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March 30, 2012

HAND DELIVERED

Ms. Ann Cole, Director
Division 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, F.S. and Chapter 25-8, F.A.C. during the twelve months ending December 31, 2011; Docket No. 100393-EI

Dear Ms. Cole:

Pursuant to Rule 25-8.009, Florida Administrative Code, and this Commission's Order No. PSC-10-0657-FOF-EI issued November 1, 2010, we enclose an original and one copy of Tampa Electric Company's Consummation Report regarding the issuance and sale of securities during the fiscal year ended December 31, 2011.

Also enclosed is a CD containing the above-referenced information.

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 ______
APA ______
ECR 1+CD
GCL ______
RAD ______
SRC ______
ADM ______
OPC ______
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, F.S., and Chapter 25-8, F.A.C.	)	DOCKET NO. 100393-EI
During the Twelve Months Ending	)	FILED: March 30, 2012
December 31, 2011	)	
	)	

CONSUMMATION REPORT

The applicant, Tampa Electric Company (the "Company"), pursuant to Commission Order No. PSC-10-0657-FOF-EI dated November 1, 2010, submits the following information with respect to the issuance and/or sale of securities during the twelve months ending December 31, 2011.

Facts of Issues

The Company regularly borrows under its two revolving credit facilities, both of which permit the Company to draw down, repay and re-borrow funds. Given the frequency of these borrowings and repayments, it is not practicable to give the details of each action. However, the Company's borrowing activity in 2011 can be summarized as follows:

	($Millions)
Minimum Outstanding	$ 0
Maximum Outstanding	$ 70.0
Average Outstanding	$ 3.0
Weighted Average Interest Cost	0.59%

Statement of Capitalization

Statements of capitalization, pretax interest coverage, debt interest requirements and preferred stock dividend requirements of the Company for the year ending December 31, 2011 are as follows:

Capital Structure	($Millions)
Short-term Debt	$ 0.0
Long-term Debt	1,991.2
Preferred Stock	-
Common Equity	2,153.5
Total Capitalization	$4,144.7
Pretax Interest Coverage	
Including AFUDC	3.71 times
Excluding AFUDC	3.72 times
Debt Interest Requirements	$140.1
Preferred Stock Dividends	-

Respectfully submitted this 30th day of March 2012

TAMPA ELECTRIC COMPANY

By: KM Caruso

Kim M. Caruso
Treasurer

Consummation Report

Exhibit List

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, 2011**

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

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 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 [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 Jun. 30, 2011 was approximately $4,074,636,754 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 Jun. 30, 2011 was zero.

The number of shares of TECO Energy, Inc.'s common stock outstanding as of Feb. 20, 2012 was 215,805,127. As of Feb. 20, 2012, 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 2012 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.

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Index to Exhibits begins on page 176

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 4,290 employees as of Dec. 31, 2011.

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 *Code of Ethics and Business Conduct*, 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 owns TECO Guatemala, Inc.

Unless otherwise indicated by the context, "TECO Energy" or the "company" 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 678,000 customers in West Central Florida with a net winter system generating capacity of 4,684 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 approximately 340,000 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 2011 was more than 1.5 billion therms.

TECO Coal Corporation (TECO Coal), a Kentucky corporation, has 11 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, owns subsidiaries that participate in two contracted Guatemalan power plants, San José and Alborada.

Revenues from Continuing Operations

(millions)	*2011*	*2010*	*2009*
Tampa Electric	$ 2,020.6	$ 2,163.2	$ 2,194.8
PGS	453.5	529.9	470.8
Total regulated businesses	2,474.1	2,693.1	2,665.6
TECO Coal	733.0	690.0	653.0
TECO Guatemala [(1)]	133.5	124.4	8.3
	3,340.6	3,507.5	3,326.9
Other and eliminations	2.8	(19.6)	(16.4)
Total revenues from continuing operations	$ 3,343.4	$ 3,487.9	$3,310.5

(1) Revenues for the year ended Dec. 31, 2009 are exclusive of entities deconsolidated as a result of accounting standards and include only revenues for the consolidated Guatemalan entities. Due to a change in these standards, these entities were reconsolidated as of Jan. 1, 2010.

For additional financial information regarding TECO Energy's significant business segments including geographic areas, see **Note 14** to the TECO Energy **Consolidated Financial Statements.**

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, Temple Terrace, 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 in long-term reserve standby located near Sebring, a city in Highlands County in South Central Florida.

Tampa Electric had 2,313 employees as of Dec. 31, 2011, of which 881 were represented by the International Brotherhood of Electrical Workers and 164 were represented by the Office and Professional Employees International Union.

In 2011, approximately 49% of Tampa Electric's total operating revenue was derived from residential sales, 30% from commercial sales, 8% from industrial sales and 13% from other sales, including bulk power sales for resale. Approximately 5% of revenues are attributed to governmental municipalities. The sources of operating revenue and megawatt-hour sales for the years indicated were as follows:

Operating Revenue

(millions)	*2011*	*2010*	*2009*
Residential	$ 994.7	$ 1,100.0	$ 1,082.4
Commercial	612.6	648.4	689.1
Industrial – Phosphate	62.0	84.2	81.2
Industrial – Other	99.3	103.7	111.0
Other retail sales of electricity	185.2	191.6	204.3
Total retail	1,953.8	2,127.9	2,168.0
Sales for resale	21.7	41.6	42.4
Other	45.1	(6.3)	(15.6)
Total operating revenues	$ 2,020.6	$ 2,163.2	$ 2,194.8

Megawatt-hour Sales

(thousands)	*2011*	*2010*	*2009*
Residential	8,718	9,185	8,667
Commercial	6,207	6,221	6,274
Industrial	1,804	2,010	1,995
Other retail sales of electricity	1,835	1,797	1,839
Total retail	18,564	19,213	18,775
Sales for resale	352	516	440
Total energy sold	18,916	19,729	19,215

No significant part of Tampa Electric's business is dependent upon a single or limited number of customers where the loss of any one or more 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

Tampa Electric's retail operations 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 provides an opportunity for the utility to collect total revenues (revenue requirements) equal to its cost to provide service, plus a reasonable return on invested capital.

The costs of owning, operating and maintaining the utility systems, excluding fuel and conservation costs as well as purchased power and certain environmental costs for the electric system, 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 service (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 (ROE). Base rates are determined in FPSC revenue requirement and rate setting hearings which occur at irregular intervals at the initiative of Tampa Electric, the FPSC or other interested parties.

Tampa Electric's rates and allowed ROE range of 10.25% to 12.25%, with a midpoint of 11.25%, which were established in 2009, 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. As a result of lower customer and energy sales growth and significant annual capital investments, 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. In March 2009, the FPSC approved a $104.3 million increase in annual base rates, authorizing a new ROE range of 10.25% to 12.25%, with a mid-point of 11.25% and an equity ratio of 54.0%, for rates effective in May 2009. The

Commission also authorized a $33.5 million change in base rates effective Jan. 1, 2010 to recover the cost of five peaking combustion turbines (CTs) and solid-fuel rail unloading facilities at the Big Bend Station, subject to the conditions that the investments were in commercial operation by Dec. 31, 2009 and the five peaking CTs are needed to serve customers. The FPSC later clarified that it would perform an audit to review the continuing need for the CTs and the costs incurred to place the CTs and rail unloading facilities in service.

In July 2009, in response to a motion for reconsideration, the FPSC determined that adjustments to the capital structure used to calculate the rates effective in 2009 should have been calculated over all sources of capital rather than only investor sources. This change resulted in a $9.3 million increase in revenue requirements in 2009 for a total increase of $113.6 million. At the same time, the FPSC voted to reject the intervenors' joint motion requesting reconsideration of the 2010 portion of base rates approved in 2009.

In September 2009, the intervenors filed a joint appeal to the Florida Supreme Court related to the FPSC's decision rejecting their motion for reconsideration of the 2010 portion of base rates approved in 2009.

In December 2009, the FPSC approved Tampa Electric's petition requesting an effective date of Jan. 1, 2010 for the proposed rates supporting the CTs and rail unloading facilities and, based on its Staff audit of Tampa Electric's actual costs incurred, the Commission determined the portion of base rates approved in 2009 should be reduced by $8.3 million to $25.7 million, subject to refund. A regulatory proceeding was scheduled for October 2010 regarding the continuing need for the CTs, the appropriate amount to be recovered and the resulting rates.

In July 2010, Tampa Electric entered into a stipulation with the intervenors to resolve all issues related to the 2008 base rate case including the base rates effective Jan. 1, 2010 as well as the intervenors' appeal to the Florida Supreme Court. Under the terms of the stipulation, the $25.7 million rate increase would remain in effect for 2010, Tampa Electric would make a one-time reduction of $24.0 million to customers' bills in 2010 and effective Jan. 1, 2011, and for subsequent years, rates of $24.4 million (a $1.3 million reduction from the $25.7 million in effect for 2010) related to the rate increase will be in effect.

In August 2010, the FPSC approved the July stipulation, as filed in Docket No. 090368-EI "Review of the continuing need and cost associated with Tampa Electric Company's 5 Combustion Turbines and Big Bend Rail Facility". This stipulation resolved all issues in the above docket and all issues in the intervenors' appeal of the FPSC's 2009 decision in Tampa Electric's base rate proceeding pending before the Florida Supreme Court. The docket related to the base rate proceeding is now closed. The one-time reduction of $24.0 million to customers' bills in 2010 was reflected in operating results as a reduction in revenue and base rates reflect a total rate increase of $137.6 million as of Jan. 1, 2011.

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 fuel, environmental compliance, conservation programs, purchased power costs and estimated customer usage for a calendar year recovery period, with a true-up adjustment to reflect the variance of actual costs to projected costs for prior periods. The FPSC may disallow recovery of any costs it considers unreasonable or imprudently incurred.

In September 2011, 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 2012. In November 2011, the FPSC approved Tampa Electric's requested rates. The rates include the projected cost for natural gas, oil and coal, including transportation, for 2012 and the net over-recovery of fuel and purchased power clause expenses, which were collected in 2011 and 2010. Rates also reflect a two-block residential fuel factor structure with a lower factor for the first 1,000 kilowatt-hours used each month for the first time. Due to increased reliance on natural gas to fuel its generating fleet and continued low natural gas prices, Tampa Electric's residential customer rate per 1,000 kilowatt-hours decreased $0.12 from $107.02 in 2011 to $106.90 in 2012.

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 and ancillary services and accounting practices.

In July 2010, Tampa Electric filed wholesale requirements and transmission rate cases with the FERC. Tampa Electric's last wholesale requirements rate case was in 1991 and the associated service agreements were approved by the FERC in the mid-1990s.

The transmission rate case updates Tampa Electric's charges under its FERC-approved Open Access Transmission Tariff (OATT) for the various forms of wholesale transmission service it provides. These rates were last updated in 2003, pursuant to a settlement agreement between the company and its then transmission customers. The wholesale requirements rate proceeding addresses the rates and terms and conditions of Tampa Electric's existing wholesale customers.

The FERC approved Tampa Electric's proposed transmission rates as filed with the FERC, which became effective Sep. 14, 2010, subject to refund. The FERC also approved Tampa Electric's proposed wholesale requirements rates, as filed with the FERC, which became effective Mar. 1, 2011, subject to refund. The proposed wholesale requirements and transmission rates are not expected to have a material impact on Tampa Electric's results.

Settlements were reached with the applicable customers in both cases last year, and these settlements will be filed with the FERC during 2012. It is expected that the FERC will accept these settlements as filed, and the settlements will take effect later this year. Refunds with interest will be provided to the customers for the differences between the settlement rates and the charges that were earlier approved by the FERC to be implemented conditionally.

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 retail and wholesale customers.

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 Matters** section).

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 quality service to retail customers.

Unlike the retail electric business, Tampa Electric competes in the wholesale power market with other energy providers in Florida, including 30 other investor-owned, municipal and other utilities, as well as co-generators and other unregulated power generators with uncontracted excess capacity. Entities compete to provide energy on a short-term basis (i.e., hourly or daily) and on a long-term basis. Competition in these markets is primarily based on having available energy to sell to the wholesale market and the price. In Florida, available energy for the wholesale markets is affected by the state's Power Plant Siting Act (the PPSA), which sets the state's electric energy and environmental policy, and governs the building of new generation involving steam capacity of 75 MW or more. The PPSA requires that applicants demonstrate that a plant is needed prior to receiving construction and operating permits. The effect of the PPSA has been to limit the number of unregulated generating units with excess capacity for sale in the wholesale power markets in Florida.

Tampa Electric is not a major participant in the wholesale market because it uses its lower cost coal-fired generation to serve its retail customers rather than the wholesale market. Over the past three years, gross revenues from wholesale sales, which include fuel that is a pass-through cost, have averaged approximately 2% of Tampa Electric's total revenue.

FPSC rules promote cost-competitiveness in the building of new steam generating capacity by requiring Investor Owned Utilities (IOUs), such as Tampa Electric, 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 MW. These rules, which allow independent power producers and others to bid to supply the new generating capacity, 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 that the self-build option is deemed the most cost-effective.

Fuel

Approximately 62% of Tampa Electric's generation of electricity for 2011 was coal-fired, with natural gas representing approximately 38% and oil representing less than 1%. Tampa Electric used its generating units to meet approximately 94% of the total system load requirements, with the remaining 6% coming from purchased power. The following table shows Tampa Electric's average delivered fuel cost per million British thermal unit (MMBtu) and average delivered cost per ton of coal burned:

Average cost per MMBtu	*2011*	*2010*	*2009*	*2008*	*2007*
Coal	$ 3.46	$ 3.08	$ 3.05	$ 2.91	$ 2.57
Oil	$ 21.21	$ 16.43	$ 16.01	$ 20.48	$ 13.87
Gas (Natural)	$ 6.20	$ 6.74	$ 8.00	$ 10.61	$ 9.52
Composite	$ 4.38	$ 4.46	$ 5.02	$ 5.56	$ 5.05
Average cost per ton of coal burned	$ 83.17	$ 74.80	$ 72.98	$ 69.14	$ 60.72

Tampa Electric's generating stations burn fuels as follows: Bayside burns natural gas; Big Bend Station, which has sulfur dioxide scrubber capabilities and nitrogen oxide reduction systems, burns a combination of high-sulfur coal and petroleum coke, No. 2 fuel oil and natural gas at CT4; Polk Power Station burns a blend of low-sulfur coal and petroleum coke (which is gasified and subject to sulfur and particulate matter removal prior to combustion), natural gas and oil; and Phillips Station, which burned residual fuel oil and was placed on long-term standby in September 2009.

Coal. Tampa Electric burned approximately 4.7 million tons of coal and petroleum coke during 2011 and estimates that its combined coal and petroleum coke consumption will be about 5.1 million tons for 2012. During 2011, Tampa Electric purchased approximately 65% of its coal under long-term contracts with four suppliers, and approximately 35% 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 76% of its coal and petroleum coke requirements in 2012 under long-term contracts with four suppliers and the remaining 24% 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 2011, approximately 77% of Tampa Electric's coal supply was deep-mined, approximately 12% was surface-mined and the remaining was 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 cannot predict, however, the effect of any future mining laws and regulations.

Natural Gas. As of Dec. 31, 2011, approximately 68% of Tampa Electric's 1,250,000 MMBtu gas storage capacity was full. Tampa Electric has contracted for 70% of the expected gas needs for the April 2012 through October 2012 period. In early March 2012, Tampa Electric expects to issue an RFP and contract for additional gas to meet its generation requirements for this time period. Additional volume requirements in excess of projected gas needs are purchased on the short-term spot market.

Oil. Tampa Electric has agreements in place to purchase low sulfur No. 2 fuel oil for its Big Bend and Polk 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. The franchises 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. The City of Temple Terrace 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 September 2040.

Franchise fees payable by Tampa Electric, which totaled $38.2 million at Dec. 31, 2011, 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.

Environmental Matters

Tampa Electric has a significant number of stationary sources with air emissions regulated by the Clean Air Act, material Clean Water Act implications and impacts by federal and state legislative initiatives. 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.

Emission Reductions

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); implementation of 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 early reductions of certain emissions; and enhanced controls and monitoring systems for certain pollutants.

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, a provision was made for environmental controls and pollution reductions, and Tampa Electric implemented a comprehensive program to dramatically decrease emissions from its power plants.

The emission reduction requirements of these agreements resulted in 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 in 2004, enhanced availability of flue gas desulfurization systems (scrubbers) at Big Bend Station to help reduce SO_2 and installation of selective catalytic reduction (SCR) systems for NO_x reduction on Big Bend Units 1 through 4. The units were reported in-service in May 2007, June 2008, May 2009 and May 2010.

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 are capable of removing more than 95% of the SO_2 emissions from the flue gas streams.

The FPSC determined that it is appropriate for Tampa Electric to recover the operating costs of and earn a return on the investment in the SCRs at the Big Bend Power Station and pre-SCR projects on Big Bend Units 1–3 (which were early plant improvements to reduce NO_x emissions prior to installing the SCRs) through the Environmental Cost Recovery Clause (ECRC) (see the **Regulation** section). Cost recovery for the SCRs began for each unit in the year that the unit entered service.

The repowering of the Gannon Power Station to the Bayside Power Station has resulted in a significant reduction in emissions of all pollutant types. Since 1998, Tampa Electric has reduced annual SO_2, NO_x and particulate matter (PM) emissions from its facilities by 164,000 tons (94%), 63,000 tons (91%) and 4,500 tons (87%), respectively.

Reductions in mercury emissions have also occurred due to the repowering of the Gannon Power Station to the 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 have been achieved from the installation of the SCRs at Big Bend Power Station, which have led to a reduction of mercury emissions of more than 75% from 1998 levels.

Carbon Reductions and Climate Change

Tampa Electric has taken significant steps to reduce overall emissions at its 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 currently emits approximately 17 million tons of CO_2 per year and expects emissions of CO_2 to remain near 1990 levels until the addition of the next baseload unit, which is not expected until early 2017. Tampa Electric estimates that the repowering to natural gas and the shut-down of the Gannon Station coal-fired units resulted in an annual decrease in CO_2 emissions of approximately 4.8 million tons below 1998 levels.

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, 2011, Tampa Electric Company has estimated its ultimate financial liability to be approximately $28.5 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.

In 2004, Merco Group at Adventura Landings I, II, and III (together Merco) filed suit against PGS in Dade County Circuit Court alleging that coal tar from a certain former PGS manufactured gas plant site had been deposited in the early 1960s onto property owned by Merco. PGS contends that the coal tar did not originate from its manufactured gas plant site and has filed a third-party complaint against Continental Holdings, Inc. as the owner at the relevant time of the site that PGS believes was the source of the coal tar on Merco's property. In addition, the court will consider PGS' counterclaim against Merco which claims that, because Merco purchased the property with actual knowledge of the presence of coal tar on the property, Merco should contribute toward any damages resulting from the presence of coal tar. The bench trial in this matter was concluded in February 2012 and a ruling is expected in March 2012.

Capital Expenditures

Tampa Electric's 2011 capital expenditures included $13.0 million primarily for upgrades to scrubbers and modifications to coal combustion by-product storage areas at the Big Bend Power Station. See the **Liquidity, Capital Expenditures** section of **Management's Discussion and Analysis of Financial Conditions and Results of Operations (MD&A)** for information on estimated future capital expenditures related to environmental compliance.

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 approximately 340,000 customers. The system includes approximately 11,200 miles of mains and 6,500 miles of service lines (see PGS's **Franchises and Other Rights** section below).

PGS had 543 employees as of Dec. 31, 2011. A total of 148 employees in seven of PGS's 14 operating divisions are represented by various union organizations.

In 2011, the total throughput for PGS was more than 1.5 billion therms. Of this total throughput, 8% was gas purchased and resold to retail customers by PGS, 77% was third-party supplied gas that was delivered for retail transportation-only customers and 15% was gas sold off-system. Industrial and power generation customers consumed approximately 53% of PGS's annual therm volume, commercial customers used approximately 27%, off-system sales customers consumed 15% and the remaining balance was consumed by residential customers.

While the residential market represents only a small percentage of total therm volume, residential operations comprised about 32% of total revenues. Approximately 3% of revenues are attributed to governmental municipalities.

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. PGS has also seen increased interest and development in natural gas vehicles. There are 12 compressed natural gas stations connected to the PGS distribution system, with five added in 2011.

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

	Revenues			Therms		
(millions)	*2011*	*2010*	*2009*	*2011*	*2010*	*2009*
Residential	$ 140.8	$ 159.5	$ 143.4	77.7	90.5	73.5
Commercial	138.0	143.8	142.2	409.3	407.9	381.7
Industrial	114.8	171.2	125.8	436.0	507.2	448.7
Power generation	10.6	9.7	10.0	614.3	582.2	538.3
Other revenues	39.9	37.2	40.6	0.0	0.0	0.0
Total	$ 444.1	$ 521.4	$ 462.0	1,537.3	1,587.8	1,442.2

No significant part of PGS's business is dependent upon a single or limited number of customers where the loss of any one or more would have a significant adverse effect on PGS. PGS's business is not highly seasonal, but winter peak throughputs are experienced due to colder temperatures.

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 provides an opportunity for 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's weighted cost of capital, primarily includes its cost for debt, deferred income taxes at a zero cost rate, and an allowed ROE. Base rates are determined in FPSC revenue requirements 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**.

On May 5, 2009, the FPSC approved a base rate increase of $19.2 million which became effective on Jun. 18, 2009, and reflects an ROE 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.

As a result of the unprecedented cold winter weather in 2010, in the second quarter of 2010, PGS projected it would earn above the top of its ROE range of 11.75% in 2010. PGS recorded a $9.2 million pretax total provision related to the 2010 earnings above the top of the range. In December 2010, PGS and the Office of Public Counsel entered into a stipulation and settlement agreement requesting Commission approval that $3.0 million of the provision be refunded to customers in the form of a credit on customers' bills in 2011, and the remainder be applied to accumulated depreciation reserves. On Jan. 25, 2011 the FPSC approved the stipulation.

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 calendar year 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 2011, the FPSC approved rates under PGS's PGA clause for the period January 2012 through December 2012 for the recovery of the costs of natural gas purchased for its distribution customers.

In addition to its base rates and PGA 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 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 the programs are cost effective for its ratepayers. The FPSC requires natural gas utilities to offer transportation-only service to all non-residential 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's 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. PGS has a "NaturalChoice" program, offering unbundled transportation service to customers consuming in excess of 1,999 therms annually, allowing these 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 17,600 transportation-only customers as of Dec. 31, 2011 out of approximately 42,000 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 62 interconnections (gate stations) serving PGS's operating divisions. In addition, PGS's Jacksonville division receives gas delivered by the Southern Natural Gas pipeline through two gate stations located northwest of Jacksonville. Gulfstream Natural Gas Pipeline provides delivery through seven gate stations. PGS also has one interconnection with its affiliate SeaCoast Gas Transmission, LLC in Clay County, Florida.

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 the 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's industrial customers are in the categories that are first curtailed in such situations. PGS's 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 and Other Rights

PGS holds franchise and other rights with approximately 100 municipalities throughout Florida. These franchises govern the placement of PGS'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 PGS's use of public rights-of-way and other public property within the municipalities it serves during the term of the franchise agreement. 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's 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's franchise agreements with the incorporated municipalities within its service area have various expiration dates ranging from the present through 2041. PGS expects to negotiate 13 franchises in 2012, the majority of which will be renewals of existing agreements. Franchise fees payable by PGS, which totaled $8.8 million at Dec. 31, 2011, 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's 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 that generally require monitoring, permitting and ongoing expenditures.

Tampa Electric Company is one of several PRPs 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, 2011, PGS did not incur any material capital expenditures to meet environmental requirements, nor are any anticipated for the 2012 through 2016 period.

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 and Bear Branch Coal Company. The TECO Coal subsidiaries own, control and operate, by lease or mineral rights, surface and underground mines and coal processing and loading facilities. TECO Coal produces, processes and sells bituminous, predominately low-sulfur coal of metallurgical, pulverized coal injection (PCI), steam and industrial grades.

TECO Coal is a supplier of metallurgical and PCI coal for use in the steel-making process and a supplier of thermal coal to electric utilities and manufacturing industries. TECO Coal subsidiaries also export metallurgical and PCI coals internationally, primarily to European markets.

Metallurgical, PCI and industrial stoker coals accounted for approximately 46% of 2011 coal sales volume. Steam coal accounted for approximately 54% of 2011 coal sales volume.

As of Dec. 31, 2011, TECO Coal owned or leased mineral rights to approximately 325.2 million tons of proven and probable coal reserves. Of the total proven and probable reserves, approximately 75% are low-sulfur reserves with high British thermal unit (Btu) content. Total proven and probable reserves are expected to support current production levels for more than 20 years.

The tons sold for 2011, 2010 and 2009 by market category is set forth in the table, Table (1), below:

Coal Sales By Market Category
(Millions of Tons)
Table 1

	Metallurgical, PCI & Stoker		Steam	
Year	**Tons**	**% Volume**	**Tons**	**% Volume**
2011	3.71	46%	4.42	54%
2010	3.48	40%	5.21	60%
2009	2.06	24%	6.69	76%

Sales of steam coal during 2011, 2010 and 2009 were made primarily to utilities and industrial customers throughout the eastern part of the United States. Sales of metallurgical and PCI coal during those years were made primarily to steel companies and coke plants in North America and Europe.

TECO Coal subsidiaries currently operate 26 underground mines which employ the room and pillar mining method and 10 surface mines.

In 2011, TECO Coal subsidiaries sold 8.1 million tons of coal. All of this coal was sold to customers other than the TECO Coal affiliate, Tampa Electric.

No significant part of TECO Coal's business is dependent upon a single or limited number of customers where the loss of any one or more would have a significant adverse effect and the business is not highly seasonal.

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 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. Also in that year, properties were 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.

