(0.6)	1,678.9
Equity earnings of unconsolidated affiliates	-	-	-	39.0	-	39.0
Depreciation	90.2	20.6	18.5	0.4	0.2	129.9
Total interest charges[1]	57.3	8.7	4.5	7.5	35.6	113.6
Internally allocated interest [1]	-	-	3.8	7.4	(11.2)	-
Provision (benefit) for taxes	32.1	9.8	2.1	4.0	(12.5)	35.5
Net income (loss) from continuing operations	$ 56.1	$ 15.3	$ 11.7	$ 25.4	$ (26.3)	$ 82.2

Segment Information (1)

(millions)	Tampa Electric	Peoples Gas	TECO Coal	TECO (2) Guatemala	Other & Eliminations	TECO Energy
At Jun. 30, 2009						
Goodwill	$ -	$ -	$ -	$ 59.4	$ -	$ 59.4
Investment in unconsolidated affiliates	-	-	-	273.6	-	273.6
Other non-current investments	-	-	-	-	9.8	9.8
Total assets	$ 5,684.7	$ 851.3	$ 323.7	$ 378.5	$ (8.1)	$ 7,230.1
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 $12.7 million and $29.6 million for the three months ended Jun. 30, 2009 and 2008, respectively and $31.4 million and $59.5 million for the six months ended Jun. 30, 2009 and 2008, respectively. Net income from continuing operations for the six months ended Jun. 30, 2009 includes the gain on the sale of a 16.5% interest in the Central American fiber optic telecommunications provider Navega (See **Note 13**).

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 Jun. 30, 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 Jun. 30, 2009 and Dec. 31, 2008:

	Total Derivatives	
(millions)	*Jun. 30, 2009*	*Dec. 31, 2008*
Current assets	$ 0.2	$ -
Long-term assets	0.6	0.1
Total assets	$ 0.8	$ 0.1
Current liabilities[1]	$ 113.7	$ 141.8
Long-term liabilities	10.3	19.4
Total liabilities	$ 124.0	$ 161.2

(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 Sheets reflect the company's net positions reduced by posted collateral of $9.7 million at Dec. 31, 2008, permitted by FSP FIN 39-1, *Amendment of FASB Interpretation No. 39.* As of Jun. 30, 2009, there was no outstanding collateral held or posted with counterparties.

The following table presents the derivative hedges of heating oil contracts at Jun. 30, 2009 and Dec. 31, 2008 to limit the exposure to changes in the market price for diesel fuel:

	Heating Oil Derivatives	
(millions)	*Jun. 30, 2009*	*Dec. 31, 2008*
Current assets	$ -	$ -
Long-term asset	-	-
Total assets	$ -	$ -
Current liability	$ 9.5	$ 21.4
Long-term liability	1.0	4.6
Total liabilities	$ 10.5	$ 26.0

The following table presents the derivative hedges of natural gas contracts at Jun. 30, 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)	*Jun. 30, 2009*	*Dec. 31, 2008*
Current assets	$ 0.2	$ -
Long-term asset	0.6	0.1
Total assets	$ 0.8	$ 0.1
Current liability	$ 104.2	$ 120.4
Long-term liability	9.3	14.8
Total liabilities	$ 113.5	$ 135.2

The ending balance in accumulated other comprehensive income (AOCI) related to the cash flow hedges and previously settled interest rate swaps at Jun. 30, 2009 is a net loss of $14.6 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 Jun. 30, 2009:

	Derivatives Designated As Hedging Instruments			
	Asset Derivatives		Liability Derivatives	
(millions) *at Jun. 30, 2009*	*Balance Sheet Location*	*Fair Value*	*Balance Sheet Location*	*Fair Value*
Commodity Contracts:				
Heating oil derivatives:				
Current	Derivative assets	$ -	Derivative liabilities	$ 9.5
Long-term	Derivative assets	-	Derivative liabilities	1.0
Natural gas derivatives:				
Current	Derivative assets	0.2	Derivative liabilities	104.2
Long-term	Derivative assets	0.6	Derivative liabilities	9.3
Total derivatives designated as hedging instruments		$ 0.8		$ 124.0

The following table presents the effect of energy related derivatives on the fuel recovery clause mechanism in the balance sheet as of Jun. 30, 2009:

	Asset Derivatives		Liability Derivatives	
(millions) *at Jun. 30, 2009*	*Balance Sheet Location* [(1)]	*Fair Value*	*Balance Sheet Location* [(1)]	*Fair Value*
Commodity Contracts:				
Natural gas derivatives:				
Current	Regulatory liabilities	$ 0.2	Regulatory assets	$ 103.8
Long-term	Regulatory liabilities	0.6	Regulatory assets	9.3
Total		$ 0.8		$ 113.1

(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 Consolidated Condensed Statements of Income.

Based on the fair value of the instruments at Jun. 30, 2009, net pretax losses of $103.6 million are expected to be reclassified from regulatory assets or liabilities to the Consolidated Condensed 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 Jun. 30, 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[(1)]		
Interest rate contracts:	$	-	Interest expense	$	(0.6)
Commodity Contracts:					
Heating oil derivatives		4.0	Mining related costs		(3.3)
Natural gas derivatives		-	Mining related costs		(0.2)
Total	$	4.0		$	(4.1)

(1) Changes in OCI and AOCI 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 Jun. 30, 2009, all hedges were effective.

The following table presents the derivative activity for instruments classified as qualifying cash flow hedges for the quarter ended Jun. 30, 2009:

(millions) *For the quarter ended Jun. 30, 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	$	(10.5)	$	4.0	$	(3.3)
Interest rate swaps		-		-		(0.6)
Natural gas derivatives		(112.7)		-		(0.2)
Total	$	(123.2)	$	4.0	$	(4.1)

(1) Changes in OCI and AOCI 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 by commodity type the company's derivative volumes at Jun. 30, 2009 that are expected to settle each year:

(millions)	Heating Oil Contracts (Gallons)		Natural Gas Contracts (MMBTUs)	
Year	Physical	Financial	Physical	Financial
2009	-	6.4	-	28.2
2010	-	6.6	-	20.5
2011	-	3.4	-	4.5
Total	-	16.4	-	53.2

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 Jun. 30, 2009, substantially all 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 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 these 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. As of Jun. 30, 2009, substantially all positions with counterparties are net liabilities.

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 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 Jun. 30, 2009:

(millions) At Jun. 30, 2009 *Contingent Feature*	Fair Value Asset/ (Liability)	Derivative Exposure Asset/ (Liability)	Posted Collateral
Credit Rating	$ 123.2	$ 123.5	$ -
Total	$ 123.2	$ 123.5	$ -

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 Jun. 30, 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 Jun. 30, 2009*			
(millions)	*Level 1*	*Level 2*	*Level 3*	*Total*
Assets				
Natural gas swaps	$ -	$ 0.8	$ -	$ 0.8
Other investments	-	-	1.9	1.9
Total	$ -	$ 0.8	$ 1.9	$ 2.7
Liabilities				
Natural gas swaps	$ -	$ 113.4	$ -	$ 113.4
Heating oil swaps	-	10.6	-	10.6
Total	$ -	$ 124.0	$ -	$ 124.0

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 $1.9 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.

The fair value of TECO Energy's long-term debt at Jun. 30, 2009 is $3,210.8 million. The determination of fair value for these instruments includes obtaining prices from third-party financial institutions and in some cases utilizing a model to discount the future cash flows produced by the instruments by a rate determined by applying a spread based on TECO Energy's or Tampa Electric Company's credit ratings (also provided by third-party financial institutions) to U.S. Treasury rates.

Other investments reflect an auction rate security backed by pools of student loans. As a result of auction failures and the lack of an alternative active market, the valuation technique for this security 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 approximating current market spreads for similar securities. The valuation at Jun. 30, 2009 reflects a discount rate of 15%; a 100 basis point change in the discount rate results in a $0.2 million change in value. Settlements during the quarter reflect sales of securities at fair value of $7.3 million.

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 security 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 Jun. 30, 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
Transfers to Level 3	-
Change in fair market value included in earnings	-
Settled	(7.3)
Balance at Jun. 30, 2009	$ 1.9

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.

14. Subsequent Events

The company has evaluated all events subsequent to the balance sheet date of Jun. 30, 2009 through the date of issuance, Jul. 31, 2009.

Organizational changes

On Jul. 29, 2009 the Board of Directors of TECO Energy approved a new executive management structure. The company expects to recognize a restructuring charge in the quarter ending Sep. 30, 2009 as a result of this management change and additional steps that the company expects to undertake to further reduce expenses by integrating operations and support functions.

Issuance of Tampa Electric Company 6.10% Notes due 2018

On Jul. 7, 2009, Tampa Electric Company completed an offering of $100 million aggregate principal amount of 6.10% Notes due 2018 (the "Notes"). The Notes form a single series and are fungible with Tampa Electric Company's 6.10% notes due 2018 issued on May 16, 2008 in the aggregate principal amount of $150 million. The Notes were sold at 102.988% of par. The offering resulted in net proceeds to Tampa Electric Company (after deducting underwriting discounts and commissions and estimated offering expenses) of approximately $102.1 million. Net proceeds were used to repay short-term debt and for general corporate purposes. Tampa Electric Company may redeem all or any part of the Notes at its option at any time and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of Notes to be redeemed or (ii) the present value of the remaining payments of principal and interest on the Notes to be redeemed, discounted at an applicable treasury rate (as defined in the Indenture), plus 35 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date.

Tampa Electric Company's Motion for Reconsideration

On May 15, 2009, Tampa Electric filed a Motion for Reconsideration regarding the calculation of the annual revenue requirements approved by the FPSC. On Jul. 14, 2009, the FPSC approved Tampa Electric's Motion (see **Note 3**).

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 Jun. 30, 2009 and Dec. 31, 2008, and the results of operations and cash flows for the periods ended Jun. 30, 2009 and 2008. The results of operations for the three months and six months ended Jun. 30, 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/A for the year ended Dec. 31, 2008 and to the notes on pages 34-46 of this report.

INDEX TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS

TAMPA ELECTRIC COMPANY
Consolidated Condensed Balance Sheets
Unaudited

Assets *(millions)*	*Jun. 30, 2009*	*Dec. 31, 2008*
Property, plant and equipment		
Utility plant in service		
Electric	$ 5,730.0	$ 5,514.9
Gas	993.3	964.4
Construction work in progress	458.5	462.4
Property, plant and equipment, at original costs	7,181.8	6,941.7
Accumulated depreciation	(1,923.7)	(1,868.5)
	5,258.1	5,073.2
Other property	4.3	4.5
Total property, plant and equipment, net	5,262.4	5,077.7
Current assets		
Cash and cash equivalents	5.6	3.6
Receivables, less allowance for uncollectibles of $2.6 and $1.6 at Jun. 30, 2009 and Dec. 31, 2008, respectively	256.1	236.1
Inventories, at average cost		
Fuel	105.8	76.8
Materials and supplies	57.3	61.8
Current regulatory assets	172.4	272.6
Current derivative asset	0.2	-
Taxes receivable	-	0.2
Prepayments and other current assets	13.3	14.1
Total current assets	610.7	665.2
Deferred debits		
Unamortized debt expense	20.8	22.3
Long-term regulatory assets	319.2	325.3
Long-term derivative assets	0.6	0.1
Other	16.9	18.0
Total deferred debits	357.5	365.7
Total assets	$ 6,230.6	$ 6,108.6

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

TAMPA ELECTRIC COMPANY
Consolidated Condensed Balance Sheets – continued
Unaudited

Liabilities and Capital (millions)	*Jun. 30, 2009*	*Dec. 31, 2008*
Capital		
Common stock	$ 1,802.4	$ 1,802.4
Accumulated other comprehensive loss	(6.5)	(6.8)
Retained earnings	300.2	295.0
Total capital	2,096.1	2,090.6
Long-term debt, less amount due within one year	1,895.0	1,894.8
Total capitalization	3,991.1	3,985.4
Current liabilities		
Long-term debt due within one year	5.5	5.5
Notes payable	159.0	29.0
Accounts payable	220.1	262.5
Customer deposits	148.6	144.6
Current regulatory liabilities	26.9	21.7
Current derivative liabilities	103.8	119.4
Current deferred income taxes	6.8	36.6
Interest accrued	31.0	27.1
Taxes accrued	36.0	20.1
Other	11.5	11.2
Total current liabilities	749.2	677.7
Deferred credits		
Non-current deferred income taxes	498.6	447.6
Investment tax credits	11.0	11.2
Long-term derivative liabilities	9.3	14.8
Long-term regulatory liabilities	579.8	588.2
Other	391.6	383.7
Total deferred credits	1,490.3	1,445.5
Total liabilities and capital	$6,230.6	$6,108.6

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

TAMPA ELECTRIC COMPANY
Consolidated Condensed Statements of Income and Comprehensive Income
Unaudited

(millions)	*Three months ended Jun. 30,* *2009*	*2008*
Revenues		
Electric (includes franchise fees and gross receipts taxes of $22.7 in 2009 and $21.5 in 2008)	$ 563.5	$ 546.0
Gas (includes franchise fees and gross receipts taxes of $5.5 in 2009 and $6.1 in 2008)	99.7	184.3
Total revenues	663.2	730.3
Expenses		
Operations		
Fuel	225.5	176.2
Purchased power	56.1	115.9
Cost of natural gas sold	50.9	133.8
Other	80.9	71.9
Maintenance	31.8	32.3
Depreciation	60.3	55.3
Taxes, federal and state	30.4	26.4
Taxes, other than income	44.2	44.3
Total expenses	580.1	656.1
Income from operations	83.1	74.2
Other income		
Allowance for other funds used during construction	2.5	1.7
Taxes, non-utility federal and state	(0.3)	(0.6)
Other income, net	1.2	2.5
Total other income	3.4	3.6
Interest charges		
Interest on long-term debt	31.4	30.2
Other interest	3.0	2.8
Allowance for borrowed funds used during construction	(1.0)	(0.7)
Total interest charges	33.4	32.3
Net income	53.1	45.5
Other comprehensive income (loss), net of tax		
Net unrealized gain (loss) on cash flow hedges	0.1	2.8
Total other comprehensive income (loss), net of tax	0.1	2.8
Comprehensive income	$ 53.2	$ 48.3

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

TAMPA ELECTRIC COMPANY
Consolidated Condensed Statements of Income and Comprehensive Income
Unaudited

(millions)	*Six months ended Jun. 30,* 2009	2008
Revenues		
Electric (includes franchise fees and gross receipts taxes of $44.8 in 2009 and $40.4 in 2008)	$ 1,071.0	$ 1,007.4
Gas (includes franchise fees and gross receipts taxes of $13.5 in 2009 and $13.6 in 2008)	246.2	363.3
Total revenues	1,317.2	1,370.7
Expenses		
Operations		
Fuel	454.2	339.8
Purchased power	98.3	197.8
Cost of natural gas sold	139.2	252.8
Other	157.8	143.1
Maintenance	68.0	66.4
Depreciation	119.1	110.8
Taxes, federal and state	46.9	41.0
Taxes, other than income	92.4	87.9
Total expenses	1,175.9	1,239.6
Income from operations	141.3	131.1
Other income		
Allowance for other funds used during construction	5.8	3.0
Taxes, non-utility federal and state	(0.4)	(0.9)
Other income, net	2.2	4.0
Total other income	7.6	6.1
Interest charges		
Interest on long-term debt	62.8	61.6
Other interest	5.8	5.4
Allowance for borrowed funds used during construction	(2.3)	(1.2)
Total interest charges	66.3	65.8
Net income	82.6	71.4
Other comprehensive income (loss), net of tax		
Net unrealized gain (loss) on cash flow hedges	0.3	(2.2)
Total other comprehensive income (loss), net of tax	0.3	(2.2)
Comprehensive income	$ 82.9	$ 69.2

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

TAMPA ELECTRIC COMPANY
Consolidated Condensed Statements of Cash Flows
Unaudited

(millions)	*Six months ended Jun. 30, 2009*	*2008*
Cash flows from operating activities		
Net income	$ 82.6	$ 71.4
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation	119.1	110.8
Deferred income taxes	17.3	55.0
Investment tax credits, net	(0.2)	(0.9)
Allowance for funds used during construction	(5.8)	(3.0)
Deferred recovery clause	83.3	(92.4)
Receivables, less allowance for uncollectibles	(20.0)	(41.4)
Inventories	(24.5)	(13.4)
Prepayments	0.8	(5.2)
Taxes accrued	16.1	25.5
Interest accrued	4.0	6.9
Accounts payable	(12.1)	93.5
Gain on sale of assets	(0.3)	(0.1)
Other	22.5	(8.8)
Cash flows from operating activities	282.8	197.9
Cash flows from investing activities		
Capital expenditures	(339.3)	(247.1)
Allowance for funds used during construction	5.8	3.0
Net proceeds from sale of assets	0.1	-
Cash flows used in investing activities	(333.4)	(244.1)
Cash flows from financing activities		
Proceeds from long-term debt	-	327.9
Common stock	-	150.0
Repayment of long-term debt/Purchase in lieu of redemption	-	(286.7)
Net increase (decrease) in short-term debt	130.0	(25.0)
Dividends	(77.4)	(71.8)
Cash flows from financing activities	52.6	94.4
Net increase in cash and cash equivalents	2.0	48.2
Cash and cash equivalents at beginning of period	3.6	11.9
Cash and cash equivalents at end of period	$ 5.6	$ 60.1

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 Jun. 30, 2009 and Dec. 31, 2008, and the results of operations and cash flows for the periods ended Jun. 30, 2009 and 2008. The results of operations for the three month and six month periods ended Jun. 30, 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 Jun. 30, 2009 and Dec. 31, 2008, unbilled revenues of $56.6 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 $56.1 million and $98.3 million for the three months and six months ended Jun. 30, 2009, respectively, compared to $115.9 million and $197.8 million for the three months and six months ended Jun. 30, 2008, respectively.