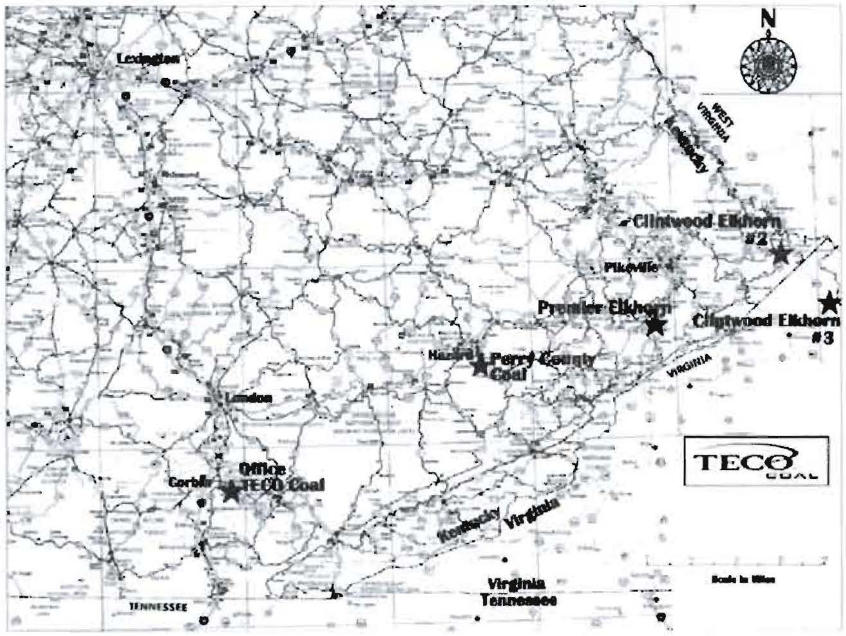
The newest mining company in the TECO Coal family is Perry County Coal Corporation, which was purchased in 2000 and is located in Perry, Knott and Leslie Counties, Kentucky.

In 2011, TECO Coal sold the idled Millard Facilities and properties located in Pike County, Kentucky.

Mining Operations

TECO Coal currently has four mining complexes, mostly operating in Kentucky with a portion of Clintwood Elkhorn Mining Company operating in Virginia. 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. 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 11 individual underground or surface mines. TECO Coal uses two distinct extraction techniques: continuous underground mining and dozer and front-end loader surface mining, sometimes accompanied by highwall mining.

The complexes have been developed at 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, barges or vessels, with rail shipments representing approximately 93% of 2011 coal shipments. The following map 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 two facilities. The equipment at each facility is in good condition and regularly maintained by qualified personnel. Table 2 below is a summary of TECO Coal processing facilities:

PROCESSING FACILITIES SUMMARY
Table 2

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
Premier Elkhorn	Burke Branch Plant	Myra, KY	CSXT Railroad	American Electric Power
Perry County Coal	Davidson Branch Plant	Hazard, KY	CSXT Railroad	American Electric Power

Significant Projects

Significant projects for 2011 included the following:

Premier Elkhorn Coal

- Premier Elkhorn's exploration activities identified 65 million tons of newly-discovered metallurgical coal in two below drainage seams underlying its current Burke Branch facilities and adjacent properties. Much of the identified reserves are owned by TECO Coal. (See Mining Complexes - New Frontier Project-Burke Branch Development for more information on that project.)

Clintwood Elkhorn Mining

- The Persimmon Branch surface mine, in Woodman, Kentucky, began operations in the spring of 2011. The mine produces metallurgical and steam coal.
- Construction of the Lick Creek slope mine was completed in the fourth quarter of 2011. This slope will access several million tons of High Volatile A metallurgical coal from the Hagy seam and began full production in January 2012.
- The Persimmon Branch deep mine construction was completed in the third quarter of 2011 and is in production. This mine produces High Volatile A metallurgical coal from the Blair seam.
- In Virginia, construction of the Abners Fork deep mine was completed in the third quarter of 2011 and is in full production. This mine produces High Volatile A metallurgical coal from the Splashdam seam and provides access to substantial reserves near the Clintwood No. 3 preparation facility.
- At the Clintwood No. 3 preparation plant, a clean coal reclaim belt was installed to facilitate the more efficient loading of trains.

Mining Complexes

Table 3 below shows annual production, for each mining complex, for each of the last three years' coal sales.

MINING COMPLEXES
Table 3

Location	Mine Type	Mining Equipment	Transportation	Tons Produced (in Millions) 2011	2010	2009	Tons Sold (1) (in Millions) 2011	Year Established Or Acquired
Gatliff Coal Co.								
Bell County, KY/ Knox County, KY/ Campbell County, TN	S	D/L	T	0.0	0.0	0.2	0.0	1974
Clintwood Elkhorn Mining								
Pike County, KY/ Buchanan County, VA	U, S	CM, D/L, HM, A	R, R/V	1.8	2.1	2.0	2.3	1988
Premier Elkhorn Coal Co.								
Pike County, KY/ Letcher County, KY/ Floyd County, KY	U, S	CM, D/L	R, T, R/B, T/B	2.2	2.6	3.2	2.7	1991
Perry County Coal Co.								
Perry County, KY/ Leslie County, KY/ Knott County, KY	U, S	CM, D/L, HM	R, T, R/B, T/B	3.1	3.1	3.1	3.1	2000
			Totals:	**7.1**	**7.8**	**8.5**	**8.1**	

(1) Tons sold include both amounts produced by TECO Coal subsidiaries and a limited amount of purchased coal.

S – Surface
CM – Continuous Miner
U – Underground
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

Gatliff Coal Company discontinued surface mine operations in Bell County, Kentucky in late autumn 2009. Poor market conditions and a depletion of the low-sulfur content coal that was previously required on its sales contract led to this cessation of mining operations. Gatliff Coal had no production in 2011 or 2010, leaving a reserve base of 3.4 million recoverable tons of predominantly low-sulfur underground mineable coal, which may later be recovered by Gatliff Coal or by neighboring competing coal companies for coal royalty considerations. Rich Mountain Coal Company formerly operated as a contractor for Gatliff Coal's Tennessee production but is currently in non-producing reclamation status.

Clintwood Elkhorn Mining

Clintwood Elkhorn Mining Company has two coal preparation facilities. One is located near Biggs, Kentucky in Pike County, and is supplied by 11 underground mines and two surface mines. The second Clintwood Elkhorn Mining facility is located near Hurley, Virginia and is supplied by four underground mines and one surface mine. Some mines have supplied both locations during the course of the year. Principal products at both locations include High Volatile metallurgical coal and steam coal. 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. In total, Clintwood Elkhorn Mining produced 1.8 million tons of coal in 2011, leaving a reserve base of 44.6 million recoverable tons.

Premier Elkhorn Coal

Located near Myra, in Pike County, Kentucky, Premier Elkhorn Coal Company is supplied by production from eight underground mines and five surface mines. Principal products include metallurgical and PCI coal for the steel mills, high-quality steam coal for utilities and specialty stoker products for ferro-silicon and industrial customers. 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 via CSXT Railroad and trucking contractors to destinations in North America and internationally. All production is performed by Premier Elkhorn Coal even though Pike-Letcher Land Company controls by fee and lease all of the recoverable reserves and leases mining rights to Premier Elkhorn Coal. In total, Premier Elkhorn Coal produced 2.2 million tons of coal in 2011 leaving a reserve base of 136.0 million recoverable tons, including the Burke Branch development reserves described below.

New Frontier Project-Burke Branch Development

Marshall Miller & Associates, Inc. (MM&A) has completed an audit of the Glamorgan and Lower Banner coal deposits associated with the New Frontier Project-Burke Branch Development, which is controlled by TECO Coal at its Premier Elkhorn Coal operating subsidiary. The subject property is located in Pike and Letcher Counties in eastern Kentucky and a substantial portion of the mineral rights for the subject coal deposits is owned by TECO Coal's subsidiary, Pike-Letcher Land. The remainder of the mineral is leased from other entities under long-term lease agreements.

The MM&A audit reviewed the classification of the TECO Coal tons by proven and probable reserves and non-reserve coal deposit (resource) categories, based on a pro-forma economic review of the demonstrated reserve areas. TECO Coal estimates that it controls 65.0 million recoverable tons of demonstrated coal reserves within the Burke Branch Development, as of Aug. 31, 2011. Of these TECO Coal total demonstrated reserves, an estimated 56.6 million recoverable tons (87%) are owned and 8.4 million tons (13%) are leased. An additional 23.4 million tons have been estimated by TECO Coal and classified as non-reserve coal deposits (resources). These resource tons have some potential to be re-classified as reserve in the future depending on various factors such as favorable results of additional exploration, property acquisition, investment of capital for project development, improvements in coal markets or mining technology.

TECO Coal has received an amendment to an existing permit to allow surface excavation and development as well as slope access to a portion of these reserves and will apply for an amendment to a second permit in 2012 to allow slope access to the remainder of the reserves.

Perry County Coal Corporation

Located in Perry County Kentucky, near Hazard, Perry County Coal Corporation is supplied by production from three underground mines and two surface mines. Principal products include PCI, high quality steam coal for utilities and industrial stoker products. Facilities include a 1,350 ton per hour preparation plant and unit train load-outs. Products from this location are shipped via CSXT Railroad and trucking contractors.

In 2009, Perry County Coal completed a comparable trade of underground reserves of 16.0 million tons with another mining company. During 2010, the boundary of reserves for the E4-2 mine area was core drilled to confirm final reserve quantities and qualities and to finalize a comprehensive mining plan. A review of reserves for the E4-2 mine area for Perry County Coal proved an additional 6.9 million tons of reserves, which were previously reported as resource coal. In 2010, Perry County Coal leased the First Creek reserve which is contiguous to its existing E4-1 underground mine. This lease will facilitate the mining of approximately 10.0 million tons of additional reserves. Perry County Coal produced 3.1 million tons of coal in 2011, leaving a total reserve base of 141.2 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 steel companies, utilities and industrial plants. 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 12 months or less.

The terms of these coal sales contracts result from bidding and negotiations with customers. Consequently, these contracts typically vary significantly in price, quantity, quality and 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.

Current sales are made to both domestic and European markets, and the metallurgical coal from the Burke Branch Development is expected to be marketed to new markets and customers in Europe, South America and Asia.

Distribution

TECO Coal transports coal from its mining complexes to customers by rail, barge, vessel and trucks. The company employs transportation specialists who coordinate the development of acceptable shipping schedules with 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 specialty coals, including coals used for making coke and furnace injection, high-quality steam coal and by effectively managing production and processing costs.

Employees

As of Dec. 31, 2011, TECO Coal and its subsidiaries employed a total of 1,162 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 recent mining accidents within the industry could lead to new legislation that could impose additional costs on TECO Coal. (See **Exhibit 95-Mine Safety Disclosures** to this annual report.)

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 December 2000, the Department of Labor issued new amendments to the regulations implementing the federal black lung laws that, among other things, establish a presumption in favor of a claimant's treating physician, limit a coal operator's ability to introduce medical evidence, and redefine Coal Workers Pneumoconiosis to include chronic obstructive pulmonary disease. TECO Coal expects these changes in the regulations, and regulations introduced by the 2010 healthcare reform act, will increase the percentage of claims approved and the overall cost of black lung to coal operators. TECO Coal, with the help of its consulting actuaries, intends to continue monitoring 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 $0.135 and $0.315 on every net ton of underground and surface coal mined, respectively, to create a fund 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 2011, TECO Coal had expenditures of approximately $4.1 million for environmental protection and reclamation programs. TECO Coal expects to spend approximately $2.1 million in 2012 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 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 Btus, which is equivalent to 0.72% 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 onto 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; and any other like causes.

High vol metallurgical 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 from the surface up to 1,000 feet deep.

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 greater than 12 months.

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. Metallurgical 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 (measure) reserves, but 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 (measured) 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.

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., has subsidiaries that have interests in independent power projects in Guatemala. The TECO Guatemala subsidiaries had 125 employees as of Dec. 31, 2011.

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 Empresa Eléctrica de Guatemala, S.A. (EEGSA), the largest private distribution company in Central America, to provide 120 MW 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, provides unloading services to third parties in addition to receiving the coal shipments for CGESJ.

The party that controls approximately 4% interest in the entity that owns the Alborada Power Station (described below) has an option to purchase 50% of CGESJ and TEMSA. This option becomes exercisable at the end of 2014, and provides that the purchase price would be based on book value as determined at that time.

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 MW of capacity ending in 2015. EEGSA is responsible for providing the fuel for the power station, with a subsidiary of TECO Guatemala providing assistance in fuel administration.

For CGESJ and TCAE, TECO Guatemala has obtained political risk insurance for currency inconvertibility, expropriation and political violence affecting TECO Guatemala's investment and economic returns.

TECO Guatemala's existing plants in Guatemala operate under environmental permits issued by the local environmental authorities. The plants were built in compliance with 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.

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 The Last Five Years
Sherrill W. Hudson	69	Executive Chairman of the Board, TECO Energy, Inc. and Tampa Electric Company, August 2010 to date; Chairman of the Board and Chief Executive Officer, TECO Energy, Inc. and Tampa Electric Company, July 2004 to August 2010.
John B. Ramil	56	President and Chief Executive Officer, TECO Energy, Inc., and Chief Executive Officer, Tampa Electric Company, August 2010 to date; President and Chief Operating Officer, TECO Energy, Inc., July 2004 to August 2010.
Charles A. Attal, III	52	Senior Vice President-General Counsel and Chief Legal Officer, TECO Energy, Inc., and General Counsel of Tampa Electric Company, February 2009 to date; Vice President-General Counsel and Chief Legal Officer, TECO Energy, Inc. and General Counsel of Tampa Electric Company, July 2007 to February 2009; and prior thereto, Vice President and Deputy General Counsel, TECO Energy, Inc.
Phil L. Barringer	58	Vice President-Human Resources of TECO Energy, Inc. and Tampa Electric Company, July 2009 to date; President, TECO Guatemala, July 2009 to date; and prior thereto, Vice President-Controller, Operations of TECO Energy, Inc. and Chief Accounting Officer of Tampa Electric Company.
Deirdre A. Brown	51	Vice President-Business Strategy and Compliance and Chief Ethics and Compliance Officer, TECO Energy, Inc., July 2009 to date; Vice President-Regulatory Affairs of Tampa Electric Company and Vice President-Customer Service, Tampa Electric Division of Tampa Electric Company, April 2006 to July 2009.
Sandra W. Callahan	59	Senior Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer), TECO Energy, Inc., February 2011 to date, and Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer), Tampa Electric Company, October 2009 to date; Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer), TECO Energy, Inc., October 2009 to February 2011; Vice President-Finance and Accounting and Chief Financial Officer (Treasurer and Chief Accounting Officer), TECO Energy, Inc. and Tampa Electric Company, July 2009 to October 2009; Vice President-Treasury and Risk Management (Treasurer and Chief Accounting Officer), TECO Energy, Inc., January 2007 to July 2009; Vice President-Treasury and Risk Management (Treasurer), TECO Energy, Inc., July 2000 to January 2007; Vice President-Treasurer and Assistant Secretary, Tampa Electric Company, April 2005 to July 2009.
Clinton E. Childress	63	Senior Vice President-Corporate Services and Chief Human Resources Officer, TECO Energy, Inc., October 2004 to date; Chief Human Resources Officer and Procurement Officer, Tampa Electric Company, September 2003 to date.
Gordon L. Gillette	52	President, Tampa Electric Company, July 2009 to date; Executive Vice

		President and Chief Financial Officer, TECO Energy, Inc., July 2004 to July 2009; President, TECO Guatemala, October 2004 to July 2009.
Clark Taylor	62	President of TECO Coal Corporation, April 2011 to date; and prior thereto, Vice President-Controller of TECO Coal Corporation.

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 May 2, 2012, and until such officer's successor is elected and qualified.

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 and the current Florida housing markets and economy to improve could adversely affect Tampa Electric's or PGS's expected performance. Weakening of 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 utilities are highly regulated; changes in regulation or the regulatory environment could reduce 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's financial performance by, for example, reducing revenues, increasing competition or costs, threatening investment recovery or impacting rate structure.

Our financial results could be adversely affected if the FPSC were to lower the allowed ROE in the next base rate proceedings by Tampa Electric or PGS.

Tampa Electric and PGS were awarded ROE ranges with mid-points of 11.25% and 10.75% in their respective 2009 base rate proceedings. Decisions by the FPSC in investor owned utility rate cases later in 2009 awarded lower ROEs of 10.5% and 10%. If ROEs were reduced or other elements of the regulatory framework were changed, 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.

Potential new regulations on the disposal and/or storage of coal combustion by-products (CCB) could add to Tampa Electric's operating costs.

In 2009, in response to a coal ash pond failure at another utility, the EPA announced that it would propose new regulations regarding CCB handling, storage and disposal. The EPA has proposed two possible new rules related to CCB that could reduce or eliminate the beneficial use of CCBs, or eliminate the use of ponds for by-product storage. These proposed new rules could increase Tampa Electric's operating costs through higher disposal costs. The hazardous designation would be expected to affect Tampa Electric's current management practices and storage facilities for CCBs. Required changes would include disposing of any CCB as hazardous waste, which would be at a cost significantly higher than current costs, converting to dry handling of coal ash, and elimination of any wet storage impoundments in current use. If the EPA eliminates the use of ponds for by-product storage, Tampa Electric would have to invest in dry handling and storage which could increase costs.

Federal or state regulation of Green House 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.

Current 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. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the Environmental Cost Recovery Clause (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 EPA has proposed a number of new rules, including the Clean Air Interstate Rule/Cross State Air Pollution Rule (CSAPR) and Hazardous Air Pollutants (HAPS) Maximum Achievable Control Technology (MACT).

Together these rules impose stringent reduction in several pollutants from electric utility steam generators, primarily coal fired, but including oil fired as well. If these rules are implemented as proposed, the EPA has estimated that the implementation of CSAPR would require significant investment in pollution control equipment for units not already equipped or result in the retirement of primarily smaller, older coal-fired power stations that do not currently have state-of-the-art air pollution control equipment already installed. The retirement of these units or switching to other fuels for compliance with this rule is likely to reduce overall demand for coal, which could reduce sales and financial results at TECO Coal.

A mandatory RPS could add to Tampa Electric's costs and adversely affect its operating results.

In the past three sessions of the Florida legislature, through 2011, an RPS was debated but ultimately not enacted. There remains considerable interest in renewable energy sources by renewable energy suppliers, developers and the utilities in Florida. Previously the FPSC made a recommendation to the Florida legislature that the RPS 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, but to date the legislature has not adopted the FPSC's recommendation. In addition, there is the potential that legislation could be proposed in the U.S. Congress to introduce an RPS 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 an RPS, as proposed by the FPSC. Tampa Electric's operating results could be adversely affected if Tampa Electric were not permitted to recover these costs from customers.

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 and cancellation of 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. However, if in the future, 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.

Our businesses are sensitive to variations in weather and the effects of extreme weather, and have seasonal variations. Climate change could lead to weather conditions other than what we routinely experience today.

Most of our businesses are affected by variations in general weather conditions and unusually severe weather, which are risks we already face. Tampa Electric's and PGS's 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. If climate change or other factors cause significant variations from normal weather, this could have a material impact on energy sales. Extreme weather conditions, such as hurricanes, can be destructive, causing outages and property damage that require the company to incur additional expenses. If warmer temperatures lead to changes in extreme weather events (increased frequency, duration and severity), these expenses could be greater. The speculative nature of such changes, however, and the long period of time over which any potential changes might be expected to take place, make estimating the physical risks difficult.

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 Tampa Electric and 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.

The state of Florida is exposed to extreme weather, including hurricanes, which can cause damage to our facilities and affect our ability to serve customers.

As a company with electric service and natural gas operations in peninsular Florida, the company has substantial experience operating in areas prone to extreme weather events, such as hurricanes. The company has storm preparations and recovery plans in its operations that are routinely assessed, and improved based upon experience during drills and events and planning with critical partners. Tampa Electric and PGS host meetings with state and local emergency management agencies to refine communications and restoration plans and consult with similarly situated utilities in preparing for restoration following extreme weather events. In addition to the design of its facilities and its storm recovery plans, the company continuously monitors and assesses the physical risks associated with severe weather conditions and adjusts its planning to reflect the results of that assessment.

While the company has storm preparation and recovery plans in place, and Tampa Electric and PGS have historically been granted regulatory approval to recover or defer the majority of significant storm costs incurred, extreme weather still poses risks to our operations and storm cost-recovery petitions may not always be granted or may not be granted in a timely manner. If costs associated with future severe weather events cannot be recovered in a timely manner, or in an amount sufficient to cover actual costs, our financial condition and operating results could be adversely affected.

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 affects the margins TECO Coal realizes on its sales, and 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, have, at times, been above or below the average price of coal used by the San José Power Station due to prices for crude oil. Depending on the price of residual oil, generation from the San José Power Station for spot sales would rise or fall with oil prices, thus increasing or reducing non-fuel energy sales revenues and net income.

Results at our utility companies may be affected by changes in customer energy usage patterns, the impact of the Florida housing market, and the cost of complying with potential new environmental regulations.

For the past several years, weather normalized energy consumption per residential customer declined due to the combined effects of voluntary conservation efforts, economic conditions, changes in lighting and appliance efficiency, which we believe have contributed additionally to voluntary conservation.

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

Compliance with proposed GHG emissions reductions, a mandatory RPS or other new regulation could raise Tampa Electric's cost. While current regulation allows Tampa Electric to recover the cost of new environmental regulation through the ECRC, increased costs for electricity may cause customers to change usage patterns, which would impact Tampa Electric's sales.

Our computer systems and Tampa Electric's infrastructure may be subject to cyber (primarily electronic or internet-based) attack, which could disrupt operations, cause loss of important data or compromise customer, employee-related or other critical information or systems.

There have been an increasing number of cyber-attacks on companies around the world, which have caused operational failures or compromised sensitive corporate or customer data. These attacks have occurred over the internet, through malware, viruses, or attachments to e-mails or through persons inside of the organization or with persons with access to systems inside of the organization.

We have security systems and infrastructure in place to prevent such attacks, and these systems are subject to internal, external and regulatory audits to ensure adequacy. Despite these efforts, we cannot be assured that a cyber-attack will not cause electric or gas system operational problems, disruptions of service to customers, or compromise important data or systems.

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 including foreign source income and capital gains. These tax credit carryforwards are subject to expiration periods of varying durations (see **Note 4** to the **TECO Energy Consolidated Financial Statements**).

The current 2013 federal budget, as proposed, includes the elimination of the percentage depletion tax deduction for coal mines and other hard minerals and fossil fuels.

If the percentage depletion tax deduction is eliminated for TECO Coal, the effective tax rate for that company would rise from the expected 20% to 25% to the general corporate tax rate of 37%, which would have an adverse effect on TECO Coal's financial results after 2012.

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.

Problems with operations could cause us to incur substantial costs.

Each of our subsidiaries is subject to various operational risks, including accidents, equipment failures and operations below expected levels of performance or efficiency. Our subsidiaries could incur problems such as the breakdown or failure of power generation equipment, transmission lines, pipelines, coal mining or processing equipment 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.

In January 2011, the EPA retracted a valid surface mining permit issued in 2007 to another coal mining company.

While the EPA has not taken this type of action on a routine basis, this action by the EPA creates additional uncertainty related to the ability to use surface mining techniques to mine coal, which could reduce the earnings expected from our coal company.

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 by various environmental groups resulting in a backlog of permit applications and very few permits being issued. TECO Coal had three permits on the list of permits subject to enhanced review by the EPA under its memorandum of understanding with the USACE, which was issued in September 2009. In October 2011, the Federal District Court for the District of Columbia set aside the Enhanced Coordination Procedures (ECP) developed by the USACE and the EPA to expedite review of pending surface coal mining permit applications. Corps Districts and the EPA Regions in Appalachia have all ceased using the ECP as of the date of the District Court's decision. It is important to note that while the court invalidated the ECP, the decision does not affect any statutory or regulatory requirements established under the Clean Water Act, including the Corps' and the EPA's Section 404 permitting regulations. Failure to obtain the necessary permits to open new surface mines, which are required to maintain and expand production, could reduce production, cause higher mining costs 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.

In 2010, the EPA issued new guidelines related to water quality for Central Appalachian coal surface mining operations that would be conditions of new surface mine permits, which would add significant cost to operations or curtail our surface mining activities and preparation plant operations.

On April 1, 2010, the EPA issued new guidance on environmental permitting requirements for Appalachian mountaintop removal and other surface mining projects. The guidance limits conductivity (level of mineral salts) in water discharges into streams from permitted areas, and was effective immediately on an interim basis. At that time, the EPA stated that it would decide whether to modify the guidance after consideration of public comments and the results of the Science Advisory Board (SAB) technical review of the EPA scientific reports. In July 2011, the EPA made this guidance final without modification. Because the EPA's standards appear to be unachievable under most circumstances, surface mining activity could be substantially curtailed since most new and pending permits would likely be rejected. This guidance could also be extended to discharges from deep mines and preparation plants, which could result in a substantial curtailing of those activities as well.

Our international projects and TECO Coal's sales to international customers 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 higher 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.

TECO Coal is exposed to international risk through its sales to international customers, primarily in Europe. TECO Coal attempts to mitigate this risk through dollar-denominated contracts, passage of title upon loading in the U.S. port, customer responsibility for the international freight, letters of credit posted by customers for the commodity and the transportation to the U.S. port, and the utilization of local agents where appropriate. TECO Coal cannot be assured that these measures will effectively mitigate all international risks.

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 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's results. However, future structural changes that we cannot predict could adversely affect PGS.

From time to time we are a party 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

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.

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 **Management's Discussion & Analysis** for descriptions of these tests and covenants.

As of Dec. 31, 2011, 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 **Liquidity, Capital Resources** sections of the **Management's Discussion & Analysis**.

Financial market conditions could limit our access to capital and increase our costs of borrowing or refinancing, or have other adverse effects on our results.

The financial market conditions that were experienced in 2008 and early 2009 impacted access to both the short- and long-term capital markets and the cost of such capital. Tampa Electric has debt maturing in 2012 for which it expects to refinance all or a portion, and TECO Finance has debt maturing in 2015 that it expects to refinance a portion. Future financial market conditions could limit our ability to raise the capital we need and could increase our interest costs which could reduce earnings.

We enter in derivative transactions, primarily with financial institutions as counterparties. Financial market turmoil could lead to a sudden decline in credit quality among these counterparties, which could make in-the-money positions uncollectable.

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, 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.

Declines in the financial markets or in interest rates used to determine benefit obligations 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, 2011, our plan was 90% funded under calculation requirements of the Pension Protection Act. However, as a result of the continued low interest rate environment, our funded percentage is expected to be approximately 85% as of the next Pension Protection Act measurement date of Jan. 1, 2012. This will require future contributions to the plan ranging from $35 million to $55 million annually over the next five years. Any future declines in the financial markets or a continued low-interest rate environment could increase the amount of contributions required to fund our plan in the future.

We estimate that pension expense in 2012 will be higher than levels experienced in 2011 primarily due to the lower interest rate environment. Any future declines in the financial markets or a continuation of the low interest rate environment could cause pension expense to increase in future years.

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

We are forecasting capital expenditures at Tampa Electric to support the current levels of customer growth, to comply with the design changes mandated by the FPSC to harden transmission and distribution facilities against hurricane damage, to maintain transmission and distribution system reliability, to maintain coal-fired generating unit reliability and efficiency, and longer-term to add generating capacity at the Polk Power Station.

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 Standard & Poor's (S&P) at BBB with a stable outlook, 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. The senior unsecured debt of Tampa Electric Company is rated by S&P at BBB+ with a stable outlook, by Moody's at Baa1 with a stable outlook and by Fitch at A- 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.

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.

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 four electric generating plants in service, with a December 2011 net winter generating capability of 4,684 MW. Tampa Electric assets include the Big Bend Power Station (1,582 MW capacity from four coal units and 61 MW from a CT), the Bayside Power Station (2,083 MW capacity from two natural gas combined cycle units and four CTs), the Polk Power Station (220 MW capacity from the IGCC unit and 732 MW capacity from four CTs) and 6 MW from the Howard Current Advanced Waste Water Treatment Plant, operated by the City of Tampa.

The Big Bend coal fired units went into service from 1970 to 1985 and the CT was installed in 2009. The Polk IGCC unit began commercial operation in 1996. In 1991, Tampa Electric purchased the Phillips Power Station from the Sebring Utilities Commission (Sebring) and it was placed on long-term reserve standby in 2009. Bayside Unit 1 was completed in April 2003, Unit 2 was completed in January 2004, Units 5 and 6 were completed in April 2009 and Units 3 and 4 were completed in July 2009.

Tampa Electric owns 180 substations having an aggregate transformer capacity of 22,392 Mega Volts Amps (MVA). The transmission system consists of approximately 1,322 pole miles (including underground and double-circuit) of high voltage transmission lines, and the distribution system consists of 6,329 pole miles of overhead lines and 4,669 trench miles of underground lines. As of Dec. 31, 2011, there were 678,027 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 or other property rights 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's distribution system extends throughout the areas it serves in Florida and consists of approximately 17,700 miles of pipe, including approximately 11,200 miles of mains and 6,500 miles of service lines. Mains and service lines are maintained under rights-of-way, franchises or permits.

PGS's 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 approximately 295,000 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. 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, 2011, the TECO Coal operating companies had a combined estimated 325.2 million tons of proven and probable recoverable reserves, a 25.1% increase from Dec 31, 2010. 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 total 85.4 million tons of coal.

Reserves are defined by 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 (measured) reserves, but 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 (measured) 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.

Reserve estimates are prepared by TECO Coal's staff of geologists. There are two chief geologists with the responsibility to track changes in reserve estimates, supervise TECO Coal's other geologists and coordinate third-party reviews of reserve estimates by qualified mining consultants. Annually, a third-party reserve audit is performed by MM&A on TECO Coal's newly identified reserves. The results of that audit are reflected in the numbers within this report.

The following table (Table 4) 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 4

Mining Complex	Location	Total	Proven	Probable	Owned	Leased	Assigned (2) 2012	Assigned (2) 2011	Unassigned (2) 2012	Unassigned (2) 2011
Gatliff Coal Company	Bell County, KY/ Knox County, KY/ Campbell County, TN	3.4	3.0	0.4	1.2	2.2	0.5	0.5	2.9	2.9
Clintwood Elkhorn Mining	Pike County, KY/ Buchanan County, VA	44.6	39.1	5.5	3.2	41.4	44.5	47.9	0.1	0
Premier Elkhorn Coal	Pike County, KY/ Letcher County, KY/ Floyd County, KY	136.1	71.5	64.6	105.7	30.3	60.9	61.8	75.1	8.4
Perry County Coal	Perry County, KY/ Leslie County, KY/ Knott County, KY	141.1	84.9	56.2	1.5	139.7	139.0	138.8	2.2	7.3
Total		325.2	198.5	126.7	111.6	213.6	244.9	249.0	80.3	18.6

(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 TECO Coal to operating mine shafts, mining equipment, and plant facilities, and all coal which has been leased by TECO Coal 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.

The following table (Table 5) shows the recoverable reserves by quality per mining complex.

RECOVERABLE RESERVES BY QUALITY [1]
Table 5

Mining Complex	Recoverable Reserves (Millions of tons)	Sulfur Content ≤ 1% (2)	Sulfur Content >1% (2)	Compliance Tons (3)	Average BTU As received	Coal Type (4)
Gatliff Coal Company	3.4	3.2	0.2	0.0	13,500	LSU
Clintwood Elkhorn Mining	44.6	20.5	24.1	15.8	14,200	HVM, LSU, PCI
Premier Elkhorn Coal	136.0	109.1	26.9	65.3	13,900	HVM, IS, LSU, PCI
Perry County Coal	141.2	108.5	32.7	74.2	13,900	LSU, PCI, V
Total	325.2	241.3	83.9	155.3		

(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 MMBtu when burned. Compliance coal meets sulfur emission standards imposed by Title IV of the Clean Air Act.
(4) Reserve holdings include metallurgical and PCI coal reserves. Although these metallurgical and PCI 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 Metallurgical
PCI – Pulverized Coal Injection
LSU – Low-Sulfur Utility
V – Various
IS – Industrial Stoker

Market Allocation of Reserves

The table below shows the allocation of TECO Coal reserves by market category (metallurgical, PCI, and steam coal), which was prepared by TECO Coal at its four operating subsidiaries. As shown below, a substantial portion of the Clintwood Elkhorn Mining coal reserves has been allocated to the metallurgical category (with the remainder to the steam coal category), a substantial portion of the Premier Elkhorn Coal reserves has been allocated to the PCI and metallurgical categories (with the remainder to the steam coal category), a substantial portion of the Perry County coal reserves has been allocated to the PCI category (with the remainder to the steam coal category); and all of the Gatliff Coal reserves have been allocated to the steam coal category.

At TECO Coal's request, MM&A completed an audit of the methodology used by TECO Coal to conduct such allocation of its coal tonnage estimates. MM&A reviewed information provided by TECO Coal and TECO Coal's methodology of processing, which included examination by certified professional geologists of all supplied coal deposit maps and supporting coal quality data using industry-accepted standards. The audit performed by MM&A concluded that TECO Coal's methodology of allocating its demonstrated reserves by market category is reasonably and responsibly prepared in accordance with industry-accepted standards and in general conformance with SEC Industry Guide 7.

Market conditions may not always permit sales of coal into the particular market as identified, however the objective of this reserve allocation is to recognize the market potential for planning and investment purposes.

The following table (Table 6) shows the recoverable reserves by market category per mining complex and in total. The total reserve mix is approximately 35% metallurgical, 49% PCI and 16% steam.

RESERVES BY MARKET CATEGORY
Table 6

	Metallurgical Reserves			PCI Reserves			Steam Reserves			Grand Totals
	Proven	Probable	Total	Proven	Probable	Total	Proven	Probable	Total	
Gatliff Coal Co.	0.0	0.0	0.0	0.0	0.0	0.0	2.8	0.6	3.4	3.4
Clintwood Elkhorn Mining	40.9	0.8	41.7	0.0	0.0	0.0	2.6	0.3	2.9	44.6
Premier Elkhorn Coal Co.	27.8	44.2	72.0	34.9	15.2	50.1	8.8	5.1	13.9	136.0
Perry County Coal Co.	0.0	0.0	0.0	63.5	45.0	108.5	21.4	11.3	32.7	141.2
Totals:	68.7	45.0	113.7	98.4	60.2	158.6	35.6	17.3	52.9	325.2
% of Total			34.9%			48.8%			16.3%	

Reserve Estimation Procedure

TECO Coal's reserves are based on over 3,100 data points, including drill holes, prospect measurements and mine measurements. Reserve estimates also include information obtained from on-going exploration drilling and in-mine channel sampling programs. Reserve classification is determined by the evaluation of engineering and geologic information along with economic analysis. These reserves are adjusted periodically to reflect market fluctuations and/or changes in engineering parameters and/or geologic conditions. Additionally, the information is constantly 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 geologists and engineers at TECO Coal, and is computer-modeled from which preliminary reserve 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-generated models and enhanced the grid models to better reflect regional trends.

During TECO Coal's reserve evaluation and mine planning, TECO Coal 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, is considered when mining near or under such facilities. Also, as part of TECO Coal's reserve and mineability evaluation, TECO Coal 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

CGESJ, an indirect subsidiary of TECO Guatemala, Inc., 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, 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 accounting standards 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.

For a discussion of certain legal proceedings and environmental matters, including an update of previously disclosed legal proceedings and environmental matters, see **Notes 12** and **9, Commitments and Contingencies**, of the TECO Energy, Inc. and Tampa Electric Company **Consolidated Financial Statements**, respectively.

Item 4. MINE SAFETY DISCLOSURES.

TECO Coal is subject to regulation by the federal Mine Safety and Health Administration (MSHA) under the Federal Mine Safety and Health Act of 1977 (the Mine Act). Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act) and the recently adopted Item 104 of Regulation S-K (17 CFR 229.106) is included in **Exhibit 95** to this annual report.

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*
2011					
	High	$ 18.82	$ 19.66	$ 19.38	$ 19.30
	Low	$ 17.47	$ 18.20	$ 15.82	$ 16.15
	Close	$ 18.76	$ 18.89	$ 17.13	$ 19.14
	Dividend	$ 0.205	$ 0.215	$ 0.215	$ 0.215
2010					
	High	$ 16.54	$ 17.35	$ 17.65	$ 18.11
	Low	$ 14.46	$ 14.46	$ 14.78	$ 16.58
	Close	$ 15.89	$ 15.07	$ 17.32	$ 17.80
	Dividend	$ 0.200	$ 0.205	$ 0.205	$ 0.205

The approximate number of shareholders of record of common stock of TECO Energy as of Feb. 20, 2012 was 12,962.

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. 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 **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 $240.7 million in 2011, $239.3 million in 2010 and $179.6 million in 2009. 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.

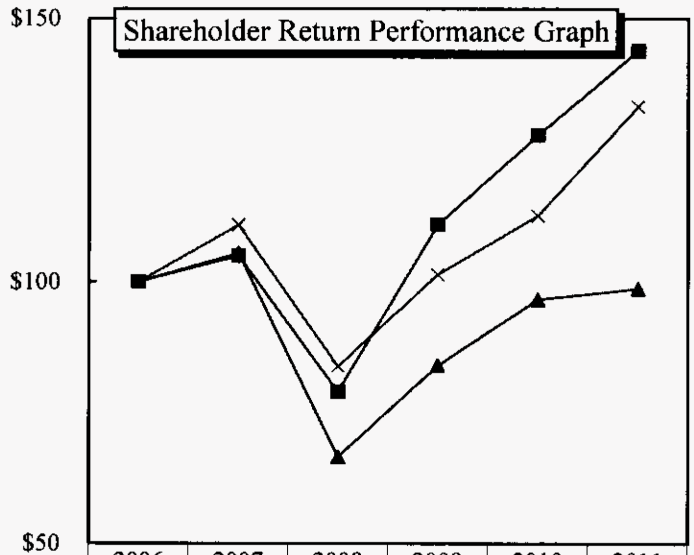
Set forth below is a table showing shares of TECO Energy common stock deemed repurchased by the issuer.

	(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, 2011 – Oct. 31, 2011	425	$17.49	0.0	0.0
Nov. 1, 2011 – Nov. 30, 2011	6,787	$18.02	0.0	0.0
Dec. 1, 2011 – Dec. 31, 2011	1,525	$18.51	0.0	0.0
Total 4th Quarter 2011	8,737	$18.08	0.0	0.0

(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 TECO Energy's common stock on a yearly basis over the five-year period ended Dec. 31, 2011, and compares this return with that of the Standard and Poor's (S&P) 500 Index and the S&P Multi Utility Index. The graph assumes that the value of the investment in TECO Energy's common stock and each index was $100 on Dec. 31, 2006 and that all dividends were reinvested.



	2006	2007	2008	2009	2010	2011
TECO Energy, Inc.	$100	$105	$79	$111	$128	$144
S&P 500 Index	$100	$105	$66	$84	$97	$99
S&P Multi Utility Index	$100	$111	$84	$101	$113	$133

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

(millions, except per share amounts) *Years ended Dec. 31,*	*2011*	*2010*	*2009*	*2008*	*2007*
Revenues	$3,343.4	$3,487.9	$3,310.5	$3,375.3	$3,536.1
Net income from continuing operations	$272.9	$239.6	$213.9	$162.4	$316.7
Net income from discontinued operations(1)	$0.0	$0.0	$0.0	$0.0	$14.3
Net income attributable to TECO Energy(2)	$272.6	$239.0	$213.9	$162.4	$413.2
Total assets	$7,322.2	$7,278.3	$7,219.5	$7,147.4	$6,765.2
Long-term debt	$3,073.4	$3,226.4	$3,309.5	$3,213.5	$3,158.4
Earnings per share (EPS) – basic;					
From continuing operations (2)	$1.27	$1.12	$1.00	$0.77	$1.90
From discontinued operations (1)	0.00	0.00	0.00	0.00	0.07
EPS basic	$1.27	$1.12	$1.00	$0.77	$1.97
Earnings per share (EPS) – diluted;					
From continuing operations (2)	$1.27	$1.11	$1.00	$0.77	$1.89
From discontinued operations (1)	0.00	0.00	0.00	0.00	0.07
EPS diluted	$1.27	$1.11	$1.00	$0.77	$1.96
Dividends declared per common share	$0.850	$0.815	$0.800	$0.795	$0.775

(1) 2007 includes a $14.3 million gain on the 2005 sale of merchant power projects after reaching a favorable conclusion with taxing authorities.

(2) 2007 also includes a $221.3 million gain on the sale of TECO Transport.

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 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 energy-related businesses in Guatemala.

Our regulated utility companies, Tampa Electric and PGS, operate in the Florida market. Tampa Electric serves more than 678,000 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 4,684 megawatts. PGS, Florida's largest gas distribution utility, serves approximately 340,000 residential, commercial, industrial and electric power generating customers in all major metropolitan areas of the state, with a total natural gas throughput of more than 1.5 billion therms in 2011.

We also have unregulated companies. TECO Coal, through its subsidiaries, operates surface and underground mines and related coal processing facilities in eastern Kentucky and southwestern Virginia, producing metallurgical-grade and high-quality steam coals. Sales in 2011 were 8.1 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.

2011 PERFORMANCE

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

In 2011, our net income and earnings per share attributable to TECO Energy were $272.6 million, or $1.27 per share, compared to $239.0 million, or $1.12 per share, in 2010. There were no charges or gains to cause full-year non-GAAP results to differ from net income in 2011.

In 2011, we focused on managing our utility businesses to earn their allowed returns on equity (ROE) despite unfavorable weather. Mild winter weather and rainy summer weather reduced energy sales for both Tampa Electric and PGS in 2011, compared to 2010 when weather was favorable. We also benefited from the retirement of parent debt, and lower interest rates on TECO Finance and Tampa Electric Company debt in 2011. Results at TECO Coal reflected improved margins from better selling prices for its specialty coal products, partially offset by higher operating costs. Following the sale of our ownership interest in EEGSA, a Guatemalan distribution utility, in October 2010, the two power plants in Guatemala performed well and provided stable earnings.

In 2010, our net income and earnings per share attributable to TECO Energy were $239.0 million, or $1.12 per share, respectively, compared to $213.9 million, or $1.00 per share, in 2009. Net income in 2010 included $33.5 million of charges related to early retirement of TECO Energy and TECO Finance debt, a net $3.9 million loss on the sale of DECA II, the final $0.9 million charge related to the 2009 restructuring and a $1.8 million benefit from the recovery of fees related to the previously sold McAdams Power Station. Net income calculated in accordance with generally accepted accounting principles (GAAP) at Tampa Electric in 2010 reflected a one-time $24.0 million reduction in base revenues ($14.7 million after tax) associated with a regulatory agreement approved by the Florida Public Service Commission (FPSC) in August that resolved all outstanding issues in the 2008 base rate case (see the **Regulation** section). As a result of the unprecedented cold winter weather in 2010, PGS recorded a $5.7 million total provision related to the earnings above the top of its allowed ROE range of 9.75% to 11.75%.

Our non-GAAP results in 2010, which excluded the charges and gains discussed above, were $1.29 on a per share basis, compared to $1.08 in 2009 (see the **2010 Reconciliation of GAAP net income from continuing operations to non-**

GAAP results table). Our results in 2010 reflected the benefits of higher base rates approved by the FPSC for Tampa Electric effective in May 2009 and January 2010, and higher base rates for PGS approved by the FPSC effective in June 2009. PGS benefited from the coldest winter in 40 years in 2010, and Tampa Electric benefited from favorable weather throughout the year. TECO Coal realized higher margins, and TECO Guatemala benefited from substantially higher earnings from the San José Power Station, as the station operated normally throughout the year following the extended unplanned outages in 2009, and better results from DECA II prior to its sale in October 2010.

OUTLOOK

Our outlook for 2012 results reflects our expectations that our Florida utilities will continue to earn within their authorized ROEs, TECO Coal will benefit from improved margins from higher contracted prices on lower volumes, and TECO Guatemala will deliver lower earnings due to a scheduled major outage. The drivers impacting 2012 are summarized below and discussed in further detail in the individual operating company sections.

Tampa Electric expects customer growth in 2012 to continue at a pace in line with 2011, when the average number of customers increased 0.7%. PGS expects customer growth at or slightly below levels in 2011 when the average number of customers increased 0.8%. Energy sales at both utilities are expected to be higher than in 2011, assuming normal weather conditions. Mild winter temperatures and, in the case of Tampa Electric, a rainy summer, reduced energy sales in 2011. In 2012, Tampa Electric expects to benefit from lower interest expense as $461 million of debt maturing or due for remarketing will be retired or refinanced in the current favorable interest rate environment.

We expect TECO Coal net income to increase in 2012 as higher contracted selling prices boost margins. With 90% of its expected 2012 sales contracted, the average selling price across all products is expected to be $96 per ton, which is $8 per ton higher than 2011, while the fully-loaded, all-in cost of production is expected to be in a range between $83 and $87 per ton, or $3 to $7 per ton higher than in 2011.

We expect lower results from TECO Guatemala in 2012 due to a scheduled steam turbine overhaul outage at the San José Power Station, which is expected to reduce net income by approximately $4 million.

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).

Our priorities for the use of cash remain investment in the utility companies and, over time, reduction of parent debt. In 2012, we expect to make additional equity contributions to Tampa Electric and PGS to support their capital structures and financial integrity. Our opportunities to invest capital in Tampa Electric are expected to grow significantly over the next several years as it invests in its next increment of new generating capacity. We anticipate capital spending in 2012 to increase to $505 million, including the initial investments in generating capacity additions at Tampa Electric and opportunities to grow the PGS system described below (see the **Liquidity, Capital Resources** section).

In 2010, we consolidated ongoing activities throughout the company involving evaluation of trends, strategies and opportunities affecting our regulated utilities, to sharpen the focus on developing longer range plans to take advantage of emerging growth opportunities and some fundamental changes in our industry. Over time we expect these initiatives to contribute to earnings growth. Some of the areas that we are currently focused on include:

- We believe that there are opportunities to grow the use of compressed natural gas (CNG) for fleet vehicles. To date, we have had success working with fleet owners to convert about 200 trash trucks to CNG. One trash truck converted to CNG for fuel has the annual fuel consumption equivalent of adding a casual dining restaurant to the PGS system. Such conversions offer compelling economics to customers, and expand PGS therm sales without significant capital investment by PGS.
- We also believe that there will be growth opportunities as electric vehicles begin entering the Tampa Bay market. We are working with local dealerships and municipalities to help ensure that the buying experience, which will be different than it is for gasoline vehicles, is as easy for customers as possible. One of the advantages of growth in electric vehicles is additional load, normally during off-peak hours, for charging. This new load has the potential to offset the load lost from increased energy efficiency and conservation efforts.
- We are looking closely at Smart Grid applications that have proven technology and offer operating and financial benefits to our overall operations. These include, among other opportunities, transitioning automatic meter reading technology to advanced metering infrastructure, which would include a significant investment in our communications infrastructure but would also result in operations and maintenance expense savings.
- We also recognize that there is a growing demand for natural gas generation in Florida over the next decade. We project that Florida may need between 0.8 and 1.25 billion cubic feet per day (Bcf/day) by as early as 2014. Given

our expertise in this area, we continue to evaluate opportunities to partner with transmission and end-use natural gas customers.

At PGS, the business model for system expansion evolved in 2011 to focus on extending the system to serve large commercial and industrial customers that are currently using petroleum and propane as fuel under multi-year contracts. The current low natural gas prices and the projections that natural gas prices are going to remain low into the future make it attractive for these customers to convert from fuels that are currently three to four times more expensive on a cost per million Btu basis.

Previously, during periods of robust residential growth, PGS extended its system to serve large residential housing developments and commercial growth followed the residential development. In the current environment where few large residential projects are being developed, commercial and industrial led expansion allows PGS to continue to provide clean and economical natural gas to areas of the state previously unserved and be positioned to serve future residential growth.

RESULTS SUMMARY

The table below compares our GAAP net income to our non-GAAP results. A reconciliation between GAAP net income and non-GAAP results is contained in the **Reconciliation of GAAP net income from continuing operations to non-GAAP results** tables 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 excluded or included from the most directly comparable GAAP measure (see the **Non-GAAP Information** section).

Results Comparisons

(millions)	***2011***	*2010*	*2009*
Net income attributable to TECO Energy	**$272.6**	$239.0	$213.9
Non-GAAP results	**$272.6**	$275.5	$230.0

The table below provides a summary of revenues, earnings per share, net income and shares outstanding for the 2011- 2009 period.

Earnings Summary

(millions) Except per-share amounts	***2011***	*2010*	*2009*
Consolidated revenues	**$3,343.4**	$3,487.9	$3,310.5
Earnings per share – basic			
Earnings per share attributable to TECO Energy	**$ 1.27**	$ 1.12	$ 1.00
Earnings per share – diluted			
Earnings per share attributable to TECO Energy	**$ 1.27**	$ 1.11	$ 1.00
Net income attributable to TECO Energy	**$ 272.6**	$ 239.0	$ 213.9
Charges and (gains)(1)	--	36.5	16.1
Non-GAAP results(2)	**$ 272.6**	$ 275.5	$ 230.0
Average common shares outstanding			
Basic	**213.6**	212.6	211.8
Diluted	**215.1**	214.8	213.1

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

(2) 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).

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

2011 Reconciliation of GAAP net income from continuing operations to non-GAAP results

There were no charges or gains in 2011 to cause non-GAAP results to differ from net income.

2010 Reconciliation of GAAP net income from continuing operations to non-GAAP results

Net income impact (millions)	*Tampa Electric*	*PGS*	*TECO Coal*	*TECO Guatemala*	*Parent/ Other*	*Total*
GAAP Net income attributable to TECO Energy	$208.8	$34.1	$53.0	$41.6	$(98.5)	$239.0
Restructuring charges	—	—	—	—	0.9	0.9
Taxes on previously undistributed earnings at DECA II	—	—	—	24.9	—	24.9
Loss (gain) on the sale of DECA II	—	—	—	(27.0)	6.0	(21.0)
Charges related to early debt retirement	—	—	—	—	33.5	33.5
Recovery of fees related to McAdams Power Station sale	—	—	—	—	(1.8)	(1.8)
Total charges and (gains)	—	—	—	(2.1)	38.6	36.5
Non-GAAP results	$208.8	$34.1	$53.0	$39.5	$(59.9)	$275.5

2009 Reconciliation of GAAP net income from continuing operations to non-GAAP results

Net income impact (millions)	*Tampa Electric*	*PGS*	*TECO Coal*	*TECO Guatemala*	*Parent/ Other*	*Total*
GAAP Net income attributable to TECO Energy	$160.2	$31.9	$37.2	$38.6	$(54.0)	$213.9
Restructuring charges	11.3	2.9	—	—	1.6	15.8
Project development cost write-off	5.2	—	—	—	—	5.2
Gain on the sale of Navega	—	—	—	(8.7)	—	(8.7)
Charge related to student loan securities	—	—	—	—	3.8	3.8
Total charges and (gains)	16.5	2.9	—	(8.7)	5.4	16.1
Non-GAAP results	$176.7	$34.8	$37.2	$29.9	$(48.6)	$230.0

NON-GAAP INFORMATION

From time to time, in this Management's Discussion & Analysis of Financial Condition and Results of Operations, we provide non-GAAP results, which present financial results after elimination of the effects of certain identified charges and gains. In 2011, there were no charges or gains to cause non-GAAP results to differ from net income. 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 are 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		***2011***	*2010*	*2009*
Segment revenues [(1)]				
Regulated companies	Tampa Electric	**$2,020.6**	$2,163.2	$2,194.8
	Peoples Gas	**453.5**	529.9	470.8
Total regulated		**$2,474.1**	$2,693.1	$2,665.6
Unregulated companies	TECO Coal	**$ 733.0**	$ 690.0	$ 653.0
	TECO Guatemala[(2)]	**133.5**	124.4	8.3
Total unregulated		**$ 866.5**	$ 814.4	$ 661.3
Net income [(3)]				
Regulated companies	Tampa Electric	**$ 202.7**	$ 208.8	$ 160.2
	Peoples Gas	**32.6**	34.1	31.9
Total regulated		**235.3**	242.9	192.1
Unregulated companies	TECO Coal	**51.5**	53.0	37.2
	TECO Guatemala	**22.4**	41.6	38.6
Total unregulated		**73.9**	94.6	75.8
Parent/other		**(36.6)**	(98.5)	(54.0)
Net income attributable to TECO Energy		**$ 272.6**	$ 239.0	$ 213.9
Earnings per share - basic [(4)]				
Regulated companies	Tampa Electric	**$0.95**	$0.98	$ 0.76
	Peoples Gas	**0.15**	0.16	0.15
Total regulated		**1.10**	1.14	0.91
Unregulated companies	TECO Coal	**0.24**	0.25	0.17
	TECO Guatemala	**0.10**	0.19	0.18
Total unregulated		**0.34**	0.44	0.35
Parent/other		**(0.17)**	(0.46)	(0.26)
Earnings attributable to TECO Energy		**$ 1.27**	$1.12	$1.00
Average shares outstanding – basic		**213.6**	212.6	211.8

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

(2) Prior to 2010, Guatemalan entities CGESJ (San Josè) and TCAE (Alborada) were deconsolidated under accounting standards that were in effect at that time for variable interest entities.