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 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 $28.2 million and $58.3 million, respectively, for the three months and six months ended Jun. 30, 2009, compared to $27.6 million and $54.0 million, respectively, for the three months and six months ended Jun. 30, 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 $28.2 million and $58.2 million, respectively, for the three months and six months ended Jun. 30, 2009, compared to $27.6 million and $53.8 million, respectively, for the three months and six months ended Jun. 30, 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

The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles

In June 2009, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard (SFAS) No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles* (FAS 168). FAS 168 replaces FAS 162, *The Hierarchy of Generally Accepted Accounting Principles* (FAS 162). It names the FASB Accounting Standards Codification (Codification) as the single source of authoritative U.S. Generally Accepted Accounting Principles (GAAP) for non-governmental entities recognized by the FASB. FAS 168 is effective for reporting periods ending after Sep. 15, 2009, and once effective, will supersede all U.S. GAAP accounting standards, aside from rules and interpretive releases issued by the Securities and Exchange Commission (SEC). The Codification is not intended to change GAAP; rather, it will change the referencing of U.S. GAAP. Therefore, it is not expected to have an impact on the company's results of operations, statement of position or cash flows.

Accounting for Transfers of Financial Assets

In June 2009, the FASB issued SFAS No. 166, *Accounting for Transfers of Financial Assets* (FAS 166). FAS 166 revises SFAS 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities-a replacement of FASB Statement No. 125* and requires companies to provide more information about sales of securitized financial assets. It is effective for fiscal periods beginning after Nov. 15, 2009. The new requirements will not have an impact on the company's results of operations, statement of position or cash flows.

Variable Interest Entities

In June 2009, the FASB issued SFAS No.167, *Amendments to FASB Interpretation No. 46(R)* (FAS 167). FAS 167 changes the way a company determines if a variable interest entity (VIE) should be consolidated. It is effective for fiscal years beginning after Nov. 15, 2009. Tampa Electric Company is evaluating the potential effects FAS 167 may have on its results of operations, statement of position or cash flows.

Subsequent Events

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events* (FAS 165). FAS 165 requires companies to disclose the date through which they evaluated subsequent events and whether that date corresponds with the filing of their financial statements. It is effective for fiscal periods ending after Jun. 15, 2009, and the adoption does not have an effect on Tampa Electric Company's results of operations, statement of position or cash flows.

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 FASB Staff Position (FSP) 157-2, *Effective Date of FASB Statement No. 157*, 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 FAS 124-2), 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 FSP did not materially affect the company's results of operations, statement of position or cash flows. The company adopted this FSP effective Apr. 1, 2009.

FSP FAS 115-2 and FAS 124-2 is 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. The FSP did not materially affect the company's results of operations, statement of position or cash flows. The company adopted this FSP effective Apr. 1, 2009.

FSP FAS 107-1 and APB 28-1 requires 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 had no effect on the company's results of operations, statement of position or cash flows. The company adopted this FSP effective Apr. 1, 2009.

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. FSP FAS 132(R)-1 will be significant to the company's financial statement disclosures but 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 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. On Mar. 17, 2009, the FPSC approved an increase to base rates, effective on May 7, 2009, of $104.2 million that reflects a return on equity of 11.25%, which is the middle of a range between 10.25% and 12.25%. Additionally, the FPSC approved a step increase of $33.6 million effective Jan. 1, 2010 for capital additions placed in service in 2009 bringing the total approved base rate increase to $137.8 million.

On May 15, 2009, Tampa Electric filed a Motion for Reconsideration regarding the calculation of the annual revenue requirements approved by the FPSC. On Jul. 14, 2009, the FPSC approved Tampa Electric's Motion resulting in an overall weighted cost of capital of 8.29%, compared to the 8.11% previously approved. This change will increase the previously approved $104.2 million to $113.6 million and the $33.6 million step increase to $34.1 million, bringing the total approved base rate increase to $147.7 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. In addition to several base rate design changes, residential base rates reflect a two-block structure which offers a lower rate for the first 1,000 kilowatt-hours of usage each month. 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.

Base Rates – PGS

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. On May 5, 2009, the FPSC approved a base rate increase of $19.2 million that became effective on Jun. 18, 2009 and reflects a return on equity of 10.75%, which is the middle of a range between 9.75% and 11.75%. The allowed equity in capital structure is 54.7% from all investor sources of capital on an allowed rate base of $560.8 million.

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 and 3) the operating cost for and a return on the capital invested in the third selective catalytic reduction (SCR) project at the Big Bend Station, which also includes 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 the refund by Tampa Electric of the 2008 final true-up amount of $35.4 million as part of the mid-course adjustment.

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, 3 and 2 entered service in 2007, 2008 and 2009, respectively, and cost recovery started in 2007, 2008 and 2009, respectively. 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' 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 $8.0 million annually effective May 2009, an increase of $4.0 million from the prior year, 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 $25.3 million and $22.7 million as of Jun. 30, 2009 and Dec. 31, 2008, respectively.

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.

Details of the regulatory assets and liabilities as of Jun. 30, 2009 and Dec. 31, 2008 are presented in the following table:

Regulatory Assets and Liabilities

(millions)	*Jun. 30, 2009*	*Dec. 31, 2008*
Regulatory assets:		
Regulatory tax asset [1]	$ 67.0	$ 65.1
Other:		
Cost recovery clauses	160.4	266.8
Postretirement benefit asset	215.7	220.3
Deferred bond refinancing costs [2]	19.8	21.7
Environmental remediation	11.1	10.8
Competitive rate adjustment	3.3	4.7
Other	14.3	8.5
Total other regulatory assets	424.6	532.8
Total regulatory assets	491.6	597.9
Less: Current portion	172.4	272.6
Long-term regulatory assets	$ 319.2	$ 325.3
Regulatory liabilities:		
Regulatory tax liability [1]	$ 15.7	$ 17.5
Other:		
Cost recovery clauses	2.4	3.4
Environmental remediation	10.4	10.6
Transmission and delivery storm reserve	25.3	22.7
Deferred gain on property sales [3]	3.8	4.1
Accumulated reserve-cost of removal	547.9	551.2
Other	1.2	0.4
Total other regulatory liabilities	591.0	592.4
Total regulatory liabilities	606.7	609.9
Less: Current portion	26.9	21.7
Long-term regulatory liabilities	$ 579.8	$ 588.2

(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 the regulatory assets and the related recovery periods:

Regulatory assets

(millions)	*Jun. 30, 2009*	*Dec. 31, 2008*
Clause recoverable [1]	$ 163.7	$ 271.5
Components of rate base [2]	223.9	227.7
Regulatory tax assets [3]	67.0	65.1
Capital structure and other [3]	37.0	33.6
Total	$ 491.6	$ 597.9

(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.

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 six months ended Jun. 30, 2009 and Jun. 30, 2008 differ from the statutory rate principally due to state income taxes, equity portion of Allowance for Funds Used During Construction (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 Jun. 30, 2009 and 2008, respectively, was \$4.2 million and \$2.1 million for pension benefits, and \$3.4 million and \$3.5 million for other postretirement benefits. For the six months ended Jun. 30, 2009 and 2008, respectively, net benefit expenses were \$7.6 million and \$4.2 million for pension benefits, and \$6.8 million and \$7.0 million for other postretirement benefits.

Included in the benefit expenses discussed above, for the three months and six months ended Jun. 30, 2009, Tampa Electric Company reclassed \$2.6 million and \$4.6 million, respectively, 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.