(3) Segment net income and earnings are reported on a basis that includes internally allocated interest costs to the non-utility companies. Internally allocated interest costs were at a pretax interest rate of 6.25% for 2011, 6.50% for July through December 2010, and 7.15% for January 2009 through June 2010.

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

TAMPA ELECTRIC

Electric Operations Results

Net income in 2011 was $202.7 million, compared to $208.8 million in 2010. There were no charges or gains in either 2011 or 2010. Net income in 2009 was $160.2 million and non-GAAP results were $176.7 million, which excluded $11.3 million of restructuring charges and a $5.2 million write-off of project development costs primarily related to the Polk Unit 6 Integrated Gasification Combined-Cycle (IGCC) project (see the **2009 Reconciliation of GAAP net income from continuing operations to non-GAAP results** table).

Results in 2011 reflected the significant impact on energy sales of extremely mild weather, partially offset by a 0.7% higher average number of customers, and lower non-fuel operations and maintenance expenses. Net income in 2011 included $1.0 million of Allowance for Funds Used During Construction (AFUDC) equity, which represents allowed equity cost capitalized to construction costs, compared with $1.9 million in the 2010 period.

Compared to the cold winter and hot summer in 2010, the mild winter and wet summer in 2011 resulted in pretax base revenue $31 million lower than in 2010 (when revenues were reduced $24 million under the regulatory agreement described below), despite a 0.7% increase in the average number of customers and improvements in the local economy. In 2011, total retail net energy for load, which is a calendar measurement of retail energy sales rather than a billing-cycle measurement, decreased 5.7%, compared to the 2010 period. In 2011, total degree days in Tampa Electric's service area were 3% above normal, but 10% lower than in 2010. In 2011, although degree days were slightly above normal, periods of cold winter weather were not sustained long enough to generate typical winter heating load and summer season cooling degree days were above normal. In the summer season, rainfall was 14% above normal, which did not affect degree days but did lower energy sales to residential customers. The energy sales shown in the summary table below reflect the energy sales based on the timing of billing cycles, which can vary from period to period.

In 2011, operations and maintenance expense, excluding all FPSC-approved cost-recovery clauses, decreased $23.6 million driven primarily by lower accruals for performance-based incentive compensation for all employees and other benefit costs, lower power plant maintenance costs, and lower costs to operate and maintain the transmission and distribution system. Compared to 2010, depreciation and amortization expense increased $3.8 million, reflecting the additions to facilities to serve customers.

Results in 2010 were driven primarily by higher base revenues from favorable weather, new base rates, 0.6% higher average number of customers, higher earnings on NO_x control projects, and higher operations and maintenance expenses. Net income in 2010 also reflected the one-time reduction in base revenues described in the **Base Rates** section. Net income included $1.9 million of AFUDC-equity, compared with $9.3 million in the 2009 period, which included AFUDC for NO_x control projects, coal rail unloading facilities and peaking combustion turbines (CTs).

In 2010, total degree days in Tampa Electric's service area were 14% above normal and 10% above 2009 levels. Pretax base revenue increased between $30 and $40 million from favorable weather in 2010. Pretax base revenues increased between $55 and $65 million in 2010 from new base rates approved by the FPSC for Tampa Electric effective in May 2009 and Jan. 1, 2010 (see the **Base Rates** and **Regulation** sections).

In 2010, total retail net energy for load increased 3.6% compared to the 2009 period, driven primarily by favorable weather and the 0.6% increase in the average number of customers. Operations and maintenance expense excluding all FPSC-approved cost recovery clauses, increased $5.1 million, due to the accrual of performance-based incentive compensation for all employees, partially offset by lower spending on generating unit maintenance.

In 2010, depreciation and amortization expense increased $9.5 million, reflecting the additions to facilities to serve customers, and interest expense increased $4.0 million due to debt issued in 2009. Net income in 2010 reflected a $3.5 million tax benefit from the domestic production deduction compared to 2009, when no domestic production deduction was recorded.

Base Rates

Tampa Electric's results reflect increased base rates established in March 2009, when the FPSC awarded $104 million higher revenue requirements effective in May 2009 that authorized an ROE mid-point of 11.25%, 54.0% equity in the capital structure, and 2009 13-month average rate base of $3.4 billion. A change to those rates was made in July 2009 to adjust an erroneous calculation made in the March decision which resulted in $9.3 million of additional revenue requirements in 2009. A final component of the March decision was a 2010 base rate step increase associated with five peaking CTs and the solid-fuel rail unloading facilities at the Big Bend Power Station that entered service before the end of 2009. This $25.7 million step increase was contested by the interveners.

In December 2009, the FPSC approved Tampa Electric's petition requesting that the proposed rates to support the CTs and rail unloading facilities be put into effect Jan. 1, 2010. At that time, the FPSC determined that, based on its staff audit of the actual costs incurred, the 2010 portion of the base rates approved in 2009 should be $25.7 million, subject to refund. A regulatory proceeding was scheduled to be held in October 2010 regarding the continuing need for the CTs, the appropriate amount to be recovered and the resulting rates.

In July 2010, Tampa Electric entered into a stipulation with the interveners to resolve all issues related to the 2008 base rate case including the 2010 step increase. Under the terms of the stipulation, the $25.7 million step increase would remain in effect for 2010, and Tampa Electric would make a one-time reduction of $24.0 million to customers' bills in 2010.

In August 2010, the FPSC voted to approve the July stipulation. This stipulation resolved all issues in the rate case and the docket was closed. The one-time reduction of $24.0 million to customers' bills in 2010 was reflected in operating results as a reduction in revenue.

Effective Jan. 1, 2011, and for subsequent years, rates of $24.4 million (a $1.3 million reduction from the $25.7 million in effect for 2010) related to the step increase are in effect (see the **Regulation** section for an additional description of the base rate proceeding).

The table below provides a summary of Tampa Electric's revenue and expenses and energy sales by customer type.

Summary of Operating Results

(millions)	*2011*	*% Change*	*2010*	*% Change*	*2009*
Revenues	**$2,020.6**	(6.6)	$2,163.2	(1.4)	$2,194.8
Other operating expenses	**242.4**	(16.3)	289.5	18.3	244.7
Maintenance	**106.8**	(8.0)	116.1	(5.9)	123.4
Depreciation	**222.1**	2.9	215.9	7.7	200.4
Taxes, other than income	**143.6**	(1.2)	145.3	0.3	144.9
Restructuring costs	—	—	—	—	18.4
Non-fuel operating expenses	**714.9**	(6.8)	766.8	4.8	731.8
Fuel	**733.5**	(4.4)	767.6	(16.9)	923.3
Purchased power	**125.9**	(29.9)	179.6	1.1	177.6
Total fuel expense	**859.4**	(9.3)	947.2	(14.0)	1,100.9
Total operating expenses	**1,574.3**	(8.2)	1,714.0	(6.5)	1,832.7
Operating income	**446.3**	(0.6)	449.2	24.1	362.1
AFUDC equity	**1.0**	(47.4)	1.9	(79.6)	9.3
Net income	**$ 202.7**	(2.9)	$ 208.8	30.3	$ 160.2
Megawatt-Hour Sales (thousands)					
Residential	**8,718**	(5.1)	9,185	6.0	8,667
Commercial	**6,207**	(0.2)	6,221	(0.8)	6,274
Industrial	**1,804**	(10.2)	2,010	0.7	1,995
Other	**1,835**	2.1	1,797	(2.3)	1,839
Total retail	**18,564**	(3.4)	19,213	2.3	18,775
Sales for resale	**352**	(31.8)	516	17.3	440
Total energy sold	**18,916**	(4.1)	19,729	2.7	19,215
Retail customers-thousands (average)	**675.8**	0.7	671.0	0.6	666.7
Retail net energy for load	**19,205**	(5.7)	20,362	3.1	19,753

Operating Revenues

In 2011, retail megawatt hours (MWh), as measured on a billing cycle basis shown in the table above, decreased 3.4%. Compared to the cold winter and hot summer in 2010, the mild winter and wet summer in 2011 resulted in pretax base revenue that was $31 million lower than in 2010 (after revenues were reduced $24 million under the regulatory agreement described above), despite a 0.7% increase in the average number of customers and improvements in the local economy. In 2011, total retail net energy for load, which is a calendar measurement of retail energy sales rather than a billing cycle measurement, decreased 5.7%, compared to the 2010 period. In 2011, total degree days in Tampa Electric's service area were 3% above normal, but 10% lower than in 2010. Despite total above normal degree days, the weather patterns described in the **Results** section above reduced energy sales.

For the past several years, weather normalized energy consumption per residential customer declined due to the combined effects of voluntary conservation efforts, economic conditions, changes in lighting and appliance efficiency, which we believe have contributed additionally to voluntary conservation.

Sales for resale, which are a decreasing portion of Tampa Electric's energy sales, declined 31.8% in 2011, primarily due to changes in Tampa Electric's wholesale rates and reduced demand due to the mild weather.

In 2010, retail MWh, as measured on a billing cycle basis, increased 2.3% primarily due to favorable weather throughout the year and 0.6% customer growth. In 2010, total retail net energy for load increased 3.1%. Off-system sales (sales for resale) increased 17.3%, primarily due to increased demand throughout Florida in response to cold winter weather.

Electricity sales to the phosphate industry decreased 23.2% in 2011 after a 5.1% increase in 2010, driven by the return to service of a phosphate customer's self-generating capacity following an outage in 2010. The increase in sales to phosphate customers in 2010 was driven by higher operating rates at the customer's facilities in response to higher demand for their products worldwide and the self-generating capacity outage. Base revenues from phosphate sales represented almost 3% of base revenues in 2011 and 2010 and less than 3% in 2009. Sales to commercial customers decreased 0.2% in 2011, primarily reflecting the mild weather, and decreased 0.8% in 2010 reflecting the local economic conditions.

Customer and Energy Sales Growth Forecast

The Florida economy continues to recover from the economic downturn, as evidenced by lower levels of unemployment, and the new housing construction market, which was a major driver of growth in the Florida economy for many years, is improving, albeit slowly (see the **Risk Factors** section). In general, economists are forecasting a continued improvement in the unemployment rate in 2012, and an acceleration of improvement in the economy in 2013 and beyond. The 2012 forecast used by Tampa Electric reflects a continuation of the modest customer growth trend that was experienced in 2011. Following the lower energy sales in 2011 due to unusually mild and rainy weather, absolute levels of energy sales are expected to increase assuming normal weather. Energy sales are expected to reflect continued lower per customer usage in response to increased energy efficiency, voluntary conservation and economic conditions. The average number of customers increased 0.7% in 2011 following a 0.6% increase in 2010.

Longer term, assuming continued economic recovery and that growth from population increases and more robust business expansion resumes, Tampa Electric expects average annual customer growth to return to a level of nearly 1.5% and weather-normalized average retail energy sales growth about 0.5% lower than customer growth. This energy sales growth projection is lower than in periods prior to the economic downturn, reflecting changes in usage patterns and changes in population trends. These growth projections assume continued modest local area economic growth, normal weather, a recovery in the housing market over time, and a continuation of the current energy market structure.

The economy in Tampa Electric's service area continued to grow modestly in 2011 after modest growth in 2010 and contraction in 2009. The growth was led primarily by the business services, healthcare and tourism related businesses, but unemployment, while now below the state average, remains above the national average. The total nonfarm employment in the Tampa metropolitan area increased 1.2% in 2011 after decreasing 1.5% in 2010 and 5.8% in 2009. The increase in nonfarm employment compared favorably with the state of Florida's increase of 0.8%. The local Tampa area unemployment rate decreased to 9.5% at year-end 2011, compared to 12.0% at year-end 2010, and 12.4% at the end of 2009. The Tampa area year-end 2011 unemployment rate was below the state of Florida's 9.7% rate, but higher than the 8.5% for the nation.

Operating Expenses

Total pretax operating expenses decreased 8.2% in 2011 driven primarily by lower purchased power expense and lower other operating expense. Excluding all FPSC-approved cost-recovery clause-related expenses, operations and maintenance expense decreased $23.6 million driven primarily by lower accruals for performance-based incentive compensation for all employees and other benefit costs, lower power plant maintenance costs, and lower costs to operate and maintain the transmission and distribution system. Tampa Electric expects operations and maintenance expense to increase in 2012 driven primarily by higher employee-related expenses, and higher costs to operate the transmission, distribution and power generating systems.

Compared to 2010, depreciation and amortization expense increased $3.8 million, reflecting the additions to facilities to serve customers. Depreciation is expected to increase at similar levels in 2012.

Total pretax operating expense decreased 6.5% in 2010 driven primarily by lower fuel expense. Excluding all FPSC-approved cost recovery clause-related expenses, the 2009 restructuring charges and the write-off of project development costs, operations and maintenance expense increased $5.1 million in 2010, due to the accrual of performance-based incentive compensation for all employees partially offset by lower spending on generating unit maintenance and other savings as a result of the 2009 restructuring actions.

In 2010, depreciation and amortization expense increased $9.5 million, reflecting the additions to facilities to serve customers, which included peaking CTs, NO_x control projects and rail coal unloading facilities.

Fuel Prices and Fuel Cost Recovery

In November 2011, the FPSC approved cost-recovery rates for fuel and purchased power, capacity, environmental and conservation costs for 2012. The rates include the expected cost for natural gas and coal in 2012, and the net over-recovery of fuel, purchased power and capacity clause expenses which were collected in 2011 and 2010.

Total fuel cost decreased in both 2011 and 2010 due to lower cost for natural gas partially offset by higher cost for coal. Purchased power expense decreased in 2011 due to lower volume purchased, as a result of higher Tampa Electric coal-fired generation, and at lower prices due to lower natural gas prices, which is the primary fuel used by other generators in Florida. Purchased power expense increased in 2010 from higher volumes purchased, but at lower prices due to lower natural gas prices. Delivered natural gas prices decreased 8.0% in 2011 as a result of abundant supplies from on-shore domestic natural gas produced from shale formations, and storage inventories above historic averages. Higher natural gas inventories resulted from lower demand for natural gas caused by mild weather and lower natural gas demand from industrial users due to economic conditions. Delivered coal costs increased 12.3% in 2011. The average coal and natural gas costs were $3.46 per million Btu (/MMBtu) and $6.20/MMBtu, respectively, in 2011.

Natural gas futures as traded on the New York Mercantile Exchange (NYMEX) and various forecasts for natural gas prices indicate that natural gas prices are expected to decline in 2012 due to increased supply from on-shore shale gas formations and very high levels of gas in storage due to increased supply and lower usage due to a milder than normal winter in the eastern portion of the United States. Beyond 2012, forecasts are for stable natural gas prices for several years due to increased availability of domestic supplies of natural gas. Delivered coal prices, while less volatile, increased in 2011 due to higher transportation costs as a result of higher diesel oil prices. Tampa Electric's primary coal supplies are from the Illinois Basin, which have experienced upward movements in prices over the past several years but not of the same magnitude as prices in the Central Appalachian coal-producing region. Excluding transportation costs, Tampa Electric's coal prices are expected to remain stable in 2012 due to long-term supply contracts.

Energy Supply

Tampa Electric's generation decreased in 2011 in line with lower energy sales due to mild weather, which also reduced purchased power volumes. Lower natural gas prices also contributed to the decrease in purchased power expense on a per MW basis. Generation in 2010 increased due to the conclusion of the major coal-fired unit outages for the installation of NO_x control equipment. Purchased power volumes increased 5.0%, but purchased power expense increased only 1.1% in 2010 due to lower natural gas prices than in 2009.

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. Longer term, natural gas prices, which declined to exceptionally low levels in late 2011 and early 2012 as a result of increased supply and lower demand due to mild winter temperatures, are to remain stable for several years after 2012, and we expect to maintain the generation mix at about 2011 levels.

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 $15 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 almost $40 million annually for the foreseeable future (see the **Regulation** section).

Capital Spending

Prior to 2010, Tampa Electric was 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, Tampa Electric made capital investments in its transmission and distribution system to improve reliability and reduce customer outages, and for generating unit reliability in 2010 and 2011.

Tampa Electric had previously deferred its next increment of new baseload generating capacity in 2013 due to the recession experienced in the Florida and national economies and the Florida housing market slowdown in 2008 and 2009. In 2011, Tampa Electric made the decision to take advantage of generating capacity available in Florida at attractive rates and to purchase power to meet its 2013 through 2016 energy demand and sales growth. Tampa Electric now plans, subject to FPSC approval, to convert four CTs in peaking service at the Polk Power Station to combined cycle with an early 2017 in-service date. The capital expenditures for the conversion and the related transmission system improvements to support the additional generating capacity are included in the capital expenditure forecast located in the **Capital Expenditures** section. Capital spending in 2012 will support initial engineering and design, and required regulatory approvals (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 will likely debate in the 2012 legislative session, Tampa Electric may need to invest capital to develop additional sources of renewable power generation.

PGS

Operating Results

In 2011, PGS reported net income of $32.6 million compared to $34.1 million in 2010. There were no charges or gains in either 2011 or 2010. Net income in 2009 was $31.9 million and non-GAAP results were $34.8 million, which excluded $2.9 million of restructuring charges. Results in 2011 reflect a 0.8% higher average number of customers. Increased volumes to commercial and industrial customers reflect improvements in the Florida and national economies and generally higher usage by those customers, while lower volumes sold to residential customers reflect the milder weather in contrast to the cold 2010 winter. Gas transported for power generation customers increased in 2011 due to lower natural gas prices, which made it more economical for some customers to switch to natural gas for power generation. Excluding the impact of the 2010 provision related to potential earnings above the top of the allowed ROE range in 2010 described below, non-fuel operations and maintenance expense was higher in 2011, including $2.5 million of expenses related to the defense of environmental contamination claims. Results in 2011 also reflect increased depreciation expense due to routine plant additions.

In 2011, the total throughput for PGS was more than 1.5 billion therms. Industrial and power generation customers consumed approximately 53% of PGS's annual therm volume, commercial customers used approximately 27%, approximately 15% was sold off system, and the balance was consumed by residential customers.

PGS reported full year net income of $34.1 million in 2010, compared to net income of $31.9 million in 2009. There were no charges or gains in 2010. Non-GAAP results of $34.8 million in 2009 excluded $2.9 million of restructuring costs (see the **2009 Reconciliation of GAAP net income from continuing operations to non-GAAP results** table). Results in 2009 included a $4.0 million favorable adjustment to previously recorded deferred tax balances. Results in 2010 reflect a 0.5% higher average number of customers. Residential customer usage increased due to the cold weather in the winter of 2010 and the coldest December on record. In 2010, pretax base revenues increased approximately $10 million due to the unprecedented cold winter weather and approximately $5 million due to the higher base rates, which became effective in June 2009 (see the **Regulation** section). Increased sales to commercial and industrial customers reflected the colder than normal weather, the return to service of several higher volume customers that were idle in the 2009 period and generally higher usage by those customers. Gas transported for power generation customers and off system sales increased in 2010 due to higher power demand in the first quarter. Non-fuel operations and maintenance expense increased, primarily due to higher spending on pipeline integrity and pipeline awareness, partially offset by lower employee related costs as a result of the 2009 restructuring actions. Results in 2010 also reflect increased depreciation expense due to routine plant additions.

In 2010, PGS recorded a $9.2 million total pretax ($5.7 million after tax) provision related to the earnings above the top of its allowed ROE range of 9.75% to 11.75%. In December 2010, PGS and the Office of Public Counsel entered into a stipulation and settlement agreement that called for $3.0 million of the provision to be refunded to customers in the form of a credit on customers' bills in 2011, and the remainder applied to deficiencies in accumulated depreciation reserves. On Jan. 25, 2011, the FPSC approved the stipulation.

In 2010, the total throughput for PGS was almost 1.6 billion therms. Industrial and power generation customers consumed approximately 49% of PGS's annual therm volume, commercial customers used approximately 26%, approximately 19% was sold off-system, and the balance was consumed by residential customers.

Residential operations were about 32% of total revenues in each of the past three years. 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. PGS has also experienced increased interest in the usage of CNG as an alternative fuel for vehicles. Currently, there are 12 CNG fueling stations connected to the PGS system, and additional stations are expected to be added in 2012. Such initiatives add therm sales to the gas system without requiring significant capital investment.

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.

The table below provides a summary of PGS's revenue and expenses and therm sales by customer type.

Summary of Operating Results

(millions)	*2011*	*% Change*	*2010*	*% Change*	*2009*
Revenues	**$453.5**	(14.4)	$529.9	12.6	$470.8
Cost of gas sold	**211.3**	(25.8)	284.8	16.5	244.5
Operating expenses	**172.2**	0.2	171.8	5.2	163.3
Operating income	**70.0**	(4.5)	73.3	16.3	63.0
Net income	**32.6**	(4.4)	34.1	6.9	31.9

Therms sold – by customer segment					
Residential	**77.7**	(14.1)	90.5	23.2	73.5
Commercial	**409.2**	0.3	407.9	6.9	381.7
Industrial	**436.1**	(14.0)	507.2	13.0	448.7
Power generation	**614.3**	5.5	582.2	8.1	538.3
Total	**1,537.3**	(3.2)	1,587.8	10.1	1,442.2
Therms sold – by sales type					
System supply	**353.3**	(21.7)	451.0	13.3	398.0
Transportation	**1,184.0**	4.2	1,136.8	8.9	1,044.2
Total	**1,537.3**	(3.2)	1,587.8	10.1	1,442.2
Customer (thousands) – average	**338.8**	0.8	336.0	0.5	334.4

In Florida, natural gas service is unbundled for non-residential customers and residential customers that use more than 1,999 therms annually 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-only 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 2011, approximately 17,600 out of 42,000 of PGS's eligible non-residential customers had elected to take service under this program.

PGS Outlook

In 2012, PGS expects continued customer growth at rates slightly below those experienced in 2011, reflecting its expectations that the housing markets in some areas of the state that it serves will be slower to recover than the Tampa area. Assuming normal weather, therm sales to weather-sensitive customers, especially residential customers, are expected to increase in 2012 compared to 2011 when mild winter weather reduced sales. Excluding all FPSC-approved cost-recovery clause-related expenses, operation and maintenance expense is expected to decrease slightly in 2012 due to projected lower legal expenses offset by higher employee-related expenses. Depreciation expense is expected to increase slightly from continued capital investments in facilities to reliably serve customers.

Since its acquisition by TECO Energy in 1997, PGS has expanded its gas distribution system into areas of Florida not previously served by natural gas, such as the lower southwest coast in the Fort Myers and Naples areas and the northeast coast in the Jacksonville area. In 2012, PGS expects higher capital spending to support system expansion to serve large commercial and industrial customers.

At PGS the business model for system expansion evolved in 2011 to focus on extending the system to serve large commercial or industrial customers that are currently using petroleum and propane as fuel under multi-year contracts. The current low natural gas prices and the projections that natural gas prices are going to remain low into the future makes it attractive for these customers to convert from fuels that are currently three to four times more expensive on a cost per MMBtu basis.

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 62 interconnections (gate stations) serving PGS's operating divisions. In addition, PGS's 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, and by SeaCoast Gas Transmission, LLC through a single gate station in northeast Florida.

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

In 2011, TECO Coal recorded full-year net income of $51.5 million on sales of 8.1 million tons, compared to $53.0 million on sales of 8.8 million tons in 2010. In 2010, full-year net income included $4.1 million of favorable net benefits from the settlement of state and federal income tax issues recorded in prior years. The 2011 sales mix was more heavily weighted to specialty coals, which included metallurgical, PCI and stoker coals. Compared to 2010, the 2011 average net per-ton selling price rose 15% to almost $88 per ton due to strong metallurgical coal markets and the product mix being more heavily weighted to higher margin products. The all-in total per-ton cost of production rose 15% to almost $80 per ton from generally higher mining costs due to higher royalty payments and severance taxes, which are a function of selling price, productivity impacts associated with increased safety inspection activities, higher surface mining costs due to higher diesel oil prices and longer hauling distances, and higher purchased coal cost. TECO Coal's 2011 effective income tax rate was 23%, essentially unchanged from 2010, excluding the income tax settlements discussed above.

In 2010, TECO Coal recorded full year net income of $53.0 million on sales of 8.8 million tons , compared to $37.2 million on sales of 8.7 million tons in 2009. The 2010 results reflected an average net per-ton selling price of more than $76 per ton, due to a sales mix that was more heavily weighted to metallurgical coal than in 2009 and higher prices for metallurgical coal. The all-in total per-ton cost of production increased to $69 per ton in 2010, from increased surface mine reclamation activities and generally higher mining costs due to productivity impacts associated with increased inspection activities. Full year 2010 net income included a net $4.1 million favorable net benefit from the settlement of state income tax issues recorded in prior years and other tax adjustments. TECO Coal's 2010 effective income tax rate was 22%, excluding the income tax settlements .

TECO Coal Outlook

We expect TECO Coal's net income to increase in 2012 over 2011 from higher contract selling prices. TECO Coal has more than 90% of its expected 2012 sales of between 7.0 and 7.3 million tons contracted. The average expected selling price across all products is expected to be $96 per ton in 2012, which reflects substantially all of the planned 2012 metallurgical coal sales committed and priced. In 2012, metallurgical coal sales volumes are expected to be at, or slightly above, 2011 levels. The higher average selling price also reflects the expiration at the end of 2011 of a 600,000 ton below market steam coal contract, and the repricing of those tons for 2012 at attractive market prices in the second quarter of 2011. The product mix in 2012 is expected to be almost 50% specialty coal, which includes stoker, metallurgical and PCI coals, and the remainder utility steam coal.

The all-in total per-ton cost of production is expected to increase to a range between $83 and $87 per ton. This cost range includes higher royalty payments and severance taxes, which are a function of selling price, and the impact of spreading fixed costs over fewer tons. Diesel fuel prices have been hedged for those contracts signed in 2011 that do not have diesel price adjustments in the contract at volumes that reflect the current higher average diesel fuel consumption, approximately two gallons per ton, associated with longer hauling distances. TECO Coal's effective income tax rate is expected to be 25% for 2012.

The 2013 federal budget as proposed on Feb. 13, 2012, contains provisions to eliminate depletion accounting for mineral extraction companies, which would increase TECO Coal's effective income tax rate and reduce net income in years after 2012 if the budget is passed as proposed (see the **Risk Factors** section).

The lower volume projected for 2012 reflects TECO Coal's response to market conditions by exercising production discipline and eliminating unsold tons from its 2012 sales projections. Mild winter weather, low natural gas prices and worldwide economic conditions caused the selling price for certain types of coal to decline in late 2011 and early 2012. As previously announced, rather than sell coal at lower prices or build inventory, TECO Coal scaled back its production and lowered its 2012 sales projections.

In November 2011, TECO Coal announced that it had made a new discovery of an additional 65 million tons of proven and probable metallurgical coal reserves on properties it controls, and an additional estimated 9 million tons of metallurgical coal classified as resource (non-reserve coal deposits) due to seam thickness. There is an additional 14 million tons of metallurgical coal classified as resource pending further geologic studies (see **Item 2 Properties** the **TECO Coal** section). These metallurgical coal reserves are located below existing reserves and substantially all of these reserves are owned by TECO Coal, which eliminates royalty payments. The coal from these reserves can be transported by conveyor belt to an existing preparation plant, which has adequate capacity. The use of conveyor belts eliminates the trucking costs. In 2012, TECO Coal will evaluate detailed mining plans and potential markets for this high-volatile metallurgical coal. TECO Coal has received one permit amendment from the state of Kentucky related to surface development activities to access a portion of these reserves, and expects to file a second permit amendment in 2012 to access the remainder of these reserves. When these permits are received, TECO Coal will begin the surface preparation and infrastructure development work to bring these reserves into production (see the **Capital Investments** section of **Liquidity, Capital Resources**).

In 2011, TECO Coal allocated its reserves by market category. As a result of this allocation, 34.9% of the reserves are classified as metallurgical coal, 48.8% as PCI coal and 16.3% as steam coal. See **Item 2 Properties**, the TECO Coal section for a discussion of this allocation.

Since 2008, the issuance of permits by the U.S. Army Corp of Engineers (USACE) under Section 404 of the Clean Water Act required for surface mining activities in the Central and Northern Appalachian mining regions has been challenged in the courts by various entities. 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. TECO Coal had six permits on the list of permits subject to enhanced review by the U.S. Environmental Protection Agency (EPA) under its memorandum of understanding with the USACE, which was issued in September 2009, however, three have subsequently been withdrawn. At this time, TECO Coal has all of the permits required to meet its 2012 sales projections.

In 2011, TECO Coal modified the mine plan for a mine that was in the queue for the USACE to act upon. The modification eliminated the requirement for a Section 404 permit and a permit was subsequently issued by the state of Kentucky. Under the revised mine plan, TECO Coal will be able to mine these reserves but at a higher cost due to moving rock and dirt longer distances to already permitted storage areas.

On April 1, 2010, the EPA issued new guidance on environmental permitting requirements for Appalachian mountaintop removal and other surface-mining projects. The guidance limits conductivity (level of mineral salts) in water discharges into streams from permitted areas, and was effective immediately on an interim basis. At that time, the EPA stated that it would decide whether to modify the guidance after consideration of public comments and the results of the Science Advisory Board (SAB) technical review of the EPA scientific reports. In July 2011, the EPA made this guidance final without modification. Because the EPA's standards appear to be unachievable under most circumstances, surface-mining activity could be substantially curtailed since most new and pending permits would likely be rejected. This guidance also could be extended to discharges from deep mines and preparation plants, which could result in a substantial curtailing of those activities as well.

This guidance was challenged in the courts by a number of coal mining industry-related organizations, states and municipalities relating to the stringency of the standards as well as the focus on the coal industry and the Appalachian region in particular. In October 2011, the United States District Court for the District of Columbia ruled that the EPA had exceeded the statutory authority conferred upon it by the Clean Water Act in implementing the coordinated review process with the USACE. There is a second portion of the lawsuits related to the actual water quality guidance discussed above that is not scheduled for hearings until the second quarter of 2012. Pending the outcome of the second portion of the case, few, if any, new permits are expected to be issued by USACE.

Coal Markets

Prices for metallurgical coal rose in 2010, driven by increased demand from expanding economies in China and India, and recovering demand in the U.S. and Europe. The U.S. steel industry operated at about a 70% utilization rate in 2010, compared to a 40% utilization rate for most of 2009. During 2010, spot price for various grades of metallurgical coal produced by TECO Coal and others reportedly ranged from $110 per ton to $180 per ton.

That trend continued in the first half of 2011, as monsoon rains in Australia caused disruptions in supplies from that important provider of metallurgical coal to Asian markets. In mid-2011, prices for certain grades of Australian metallurgical coal peaked at $335 per metric ton. Subsequent to that peak, coal prices declined as supplies from Australia returned to the market and concerns related to worldwide demand for steel in the weakening international economy became more pronounced. In January 2012, prices for the same grade of Australian metallurgical coal were $235 per metric tonne. In the U.S., the steel industry continued to operate above a 70% utilization rate in 2011 and demand for metallurgical coal remained stable. However, weaker demand in the international market and increased supply of metallurgical coal for the domestic markets caused prices for most grades of metallurgical coal to decline.

In 2011, demand for coal used by utilities to generate electricity declined due to mild weather and low natural gas prices, which made it more economical to generate electricity with natural gas than with coal, and uncertainty regarding the impact of certain proposed EPA regulations' on utilities' ability to burn coal in the future. Various industry reports, and estimates by the EPA, indicate that a number of smaller, older coal-fired utility boilers without current environmental controls would be retired in response to the proposed rules. In December 2011, the United States District Court for the District of Columbia stayed the implementation of the EPA's proposed Cross State Air Pollution Rule (CSAPR) (see the **Environmental** section) pending hearings to be held in the spring of 2012. Despite the stay of CSAPR, demand for coal by utilities remains weak.

The significant factors that could influence TECO Coal's results in 2012 include the cost of production, the pricing on uncontracted tons, and customers taking contracted volumes. Longer-term factors that could influence results include inventories at steam coal users, weather, the ability for utilities to continue to burn coal under new rules proposed by the EPA, the ability to obtain environmental permits for mining operations, general economic conditions, the level of oil and natural gas prices, commodity price changes that impact the cost of production, and changes in environmental regulations (see the **Environmental Compliance** and **Risk Factors** sections).

TECO GUATEMALA

Our TECO Guatemala operations include two power plants operating in Guatemala under long-term contracts. The San José and Alborada power stations both have long-term power sales contracts with EEGSA, the largest Guatemalan distribution utility, which serves Guatemala City, the capital of Guatemala, and the surrounding region. In 2001, the company that owns the San José Power Station signed an option with EEGSA to extend its power sales contract for five years at the end of its current term in 2015. The current Alborada power sales contract expires in 2015.

TECO Guatemala reported full-year net income of $22.4 million in 2011, compared to $41.6 million in 2010. In 2010, non-GAAP results were $39.5 million, which excluded the gain on the sale of DECA II described below, and a related tax charge. Results at the San José Power Station reflected higher spot energy sales and prices, and lower interest expense due to a lower balance and lower rates on the non-recourse debt related to the plant. Full-year 2011 results reflect the absence of DECA II earnings, which were $13.2 million in 2010, and $5.2 million of lower capacity payments related to the Alborada Power Station contract extension, which became effective September 2010.

In October 2010, a TECO Guatemala subsidiary sold its 30% interest in DECA II to EPM, a multi-utility company based in Medellín Colombia, for a sales price of $181.5 million.

DECA II was a holding company in which, prior to the sale, TECO Guatemala Holdings, LLC (TGH), a wholly-owned subsidiary of TECO Guatemala, held a 30% interest, Iberdrola Energia, S.A. (Iberdrola) held a 49% interest and Energias de Portugal, S.A. (EDP) held a 21% interest. Each of these parties sold its interest in DECA II. DECA II held an 80.9% ownership interest in EEGSA and affiliated companies.

TGH received $181.5 million of the $605.0 million total purchase price for its 30% interest. In addition, TGH repatriated approximately $25.0 million of cash previously held offshore in a tax deferral structure. TECO Guatemala recorded a $27.0 million gain on the sale, but the sale transaction resulted in a total net gain of $21.0 million for TECO Energy due to the $6.0 million negative valuation allowance recorded against foreign tax credits at TECO Energy Parent (see the **2010** and **2009 Reconciliation of GAAP net income from continuing operations to non-GAAP results** tables). TECO Guatemala also recorded a $24.9 million income tax charge related to the unwinding of the tax deferral structure, as the earnings from DECA II were no longer considered indefinitely reinvested.

The Alborada Power Station, which consists of oil-fired, simple-cycle CTs, is a peak-load facility with high availability, but operates at a low capacity factor by design. The Alborada Power Station is under contract to EEGSA, but it is designated to be an operating reserve for 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 2001, TECO Guatemala exercised an option to extend the Alborada power sales contract for five years at the end of the contract period, which was originally scheduled for September 2010. The contract was extended for five years effective Sep. 14, 2010, at rates approximately

55%, or $7 million after tax on an annual basis, below the previous contract.

In 2010, TECO Guatemala reported net income of $41.6 million, compared to $38.6 million in 2009. In 2010, non-GAAP results were $39.5 million, which excluded the charges and gains related to the sale of its ownership interest in DECA II described above.

Results in 2010 reflected the absence of earnings from DECA II for most of the fourth quarter, lower capacity payments at the Alborada Power Station under the contract extension effective Sep. 14, 2010, and substantially higher earnings from the San José Power Station as the station operated normally throughout the year following extended unplanned outages in 2009.

On Jan. 13, 2009, TGH delivered a Notice of Intent to the Guatemalan government that it intended to file an arbitration claim against the Republic of Guatemala under the Dominican Republic Central America – United States Free Trade Agreement (DR – CAFTA) alleging a violation of fair and equitable treatment of its investment in EEGSA. On Oct. 20, 2010, TGH filed a Notice of Arbitration with the International Centre for Settlement of Investment Disputes to proceed with its arbitration claim.

The arbitration was prompted by actions of the Guatemalan government in July 2008, which, among other things, unilaterally reset the distribution tariff for EEGSA at levels well below the tariffs in effect at the time that the distribution tariff was reset. These actions caused a significant reduction in earnings from EEGSA. As discussed above, until Oct. 21, 2010, TGH held a 24% ownership interest in EEGSA through a holding company DECA II when TGH's interest was sold. In connection with the sale of TGH's ownership interest in EEGSA, TGH reserved the right to pursue the arbitration claim described above. Iberdrola is in international arbitration under the bilateral trade treaty in place between the Republic of Guatemala and the Kingdom of Spain.

TECO Guatemala Outlook

In 2012, we expect normal operations for the Alborada Power Station. At the San José Power Station there will be an extended steam turbine overhaul outage, which will reduce energy sales primarily in the fourth quarter when the opportunity for spot sales is lowest, and is expected to reduce net income approximately $4 million compared to 2011.

The party that controls an approximately 4% interest in the entity that owns the Alborada Power Station has an option to purchase 50% of the company that owns the San José Power Station. This option becomes exercisable at the end of 2014, and provides that the purchase price would be based on book value as determined at that time. Income from the San José Power Station may be reduced beginning in 2015 if such option is exercised. Also as described above, the company that owns the San José Power Station signed an option to extend its PPA for an additional five years at the end of its current term in 2015. If the PPA is not extended pursuant to such option, or is extended at less favorable terms, income from the San José Power Station may also be reduced beginning in 2015.

PARENT/OTHER

The cost for Parent/other in 2011 was $36.6 million, compared to $98.5 million in 2010. The 2010 non-GAAP cost was $59.9 million, which excluded the charges and gains described below in the 2010 results discussion. Improved results in 2011 reflect $13.3 million lower interest expense as a result of the 2010 and 2011 debt retirements and the absence of negative tax valuation adjustments that affected results in 2010.

The cost for Parent/other in 2010 was $98.5 million, compared to $54.0 million in 2009. The 2010 non-GAAP cost for Parent & other was $59.9 million, which excluded a $33.5 million charge related to early retirement of TECO Energy debt, and a $6.0 million foreign tax credit valuation allowance as a result of the sale of DECA II based on estimated foreign source income and projected timing of the utilization of the net operating loss carry forwards. The non-GAAP cost also excluded the $1.8 million benefit related to the recovery of fees paid for the previously sold McAdams Power station, and $0.9 million of final restructuring costs. Non-GAAP results in 2009 were $48.6 million which included a $2.6 million benefit from a sale of property by TECO Properties but excluded $1.6 million of restructuring cost and a $3.8 million charge associated with the sale of auction-rate securities held at TECO Energy parent (see the **2010** and **2009 Reconciliation of GAAP net income from continuing operations to non-GAAP results** tables).

The GAAP cost in 2010 included $9.6 million of foreign tax credit and other tax valuation adjustments based on estimated foreign source income and projected timing of the utilization of the net operating loss carry forwards, and a $1.1 million charge to adjust deferred tax balances related to Medicare Part D subsidies as a result of the Patient Protection and Affordable Care Act enacted early in 2010. Results also included a $3.5 million unfavorable tax adjustment that offsets the favorable domestic production deduction at Tampa Electric due to TECO Energy's consolidated net operating loss (NOL) position. Results also reflected $3.4 million lower interest expense as a result of debt restructuring and retirement.

OTHER ITEMS IMPACTING NET INCOME

Other income (expense)

In 2011, Other income (expense) of $10.2 million included income from miscellaneous services at the utilities, such as lightning surge protection equipment, royalties for coal mined on properties leased by TECO Coal and from the sale of assets no longer in service.

In 2010, Other income (expense) of $14.1 million included a $55.5 million pretax charge related to early debt retirement; $13.1 million from DECA II prior to its sale, when it was accounted for as an equity investment; and a $38.4 million pretax gain on TECO Guatemala's sale of its ownership interest in DECA II.

In 2009, Other income (expense) of $79.3 million reflected $68.5 million, which included an $18.3 million pretax gain on the sale of Navega, from the Guatemalan operations, which operations were accounted for as equity investments, and a net $3.3 million pretax charge related to the sale of various investments.

AFUDC equity at Tampa Electric, which is included in Other income (expense), was $1.0 million, $1.9 million, and $9.3 million in 2011, 2010 and 2009, respectively. AFUDC is expected to increase in 2012 due to the construction of a reclaimed water pipeline to eliminate ground water usage at the Polk Power Station (see the **Liquidity, Capital Resources** section).

Interest Expense

In 2011, total interest expense was $205.1 million compared to $231.3 million in 2010 and $227.0 million in 2009. In 2011, interest expense decreased due to lower debt balances as a result of the early retirement of TECO Energy and TECO Finance debt in December 2010 and the retirement of $64 million of TECO Energy debt at maturity in May 2011.

Interest expense increased in 2010 due to higher debt balances for six months of the year (see the **Financing Activity** section), prior to the early retirement of TECO Energy and TECO Finance debt in December, and lower AFUDC debt at Tampa Electric, which is a credit to interest expense.

Interest expense is expected to be lower in 2012. Tampa Electric Company has $461 million of notes maturing or due for remarketing in 2012, and expects to refinance or remarket $300 to $400 million of that total in a lower interest rate environment (see the **Liquidity, Capital Resources** section).

Income Taxes

The provision for income taxes decreased in 2011, primarily due to the absence of both taxes on cash repatriated from Guatemala and the foreign tax credit valuation allowance recorded in 2010. The provision for income taxes increased in 2010, primarily due to higher operating income, taxes on TECO Guatemala's sale of its ownership interest in DECA II including the taxes on previously undistributed earnings, and an increase to the foreign tax credit valuation allowance. Income tax expense as a percentage of income from continuing operations before taxes was 36.1% in 2011, 41.5% in 2010 and 31.6% in 2009. We expect our 2012 annual effective tax rate to range between 35.0% and 36.0%.

For more information on our income taxes, including a reconciliation between the statutory federal income tax rate and the effective tax rate, see **Note 4** to the **TECO Energy Consolidated Financial Statements**.

The cash payments for federal income taxes, as required by the federal Alternative Minimum Tax rules (AMT), state income taxes, foreign income taxes and payments (refunds) related to prior years' audits totaled $9.4 million, $5.5 million and $4.1 million in 2011, 2010 and 2009, respectively.

Due to the NOL carry forward position resulting from the disposition of the generating assets formerly held by TWG Merchant, our merchant power subsidiary, cash tax payments for income taxes are limited to approximately 10% of the AMT rate. We expect future cash tax payments to be limited to a similar level (reduced by AMT foreign tax credits) and various state taxes. Due to additional bonus depreciation allowed in the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, we currently project to fully utilize these NOLs by 2017. Beginning with 2016, we expect to start using more than $196 million of AMT carry-forward to limit future cash tax payments for federal income taxes to the level of AMT. We currently project minimal cash tax payments over the next five years.

The utilization of the NOL and AMT carry forward are dependent on the generation of sufficient taxable income in future periods.

LIQUIDITY, CAPITAL RESOURCES

The table below sets forth the Dec. 31, 2011 consolidated liquidity and cash balances, the cash balances at the operating companies and TECO Energy parent, and amounts available under the TECO Energy/Finance and Tampa Electric Company credit facilities.

	Balances as of Dec. 31, 2011			
(millions)	Consolidated	Tampa Electric Company	Unregulated Companies	Parent
Credit facilities	$ 675.0	$ 475.0	$ --	$ 200.0
Drawn amounts/LCs	0.7	0.7	--	--
Available credit facilities	674.3	474.3	--	200.0
Cash and short-term investments	44.1	13.9	30.1	0.1
Total liquidity	$718.4	$488.2	$30.1	$200.1

In 2011, we met our cash needs primarily from internal sources. Cash from operations was $754 million. We paid dividends of $183 million in 2011, and capital expenditures were $454 million. Net long-term debt declined $154 million, which included the retirement of $64 million of TECO Energy parent and TECO Finance debt and Tampa Electric's purchase in lieu of redemption of $75 million of tax-exempt notes. Short-term debt declined $12 million.

In 2010, we met our cash needs primarily from internal sources. Cash from operations was $664 million. We paid dividends of $175 million in 2010, and capital expenditures were $490 million. Other sources of cash included $183 million of proceeds from the sale of businesses, primarily the sale of our ownership interest in DECA II for $181 million. Proceeds from the sale of DECA II, along with repatriated cash of $25 million and cash on hand, were used to retire long-term debt. Net long-term debt declined $136 million, representing debt retirement at TECO Energy parent and TECO Finance and a $75 million remarketing by Tampa Electric Company of tax-exempt notes previously held in lieu of redemption. Short-term debt declined $43 million.

In 2009, we met our cash needs primarily from internal sources supplemented with net borrowings of $57 million, including $102 million of notes issued by Tampa Electric Company. Cash from operations was $725 million. We paid dividends of $171 million in 2009, and capital expenditures were $640 million.

Cash from Operations

In 2011, consolidated cash flow from operations was $754 million. Although the timing of recoveries, particularly fuel and purchased power, under FPSC-approved cost-recovery clauses can have a significant impact on cash from operations in any one year, in 2011 the net impact was only $9 million. We had anticipated a more significant impact as the 2011 FPSC-approved clause rates provided for refunds of previous over-recoveries; however, lower than expected actual fuel prices resulted in a net over-recovered balance at the end of 2011. The 2011 cash from operations reflects no pension contributions since the $47 million required contribution for 2011 was prefunded in 2010. Cash from operations also reflects the benefit of our tax NOL position, which resulted in minimal cash payments for state and federal income taxes (see the **Income Taxes** section).

We expect cash from operations in 2012 to be lower than the 2011 level. We expect higher net income in 2012, but lower net recoveries under various regulatory clauses to reduce cash from operations. In November 2011, the FPSC approved fuel-adjustment and other recovery clause rates that provide for refunds to customers of estimated 2011 net over-recoveries of fuel and purchased power over 12 months beginning Jan. 1, 2012 (see the **Regulation** section). Like 2011, we expect our NOL carry forwards to result in minimal state and federal income tax payments in 2012 (see the **Income Taxes** section).

Cash from Investing Activities

Our investing activities in 2011 resulted in a net use of cash of $435 million, including capital expenditures totaling $454 million.

We expect capital spending for the next several years to be above 2011 levels, primarily due to plans for generating capacity additions at Tampa Electric and opportunities to expand the PGS system to serve large commercial and industrial customers (see the **Capital Expenditures** section).

Cash from Financing Activities

Our financing activities in 2011 resulted in a net use of cash of $342 million. Major items included the repayment of $64 million of TECO Parent and TECO Finance long-term debt, Tampa Electric's purchase in lieu of redemption of $75 million of tax-exempt notes, and the repayment of $12 million of short-term debt (see the **Financing Activity** section). We paid $183 million in common stock dividends, and we received $5 million from exercises of stock options.

In 2012, Tampa Electric Company has $461 million of notes maturing or due for remarketing in 2012, and expects to refinance or remarket between $300 and $400 million of these notes. See the **Cash and Liquidity Outlook** section below for a discussion of financing expectations in 2012 and beyond.

Cash and Liquidity Outlook

In general, we target consolidated liquidity (unrestricted cash on hand plus undrawn credit facilities) of at least $500 million. At Dec. 31, 2011, our consolidated liquidity was $718 million, consisting of $488 million at Tampa Electric Company, $200 million at TECO Energy parent and $30 million at the other operating companies.

We expect our sources of cash in 2012 to include cash from operations at levels below 2011, due in large part to higher net income from the operating companies offset by lower net recoveries under various regulatory clauses in 2012 as described above. We plan to use cash generated in 2012 to fund capital spending estimated at $505 million and for dividends to shareholders. In 2012, Tampa Electric Company has $461 million of notes maturing or due for remarketing in 2012, and expects to refinance or remarket between $300 and $400 million of these notes.

We expect to continue to make equity contributions to Tampa Electric Company in order to support the capital structure and financial integrity of the utilities. Tampa Electric Company expects to fund its capital needs with a combination of internally generated cash and equity contributions from us, and we anticipate that these contributions will total $100 to $150 million in 2012. Through 2016, we expect to realize significant cash benefits from the utilization of NOL carry forwards generated in 2004 and 2005 upon the disposition of merchant power assets to reduce federal and certain state income taxes. We currently project minimal cash tax payments over the next five years.

Tampa Electric Company expects to utilize cash from operations and equity contributions from TECO Energy to support its capital spending program, supplemented with incremental utilization of its credit facilities. 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 2012 and remain within the covenant restrictions.

Beyond 2012, our long-term debt maturities for TECO Energy parent and TECO Finance total $200 million in 2015, $250 million in 2016, $300 million in 2017 and $300 million in 2020.

Our expected cash flow could be affected by variables discussed in the individual operating company sections, such as customer growth, weather and usage changes at our regulated businesses, and coal margins. 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).

As a result of our significant reduction of parent debt, and reduced business risk, we have improved our debt credit ratings and ratings outlooks (see **Credit Ratings** 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, 2011, we could have been required to post additional collateral or settle existing positions with counterparties totaling $65.8 million, which are Tampa Electric Company positions. 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 $64.4 million. None of our credit facilities or financing agreements have ratings downgrade covenants that would require immediate repayment or collateralization; however, in the event of a downgrade, our interest expense could be higher.

SHORT-TERM BORROWING

Credit Facilities

At Dec. 31, 2011, and 2010, the following credit facilities and related borrowings existed:

(millions)	Dec. 31, 2011 Credit Facilities	Dec. 31, 2011 Borrowings Outstanding[1]	Dec. 31, 2011 Letters of Credit Outstanding	Dec. 31, 2010 Credit Facilities	Dec. 31, 2010 Borrowings Outstanding[1]	Dec. 31, 2010 Letters of Credit Outstanding
Tampa Electric Company:						
5-year facility[2]	$325.0	$—	$0.7	$325.0	$ 5.0	$0.7
1-year accounts receivable facility	150.0	—	—	150.0	7.0	—
TECO Energy/TECO Finance :						
5-year facility[2][3]	200.0	—	—	200.0	—	6.7
Total	$675.0	$ —	$0.7	$675.0	$12.0	$7.4

(1) Borrowings outstanding are reported as notes payable.
(2) This 5-year facility matures Oct. 25, 2016.
(3) TECO Finance is the borrower and TECO Energy is the guarantor of this facility.

These credit facilities, including the one-year accounts receivable facility that was renewed in February 2012, require commitment fees ranging from 17.5 to 35.0 basis points. There were no notes payable outstanding at Dec. 31, 2011, and the weighted-average interest rates on outstanding notes payable under the credit facilities at Dec. 31, 2010, was 0.64%.

At Dec. 31, 2011, TECO Finance had a $200 million bank credit facility in place guaranteed by TECO Energy with a maturity date in October 2016. Tampa Electric Company had a bank credit facility totaling $325 million, also maturing in October 2016. In addition, Tampa Electric Company had a $150 million accounts receivable securitized borrowing facility that was renewed in February 2012 with a maturity date of February 2013. The TECO Finance and Tampa Electric Company bank credit facilities both include sub-limits for letters of credit of $200 million. At Dec. 31, 2011, the TECO Finance credit facility was undrawn and no letters of credit were outstanding. At Dec. 31, 2011, the Tampa Electric Company credit facilities were undrawn and $0.7 million of letters of credit were outstanding.

The table below sets forth TECO Finance and Tampa Electric maximum, minimum, and average credit facility utilization in 2011.