6. Short-Term Debt

At Jun. 30, 2009 and Dec. 31, 2008, the following credit facilities and related borrowings existed:

Credit Facilities

	Jun. 30, 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	\$ 60.0	\$ 6.3	\$ 325.0	\$ -	\$ 1.4
1-year accounts receivable facility	150.0	99.0	-	150.0	29.0	-
Total	\$ 475.0	\$ 159.0	\$ 6.3	\$ 475.0	\$ 29.0	\$ 1.4

(1) Borrowings outstanding are reported as notes payable.

These credit facilities require commitment fees ranging from 7.0 to 125.0 basis points. The weighted-average interest rate on outstanding amounts payable under the credit facilities at Jun. 30, 2009 and Dec. 31, 2008 was 1.04% and 2.13%, respectively.

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 Jun. 30, 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 consolidated condensed 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 Jun. 30, 2009, Tampa Electric Company was not obligated under guarantees, but had $6.3 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 Jun. 30, 2009*
Tampa Electric					
Letters of credit	$ 4.9	$ -	$ 1.4	$ 6.3	$ 5.2
Total	$ 4.9	$ -	$ 1.4	$ 6.3	$ 5.2

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

At Jun. 30, 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 Jun. 30, 2009, Tampa Electric Company was in compliance with all applicable financial covenants.

8. Segment Information

(millions) *Three months ended Jun. 30,*	*Tampa Electric*	*Peoples Gas*	*Other & Eliminations*	*Tampa Electric Company*
2009				
Revenues - external	$ 563.2	$ 99.7	$ -	$ 662.9
Sales to affiliates	0.4	3.4	(3.5)	0.3
Total revenues	563.6	103.1	(3.5)	663.2
Depreciation	49.3	11.0	-	60.3
Total interest charges	28.6	4.8	-	33.4
Provision for taxes	27.8	2.9	-	30.7
Net income	$ 48.5	$ 4.6	$ -	$ 53.1
2008				
Revenues - external	$ 545.7	$ 184.3	$ -	$ 730.0
Sales to affiliates	0.4	-	(0.1)	0.3
Total revenues	546.1	184.3	(0.1)	730.3
Depreciation	45.0	10.3	-	55.3
Total interest charges	27.9	4.5	(0.1)	32.3
Provision for taxes	23.6	3.4	-	27.0
Net income	$ 40.2	$ 5.3	$ -	$ 45.5
Six months ended Jun. 30,				
2009				
Revenues - external	$ 1,070.5	$ 246.2	$ -	$ 1,316.7
Sales to affiliates	0.7	9.9	(10.1)	0.5
Total revenues	1,071.2	256.1	(10.1)	1,317.2
Depreciation	97.3	21.8	-	119.1
Total interest charges	56.8	9.5	-	66.3
Provision for taxes	37.2	10.1	-	47.3
Net income	$ 66.8	$ 15.8	$ -	$ 82.6
Total assets at Jun. 30, 2009	$ 5,439.7	$ 800.5	$ (9.6)	$ 6,230.6
2008				
Revenues - external	$ 1,006.9	$ 363.3	$ -	$ 1,370.2
Sales to affiliates	0.7	-	(0.2)	0.5
Total revenues	1,007.6	363.3	(0.2)	1,370.7
Depreciation	90.2	20.6	-	110.8
Total interest charges	57.3	8.7	(0.2)	65.8
Provision for taxes	32.1	9.8	-	41.9
Net income	$ 56.1	$ 15.3	$ -	$ 71.4
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**).

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 Jun. 30, 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 Jun. 30, 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)	*Jun. 30, 2009*	*Dec. 31, 2008*
Current assets	$ 0.2	$ -
Long-term assets	0.6	0.1
Total assets	$ 0.8	$ 0.1
Current liabilities(1)	$ 103.8	$ 120.1
Long-term liabilities	9.3	14.8
Total liabilities	$ 113.1	$ 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 Tampa Electric Company's net positions reduced by posted collateral of $0.7 million permitted by FSP FIN 39-1, *Amendment of FASB Interpretation No. 39.* As of Jun. 30, 2009, there was no outstanding collateral held or posted with counterparties.

The ending balance in accumulated other comprehensive income (AOCI) related to previously settled interest rate swaps at Jun. 30, 2009 is a net loss of $6.5 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 Jun. 30, 2009:

	Asset Derivatives		Liability Derivatives	
(millions)	Balance Sheet	Fair	Balance Sheet	Fair
at Jun. 30, 2009	Location[1]	Value	Location[1]	Value
Commodity Contracts:				
Natural gas derivatives:				
Current	Regulatory liabilities	$ 0.2	Regulatory assets	$ 103.8
Long-term	Regulatory liabilities	0.6	Regulatory assets	9.3
Total		$ 0.8		$ 113.1

(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 Consolidated Condensed Statements of Income.

Based on the fair value of the instruments at Jun. 30, 2009, net pretax losses of $103.6 million are expected to be reclassified from regulatory assets to the Consolidated Condensed 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 Jun. 30, 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	$ (0.1)	Interest expense	$ -
Total	$ -		$ (0.1)		$ -

(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 Jun. 30, 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 Dec. 31, 2011 for the financial natural gas contracts. The following table presents by commodity type the company's derivative volumes at Jun. 30, 2009 that are expected to settle each year:

(millions)	(MMBTUs)	
Year	Physical	Financial
2009	-	28.1
2010	-	20.5
2011	-	4.5
Total	-	53.1

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 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 Jun. 30, 2009, substantially all 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 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 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. As of Jun. 30, 2009, substantially all positions with counterparties are net liabilities.

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 Jun. 30, 2009:

(millions) At Jun. 30, 2009 *Contingent Feature*	Fair Value Asset/ (Liability)	Derivative Exposure Asset/ (Liability)	Posted Collateral
Credit Rating	$ (112.3)	$ (112.5)	$ -
Total	$ (112.3)	$ (112.5)	$ -

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 Jun. 30, 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 Jun. 30, 2009*			
(millions)	*Level 1*	*Level 2*	*Level 3*	*Total*
Assets				
Natural gas swaps	$ -	$ 0.8	$ -	$ 0.8
Total	$ -	$ 0.8	$ -	$ 0.8
Liabilities				
Natural gas swaps	$ -	$ 113.1	$ -	$ 113.1
Total	$ -	$ 113.1	$ -	$ 113.1

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.

The fair value of Tampa Electric Company's long-term debt at Jun. 30, 2009 is $1,934.7 million. The determination of fair value for these instruments includes obtaining prices from third party financial institutions and in some cases utilizing a model to discount the future cash flows produced by the instruments by a rate determined by applying a spread based on Tampa Electric Company's credit ratings (also provided by third party financial institutions) to U.S. Treasury rates.

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 Jun. 30, 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	*Three months ended Jun. 30,*			*Six months ended Jun. 30,*		
(millions)	*Gross*	*Tax*	*Net*	*Gross*	*Tax*	*Net*
2009						
Unrealized gain (loss) on cash flow hedges	$ -	$ -	$ -	$ -	$ -	$ -
Add: Loss reclassified to net income	0.2	(0.1)	0.1	0.5	(0.2)	0.3
Gain on cash flow hedges	0.2	(0.1)	0.1	0.5	(0.2)	0.3
Total other comprehensive income	$ 0.2	$ (0.1)	$ 0.1	$ 0.5	$ (0.2)	$ 0.3
2008						
Unrealized gain (loss) on cash flow hedges	$ 4.5	$ (1.7)	$ 2.8	$ (3.6)	$ 1.4	$ (2.2)
Add: Loss reclassified to net income	-	-	-	-	-	-
Gain (loss) on cash flow hedges	4.5	(1.7)	2.8	(3.6)	1.4	(2.2)
Total other comprehensive income (loss)	$ 4.5	$ (1.7)	$ 2.8	$ (3.6)	$ 1.4	$ (2.2)

Accumulated Other Comprehensive Loss		
(millions)	*Jun. 30, 2009*	*Dec. 31, 2008*
Net unrealized losses from cash flow hedges (1)	$ (6.5)	$ (6.8)
Total accumulated other comprehensive loss	$ (6.5)	$ (6.8)

(1) Net of tax benefit of $4.0 million and $4.3 million as of Jun. 30, 2009 and Dec. 31, 2008, respectively.

12. Subsequent Events

Tampa Electric Company has evaluated all events subsequent to the balance sheet date of Jun. 30, 2009 through the date of issuance, Jul. 31, 2009.