2011 Credit Facility Utilization

(millions)	Maximum drawn amount	Minimum drawn amount	Average drawn amount	Average interest rate
TECO Finance	$ 50.0	$ —	$ 8.9	0.71%
Tampa Electric	$ 70.0	$ —	$ 3.0	0.59%

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 (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, 2011, 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, 2011. 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, 2011*
Tampa Electric Company			
Credit facility(2)	Debt/capital	Cannot exceed 65%	48.0%
Accounts receivable credit facility(2)	Debt/capital	Cannot exceed 65%	48.0%
6.25% senior notes	Debt/capital	Cannot exceed 60%	48.0%
	Limit on liens(3)	Cannot exceed $700	$0 liens outstanding
Insurance agreement relating to certain pollution bonds	Limit on liens(3)	Cannot exceed $452 (7.5% of net assets)	$0 liens outstanding
TECO Energy/TECO Finance			
Credit facility(2)	Debt/capital	Cannot exceed 65%	57.1%
TECO Energy 6.75% notes and TECO Finance 6.75% notes	Restrictions on secured debt(4)	(5)	(5)

(1) As defined in each applicable instrument.
(2) See description of credit facilities in **Note 6** to the **TECO Energy Consolidated Financial Statements.**
(3) If the limitation on liens is exceeded, the company is required to provide ratable security to the holders of these notes.
(4) These restrictions would not apply to first mortgage bonds of Tampa Electric Company if any were outstanding.
(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. At Dec. 31, 2011, neither TECO Energy nor TECO Finance had secured debt outstanding.

Credit Ratings of Senior Unsecured Debt at Dec. 31, 2011

	Standard & Poor's (S&P)	*Moody's*	*Fitch*
Tampa Electric Company	BBB+	Baa1	A-
TECO Energy/TECO Finance	BBB	Baa3	BBB

On May 27, 2011, S&P upgraded Tampa Electric Company, TECO Finance and TECO Energy to BBB+, BBB, and BBB, respectively, all with stable outlooks.

On March 24, 2011, Fitch Ratings upgraded Tampa Electric, TECO Finance and TECO Energy to A-, BBB and BBB, respectively, all with stable outlooks.

S&P, 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 S&P is BBB-, for Moody's is Baa3 and for Fitch is BBB-; thus all three credit rating agencies assign TECO Energy, TECO Finance and Tampa Electric Company's senior unsecured debt investment-grade ratings.

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. Our access to capital markets and cost of financing, including the applicability of restrictive financial covenants, are influenced by the ratings of our securities. In addition, certain of Tampa Electric Company's derivative instruments contain provisions that require Tampa Electric Company's debt to maintain investment grade credit ratings (see **Note 12** to the **TECO Energy Consolidated Financial Statements**). The credit ratings listed above are included in this report in order to provide information that may be relevant to these matters and because downgrades, if any, in credit ratings may affect our ability to borrow and may increase financing costs, which may decrease earnings (see the **Risk Factors** section). These credit ratings are not necessarily applicable to any particular security that we may offer and therefore should not be relied upon for making a decision to buy, sell or hold any of our securities.

Summary of Contractual Obligations

The following table lists the obligations of TECO Energy and its subsidiaries for cash payments to repay debt, lease payments 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, 2011

		Payments Due by Period				
(millions)	Total	2012	2013	2014	2015-2016	After 2016
Long-term debt (1)						
Recourse	$3,042.3	$374.9	$60.7	$83.3	$616.6	$1,906.8
Non-recourse (2)	33.5	11.2	11.2	11.1	--	--
Operating leases/rentals (3)	121.1	17.9	16.2	15.9	32.7	38.4
Net purchase obligations/commitments (4)	210.2	120.5	37.6	27.2	24.9	--
Interest payment obligations	1,665.6	171.5	154.3	144.5	247.6	947.7
Pension plans (5)	224.8	35.5	41.3	48.0	100.0	--
Total contractual obligations	$5,297.5	$731.5	$321.3	$330.0	$1,021.8	$2,892.9

(1) Includes debt at TECO Energy, TECO Finance, Tampa Electric, Peoples Gas 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).

(2) Reflects non-recourse project debt of the San José power project.

(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 from customers under regulatory clauses approved by the FPSC annually (see the **Regulation** section). One of these agreements, in accordance with EITF 01-08 "Determining Whether an 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 2011, these commitments include Tampa Electric's outstanding commitments for major projects and long-term capitalized maintenance agreements for its CTs.

(5) The total includes the estimated minimum required contributions to the qualified pension plan as of the measurement date. Future contributions 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 **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.

Contingent Obligations at Dec. 31, 2011

		Commitment Expiration					
(millions)		Total(2)	2012	2013	2014	2015 - 2016	After 2016(1)
Letters of credit		$ 0.7	$ —	$ —	$ —	$ —	$ 0.7
Guarantees	Fuel purchase/energy management (2)	109.7	—	—	—	—	109.7
	Other	5.4	—	—	—	—	5.4
Total contingent obligations		$115.8	$ —	$ —	$ —	$ —	$115.8

(1) These guarantees renew annually and are shown on the basis that they will continue to renew beyond 2016.

(2) The amounts shown are the maximum theoretical amounts guaranteed under current agreements.

CAPITAL INVESTMENTS

	Capital Expenditures				
	Actual		Forecast		
(millions)	2011	2012	2013	2014 – 2016	2012 – 2016 Total
Tampa Electric					
Transmission	$ 39	$ 35	$ 30	$85	$ 150
Distribution	94	100	100	295	495
Generation	145	150	140	370	660
New generation and transmission	--	10	50	650	710
Other	35	30	40	115	185
Environmental	13	20	25	65	110
Tampa Electric total	326	345	385	1,580	2,310
Net cash effect of accruals and retentions	(12)	--	--	--	--
Tampa Electric, net	314	345	385	1,580	2,310
PGS	72	105	100	300	505
Unregulated companies[(1)]	68	55	50	165	270
Total	$454	$505	$535	$2,045	$3,085

(1) Includes the capital expenditures of TECO Coal and TECO Guatemala.

TECO Energy's 2011 capital expenditures of $454 million included $326 million at Tampa Electric, including $1.0 million of AFUDC – debt and equity. Capital expenditures at PGS were $72 million in 2011. Tampa Electric's capital expenditures in 2011 were primarily for equipment and facilities to meet modest customer growth, generating equipment maintenance, and environmental compliance. Capital expenditures for PGS were approximately $35 million for system expansion and approximately $35 million for maintenance of the existing system. TECO Coal's capital expenditures included $55 million primarily for normal mining equipment replacement, and $3 million for exploration of new metallurgical coal reserves.

TECO Energy estimates capital spending for ongoing operations to be $505 million for 2012 and approximately $2.6 billion during the 2013 – 2016 period. As described below, this forecast includes $710 million for Tampa Electric's next increment of generation expansion.

For 2012, Tampa Electric expects to spend $345 million. For the transmission and distribution systems, Tampa Electric expects to spend $130 million in 2012, including approximately $90 million for normal transmission and distribution system expansion and reliability, and approximately $40 million for transmission and distribution system storm hardening. Capital expenditures for the existing generating facilities of $150 million include approximately $20 million for repair and refurbishments of CTs under long-term agreements with equipment manufacturers, approximately $30 million for generating unit outages, $35 million for a reclaimed water pipeline to eliminate ground water usage at the Polk Power Station, and $65 million for other improvements and refurbishments to generating units, combustion by-product handling and storage and coal handling equipment. In addition, Tampa Electric expects to spend $20 million for environmental compliance programs in 2012.

In the 2013 – 2016 period, Tampa Electric expects to spend approximately $320 million annually to support normal system growth and reliability and environmental compliance. 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 programs and requirements include: approximately $25 million annually for repair and refurbishments of CTs under long-term agreements with equipment manufacturers, average annual expenditures of more than $100 million to support generating unit availability and reliability, combustion by-product handling and storage, and coal-handling equipment replacement and refurbishment; average annual expenditures of $40 million for general infrastructure to support customers; average annual expenditures of approximately $40 million for transmission and distribution system storm hardening; approximately $90 million annually for transmission and distribution system reliability and capacity improvements to meet expected customer growth.

Tampa Electric's capital spending forecast includes amounts related to its plan, subject to FPSC approval, to convert four CTs in peaking service at the Polk Power Station to combined cycle with an early 2017 in-service date. The capital expenditures for the conversion and the related transmission system improvements to support the additional generating capacity are included in the "New generation and transmission" line in the capital expenditure table above. Following the expiration of the PPA with the Hardee Power Station in Central Florida, Tampa Electric will take advantage of generating capacity available in Florida at attractive rates and purchase power to meet its 2013 through 2016 energy demand and sales growth.

Capital expenditures for PGS are expected to be about $105 million in 2012 and $400 million during the 2013 – 2016 period. Included in these amounts is an average of approximately $70 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing renewal, replacement and system safety, including approximately $10 million annually for the replacement of cast iron and bare steel pipe.

At PGS, higher capital expenditures are focused on extending the system to serve large commercial or industrial customers that are currently using petroleum and propane as fuel under multi-year contracts. The current low natural gas prices and the projections that natural gas prices are going to remain low into the future makes it attractive for these customers to convert from fuels that are currently three to four times more expensive on a cost per million BTU basis.

The unregulated companies expect to invest $55 million in 2012, including $5 million for the initial surface preparation and infrastructure development of new metallurgical coal reserves described below, and $10 million for the scheduled steam turbine overhaul at the San José Power Station in Guatemala. The unregulated companies expect to spend $215 million during the 2013 – 2016 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, and capital to support generating unit reliability at TECO Guatemala.

The capital expenditure forecast beyond 2012 excludes additional investment to develop the metallurgical coal reserves that TECO Coal announced in November 2011. These reserves constitute an additional estimated 65 million tons of metallurgical coal on properties it controls that are classified as proven and probable reserves, and an additional estimated 9 million tons of metallurgical coal classified as resource (non-reserve coal deposits) due to seam thickness. There is an additional 14 million tons of metallurgical coal also classified as resource pending further geologic studies (see **Item 2 Properties** the **TECO Coal** section). In 2012, TECO Coal is evaluating detailed mining plans and potential markets for this high-volatile metallurgical coal. TECO Coal has received one permit amendment from the State of Kentucky related to surface development activities to access a portion of these reserves, and expects to file a second permit amendment in 2012 to access the remainder of these reserves. When these permits are received, TECO Coal will begin the surface preparation infrastructure development work to bring these reserves into production. Based on current estimates, subject to development of final plans, the cost to develop these reserves is estimated to be approximately $160 million in the 2013 – 2016 period.

If the U.S. Congress or the Florida Legislature enacted a national or Florida RPS, additional capital spending for renewable generating resources to meet the requirements of an RPS would likely be needed (see the **Environmental Compliance** section). Depending on the final federal or state rules, which may be enacted in 2012, Tampa Electric may need to invest capital to develop additional sources of renewable power generation.

The forecast of capital expenditures shown above is based on our current estimates and assumptions for normal maintenance capital at the operating companies; capital expenditures to support normal system reliability and growth at Tampa Electric and PGS; the programs for transmission and distribution system storm hardening and transmission system reliability requirements; generating capacity expansion at Tampa Electric and incremental investments above normal maintenance capital to expand the PGS system and production 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 year-end 2011 consolidated capital structure was 57.5% debt and 42.5% common equity. The debt-to-total-capital ratio has improved significantly over the past five years, primarily due to the repayment of almost $1.0 billion of parent and parent guaranteed debt, consisting of $765 million in 2007, a net $189 million in 2010, and $64 million in 2011, as well as the increase in retained earnings. At Dec. 31, 2011, Tampa Electric Company's year-end capital structure was 48.0% debt and 52.0% common equity.

In 2011, we raised $7.0 million of equity primarily through the exercise of stock options.

On March 1, 2011, Tampa Electric Company purchased in lieu of redemption $75.0 million Polk County Industrial Development Authority (PCIDA) Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2010 (the PCIDA Bonds). On Nov. 23, 2010, the PCIDA issued the PCIDA Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. Proceeds of the PCIDA Bonds were used to redeem $75.0 million PCIDA Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007, which previously had been in auction rate mode and had been held by Tampa Electric Company since March 26, 2008. The PCIDA Bonds bore interest at the initial term rate of 1.50% per annum from Nov. 23, 2010 to March 1, 2011.

On Dec. 29, 2010, Central Generadora Eléctrica San José, Limitada refinanced its $44.7 million loan at a fixed rate of 3.0% for 2011 and a floating rate of 3-month Libor plus 275 basis points for 2012-2014. The loan is repaid quarterly with a final payment on Dec. 31, 2014. In connection with this transaction, $0.9 million of unamortized costs were expensed, and are included in "Loss on debt extinguishment" on the Consolidated Statements of Income for the twelve months ended Dec. 31, 2010.

On Dec. 14, 2010, Tampa Electric Company completed an exchange offer (the Exchange Offer) which resulted in the exchange of approximately $278.5 million principal amount of Tampa Electric Company notes for approximately $278.5 million principal amount of newly issued Tampa Electric Company 5.40% Notes due 2021.

The Exchange Offer resulted in the exchange and retirement of approximately: $131.5 million principal amount of Tampa Electric Company 6.875% Notes due 2012; $147.0 million principal amount of Tampa Electric Company 6.375% Notes due 2012 for approximately $278.5 million principal amount of newly issued Tampa Electric Company 5.40% Notes due 2021.

The 5.40% Notes bear interest at a rate of 5.40% per year, payable on May 15 and November 15 each year, beginning May 15, 2011, and mature May 15, 2021. Tampa Electric Company may redeem some or all of the 5.40% Notes at a price equal to the greater of (i) 100% of the principal amount of the applicable Tampa Electric Company notes to be redeemed, plus accrued and unpaid interest, or (ii) the net present value of the remaining payments of principal and interest on the Tampa Electric Company 5.40% Notes, discounted at the applicable treasury rate (as defined in the applicable supplemental indenture), plus 25 basis points. Such redemption price would include accrued and unpaid interest to the redemption date. In accordance with allowed regulatory treatment, the unamortized costs are being amortized over the life of the original notes.

After the Exchange Offer, approximately $118.6 million principal amount of Tampa Electric Company 6.875% Notes due 2012 and $253.0 million principal amount of Tampa Electric Company 6.375% Notes due 2012 remain outstanding.

On Dec. 2, 2010, TECO Energy and TECO Finance redeemed $73.2 million and $163.1 million, respectively, of 7.0% Notes due May 1, 2012. The redemption price was equal to $1,089.73 per $1,000 principal amount of notes redeemed, plus accrued and unpaid interest on the redeemed notes up to the redemption date. In connection with this transaction, $21.6 million of premiums and fees were expensed, and are included in "Loss on debt extinguishment" on the Consolidated Statements of Income and as part of the "Cash flows from operating activities" in the Consolidated Statements of Cash Flows for the twelve months ended Dec. 31, 2010.

On April 22, 2010, TECO Energy redeemed $100.0 million aggregate principal amount of its 7.2% Notes due 2011. The redemption price was equal to $1,066.38 per $1,000 principal amount of notes redeemed, plus accrued and unpaid interest on the redeemed notes up to the redemption date. In connection with this transaction, $6.6 million of premiums and fees were expensed, and are included in "Loss on debt extinguishment" on the Consolidated Statements of Income and as part of the "Cash flows from operating activities" in the Consolidated Statements of Cash Flows for the twelve months ended Dec. 31, 2010.

On April 14, 2010, TECO Energy redeemed all of the outstanding $100.0 million aggregate principal amount of its Floating Rate Notes due 2010. The redemption price was equal to 100% of the principal amount of notes redeemed, plus accrued and unpaid interest on the redeemed notes up to the redemption date.

On March 22, 2010, TECO Energy and TECO Finance completed debt tender offers which resulted in the purchase of approximately $70.0 million principal amount of TECO Energy notes for cash and approximately $230.0 million principal amount of TECO Finance notes for cash.

The tender offers resulted in the purchase and retirement of approximately: $43.0 million principal amount of TECO Energy 7.2% Notes due 2011; $27.0 million principal amount of TECO Energy 7.0% Notes due 2012; $156.9 million principal amount of TECO Finance 7.2% Notes due 2011; and $73.1 million principal amount of TECO Finance 7.0% Notes due 2012.

In connection with these debt tender transactions, $25.5 million of premiums and fees were expensed, and are included in "Loss on debt extinguishment" on the Consolidated Statements of Income and as part of the "Cash flows from operating activities" in the Consolidated Statements of Cash Flows for the twelve months ended Dec. 31, 2010. "Loss on debt extinguishment" also includes remaining unamortized debt issue costs of $0.9 million.

On March 15, 2010, TECO Finance, Inc. issued $250.0 million aggregate principal amount of 4.00% Notes due March 15, 2016, and $300.0 million aggregate principal amount of 5.15% Notes due March 15, 2020. The 2016 Notes were priced at 99.594% of the principal amount to yield 4.077% to maturity, and the 2020 Notes were priced at 99.552% of the principal amount to yield 5.208% to maturity. TECO Finance is a wholly–owned subsidiary of TECO Energy whose business activities consist solely of providing funds to TECO Energy for its diversified activities. The TECO Finance notes are fully and unconditionally guaranteed by TECO Energy.

The offering resulted in net proceeds to TECO Finance (after deducting underwriting discounts and commissions and estimated offering expenses) of approximately $543.5 million. TECO Finance used a portion of these net proceeds to fund the cash purchase of the TECO Energy and TECO Finance notes tendered in March 2010 and to fund the redemptions of the TECO Energy Floating Rate Notes due 2010 and 7.20% Notes due 2011 in April 2010. TECO Finance may redeem some or all 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 sum of 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 25 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date.

Effective Jan. 1, 2010, new accounting standards for consolidations amended the determination of the primary beneficiaries for variable interest entities. As a result of adopting these standards, TECO Guatemala, Inc., a wholly–owned subsidiary of TECO Energy, was determined to be the primary beneficiary of, and therefore required to consolidate, both the San José and Alborada projects in Guatemala (see **Note 19** to the **TECO Energy Consolidated Financial Statements**). The consolidation resulted in a net $44.4 million increase of non–recourse debt.

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 asset and liability method in the measurement of deferred income taxes. Under the asset and 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, 2011, we had a net deferred income tax liability of $78.1 million, attributable primarily to property-related items, AMT credit carry forwards, operating loss carry forwards, foreign tax credits and a valuation allowance. Based primarily on historical income levels and the company's expectations for steady future earnings growth, management has determined that the deferred tax assets associated with operating losses, AMT credit and foreign tax credit carry forwards recorded at Dec. 31, 2011, 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, both operating and capital, 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 Internal Revenue Service (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.

The Financial Accounting Standards Board (FASB) has guidance that 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 uncertainty in income taxes and other tax items 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 members of 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.

We believe that the accounting related to employee postretirement benefits is a critical accounting estimate for the following reasons: 1) a change in the estimated benefit obligation could have a material impact on reported assets, accumulated other comprehensive income (AOCI) and results of operations; and 2) changes in assumptions could change our annual pension funding requirements, having a significant impact on our annual cash requirements.

Pension plan assets (plan assets) are invested in a mix of equity and fixed-income securities. 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 for net periodic benefit cost was based on a cash flow matching technique developed by our outside actuaries and reflects 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 discount rate assumption used to determine the Dec. 31, 2011, benefit obligation was based on a cash flow matching technique developed by our outside actuaries and a review of current economic conditions. This technique constructs hypothetical bond portfolios using high-quality (AA or better by S&P) corporate bonds available from the Barclays Capital database at the measurement date to meet the plan's year-by-year projected cash flows. The technique calculates all possible bond portfolios that produce adequate cash flows to pay the yearly benefits and then selects the portfolio with the highest yield and uses that yield as the recommended 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. Holding all other assumptions constant, a 1% decrease in the assumed rate of return on plan assets would have increased 2011 pretax pension cost by approximately $5.0 million. Likewise, a 1% decrease in the discount rate assumption would have increased 2011 pretax pension cost approximately $3.2 million. For 2012, a 1% decrease in the discount rate assumption would result in an approximately $3.2 million pretax increase in the expected pension cost. A 1% decrease in the assumed rate of return on plan assets would result in an approximately $5.0 million pretax increase in expected pension cost.

Unrecognized actuarial gains and losses for the pension plan are being recognized over a period of approximately 11 years, 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 applicable accounting guidance for pensions. 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. In March 2010, the Patient Protection and Affordability Care Act and a companion bill, the Health Care and Education Reconciliation Act, combined the Health Care Reform Acts, were signed into law. Among other things, both acts reduce the tax benefits available to an employer that receives the Medicare Part D subsidy, resulting in a write-off of any associated deferred tax asset. As a result, TECO Energy reduced its deferred tax asset by $6.4 million and recorded a corresponding charge of $1.1 million in 2010 and a regulatory tax asset of $5.3 million in 2010.

Additionally, the Health Care Reform Acts contain other provisions that may impact TECO Energy's obligation for retiree medical benefits. In particular, the Health Care Reform Acts include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. TECO Energy does not currently believe the excise tax or other provisions of the Health Care Reform Acts will materially increase its postretirement benefit obligation. Accordingly, a re-measurement of TECO Energy's postretirement benefit obligation is not required at this time. However, TECO Energy will continue to monitor and assess the impact of the Health Care Reform Acts, including any clarifying regulations issued to address how the provisions are to be implemented, on its future results of operations, cash flows or financial position.

The key assumptions used in determining the amount of obligation and expense recorded for postretirement benefits other than pension (OPEB), under the applicable accounting guidance, include the assumed discount rate and the assumed rate of increases in future health care costs. In 2009 we elected to begin determining the discount rate for the OPEB using that individual plan's projected benefit cash flow rather than using the same discount rate that was determined for the pension plan. 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.

The assumed health care cost trend rate for medical costs was 8.0% in 2011 and decreases to 4.50% in 2023 and thereafter. A 1% increase in the health care trend rates would have produced a $0.5 million increase in the aggregate service and interest cost for 2011, and a $7.5 million increase in the accumulated postretirement benefit obligation as of Dec. 31, 2011. A 1% decrease in the health care trend rates would have produced a $0.4 million decrease in the aggregate service and interest cost for 2011, and a $6.3 million decrease in the accumulated postretirement benefit obligation as of Dec. 31, 2011.

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 accounting guidance for long-lived assets, 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, 2011, there were no indications of impairment for any of the company's long-lived assets.

Goodwill

Under the accounting guidance for goodwill, goodwill is not subject to amortization. Rather, goodwill is 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.

At Dec. 31, 2011, the company had $55.4 million of goodwill on its balance sheet, which is reflected in the TECO Guatemala segment. This goodwill balance 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 $3.0 million, respectively). Since these two 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. At Dec. 31, 2011, there was no impairment of this goodwill.

Regulatory Accounting

Tampa Electric's and PGS's retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by the FERC. As a result, the regulated utilities qualify for the application of accounting guidance for certain types of regulation. This guidance 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 GAAP 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. We believe the application of regulatory accounting guidance is a critical accounting policy since 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

Offsetting Assets and Liabilities

In December 2011, the FASB issued guidance enhancing disclosures of financial instruments and derivative instruments that are offset in the statement of financial position or subject to enforceable master netting agreements. The guidance is effective for interim and annual reporting periods beginning on or after Jan. 1, 2013. The company will adopt this guidance as required. It will have no effect on the company's results of operations, financial position or cash flows.

Intangibles – Goodwill and Other

In September 2011, the FASB issued guidance that allows companies to perform a qualitative analysis as the first step in determining whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If it is determined that it is not more likely than not that the fair value of the reporting unit is less than its carrying amount, then a quantitative analysis for impairment is not required. The guidance is effective for interim and annual impairment tests for fiscal periods beginning after Dec. 15, 2011. Early adoption was permitted. The company has adopted this guidance early and it has had no effect on the company's results of operations, financial position or cash flows.

Presentation of Comprehensive Income

In June 2011, the FASB issued guidance requiring companies to present the total of comprehensive income, the components of net income and the components of other comprehensive income (OCI), in a single continuous statement of comprehensive income or in two separate but consecutive statements. The guidance is effective for interim and annual periods beginning after Dec. 15, 2011. The company will adopt this guidance as required. It will have no effect on the company's results of operations, financial position or cash flows.

Additionally, in December 2011, the FASB issued guidance that indefinitely delayed the effective date of the requirement to present the reclassification adjustment out of AOCI. The guidance is effective for interim and annual periods beginning after Dec. 15, 2011. The company will adopt this guidance as required. It will have no effect on the company's results of operations, financial position or cash flows.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS)

In May 2011, the FASB issued guidance to more closely align its fair value measurement and disclosure requirements with IFRS. The guidance relates to: measuring the fair value of financial instruments that are managed in a portfolio; the application of premiums and discounts in fair value measurement; and disclosures for items required to be disclosed, but not reported on the statement of financial position, at fair value and Level 3 measures. The guidance is effective for interim and annual periods beginning after Dec. 15, 2011. The company will adopt the guidance as required. It will have no effect on the company's results of operations, financial 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 3.0%, 1.5% and 2.7% in 2011, 2010 and 2009, respectively. The current economic outlook and the slower than previously expected economic recovery have caused the outlook for inflation in 2012 to be lower than 2011, when oil and commodity prices rose sharply. Reports published by the Federal Reserve Bank of Atlanta indicate that CPI-U is expected to be about 2.0% in 2012.

ENVIRONMENTAL COMPLIANCE

Environmental Matters

All of our companies have significant environmental considerations. Tampa Electric has the most significant number of stationary sources with air emissions regulated by the Clean Air Act, material Clean Water Act implications and impacts by federal and state legislative initiatives. 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. In the case of TECO Guatemala, the coal-fired San José Power Station in Guatemala is in compliance with World Bank and Guatemalan Environmental Guidelines. Additionally, TECO Coal has considerations concerning waste water management and environmental permitting.

Air Quality Control

Emission Reductions

Tampa Electric has undertaken major steps to dramatically reduce its air emissions through a series of voluntary actions, including technology selection (e.g., Integrated Combined-Cycle Gasification (IGCC) and conversion of coal-fired units to natural-gas fired combined cycle); implementation of 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 early reductions of certain emissions; and enhanced controls and monitoring systems for certain pollutants.

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, a provision was made for environmental controls and pollution reductions, and Tampa Electric implemented a comprehensive program to dramatically decrease emissions from its power plants.

The emission reduction requirements of these agreements resulted in 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, enhanced availability of flue-gas desulfurization systems (scrubbers) at Big Bend Station to help reduce SO_2, and installation of selective catalytic reduction (SCR) systems for NO_x reduction on Big Bend Units 1 through 4. The units were reported in-service in May 2007, June 2008, May 2009 and May 2010.

The FPSC determined that it is appropriate for Tampa Electric to recover the operating costs of and earn a return on the investment in the SCRs at the Big Bend Power Station and pre-SCR projects on Big Bend Units 1–3 (which were early plant improvements to reduce NO_x emissions prior to installing the SCRs) through the ECRC (see the **Regulation** section). Cost recovery for the SCRs began for each unit in the year that the unit entered service.

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 are capable of removing 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. Since 1998, Tampa Electric has reduced annual SO_2, NO_x and PM emissions from its facilities by 164,000 tons (94%), 63,000 tons (91%) and 4,500 tons (87%), respectively.

Reductions in mercury emissions also have occurred due to the repowering of the Gannon Power Station to the 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 have been achieved from the installation of the SCRs at Big Bend Power Station, which have led to a reduction of mercury emissions of more than 75% from 1998 levels.

Clean Air Interstate Rule/Cross State Air Pollution Rule (CSAPR)

As a result of all its completed emission reduction actions, Tampa Electric has achieved emission reduction levels called for in Phase I of the Clean Air Interstate Rule (CAIR). In July 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated CAIR on emissions of SO_2 and NO_x. The federal appeals court reinstated CAIR in December 2008 as an interim solution. In July 2011, the EPA issued the final CAIR replacement rule, called the CSAPR. The final CSAPR is focused on reducing SO_2 and NO_x in 27 eastern states that contribute to ozone and/or fine particle pollution in other states. Compliance with CSAPR, which would be measured at the individual power plant level, requires the additions of scrubbers or SCRs on most coal-fired power plants. In addition, the rule proposes intrastate emissions allowance trading and limited interstate emissions allowance trading to achieve compliance. It is likely that the EPA will propose new ozone and particulate rules and would incorporate them into CSAPR. All of Tampa Electric's conventional coal-fired units are already equipped with scrubbers and SCRs, and the Polk Unit 1 IGCC unit removes SO_2 in the gasification process.

The EPA has estimated that the implementation of CSAPR would result in the retirement of primarily, smaller, older coal-fired power stations that do not currently have state-of-the-art air pollution control equipment already installed. The retirement of these units or switching to other fuels for compliance with this rule is likely to reduce overall demand for coal, which could reduce sales at TECO Coal.

On Dec. 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit granted the motion to stay the implementation of CSAPR in all aspects, which had been scheduled to take effect Jan. 1, 2012, and ordered the reinstatement of CAIR pending the outcome of the litigation. The case is currently anticipated to be heard in April 2012, but it remains unclear how long the litigation period will take. The reinstatement of CAIR means that Florida power plants such as Tampa Electric's that relied on CAIR controls to meet Best Available Retrofit Technology requirements continue to be in compliance with that rule.

Hazardous Air Pollutants (HAPS) Maximum Achievable Control Technology (MACT)

The EPA published proposed rules under National Emission Standards for HAPS on May 3, 2011, pursuant to a court order. These rules are expected to reduce mercury, acid gases, organics, and certain non-mercury metals emissions and require MACT. The final Utility MACT rules, now called Mercury Air Toxics Standards (MATS), were published in December 2011 with implementation called for in early 2015 with extensions to early 2016 or 2017 under certain specific criteria. A potential outcome of the Utility MACT rule is the retirement of smaller, older coal-fired power plants that do not already have emissions controls installed.

All of Tampa Electric's conventional coal-fired units are already equipped with scrubbers and SCRs, and the Polk Unit 1 IGCC unit emissions are minimized in the gasification process. Tampa Electric is uniquely positioned to be able to meet the new standards without considerable impacts, compared to others who have not taken similar early actions. Therefore, Tampa Electric expects the benefits of these control devices for mercury removal to minimize the impact of this rule and expects that it will be in compliance with MATS with nominal additional capital investment.

Carbon Reductions and Climate Change

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 not expected until early 2017 (see the **Tampa Electric** and **Capital Expenditures** sections). Tampa Electric estimates that the repowering to natural gas and the shut-down of the Gannon Station coal-fired units resulted in an annual decrease in CO_2 emissions of approximately 4.8 million tons below 1998 levels. During this same time frame, the numbers of retail customers and retail energy sales have risen by approximately 25%.

Tampa Electric currently emits approximately 17 million tons of CO_2 per year. Assuming a projected long-term average annual load growth of 1.0% to 2.0%, Tampa Electric may emit approximately 20 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's historical 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, and voluntary annual reporting of

GHG emissions through the Energy Information Agency (EIA) EIA-1605(b) Report beginning in 1995.

In 2010, the EPA issued its Final Rule on the mandatory reporting of GHGs, requiring facilities that emit 25,000 metric tons or more of CO_2 per year to begin collecting GHG data under a new reporting system on Jan. 1, 2010, with the first annual report due March 31, 2011. Tampa Electric complied with the mandatory reporting requirement, in large part through the methods and procedures already utilized. The rule also requires natural gas distribution and underground coal mining facilities, including PGS and TECO Coal that emit 25,000 metric tons or more of CO_2 per year to begin collecting GHG data under a new reporting system on Jan. 1, 2011, with the first annual report due March 31, 2012.

In December 2009, the EPA published the final Endangerment Finding in the Federal Register. Although the finding was technically made in the context of GHG emissions from new motor vehicles and did not in itself impose any requirements on industry or other entities, the finding triggered GHG regulation of a variety of sources under the Clean Air Act (CAA). Related to utility sources, the EPA's "tailoring rule", which addresses the GHG emission threshold triggers that would require permitting review of new and/or major modifications to existing stationary sources of GHG emissions, became effective Jan. 2, 2011. While this rule does not have an immediate impact on Tampa Electric's ongoing operations, it is expected to be a factor in any permitting activities for new and modified fossil-fuel fired electric generating units going forward.

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 cannot predict whether the FPSC would grant such recovery. Although Tampa Electric's current coal-based generation has declined to about 60% of its output in 2011 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 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, there are not yet federal limits on GHG emissions, and it is unclear if future requirements for GHG emissions reductions would directly impact it as a carbon-based fuel provider or the end users of its products. In either case, these requirements 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, 48 million kilowatt hours (kWh) of renewable energy have been produced to support participating customer requirements.

Tampa Electric has installed 91.3 kilowatts (kW) of solar panels to generate electricity from the sun at three schools, Tampa Electric's Manatee Viewing Center, the Museum of Science and Industry, Tampa's Lowry Park Zoo and the Florida Aquarium, and continues to evaluate opportunities for additional solar panel installations. Tampa Electric's largest solar panel array, rated at 23.8 kW, is located at Tampa Electric's Manatee Viewing Center in Apollo Beach, Florida. The electricity the photovoltaic array generates, which flows to Tampa Electric's grid, could offset the carbon dioxide emissions produced by four typical-size cars in a year. The company continues to evaluate opportunities for additional solar panel installations.

Florida's IOUs are currently limited in their ability to pursue renewable energy projects by laws that prohibit them from buying power from qualifying facility (QFs) and renewable power at prices above avoided cost – federal and state – absent a renewable mandate.

Despite the emphasis on the use of renewable energy sources, an FPSC study conducted by Navigant Consulting in 2008 indicates that only in the most favorable conditions, which included high customer incentives, a mature Renewable Energy Credit (REC) market and a high revenue rate cap, would Florida utilities have a significant contribution from renewable energy sources to the generation mix. Solar photovoltaic power generation and biomass are the most viable sources of renewable energy in Florida, which is a poor location for significant land-based wind generation. While support for tax incentives for renewable energy specific to certain regions or technologies may facilitate the development of new sources, if mandates for renewable portfolios at high percentages are enacted RECs would likely have to be purchased to meet such mandates, rates for customers would likely increase and such mandates would not likely result in significant quantities of renewable energy sources to be developed in Florida. A mandatory RPS could add to Tampa Electric's costs and adversely affect its operating results.

Water Supply and Quality

The EPA's final Clean Water Act Section 316(b) rule took effect in 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 as 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. In 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 EPA decided to rewrite the rule, and expects to propose a new rule in the summer of 2012. The full impact of the new regulations will depend on subsequent legal proceedings, the results of studies and analyses performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies.

On Dec. 6, 2010, the EPA published its final rule, setting numeric nutrient criteria for Florida's lakes and flowing waters. The rule, as published, is being challenged in the courts by numerous parties, including the state of Florida. The rule sets numeric limits for nitrogen and phosphorous in lakes and streams and for nitrate plus nitrite in springs. The EPA promulgated the rule pursuant to the terms of a consent decree approved by the court in Florida Wildlife Federation v. Jackson, 08-0324 (N.D. Fla.), in which environmentalists sued the EPA for allegedly violating a duty under the Federal Water Pollution Control Act (Clean Water Act or Act) to set the numeric criteria. In response to comments raising numerous implementation concerns, the EPA decided to delay the effective date of the criteria until 15 months after publication. The EPA announced that, in the interim, it would undertake a series of implementation steps in Florida, including an "education and outreach rollout," training meetings, and the development of guidance materials to coincide with the expected comment period on proposed site-specific alternative criteria. If the rule is implemented as published, it would directly affect Polk Power Station's cooling reservoir discharge to surface water, requiring the station to reduce the amount of nutrients in the cooling reservoir water before discharge. However, the full effect of the EPA's numeric nutrient criteria will depend on the outcome of the various legal proceedings. The schedule for implementation is uncertain due to the various legal proceedings.

In December 2010, Clintwood Elkhorn Mining Company, a subsidiary of TECO Coal, received an Administrative Order from the EPA relating to the discharge of wastewater associated with inactive mining operations in Pike County, Kentucky. TECO Coal has responded to such matter, and the scope and extent of its potential liability, if any, and the costs of any required investigation and remediation related to its inactive mining operations in the area have not been determined.

Section 404 of the Clean Water Act and Coal Surface Mine Permits

For the past several years, permits issued by the USACE under Section 404 of the Clean Water Act for new surface coal mining operations have been challenged in court by various environmental groups resulting in a backlog of permit applications and very few permits being issued (see the **TECO Coal Outlook** section).

On April 1, 2010, the EPA issued new guidance on environmental permitting requirements for permits for new Appalachian mountaintop removal and other new surface mining projects. This guidance was finalized in July 2011 after consideration of public comments and the results of the SAB technical review of the EPA scientific reports. The guidance limits conductivity (level of mineral salts) in water discharges into streams from permitted areas, and was effective immediately on an interim basis. Because the EPA's standards appear to be unachievable under most circumstances, surface mining activity could be substantially curtailed since most new and pending permits would likely be rejected. This guidance could also be extended to discharges from deep mines and preparation plants, which could result in a substantial curtailing of those activities as well.

This guidance is facing legal challenges from coal mining industry-related organizations and states relating to the stringency of the standards as well as the focus on the coal industry and the Appalachian region in particular. In October 2011, the United States District Court for the District of Columbia ruled that the EPA had exceeded the statutory authority conferred upon it by the Clean Water Act in implementing the coordinated review process with the USACE. There is a second portion of the lawsuits related to the actual water quality guidance discussed above that is not scheduled for hearings until the second quarter of 2012. Pending the outcome of the second portion of the case, few, if any, new permits are expected to be issued by USACE.

Conservation

Energy conservation is becoming increasingly important in a period of volatile energy prices and in the GHG emissions reduction debate. In December 2009, the FPSC established new aggressive demand-side-management (DSM) goals for 2010-2019 for all investor-owned electric utilities. For Tampa Electric, the summer and winter demand goals are 138 and 109 MWs, respectively, and the annual energy goal is 360 gigawatt-hours.

During 2011, Tampa Electric deployed the newly approved plan to its customers offering a comprehensive array of programs designed to reduce weather-sensitive peak demand and to conserve energy. This strategy continues to allow Tampa Electric to delay construction of future generation facilities. Since their inception, the company's conservation programs have reduced the summer peak demand by 285 MW, and the winter peak demand by 706 MW. These programs and their costs are approved annually by the FPSC with the costs recovered through a clause on the customer's bill. In addition, PGS offers programs that enable customers to reduce their energy consumption with the costs also recovered through a clause on the customer's bill.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric division, is a 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, 2011, Tampa Electric Company has estimated its ultimate financial liability to be approximately $28.5 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.

In 2004, Merco Group at Adventura Landings I, II, and III (together Merco) filed suit against PGS in Dade County Circuit Court alleging that coal tar from a certain former PGS manufactured gas plant site had been deposited in the early 1960s onto property owned by Merco. PGS contends that the coal tar did not originate from its manufactured gas plant site and has filed a third-party complaint against Continental Holdings, Inc. as the owner at the relevant time of the site that PGS believes was the source of the coal tar on Merco's property. In addition, the court will consider PGS's counterclaim against Merco which claims that, because Merco purchased the property with actual knowledge of the presence of coal tar on the property, Merco should contribute toward any damages resulting from the presence of coal tar. The bench trial in this matter was concluded on February 2012 and a ruling is expected in March 2012 (see **Note 12** to the **TECO Energy Consolidated Financial Statements**).

Coal Combustion By-products (CCBS) Recycling

The combustion of coal at two of Tampa Electric's power-generating facilities, the Big Bend and Polk Power stations, produces ash and other by-products, collectively known as CCBs. The CCBs produced at Big Bend include fly ash, gypsum, boiler slag, bottom ash and economizer ash. The CCBs produced at the Polk Power Station include gasifier slag and sulfuric acid. Overall, over 97% of all CCBs produced at these facilities were marketed to customers for beneficial use in commercial and industrial products in 2011.

In response to a coal ash pond failure in December 2008, the EPA proposed new regulations for the management and disposal of CCBs. These proposed rules include two potential designations of CCBs, both of which are intended to eliminate unlined wet impoundments. One designation would categorize CCBs as hazardous wastes. The other proposed rule would set minimum standards for the final disposal of CCBs. In addition, these rules would prohibit construction of new unlined by-product storage ponds and place additional management requirements on existing ash ponds such as those at Big Bend. Only the hazardous designation would be expected to affect Tampa Electric's current management practices and storage facilities for CCBs. Required changes would include disposing of any CCB waste as hazardous waste at significantly higher cost than current methods, converting to dry handling of coal ash, and elimination of any wet storage impoundments in current use. The non-hazardous option would not be expected to have as great an impact on Tampa Electric, since this option would allow for the continued operation of lined wet impoundments and all of its CCB storage areas are either lined or are in the process of being lined in accordance with current requirements.

REGULATION

Tampa Electric's and PGS's retail operations 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 provides an opportunity for the utility to collect total revenues (revenue requirements) equal to its cost to provide service, plus a reasonable return on invested capital.

For both Tampa Electric and PGS, the costs of owning, operating and maintaining the utility systems, excluding fuel and conservation costs as well as purchased power and certain environmental costs for the electric system, 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 ROE. Base rates are determined in FPSC revenue requirement and 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 FERC in various respects, including wholesale power sales, certain wholesale power purchases, transmission and ancillary 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 ROE range of 10.25% to 12.25%, with a midpoint of 11.25%, were established in 2009, and 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's 13-month average regulatory ROE was 8.7% at the end of 2008 compared to an authorized midpoint of 11.75%, due to lower customer growth, slower energy sales growth, and ongoing high levels of capital investment. As a result, Tampa Electric filed for a $228 million base rate increase in August 2008. In March 2009, the FPSC awarded $104 million higher revenue requirements effective in May 2009 that authorized an ROE mid-point of 11.25%, 54.0% equity in the capital structure, and 2009 13-month average rate base of $3.4 billion. A component of that decision was a $33.5 million 2010 base rate increase associated with the five peaking CTs and the solid-fuel rail unloading facilities at the Big Bend Power Station scheduled to enter service before the end of 2009. The FPSC later clarified that it would perform an audit to review the continuing need for the CTs and the costs incurred to place the CTs and rail unloading facilities in service.

In July 2009, in response to a motion for reconsideration, the FPSC determined that adjustments to the capital structure used to calculate the rates effective in 2009 should have been calculated over all sources of capital rather than only investor sources. This change resulted in a $9.3 million increase in revenue requirements in 2009 for a total increase of $113.6 million. At the same time, the FPSC voted to reject the intervenors' joint motion requesting reconsideration of the 2010 portion of base rates approved in 2009.

In September 2009, the intervenors filed a joint appeal to the Florida Supreme Court related to the FPSC's decision rejecting their motion for reconsideration of the 2010 portion of base rates approved in 2009.

In December 2009, the FPSC approved Tampa Electric's petition requesting an effective date of Jan. 1, 2010, for the proposed rates supporting the CTs and rail unloading facilities and based on its staff audit of Tampa Electric's actual costs incurred, the FPSC determined the portion of base rates approved in 2009 should be reduced by $8.3 million to $25.7 million, subject to refund. A regulatory proceeding was scheduled for October 2010 regarding the continuing need for the CTs, the appropriate amount to be recovered and the resulting rates.

In July 2010, Tampa Electric entered into a stipulation with the intervenors to resolve all issues related to the 2008 base rate case including the base rates effective Jan. 1, 2010, as well as the intervenors' appeal to the Florida Supreme Court. Under the terms of the stipulation, the $25.7 million rate increase would remain in effect for 2010, and Tampa Electric would make a one-time reduction of $24.0 million to customers' bills in 2010. Effective Jan. 1, 2011, and for subsequent years, rates of $24.4 million (a $1.3 million reduction from the $25.7 million in effect for 2010) related to the rate increase will be in effect.

In August 2010, the FPSC approved the July stipulation. This stipulation resolved all issues in the rate case and all issues in the intervenors' appeal of the FPSC's 2009 decision in Tampa Electric's base rate proceeding pending before the Florida Supreme Court. The docket related to the base rate proceeding is now closed. The one-time reduction of $24.0 million to customers' bills in 2010 was reflected in operating results as a reduction in revenue and base rates reflect a total rate increase of $137.6 million as of Jan. 1, 2011.

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 fuel, environmental compliance, conservation programs and purchased power costs and estimated customer usage for a calendar year recovery period, with a true-up adjustment to reflect the variance of actual costs to projected costs for prior periods. The FPSC may disallow recovery of any costs it considers unreasonable or imprudently incurred.

In September 2011, 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 2012. In November 2011, the FPSC approved Tampa Electric's requested rates. The rates include the projected cost for natural gas, oil and coal, including transportation, for 2012 and the net over-recovery of fuel, purchased power and capacity clause expenses, which were collected in 2010 and 2011. Rates approved for 2012 also reflected a two-tiered residential fuel factor structure with a lower factor for the first 1,000 kWh used each month. Due to increased reliance on natural gas to fuel its generating fleet and continued low natural gas prices, Tampa Electric's residential customer rate per 1,000 kWh decreased slightly from $107.02 in 2011 to $106.90 in 2012.

Wholesale and Transmission Rate Cases

In July 2010, Tampa Electric filed wholesale requirements and transmission rate cases with the FERC. Tampa Electric's last wholesale requirements rate case was in 1991, and the associated service agreements were approved by the FERC in the mid-1990s.

The transmission rate case updates Tampa Electric's charges under its FERC-approved Open Access Transmission Tariff (OATT) for the various forms of wholesale transmission service it provides. These rates were last updated in 2003, pursuant to a settlement agreement between the company and its then transmission customers. The wholesale requirements rate proceeding addresses the rates and terms and conditions of Tampa Electric's existing wholesale customers.

The FERC approved Tampa Electric's proposed transmission rates as filed with the FERC, which became effective Sep. 14, 2010, subject to refund. The FERC also approved Tampa Electric's proposed wholesale requirements rates, as filed with the FERC, which became effective March 1, 2011, subject to refund. The proposed wholesale requirements and transmission rates are not expected to have a material impact on Tampa Electric's results.

Settlements were reached with the applicable customers in both cases last year, and these settlements will be filed with the FERC during 2012. It is expected that the FERC will accept these settlements as filed, and the settlements will take effect later this year. Refunds with interest will be provided to the customers for the differences between the settlement rates and the charges that were earlier approved by the FERC to be implemented conditionally.

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.

Unlike the retail electric business, Tampa Electric competes in the wholesale power market with other energy providers in Florida, including 30 other IOUs, municipal and other utilities, as well as co-generators or other unregulated power generators with uncontracted excess capacity. Entities compete to provide energy on a short-term basis (i.e., hourly or daily) and on a longer term basis. Competition in these markets is primarily based on having available energy to sell to the wholesale market and the price. In Florida, available energy for the wholesale market is affected by the state's Power Plant Siting Act (the PPSA), which sets the state's electric energy and environmental policy and governs the building of new generation involving steam capacity of 75 MW or more, requires that applicants demonstrate that a plant is needed prior to receiving construction and operating permits. The effect of the PPSA has been to limit the number of unregulated generating units with excess capacity for sale in the wholesale power markets in Florida.

Tampa Electric is not a major participant in the wholesale market because it uses lower cost coal-fired generation to serve its retail customers rather than the wholesale market. Over the past three years, gross revenues from wholesale sales, which includes fuel that is a pass-through cost, has averaged approximately 2% of Tampa Electric's total revenue.

FPSC rules promote cost-competitiveness in the building of new steam generating capacity by requiring IOUs, such as Tampa Electric, to issue Requests 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 MW. The rules, which allow independent power producers and others to bid to supply the new generating capacity, 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.

PGS Rates

PGS's rates and allowed ROE range of 9.75% to 11.75%, with a midpoint of 10.75%, which was established in 2009, 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 PGS, FPSC staff or other interested parties.

At the end of 2007, PGS's 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.

In August 2008, PGS filed for a $26.5 million base rate increase. In May 2009, the FPSC approved a $19.2 million increase in annual base rates, authorizing a new ROE range of 9.75% to 11.75% with a mid-point of 10.75% and an equity ratio of 54.7% for rates effective in June 2009.

As a result of the unprecedented cold winter weather in 2010, in the second quarter of 2010 PGS projected it would earn above the top of its ROE cap of 11.75% in 2010. PGS recorded a $9.2 million total provision related to the 2010 earnings above the top of the range. In December 2010, PGS and the Office of Public Counsel entered into a stipulation and settlement agreement requesting FPSC approval that $3.0 million of the provision to be refunded to customers in the form of a credit on customers' bills in 2011, and the remainder be applied to accumulated depreciation reserves. On Jan. 25, 2011 the FPSC approved the stipulation.

PGS Cost-Recovery Clauses

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through the PGA clause. This clause 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 during an FPSC hearing. The cap is based on estimated costs of purchased gas and pipeline capacity, and estimated customer usage for a calendar year recovery period, with a true-up adjustment to reflect the variance of actual costs and usage to projected charges for prior periods. In November 2011, the FPSC approved rates under PGS's PGA for 2012 for the recovery of the costs of natural gas purchased for its distribution customers.

In addition to its base rates and PGA 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 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 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. PGS has a "NaturalChoice" program, offering unbundled transportation service to all eligible customers and allowing non-residential customers and residential customers using more than 1,999 therms annually 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 17,600 transportation-only customers as of Dec. 31, 2011 out of approximately 42,000 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 by-passing PGS facilities, or by other utilities seeking to expand existing distribution systems to new customers previously unserved by another utility. In response to this competition, PGS has developed various programs, including the provision of transportation services at discounted rates.

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, our companies enter into futures, forwards, swaps and option contracts to limit the exposure to items such as:

- 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 at TECO Coal.

Our 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

Accounting standards for derivative instruments and hedging activities require us 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 OCI 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

The company has adopted the accounting standards for fair value measurement. These standards define fair value, establish a framework for measuring fair value under GAAP, and expand 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 or interest rate derivatives classified as cash flow hedges. This adoption 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 accounting standards for regulated activities, 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 and diesel fuel 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, 2011, was $67.0 million, of which $65.8 million were Tampa Electric Company positions and $1.2 million were TECO Energy positions. If the credit-risk-related contingent features underlying these agreements were triggered as of Dec. 31, 2011, we could have been required to post collateral or settle existing positions with counterparties totaling $67.0 million. In the unlikely event that this situation would occur, we believe that 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, 2011 and 2010, 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 TECO Energy and at 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 2.4% at Dec. 31, 2011, and 2.7% at Dec. 31, 2010 (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. 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's commodity price risk is largely mitigated by the fact that increases in the price of fuel and purchased power are recovered through FPSC-approved 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, 2011 and 2010, 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, 2011, TECO Coal had derivative instruments in place to reduce the price variability for its anticipated 2012 diesel oil purchases for nearly 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 significantly 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.

Changes in Fair Value of Derivatives

The change in fair value of derivatives is largely due to the decrease in the average market price component of the company's outstanding natural gas swaps of approximately 31% from Dec. 31, 2010 to Dec. 31, 2011. For natural gas, the company maintained a similar volume hedged as of Dec. 31, 2011 from Dec. 31, 2010.

The following tables summarize the changes in and the fair value balances of derivative assets (liabilities) for the 12-month period ended Dec. 31, 2011:

Changes in Fair Value of Derivatives ***(millions)***	
Net fair value of derivatives as of Dec. 31, 2010	$ (26.9)
Additions and net changes in unrealized fair value of derivatives	(79.3)
Changes in valuation techniques and assumptions	0.0
Realized net settlement of derivatives	40.1
Net fair value of derivatives as of Dec. 31, 2011	$ (66.1)

Roll-Forward of Derivative Net Assets (Liabilities) ***(millions)***	
Total derivative net liabilities as of Dec. 31, 2010	$ (26.9)
Change in fair value of net derivative assets:	
Recorded as regulatory assets and liabilities or other comprehensive income	(79.3)
Recorded in earnings	0.0
Realized net settlement of derivatives	40.1
Net option premium payments	0.0
Net purchase (sale) of existing contracts	0.0
Net fair value of derivatives as of Dec. 31, 2011	$ (66.1)

Below is a summary table of sources of fair value, by maturity period, for derivative contracts at Dec. 31, 2011:

Maturity and Source of Derivative Contracts Net Assets (Liabilities) ***(millions)***

Contracts Maturing in	*Current*	*Non-current*	*Total Fair Value*
Source of fair value			
Actively quoted prices	$ 0.0	$ 0.0	$ 0.0
Other external sources (1)	(57.5)	(8.6)	(66.1)
Model prices (2)	0.0	0.0	0.0
Total	$ (57.5)	$ (8.6)	$ (66.1)

(1) Reflects over-the-counter natural gas or diesel fuel 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 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 (the Company) at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 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, 2011, 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 19 to the financial statements, the Company changed its method of accounting for consolidation of Variable Interest Entities as of January 1, 2010.