Organizational changes

On Jul. 29, 2009 the Board of Directors of Tampa Electric Company approved a new executive management structure, including the establishment of a single management team over the electric and gas divisions of Tampa Electric Company. The company expects to recognize a restructuring charge in the quarter ending Sep. 30, 2009 as a result of this management change and additional steps that the company expects to undertake to further reduce expenses by integrating operations and support functions.

Issuance of Tampa Electric Company 6.10% Notes due 2018

On Jul. 7, 2009, Tampa Electric Company completed an offering of $100 million aggregate principal amount of 6.10% Notes due 2018 (the "Notes"). The Notes form a single series and are fungible with Tampa Electric Company's 6.10% notes due 2018 issued on May 16, 2008 in the aggregate principal amount of $150 million. The Notes were sold at 102.988% of par. The offering resulted in net proceeds to Tampa Electric Company (after deducting underwriting discounts and commissions and estimated offering expenses) of approximately $102.1 million. Net proceeds were used to repay short-term debt and for general corporate purposes. Tampa Electric Company may redeem all or any part of the Notes at its option at any time and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of Notes to be redeemed or (ii) the present value of the remaining payments of principal and interest on the Notes to be redeemed, discounted at an applicable treasury rate (as defined in the Indenture), plus 35 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date.

Tampa Electric Company's Motion for Reconsideration

On May 15, 2009, Tampa Electric filed a Motion for Reconsideration regarding the calculation of the annual revenue requirements approved by the FPSC. On Jul. 14, 2009, the FPSC approved Tampa Electric's Motion (see **Note 3**).

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 Management's Discussion and Analysis, except as may be required by law. Factors that could impact actual results include: regulatory actions by federal, state or local authorities; unexpected capital needs or unanticipated reductions in cash flow that affect liquidity; the ability to access capital and credit markets when required; 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 related 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; changes in the U.S. federal tax code on earnings from foreign investments that could reduce earnings; the ability to increase the utilization of the coal-fired San José Power Station versus competing oil-fired generators 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 Amendment No. 1 to Annual Report on Form 10-K/A for the period ended Dec. 31, 2008.

Earnings Summary - Unaudited

(millions, except per share amounts)	*Three months ended Jun. 30, 2009*	*Three months ended Jun. 30, 2008*	*Six months ended Jun. 30, 2009*	*Six months ended Jun. 30, 2008*
Consolidated revenues	$ 825.2	$ 887.2	$ 1,649.2	$ 1,678.9
Net income	$ 60.9	$ 51.4	$ 95.6	$ 82.2
Average common shares outstanding				
Basic	211.7	210.4	211.6	210.1
Diluted	212.5	212.1	212.3	211.6
Earnings per share - basic				
Earnings per share - basic	$ 0.29	$ 0.24	$ 0.45	$ 0.39
Earnings per share - diluted				
Earnings per share - diluted	$ 0.29	$ 0.24	$ 0.45	$ 0.39

Three Months Ended Jun. 30, 2009

TECO Energy recorded second quarter net income of $60.9 million or $0.29 per share, compared to $51.4 million or $0.24 per share in the second quarter of 2008.

Six Months Ended Jun. 30, 2009

Year-to-date net income and earnings per share were $95.6 million or $0.45 per share in 2009, compared to $82.2 million or $0.39 per share in the same period in 2008. Year-to-date net income and earnings per share include an $8.7 million gain on the sale of the telecommunication company, Navega, recorded in the first quarter at TECO Guatemala, and the $3.6 million valuation adjustment recorded in the first quarter on student-loan securities held at TECO Energy parent.

Operating Company Results:

All amounts included in the operating company and Parent / Other results discussions are after tax, unless otherwise noted.

Tampa Electric Company – Electric Division

Tampa Electric reported net income for the second quarter of $48.5 million, compared with $40.2 million for the same period in 2008. Results for the quarter reflected 4.8% higher base revenues due to the increase in base rates effective May 7, 2009, higher earnings on nitrogen oxide (NO_x) control projects, a 0.2% lower average number of customers and slightly higher operations and maintenance expenses. Net income included $2.5 million of AFUDC - equity, which represents allowed equity cost capitalized to construction costs, related to the installation of NO_x control equipment and combustion turbines for peak loads, compared with $1.7 million in the 2008 period.

In the second quarter of 2009, there was no reduction in net income due to the previous waterborne transportation disallowance for the transportation of solid fuel, which reduced net income $2.3 million 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 eliminated the annual reduction in net income that occurred in 2004 through 2008 during the previous transportation contract.

Total retail energy sales decreased 4.7% in the second quarter of 2009, compared to the same period in 2008. Although total degree days in Tampa Electric's service area were 5% above normal and 3% above the second quarter of 2008, the 15 consecutive days of rain in May, the third wettest May on record, contributed to the lower energy sales. Sales to the residential, commercial and industrial customer segments decreased 4.5%, 3.6% and 10.1%, respectively, in the second quarter, driven primarily by the weak housing market, economic conditions and the weather. Pretax base revenues increased approximately $15 million in the second quarter due to higher base rates approved by the Florida Public Service Commission for Tampa Electric effective May 7, 2009, which were partially offset by the lower number of customers and the effects of the weather.

Operations and maintenance expense, excluding all FPSC-approved cost recovery clauses, increased $0.6 million. The increase included the write-off of $0.6 million of disallowed rate case expenses, and higher employee-related expenses, including pension, that were offset by lower power generating unit maintenance and lower overhead expenses. Bad-debt expense was $0.1 million higher than in the second quarter of 2008.

Compared to the second quarter of 2008, depreciation expense increased $2.3 million, reflecting additions to facilities to serve customers. Interest expense at Tampa Electric increased slightly due to higher long-term debt balances outstanding, and interest income decreased due to lower interest rates and lower under-recovered fuel balances on which interest is accrued.

Year-to-date net income was $66.8 million, compared with $56.1 million in the 2008 period, driven primarily by the higher base revenues from the new base rates and higher earnings on NO_x control projects, partially offset by 0.2% lower average number of customers, and higher operations and maintenance expenses. Net income included $5.8 million of AFUDC - equity related to the installation of NO_x control equipment and combustion turbines for peak loads, compared with $3.0 million in the 2008 period. Sales to other utilities declined 37% from the 2008 period, reflecting lower demand and lower natural gas prices. In the 2009 year-to-date period, there was no reduction in net income due to the waterborne transportation disallowance for the transportation of solid fuel, compared to a $3.9 million reduction in the 2008 period.

In the 2009 year-to-date period, total retail energy sales decreased 2.4%, compared to the 2008 period, driven primarily by the economy, weather in the second quarter, and the 0.2% decline in the average number of customers. Total degree days in Tampa Electric's service area were 5% above normal and 6% above the prior year; however, extended periods of rain reduced sales in May. Colder winter weather in the first quarter contributed to a 0.3% increase in sales to the weather-sensitive residential customer class. Sales to commercial and industrial customers declined by 4.1% and 7.9%, respectively, primarily due to economic conditions.

Operations and maintenance expense, excluding all FPSC-approved cost recovery clauses, increased $3.5 million. The increase included the second quarter write-off of disallowed rate case expenses and higher employee related expenses that were partially offset by lower power generating unit maintenance and overhead costs. Bad-debt expense was $0.3 million higher in the 2009 year-to-date period than in 2008.

Compared to the 2008 year-to-date period, depreciation expense increased $4.0 million, reflecting additions to facilities to serve customers. Interest expense at Tampa Electric increased slightly due to higher long-term debt balances outstanding.

A summary of Tampa Electric's operating statistics for the three months and six months ended Jun. 30, 2009 and 2008 follows:

	Operating Revenues			Kilowatt-hour sales		
(millions, except average customers)	*2009*	*2008*	*% Change*	*2009*	*2008*	*% Change*
Three months ended Jun. 30,						
By Customer Type						
Residential	$ 257.6	$ 247.3	4.2	2,057.1	2,153.5	(4.5)
Commercial	173.3	161.9	7.0	1,563.6	1,621.5	(3.6)
Industrial – Phosphate	19.9	16.5	20.6	220.3	240.2	(8.3)
Industrial – Other	29.3	30.3	(3.3)	287.1	324.2	(11.4)
Other sales of electricity	50.5	46.8	7.9	450.3	464.0	(3.0)
Deferred and other revenues (1)	7.4	13.0	(43.1)	-	-	-
Total	538.0	515.8	4.3	4,578.4	4,803.4	(4.7)
Sales for resale	13.1	19.2	(31.8)	121.1	230.6	(47.5)
Other operating revenue	12.4	10.1	22.8	-	-	-
SO_2 Allowance sales	0.1	1.0	(90.0)	-	-	-
Total	$ 563.6	$ 546.1	3.2	4,699.5	5,034.0	(6.6)
Average customers (thousands)	666.4	668.0	(0.2)			
Retail output to line (kilowatt hours)				5,100.7	5,278.0	(3.4)
Six months ended Jun. 30,						
By Customer Type						
Residential	$ 508.7	$ 454.3	12.0	3,944.8	3,931.5	0.3
Commercial	339.5	309.3	9.8	2,963.5	3,089.5	(4.1)
Industrial – Phosphate	40.8	33.1	23.3	467.1	484.8	(3.7)
Industrial – Other	58.6	57.7	1.6	559.2	630.1	(11.3)
Other sales of electricity	100.5	89.4	12.4	864.8	882.6	(2.0)
Deferred and other revenues (1)	(25.1)	5.8	-	-	-	-
Total	1,023.0	949.6	7.7	8,799.4	9,018.5	(2.4)
Sales for resale	25.2	35.2	(28.4)	266.7	419.8	(36.5)
Other operating revenue	22.9	20.9	9.6	-	-	-
SO_2 Allowance sales	0.1	1.9	(94.7)	-	-	-
Total	$ 1,071.2	$ 1,007.6	6.3	9,066.1	9,438.3	(3.9)
Average customers (thousands)	666.8	668.3	(0.2)			
Retail output to line (kilowatt hours)				9,463.4	9,635.7	(1.8)

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

Tampa Electric Company – Natural gas division (PGS)

Peoples Gas reported net income of $4.6 million for the second quarter, compared to $5.3 million in the same period in 2008. Quarterly results reflect a 0.2% lower average number of customers due to the weak Florida housing market, decreased sales to residential customers and increased sales to commercial customers due to several higher volume new customers. Base rates increased due to an interim base rate increase granted in October 2008 and the higher permanent base rates effective Jun. 18, 2009. Gas transported for power generation customers increased in 2009, compared to the second quarter of 2008 when mild weather, generating unit outages, and the use of other fuels for power generation due to high gas prices affected natural gas used for power generation. Lower sales volumes to industrial customers reflected economic conditions and reduced operations by industries sensitive to the housing market, such as cement plants and wallboard producers. Non-fuel operations and maintenance expense increased, primarily due to higher spending on pipeline integrity inspections and the $0.4 million write-off of disallowed rate case expenses partially offset by lower overhead costs. Results also reflect increased depreciation expense due to routine plant additions.

Peoples Gas reported net income of $15.8 million for the year-to-date period, compared to $15.3 million in the same period in 2008. Results reflect a 0.2% lower average number of customers. Residential customer usage increased due to colder winter weather in the first quarter of 2009, compared to the very mild winter weather in 2008. Gas transported for power generation customers increased over the year-to-date period 2008. Non-fuel operations and maintenance expense increased, due to the same factors as the second quarter. Revenues associated with off-system sales declined in 2009 due to lower commodity natural gas prices, which are included in off-system sales revenues. Average commodity gas prices in 2008 were almost three times higher than average prices in 2009. In addition, off-system sales volumes were lower in 2009 largely reflecting lower demand for gas used in power generation due to lower power demand. Off-system sales of natural gas are low margin and therefore do not have a material impact on net income.

A summary of PGS' regulated operating statistics for the three months and six months ended Jun. 30, 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 Jun. 30,						
By Customer Type						
Residential	$ 27.1	$ 32.2	(15.8)	13.7	14.8	(7.4)
Commercial	33.2	38.0	(12.6)	91.6	90.8	0.9
Industrial	1.8	2.3	(21.7)	45.4	53.4	(15.0)
Off system sales	26.3	97.8	(73.1)	62.2	82.1	(24.2)
Power generation	2.6	3.8	(31.6)	144.9	132.9	9.0
Other revenues	10.0	8.6	16.3	-	-	-
Total	$ 101.0	$ 182.7	(44.7)	357.8	374.0	(4.3)
By Sales Type						
System supply	$ 69.5	$ 151.7	(54.2)	89.0	111.0	(19.8)
Transportation	21.5	22.4	(4.0)	268.8	263.0	2.2
Other revenues	10.0	8.6	16.3	-	-	-
Total	$ 101.0	$ 182.7	(44.7)	357.8	374.0	(4.3)
Average customers (thousands)	335.5	336.3	(0.2)			
Six months ended Jun. 30,						
By Customer Type						
Residential	$ 86.5	$ 80.9	6.9	46.8	42.6	9.9
Commercial	80.5	82.4	(2.3)	201.7	197.8	2.0
Industrial	4.0	4.5	(11.1)	92.3	100.2	(7.9)
Off system sales	52.7	166.4	(68.3)	113.2	160.6	(29.5)
Power generation	5.3	7.2	(26.4)	253.0	239.6	5.6
Other revenues	23.0	18.4	25.0	-	-	-
Total	$ 252.0	$ 359.8	(30.0)	707.0	740.8	(4.6)
By Sales Type						
System supply	$ 183.2	$ 294.4	(37.8)	191.2	234.9	(18.6)
Transportation	45.8	47.0	(2.6)	515.8	505.9	2.0
Other revenues	23.0	18.4	25.0	-	-	-
Total	$ 252.0	$ 359.8	(30.0)	707.0	740.8	(4.6)
Average customers (thousands)	335.5	336.2	(0.2)			

TECO Coal

In 2009, TECO Coal achieved second quarter net income of $10.1 million on sales of 2.2 million tons, compared to $4.2 million on sales of 2.4 million tons in the same period in 2008. Results reflect an average net per-ton selling price, excluding transportation allowances, of more than $70 per ton, almost 17% higher than 2008, but below prior guidance due to a sales mix that was more heavily weighted to steam coal. Second quarter 2009 metallurgical coal sales were below prior projections due to economic conditions that have reduced demand for steel products worldwide. In the second quarter of 2009, the all-in total per-ton cost of production increased to more than $65 per ton, almost 12% over 2008's level, and within the cost guidance range previously provided. Net income for the quarter included $2.0 million related to a payment for a contract renegotiation with a steam coal customer, which resulted in higher selling prices in 2009 in exchange for deferred deliveries of contracted tons into 2010 and 2011. Due to tax percentage depletion differences between periods, in the second quarter of 2009 TECO Coal's effective income tax rate was 14% compared to 6% in the 2008 period.

TECO Coal recorded year-to-date net income of $18.1 million on sales of 4.5 million tons in 2009, compared to $11.7 million on sales of 4.9 million tons in the 2008 period. The year-to-date sales mix was driven by the same factors as the second quarter. The 2009 year-to-date average net per-ton selling price and the all-in total per-ton cost of production were similar to those in the second quarter. Results in 2008 reflected a $0.6 million benefit in the first quarter from the true-up of the 2007 synthetic fuel tax credit rate. In the 2009 year-to-date period, TECO Coal's effective income tax rate was 14% compared to 15% in the 2008 period.

TECO Guatemala

TECO Guatemala reported second quarter net income of $7.9 million in 2009, compared to $14.9 million in the 2008 period. Year-to-date 2009 net income was $21.1 million, compared to $25.4 million in the 2008 period. Year-to-date 2009 net income includes the $8.7 million gain on the sale of the telecommunication company, Navega, recorded in the first quarter. Results in the 2009 second quarter for the distribution utility (EEGSA) and affiliated companies also include a $2.5 million benefit related to an adjustment to previously estimated year-end equity balances, compared to a similar $3.1 million benefit in 2008.

Lower contract and spot energy sales at the San José Power Station reduced net income $3.8 million in the second quarter of 2009 due to the extended unplanned outage as a result of a generator rotor failure. The repairs were completed and the unit returned to service July 2. The 2009 results reflect $2.5 million of lower net income from EEGSA as a result of the reduction in the Value Added Distribution tariff (VAD) in August 2008, partially offset by energy sales growth and lower operating expenses. The earnings from the unregulated EEGSA-affiliated companies (DECA II), which provide, among other things, electricity transmission services, wholesale power sales to unregulated electric customers and engineering services, increased in both periods from fundamental growth in the businesses.

Other and Eliminations

The cost for "Parent/other" in the second quarter of 2009 was $10.2 million, compared to a cost of $13.2 million in the same period in 2008. Results in 2009 included a $2.6 million benefit from a sale of property by TECO Properties. The year-to-date "Parent/other" cost was $26.2 million in 2009, compared to $26.3 million in the 2008 period. The 2009 year-to-date Parent/other included the $3.6 million valuation adjustment recorded in the first quarter on student-loan securities held at TECO Energy parent. In 2008, the year-to-date cost for Parent/other included the $0.6 million after-tax adjustment to previously estimated transaction costs related to the sale of TECO Transport.

Income Taxes

The provisions for income taxes from continuing operations for the six month periods ended Jun. 30, 2009 and Jun. 30, 2008 were $45.1 million and $35.5 million, respectively. The provision for income taxes from continuing operations in the six months ended Jun. 30, 2009 was impacted by $9.7 million related to TECO Guatemala's sale of its 16.5% interest in Navega.

Liquidity and Capital Resources

The table below sets forth the Jun. 30, 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.

(millions)		Balances as of Jun. 30, 2009		
	Consolidated	*Tampa Electric Company*	*Unregulated Companies*	*Parent*
Credit facilities	$ 675.0	$ 475.0	$ -	$ 200.0
Drawn amounts / LCs	201.4	165.3	-	36.1
Available credit facilities	473.6	309.7	-	163.9
Cash and short-term investments	28.0	5.6	17.9	4.5
Total liquidity	$ 501.6	$ 315.3	$ 17.9	$ 168.4

Consolidated other cash and short-term investments includes $17.9 million of cash at the unregulated operating companies for normal operations. In addition to consolidated cash, as of Jun. 30, 2009 unconsolidated affiliates owned by TECO Guatemala, CGESJ (San José) and TCAE (Alborada), had unrestricted cash balances of $18.9 million, which are not included in the table above.

On Jul. 7, 2009, Tampa Electric Company issued $100 million of senior unsecured notes at a premium to yield net proceeds of $102.1 million and an effective interest rate of 5.7%. Proceeds were used to reduce amounts drawn under its credit facilities and for general corporate purposes.

Capital Expenditures

(millions)	**2009 Forecast**
Tampa Electric	
Transmission	$ 40
Distribution	100
Generation	190
Committed generation expansion	85
Other	30
NO_x control projects	50
Other environmental	5
Tampa Electric total	500
Peoples Gas	50
Unregulated companies	50
Total	$ 600

TECO Energy now estimates capital expenditures for ongoing operations will be $600 million for 2009, which is $140 million lower than previous estimates.

For 2009, Tampa Electric expects to spend $500 million. For the transmission and distribution systems, Tampa Electric expects to spend $140 million in 2009, including $20 million for transmission and distribution system storm hardening, and $40 million for new high-voltage transmission system improvements and to meet reliability requirements. Based on the most recent Florida Reliability Coordinating Council studies, the central Florida transmission system upgrades have been deferred due to lower state-wide transmission system demand. Capital expenditures for the existing generating facilities of $190 million include $60 million for the construction of Big Bend Station rail coal facilities for delivery of solid fuel and $130 million for generating system reliability, including approximately $75 million in major improvements to coal-fired units at Big Bend Station during the extended outages to install NO_x control equipment. In addition, Tampa Electric expects to spend $85 million for the addition of five combustion turbines, $50 million for the additional NO_x control equipment at the Big Bend Power Station and $5 million for other environmental compliance programs in 2009.

Capital expenditures at Peoples Gas are expected to be about $50 million in 2009. Capital expenditures for the unregulated companies are expected to be about $50 million.

In 2010 and beyond, Tampa Electric's capital spending is expected to be about $300 million annually, absent any spending on generation expansion or for sources of renewable energy. Peoples Gas expects to spend about $50 million annually in 2010 and beyond.

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 Jun. 30, 2009. Reference is made to the specific agreements and instruments for more details.

Significant Financial Covenants

(millions, unless otherwise indicated) *Instrument*	*Financial Covenant* [(1)]	*Requirement/Restriction*	*Calculation at Jun. 30, 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	$2,096
	Funded debt/capital	Cannot exceed 65%	49.9%
	Sale of assets	Less than 20% of total assets	0%
Credit facility [(3)]	Debt/capital	Cannot exceed 65%	49.6%
Accounts receivable credit facility [(3)]	Debt/capital	Cannot exceed 65%	49.6%
6.25% senior notes	Debt/capital	Cannot exceed 60%	49.6%
	Limit on liens [(4)]	Cannot exceed $700	$0 liens outstanding
Insurance agreements relating to certain pollution bonds	Limit on liens [(4)]	Cannot exceed $423 (7.5% of net assets)	$0 liens outstanding
TECO Energy/TECO Finance			
Credit facility [(3)]	EBITDA/interest [(2)]	Minimum of 2.6 times	3.7 times
TECO Energy floating rate and 6.75% notes and TECO Finance 6.75% notes	Restrictions on secured debt [(6)]	[(5)]	[(5)]
TECO Diversified			
Coal supply agreement guarantee	Dividend restriction	Net worth not less than $302 (40% of tangible net assets)	$552

(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 TECO Energy, Inc. Annual Report on Form 10-K/A for the year ended Dec. 31, 2008.
(4) If the limitation on liens is exceeded, the company is required to provide ratable security to the holders of these notes.
(5) 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.
(6) These limitations would not include first mortgage bonds of Tampa Electric Company if any were outstanding.

Credit Ratings of Senior Unsecured Debt at Jun. 30, 2009

	Standard & Poor's	*Moody's*	*Fitch*
Tampa Electric Company	BBB	Baa1	BBB+
TECO Energy/TECO Finance	BBB-	Baa3	BBB-

On May 6, 2009, Standard & Poor's Rating Services upgraded the senior unsecured debt ratings on Tampa Electric Company and TECO Energy to 'BBB' and 'BBB-' respectively, from 'BBB-' and 'BB+'. At the same time, Standard & Poor's affirmed the outlook on all entities as stable. The higher ratings reflect an improvement in credit metrics by 2010 tied to rate increases at Tampa Electric Company and stability premised on a modest rebound in service territory economy by 2010.

On May 15, 2009, Moody's Investors Service upgraded the ratings of Tampa Electric Company's senior unsecured to 'Baa1' from 'Baa2' with a stable outlook. The higher rating also reflects recently obtained favorable decisions in rate cases.

Standard & Poor's, Moody's and Fitch describe credit ratings in the BBB or Baa category as representing adequate capacity for payment of financial obligations. The lowest investment grade credit ratings for Standard & Poor's is BBB-, for Moody's is Baa3 and for Fitch is BBB-; thus all three credit rating agencies have assigned investment grade ratings to TECO Energy, Inc. and its subsidiaries' senior unsecured debt.

A credit rating agency rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency. Any future downgrades in credit ratings may affect our ability to borrow and may increase financing costs, which may decrease earnings.

Off-Balance Sheet Financing

Unconsolidated affiliates have project debt balances as follows at Jun. 30, 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	$ 59.0	100%
Alborada Power Station	$ 2.2	96%
DECA II	$ 184.7	30%

2009 Earnings Outlook

TECO Energy indicated in May an outlook for 2009 earnings per share to be within a range of $1.00 and $1.15 per share, excluding charges and gains, and continues to expect earnings to be within that range.

The May guidance was provided in the form of a range to allow for varying outcomes with respect to important variables, such as a start to an economic recovery late in 2009, weather and customer usage at the Florida utilities, pricing and demand for production at TECO Coal for uncontracted tons and the potential impact of the world-wide economic slowdown on coal demand. The upper end of the guidance range in May included TECO Coal's full sales forecast of 9.9 million tons, including the 0.4 million tons that were unsold at that time, at an average selling price of $73 per ton and an average all-in, total cost of production in a range between $63 and $66 per ton. At the same time, Tampa Electric forecasted that an economic recovery would begin later in 2009 and there would be 0.1% customer growth for the year with energy sales growth slightly above that.

Consistent with the guidance provided in May, for the remainder of 2009 Tampa Electric will benefit from the higher base rates that became effective May 7. Additionally, a base rate increase will become effective August 13 as a result of the recent FPSC decision on Tampa Electric's Motion for Reconsideration. Tampa Electric and Peoples Gas have continued to experience lower numbers of retail customers and continued economic weakness in the areas served, which has reduced sales to commercial and industrial customers. Both utilities are focused on managing costs to offset the lower number of customers and lower energy sales forecasts than were included in their base rate proceedings. Tampa Electric continues to anticipate the start of an economic recovery late in 2009 to produce limited customer and weather-normalized energy sales growth, and also expects higher AFUDC, and ECRC-related earnings on an additional NO_x control project that entered service in May. Peoples Gas will benefit from higher base rates that were effective June 18, but expects resumption of customer growth to lag Tampa Electric. The rate design approved by the FPSC in Peoples Gas' base rate proceeding makes it less volume and weather sensitive.

At TECO Coal, the world-wide demand for metallurgical coal remains weak, and domestic steam coal usage has been reduced due to declining electricity sales to commercial and industrial customers nationwide. TECO Coal expects total sales volumes below prior guidance due to the 0.4 million tons of metallurgical coal that remains unsold and the possible net deferral of 0.2 to 0.7 million tons of steam and metallurgical coal from 2009 into 2010 and 2011. Due to less metallurgical coal in the product mix, the average per-ton selling price is expected to be slightly below the previously provided guidance. TECO Coal expects the all-in total cost of production to be within the previously provided range but towards the high end reflecting the lower volume. TECO Coal's effective income tax rate is now expected to be about 18% in 2009.

TECO Guatemala previously indicated earnings for 2009 would be lower than 2008 levels and that outlook remains unchanged. Repairs were completed on the San José Power Station and the unit returned to service July 2. Provided crude oil prices remain in the $60 per barrel or higher range, the station is expected to run at 65% capacity factor or more for the remainder of the year. TECO Guatemala benefited from the second quarter adjustment to previously estimated year-end equity balances, and the DECA II companies continue to seek opportunities to offset the impact of the 2008 VAD decision.

Organizational changes

On Jul. 29, 2009 the Board of Directors approved a new executive management structure, including the establishment of a single management team over the electric and gas divisions of Tampa Electric Company. The company expects that the consolidation of functions will reduce costs through the identification of efficiencies in electric and gas operations and support functions. The company expects to recognize a restructuring charge in the quarter ending Sep. 30, 2009 as a result of this management change and additional steps that the company expects to undertake to reduce costs.

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.

Substantially 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.

The valuation methods we used to determine fair value are described in **Note 12** 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 Jun. 30, 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 Amendment No. 1 to TECO Energy, Inc.'s Annual Report on Form 10-K/A for the year ended Dec. 31, 2008.

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 Jun. 30, 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 36% from Dec. 31, 2008 to Jun. 30, 2009. For natural gas, the company maintains a similar volume hedged as of Jun. 30, 2009 compared to Dec. 31, 2008.

The following tables summarize the changes in and the fair value balances of derivative assets (liabilities) for the six months ended Jun. 30, 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	166.8
Changes in valuation techniques and assumptions	—
Realized net settlement of derivatives	(138.6)
Net fair value of derivatives as of Jun. 30, 2009	$ (123.2)

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	166.8
Recorded in earnings	—
Realized net settlement of derivatives	(138.6)
Net option premium payments	—
Net purchase (sale) of existing contracts	—
Net fair value of derivatives as of Jun. 30, 2009	$ (123.2)

Below is a summary table of sources of fair value, by maturity period, for derivative contracts at Jun. 30, 2009:

Maturity and Source of Derivative Contracts Net Assets (Liabilities) at Jun. 30, 2009 ***(millions)***

Contracts Maturing in	*Current*	*Non-current*	*Total Fair Value*
Source of fair value			
Actively quoted prices	$ —	$ —	$ —
Other external sources (1)	(113.5)	(9.7)	(123.2)
Model prices (2)	—	—	—
Total	$ (113.5)	$ (9.7)	$ (123.2)

(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.

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 period covered by this quarterly report (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.

PART II. OTHER INFORMATION

Item 1A. RISK FACTORS

Information regarding risk factors appears in Item 1A to the Annual Report on Form 10-K for the year ended Dec. 31, 2008 of TECO Energy and Tampa Electric Company. The risk factor described below updates, and should be read in conjunction with, the risk factors identified in the Amendment No. 1 to Annual Report on Form 10-K/A for the period ended Dec. 31, 2008.

Our financial results could be reduced if certain proposed revisions to the U.S. tax code related to foreign earnings are implemented.

The administration has announced initiatives that could substantially reduce our ability to defer U.S. income taxes. These proposals include: repealing the deferral of U.S. taxation of foreign earnings, eliminating utilization of, or substantially reducing our ability to claim foreign tax credits, and eliminating certain tax deductions until foreign earnings are repatriated to the U.S.

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.

Period	*(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*
Apr. 1, 2009 – Apr. 30, 2009	29,339	$10.51	—	—
May 1, 2009 – May 31, 2009	11,558	$11.07	—	—
Jun. 1, 2009 – Jun. 30, 2009	1,413	$11.49	—	—
Total 2nd Quarter 2009	42,310	$10.70	—	—

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

At the Annual Meeting of Shareholders held on Apr. 29, 2009, the shareholders of TECO Energy, Inc. elected three directors, ratified the actions taken by the Audit Committee appointing PricewaterhouseCoopers LLP as TECO Energy, Inc.'s independent auditor, re-approved the performance criteria under the Company's 2004 Equity Incentive Plan and approved a shareholder proposal recommending the declassification of the Board. The following table details the voting results:

	Votes Cast For	Votes Cast Against	Abstentions	Broker Non-Vote
Election of Directors				
Sherrill W. Hudson	171,263,651	9,958,752	1,631,809	
Joseph P. Lacher	173,803,596	7,257,402	1,793,214	
Loretta A. Penn	170,277,353	10,828,334	1,748,524	
Ratification of appointment by Audit Committee of PricewaterhouseCoopers LLP as independent auditor	179,007,566	2,908,291	938,354	
Re-approval of performance criteria under the TECO Energy, Inc. 2004 Equity Incentive Plan	164,815,260	14,855,461	3,183,489	
Shareholder proposal for declassification of the Board	88,412,300	47,486,900	2,384,050	44,570,961

For a complete listing of the Board of Directors, please see **Item 10. Directors, Executive Officers and Corporate Governance** of TECO Energy, Inc.'s Amendment No. 1 to Annual Report on Form 10-K/A for the year ended Dec. 31, 2008.

Item 6. EXHIBITS

Exhibits - See index on page 61.

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: July 31, 2009

By: /s/ S. W. CALLAHAN
S. W. CALLAHAN
Vice President-Finance and Accounting
and Chief Financial Officer
(Treasurer and Chief Accounting Officer)
(Principal Financial and Accounting Officer)

TAMPA ELECTRIC COMPANY
(Registrant)

Date: July 31, 2009

By: /s/ S. W. CALLAHAN
S. W. CALLAHAN
Vice President-Finance and Accounting
and Chief Financial Officer
(Treasurer and Chief Accounting Officer)
(Principal Financial and Accounting Officer)

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).	*
10.1	Amendment No. 1 to TECO Energy Directors' Deferred Compensation Plan, effective as of Apr. 29, 2009.	
10.2	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2004 Equity Incentive Plan.	
10.3	Form of Performance Shares Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2004 Equity Incentive Plan.	
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.

* Indicates exhibit previously filed with the Securities and Exchange Commission and incorporated herein by reference. Exhibits filed with periodic reports of TECO Energy, Inc. and Tampa Electric Company were filed under Commission File Nos. 1-8180 and 1-5007, respectively.

Exhibit B

TAMPA ELECTRIC DIVISION
PROJECTED STATEMENT OF SOURCES AND USES OF FUNDS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2010
(MILLIONS)

FUNDS PROVIDED BY

Cash Flows from Operating Activities:	
Depreciation	$216
Deferred Income Taxes	57
Investment Tax Credit	-
Other	60
	$333
Cash Flows from Investing Activities:	
Capital Expenditures (excluding AFDUC)	(300)
Cash Flows from Financing Activities:	
Changes in Financing	(33)
Total Cash Flows excluding Net Income	$0

TAMPA ELECTRIC DIVISION
PROJECTED CONSTRUCTION BUDGET
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2010
(MILLIONS)

Transmission & Distribution	$142
Production (including environmental)	138
General	20
Total Projected Construction Budget (Excluding AFUDC)	$300

EXHIBIT B
PAGE 2 OF 2

PEOPLES GAS SYSTEM DIVISION
PROJECTED STATEMENT OF SOURCES AND USES OF FUNDS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2010
(MILLIONS)

Cash Flows from Operating Activities:	
Depreciation	$45
Deferred Income Taxes	2
Other	(5)
	$42
Cash Flows from Investing Activities:	
Capital Expenditures (excluding AFUDC)	50
Cash Flows from Financing Activities:	
Changes in Financing	8
Total Cash Flow excluding Net Income	$0

PEOPLES GAS SYSTEM DIVISION
PROJECTED CONSTRUCTION BUDGET
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2010
(MILLIONS)

Total Projected Construction (excluding AFUDC)	$50