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 24, 2012

TECO ENERGY, INC.
Consolidated Balance Sheets

Assets *(millions)*	*Dec. 31, 2011*	*Dec. 31, 2010*
Current assets		
Cash and cash equivalents	$ 44.0	$ 67.5
Restricted cash	8.7	0.0
Short-term investments	0.0	14.8
Receivables, less allowance for uncollectibles of $2.6 and $4.5 at Dec. 31, 2011 and 2010, respectively	327.7	333.4
Inventories, at average cost		
Fuel	136.8	169.5
Materials and supplies	87.3	78.1
Current derivative assets	0.9	2.7
Current regulatory assets	87.3	62.7
Current deferred tax assets	72.7	141.0
Prepayments and other current assets	31.9	28.5
Income tax receivables	0.6	0.4
Total current assets	797.9	898.6
Property, plant and equipment		
Utility plant in service		
Electric	6,731.7	6,558.9
Gas	1,169.9	1,115.0
Construction work in progress	247.4	212.4
Other property	432.3	398.5
Property, plant and equipment	8,581.3	8,284.8
Accumulated depreciation	(2,613.5)	(2,443.8)
Total property, plant and equipment, net	5,967.8	5,841.0
Other assets		
Long-term regulatory assets	364.5	341.9
Long-term derivative assets	0.0	0.2
Goodwill	55.4	55.4
Deferred charges and other assets	136.6	141.2
Total other assets	556.5	538.7
Total assets	$ 7,322.2	$ 7,278.3

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, 2011*	*Dec. 31, 2010*
Current liabilities		
Long-term debt due within one year		
Recourse	$ 374.9	$ 67.1
Non-recourse	11.2	11.2
Notes payable	0.0	12.0
Accounts payable	252.3	281.5
Customer deposits	159.5	156.5
Current regulatory liabilities	86.2	110.0
Current derivative liabilities	58.4	27.2
Interest accrued	39.3	42.4
Taxes accrued	20.7	26.2
Other current liabilites	17.2	18.2
Total current liabilities	1,019.7	752.3
Other liabilities		
Deferred income taxes, net	150.8	75.4
Investment tax credits	10.0	10.4
Long-term regulatory liabilities	647.8	630.8
Long-term derivative liabilities	8.6	2.6
Deferred credits and other liabilities	530.8	488.1
Long-term debt, less amount due within one year		
Recourse	2,665.0	3,114.6
Non-recourse	22.3	33.5
Total other liabilities	4,035.3	4,355.4
Commitments and Contingencies (see **Note 12**)		
Capital		
Common equity (400 million shares authorized; par value $1; 215.8 million and 214.9 million shares outstanding at Dec. 31, 2011 and 2010, respectively)	215.8	214.9
Additional paid in capital	1,553.4	1,542.0
Retained earnings	519.4	430.0
Accumulated other comprehensive loss	(22.0)	(17.2)
TECO Energy stockholder's equity	2,266.6	2,169.7
Noncontrolling interest	0.6	0.9
Total capital	2,267.2	2,170.6
Total liabilities and capital	$ 7,322.2	$ 7,278.3

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,*		*2011*	*2010*	*2009*
Revenues				
Regulated electric and gas (includes franchise fees and gross receipts taxes of $109.3 in 2011, $116.1 in 2010 and $115.7 in 2009)		$2,469.8	$2,672.6	$2,649.1
Unregulated		873.6	815.3	661.4
Total revenues		3,343.4	3,487.9	3,310.5
Expenses				
Regulated operations				
Fuel		731.4	748.9	909.9
Purchased power		125.9	179.6	177.6
Cost of natural gas sold		210.4	284.5	242.7
Other		322.8	370.0	318.7
Operation other expense				
Mining related costs		508.0	482.7	458.7
Guatemalan power generation		82.8	65.1	12.3
Other		7.5	6.6	4.8
Maintenance		183.1	184.8	187.6
Depreciation and amortization		324.6	312.9	287.9
Restructuring charges		0.0	1.5	25.7
Recoveries from previously impaired assets		0.0	(2.9)	0.0
Taxes, other than income		225.2	227.4	224.4
Total expenses		2,721.7	2,861.1	2,850.3
Income from operations		621.7	626.8	460.2
Other income (expense)				
Allowance for other funds used during construction		1.0	1.9	9.3
Other income		9.2	57.3	23.3
Loss on debt extinguishment		0.0	(55.5)	0.0
Income from equity investments		0.0	10.4	46.7
Total other income		10.2	14.1	79.3
Interest charges				
Interest expense		205.7	232.4	231.5
Allowance for borrowed funds used during construction		(0.6)	(1.1)	(4.5)
Total interest charges		205.1	231.3	227.0
Income before provision for income taxes		426.8	409.6	312.5
Provision for income taxes		153.9	170.0	98.6
Net income		272.9	239.6	213.9
Less: Net income attributable to noncontrolling interest		(0.3)	(0.6)	0.0
Net income attributable to TECO Energy		$272.6	$239.0	$213.9
Average common shares outstanding	– Basic	213.6	212.6	211.8
	– Diluted	215.1	214.8	213.1
Earnings per share	– Basic	$ 1.27	$ 1.12	$ 1.00
	– Diluted	$ 1.27	$ 1.11	$ 1.00
Dividends declared and paid per common share outstanding		$ 0.850	$ 0.815	$ 0.800

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

TECO ENERGY, INC.
Consolidated Statements of Comprehensive Income
Unaudited

(millions) *For the years ended Dec. 31,*	*2011*	*2010*	*2009*
Net income	$272.9	$239.6	$213.9
Other comprehensive income (loss), net of tax			
Net unrealized (losses) gains on cash flow hedges	(0.8)	3.1	17.8
Amortization of unrecognized benefit costs and other	(3.6)	3.7	1.3
Change in benefit obligation due to annual remeasurement	(1.0)	0.0	0.2
Recognized benefit costs due to settlement	0.6	1.0	0.0
Reclassification to earnings - loss on available-for-sale securities	0.0	0.0	1.7
Other comprehensive (loss) income, net of tax	(4.8)	7.8	21.0
Comprehensive income			
Less: Comprehensive income attributable to noncontrolling interest	(0.3)	(0.6)	0.0
Comprehensive income attributable to TECO Energy, Inc.	$267.8	$246.8	$234.9

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,		*2011*		*2010*		*2009*
Cash flows from operating activities						
Net income	$	272.9	$	239.6	$	213.9
Adjustments to reconcile net income to net cash from operating activities:						
Depreciation and amortization		324.6		312.9		287.9
Deferred income taxes		146.0		162.9		98.5
Investment tax credits, net		(0.4)		(0.4)		(0.4)
Allowance for other funds used during construction		(1.0)		(1.9)		(9.3)
Non-cash stock compensation		9.1		7.4		10.3
Gain on sales of business/assets, pretax		(0.5)		(39.6)		(16.0)
Non-cash debt extinguishment/exchange, pretax		0.0		2.2		0.0
Equity in earnings of unconsolidated affiliates, net of cash distributions on earnings		0.0		6.9		(4.3)
Deferred recovery clause		(9.0)		55.0		136.6
Receivables, less allowance for uncollectibles		5.7		(43.9)		8.5
Inventories		23.5		(41.4)		(27.0)
Prepayments and other current assets		(2.8)		(1.3)		0.1
Taxes accrued		(5.7)		4.9		0.2
Interest accrued		0.3		(6.0)		0.1
Accounts payable		(42.6)		51.0		(38.7)
Other		34.0		(43.9)		64.3
Cash flows from operating activities		754.1		664.4		724.7
Cash flows from investing activities						
Capital expenditures		(454.1)		(489.7)		(639.8)
Allowance for other funds used during construction		1.0		1.9		9.3
Net proceeds from sales of business/assets		3.5		183.1		31.6
Net cash increase from consolidation		0.0		24.1		0.0
Restricted cash		0.0		0.0		0.5
Contributions to unconsolidated affiliates		0.0		(1.7)		(0.2)
Other investments		14.4		(14.0)		16.3
Cash flows used in investing activities		(435.2)		(296.3)		(582.3)
Cash flows from financing activities						
Dividends		(183.2)		(174.7)		(170.8)
Proceeds from sale of common stock		7.0		7.8		5.1
Proceeds from long-term debt issuance		0.0		661.2		102.0
Repayment of long-term debt/Purchase in lieu of redemption		(153.6)		(797.2)		(6.9)
Dividends to noncontrolling interest		(0.6)		(0.7)		0.0
Net decrease in short-term debt		(12.0)		(43.0)		(38.0)
Cash flows used in financing activities		(342.4)		(346.6)		(108.6)
Net (decrease) increase in cash and cash equivalents		(23.5)		21.5		33.8
Cash and cash equivalents at beginning of the year		67.5		46.0		12.2
Cash and cash equivalents at end of the year	$	44.0	$	67.5	$	46.0
Supplemental disclosure of cash flow information						
Cash paid during the year for:						
Interest	$	191.6	$	219.0	$	216.4
Income taxes paid	$	9.4	$	5.5	$	4.1

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	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Capital
Balance, Dec. 31, 2008	212.9	$212.9	$1,518.2	$322.6	($46.0)	$0.0	$2,007.7
Net income				213.9			213.9
Other comprehensive income, after tax					21.0		21.0
Common stock issued	1.0	1.0	2.2				3.2
Cash dividends declared				(170.8)			(170.8)
Stock compensation expense			10.4				10.4
Tax benefits - stock options							0.0
Balance, Dec. 31, 2009	213.9	$213.9	$1,530.8	$365.7	($25.0)	$0.0	$2,085.4
Net income				239.0		0.6	239.6
Other comprehensive income, after tax					7.8		7.8
Common stock issued	1.0	1.0	2.6				3.6
Cash dividends declared				(174.7)			(174.7)
Stock compensation expense			7.4				7.4
Noncontrolling - dividends						(0.7)	(0.7)
Noncontrolling - effect of TCAE consolidation						1.0	1.0
Tax benefits - stock options			1.2				1.2
Balance, Dec. 31, 2010	214.9	$214.9	$1,542.0	$430.0	($17.2)	$0.9	$2,170.6
Net income				272.6		0.3	272.9
Other comprehensive loss, after tax					(4.8)		(4.8)
Common stock issued	0.9	0.9	0.1				1.0
Cash dividends declared				(183.2)			(183.2)
Stock compensation expense			9.1				9.1
Noncontrolling - dividends						(0.6)	(0.6)
Tax benefits - stock options			2.2				2.2
Balance, Dec. 31, 2011	215.8	$215.8	$1,553.4	$519.4	($22.0)	$0.6	$2,267.2

(1) TECO Energy had a maximum of 400.0 million shares of $1 par value common stock authorized as of Dec. 31, 2011, 2010, 2009 and 2008.

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. 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 or its subsidiaries 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**).

Use of Estimates

The use of estimates is inherent in the preparation of financial statements in accordance with 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 at Dec. 31, 2011 and Dec. 31, 2010 of $8.7 million and $8.4 million, respectively, is included in "Restricted cash" at Dec. 31, 2011 and "Deferred charges and other assets" at Dec. 31, 2010. This relates to cash held in escrow related to the 2003 sale of Hardee Power Partners (HPP). The cash is expected to be released from escrow in 2012 upon maturity of debt financing currently held by the purchaser of HPP. The $0.3 million change reflects the accretion of a related investment that is carried on the amortized cost basis.

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.

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 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 FPSC and FERC regulations.

The San José and Alborada plants in Guatemala have PPAs 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

The company computes depreciation and amortization for electric generation, electric transmission and distribution, gas distribution and general plant facilities using the following methods:

- the group remaining life method, approved by the FPSC, is applied to the average investment, adjusted for anticipated costs of removal less salvage, in functional classes of depreciable property,
- the amortizable life method, approved by the FPSC, is applied to the net book value to date over the remaining life of those assets not classified as depreciable property above.

The provision for total regulated utility plant in service, expressed as a percentage of the original cost of depreciable property, was 3.6% for 2011, 2010 and 2009.

Other 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 the following estimated useful lives:

Asset	Estimated Useful Lives
Non-regulated generation and transmission facilities	25 - 40 years
Building and improvements	5 - 40 years
Office equipment and furniture	3 - 30 years
Vehicles, mining and other equipment	2 - 15 years
Coal processing facilities	7 - 20 years
Computer software	2 -5 years

Total depreciation expense for the years ended Dec. 31, 2011, 2010 and 2009 was $306.6 million, $297.1 million and $275.2 million, 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. The rate used to calculate AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. The rate was 8.16% for May 2009 through December 2011 and 7.79% for January 2009 through April 2009. Total AFUDC for the years ended Dec. 31, 2011, 2010 and 2009 was $1.6 million, $3.0 million and $13.8 million, respectively.

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.

Fuel Inventory *(millions)*	*Dec. 31, 2011*	*Dec. 31, 2010*
Tampa Electric Company	$97.9	$119.0
TECO Coal	26.5	33.9
TECO Guatemala	12.4	16.6
Total	$136.8	$169.5

Regulatory Assets and Liabilities

Tampa Electric and PGS are subject to accounting guidance for the effects of certain types of regulation (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 assets will not be realized. If management determines that it is likely that some or all of deferred tax assets 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 accounting standards for revenue recognition. 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.

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 the FERC. See **Note 3** for a discussion of significant regulatory matters and the applicability of the accounting guidance for certain types of regulation to the company.

Revenues for TECO Coal shipments, both domestic and international, are recognized when title and risk of loss transfer to the customer.

Revenues for energy marketing operations at TECO Gas Services are presented on a net basis in accordance with the accounting guidance for reporting revenue gross as a principal versus net as an agent and recognition and reporting of gains and losses on energy trading contracts 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, 2011, 2010 and 2009 were $2.5 million, $8.7 million and $1.9 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 which for the years ended Dec. 31, 2011, 2010 and 2009 were $16.6 million, $27.3 million and $24.3 million, respectively.

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 diesel fuel swaps, which are used to mitigate the fluctuations in the price of diesel fuel, primarily at TECO Coal, the cash inflows and outflows are included in the operating section. For natural gas, primarily at Tampa Electric and PGS, 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 Statements of Cash Flows.

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, 2011 and 2010, unbilled revenues of $50.2 million and $65.5 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 $125.9 million, $179.6 million and $177.6 million, for the years ended Dec. 31, 2011, 2010 and 2009, 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 on a dollar-per-dollar basis 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. 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". These amounts totaled $109.3 million, $116.1 million and $115.7 million for the years ended Dec. 31, 2011, 2010 and 2009, respectively.

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 postretirement 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 and workers' compensation using discount rates mandated by statute or otherwise deemed appropriate for the circumstances. Discount rates used in estimating these other self-insurance liabilities at both Dec. 31, 2011 and 2010 ranged from 3.75% to 4.75%.

Stock-Based Compensation

TECO Energy accounts for its stock-based compensation in accordance with the accounting guidance for share-based payment. Under the provisions of this guidance, 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). See **Note 9** 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. 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 2011, 2010 and 2009 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.

Receivables and Allowance for Uncollectible Accounts

Receivables consist of services billed to residential, commercial, industrial and other customers. An allowance for uncollectible 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.

Reclassifications

Certain reclassifications were made to prior year amounts to conform to current period presentation. None of the reclassifications affected our net income in any period.

2. New Accounting Pronouncements

Offsetting Assets and Liabilities

In December 2011, the FASB issued guidance enhancing disclosures of financial instruments and derivative instruments that are offset in the statement of financial position or subject to enforceable master netting agreements. The guidance is effective for interim and annual reporting periods beginning on or after Jan. 1, 2013. The company will adopt this guidance as required. It will have no effect on the company's results of operations, financial position or cash flows.

Intangibles – Goodwill and Other

In September 2011, the FASB issued guidance that allows companies to perform a qualitative analysis as the first step in determining whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If it is determined that it is not more likely than not that the fair value of the reporting unit is less than its carrying amount, then a quantitative analysis for impairment is not required. The guidance is effective for interim and annual impairment tests for fiscal periods beginning after Dec. 15, 2011. Early adoption was permitted. The company has adopted this guidance early and it has had no effect on the company's results of operations, financial position or cash flows.

Presentation of Comprehensive Income

In June 2011, the FASB issued guidance requiring companies to present the total of comprehensive income, the components of net income and the components of other comprehensive income, in a single continuous statement of comprehensive income or in two separate but consecutive statements. The guidance is effective for interim and annual periods beginning after Dec. 15, 2011. The company will adopt this guidance as required. It will have no effect on the company's results of operations, financial position or cash flows.

Additionally, in December 2011, the FASB issued guidance that indefinitely delayed the effective date of the requirement to present the reclassification adjustment out of accumulated other comprehensive income. The guidance is effective for interim and annual periods beginning after Dec. 15, 2011. The company will adopt this guidance as required. It will have no effect on the company's results of operations, financial position or cash flows.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS)

In May 2011, the FASB issued guidance to more closely align its fair value measurement and disclosure requirements with IFRS. The guidance relates to: measuring the fair value of financial instruments that are managed in a portfolio; the application of premiums and discounts in fair value measurement; and disclosures for items required to be disclosed, but not reported on the statement of financial position, at fair value and Level 3 measures. The guidance is effective for interim and annual periods beginning after Dec. 15, 2011. The company will adopt the guidance as required. It will have no effect on the company's results of operations, financial position or cash flows.

3. Regulatory

Tampa Electric's and PGS's retail businesses are regulated by the FPSC. Tampa Electric also 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 the FERC's regulations, TECO Energy is not subject to certain accounting, record-keeping and reporting requirements prescribed by the FERC's regulations under PUHCA 2005. 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 utilities such as Tampa Electric and PGS to collect total revenues (revenue requirements) equal to their cost of providing service, plus a reasonable return on invested capital.

Stipulation with Intervenors – Tampa Electric

The FPSC, in connection with Tampa Electric's 2008 base rate request, approved a $25.7 million increase in base rates effective Jan. 1, 2010 (step increase), subject to refund, for certain capital additions placed in service in 2009.

In connection with the base rate request, the FPSC had rejected the intervenors' arguments that the approved 2010 increase violated the intervenors' due process rights, Florida Statutes or FPSC rules. The intervenors filed an appeal with the Florida Supreme Court in September 2009, which Tampa Electric opposed.

In July 2010, Tampa Electric entered into a stipulation with the intervenors to resolve all issues related to the 2008 base rate case, including the 2010 step increase, as well as the intervenors' appeal to the Florida Supreme Court. Under the terms of the stipulation, the $25.7 million step increase would remain in effect for 2010, and Tampa Electric would make a one-time reduction of $24.0 million to customers' bills in 2010.

In August 2010, the FPSC voted to approve the July stipulation, which was contained in their Docket No. 090368-EI "Review of the continuing need and cost associated with Tampa Electric Company's 5 Combustion Turbines and Big Bend Rail Facility". This stipulation resolved all issues in the above docket and all issues in the intervenors' appeal of the FPSC's 2009 decision in Tampa Electric's base rate proceeding pending before the Florida Supreme Court. The docket related to the base rate proceeding is now closed. The one-time reduction of $24.0 million to customers' bills in 2010 was reflected in the operating results as a reduction in revenue.

Effective Jan. 1, 2011, and for subsequent years, rates of $24.4 million (a $1.3 million reduction from the $25.7 million in effect for 2010) related to the step increase were in effect.

Wholesale and Transmission Rate Cases

In July 2010, Tampa Electric filed wholesale requirements and transmission rate cases with the FERC. Tampa Electric's last wholesale requirements rate case was in 1991 and the associated service agreements were approved by the FERC in the mid-1990s. The FERC approved Tampa Electric's proposed transmission rates as filed, which became effective Sep. 14, 2010, subject to refund. The FERC also approved Tampa Electric's proposed wholesale requirements rates as filed, which became effective Mar. 1, 2011, subject to refund. The proposed wholesale requirements and transmission rates did not have a material impact on Tampa Electric's results.

Storm Damage Cost Recovery

Tampa Electric accrues $8.0 million annually to a FERC-authorized and FPSC-approved self-insured storm damage reserve. This reserve was created after Florida's IOUs were unable to obtain transmission and distribution insurance coverage due to destructive acts of nature. Tampa Electric's storm reserve was $43.6 million and $37.4 million as of Dec. 31, 2011 and 2010, respectively.

Stipulation with the Office of Public Counsel - PGS

On Jun. 9, 2010, PGS filed a letter with the FPSC agreeing to cap its earned ROE for the year ending Dec. 31, 2010 at 11.75%, the maximum of the ROE range established in its last base rate proceeding.

On Dec. 16, 2010, PGS and the Office of Public Counsel filed a joint motion for FPSC approval of a proposed stipulation resolving all issues relating to any 2010 overearnings of PGS.

On Jan. 25, 2011, the FPSC approved the stipulation for PGS to provide a one-time credit to customer bills totaling $3.0 million for 2010 earnings above 11.75%, excluding the portion of the company's share of net revenues derived from off-system sales, and credit the remaining balance to its accumulated depreciation reserves. This one-time credit was applied to customer bills in April 2011 and the $6.2 million remaining balance was credited to the accumulated depreciation reserves in June 2011.

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 standards for regulated operations. Areas of applicability include: the 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, 2011 and 2010 are presented in the following table:

Regulatory Assets and Liabilities

(millions)	*Dec. 31, 2011*	*Dec. 31, 2010*
Regulatory assets:		
Regulatory tax asset(1)	$ 63.6	$ 66.6
Other:		
Cost recovery clauses	73.3	41.9
Postretirement benefit asset	252.4	237.5
Deferred bond refinancing costs(2)	11.1	15.4
Environmental remediation	30.5	23.6
Competitive rate adjustment	3.5	3.3
Other	17.4	16.3
Total other regulatory assets	388.2	338.0
Total regulatory assets	451.8	404.6
Less: Current portion	87.3	62.7
Long-term regulatory assets	$ 364.5	$ 341.9
Regulatory liabilities:		
Regulatory tax liability (1)	$ 16.0	$ 17.7
Other:		
Cost recovery clauses	61.4	76.2
Environmental remediation	28.4	21.2
Transmission and delivery storm reserve	43.6	37.4
Deferred gain on property sales(3)	5.0	6.3
Provision for stipulation and other(4)	0.8	9.8
Accumulated reserve-cost of removal	578.8	572.2
Total other regulatory liabilities	718.0	723.1
Total regulatory liabilities	734.0	740.8
Less: Current portion	86.2	110.0
Long-term regulatory liabilities	$ 647.8	$ 630.8

(1) Primarily related to plant life and derivative positions.
(2) Amortized over the term of the related debt instruments.
(3) Amortized over a 4 or 5-year period with various ending dates.
(4) Includes a provision to reflect the FPSC-approved PGS stipulation regarding PGS's 2010 earnings above 11.75%. A one-time credit to customer bills totaling $3.0 million was applied in April 2011 and the $6.2 million remaining balance of the 2010 earnings above 11.75% was credited to accumulated depreciation reserves in June 2011.

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)	*Dec. 31, 2011*	*Dec. 31, 2010*
Clause recoverable [(1)]	$ 76.8	$ 45.2
Components of rate base [(2)]	264.9	248.1
Regulatory tax assets [(3)]	63.6	66.6
Capital structure and other [(3)]	46.5	44.7
Total	$ 451.8	$ 404.6

(1) To be recovered through cost recovery clauses approved by the FPSC on a dollar-for-dollar basis in the next year.
(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 debt 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

Income tax expense consists of the following components:

Income Tax Expense (Benefit) *(millions)* *For the year ended Dec. 31,*	*2011*	*2010*	*2009*
Current income taxes			
Federal	$0.0	$5.7	$0.0
Foreign	7.4	7.0	0.6
State	0.9	(5.2)	(0.1)
Deferred income taxes			
Federal	128.4	147.4	86.0
Foreign	(0.3)	0.0	0.0
State	17.9	15.5	12.5
Amortization of investment tax credits	(0.4)	(0.4)	(0.4)
Total income tax expense	$153.9	$170.0	$98.6

The current income tax expense for the years ended Dec. 31, 2011, 2010 and 2009 has been reduced by $32.1 million, $78.4 million and $13.3 million, respectively, to reflect the benefits of operating loss carry forwards.

The reconciliation of the federal statutory rate to the company's effective income tax rate is as follows:

Effective Income Tax Rate *(millions)* *For the years ended Dec. 31,*	*2011*	*2010*	*2009*
Income tax expense at the federal statutory rate of 35%	$ 149.4	$ 143.4	$ 109.4
Increase (decrease) due to			
State income tax, net of federal income tax	12.2	6.7	8.0
Foreign income taxed at different rates	(6.8)	(20.1)	(18.0)
Equity portion of AFUDC	(0.4)	(0.7)	(3.2)
Tax on repatriation of foreign earnings	6.8	37.1	12.5
Valuation allowance	0.0	15.6	2.6
Depletion	(9.1)	(9.1)	(7.3)
Other	1.8	(2.9)	(5.4)
Total income tax expense on consolidated statements of income	$ 153.9	$ 170.0	$ 98.6
Income tax expense as a percent of income from continuing operations, before income taxes	36.1%	41.5%	31.6%

For the three years presented, the company experienced a number of events that impacted the overall effective tax rate on continuing operations. These events included permanent reinvestment of foreign income as required by the accounting standards, repatriation of foreign earnings to the United States, the sale of foreign subsidiaries (see **Note 16**), valuation allowance on foreign tax credits and depletion. The decrease in the company's 2011 effective tax rate compared to 2010 was primarily due to the absence of tax on repatriation of Distribución Eléctrica Centro Americana II, S.A. (DECA II) foreign earnings and valuation allowance on foreign tax credits.

During 2010, the company repatriated $224.2 million of foreign earnings resulting in a $38.1 million additional tax expense, net of foreign tax credits. Of this amount, $34.0 million represented the tax expense on the repatriation of foreign earnings due to TECO Guatemala's sale of its ownership interest in DECA II. At the end of 2010, the company no longer had any foreign earnings considered indefinitely reinvested.

The actual cash paid for income taxes as required for the alternative minimum tax, state income taxes, foreign income taxes and prior year audits in 2011, 2010 and 2009 was $9.4 million, $5.5 million and $4.1 million, respectively.

As discussed in **Note 1**, TECO Energy uses the asset and liability method to determine deferred income taxes. Based primarily on the reversal of deferred income tax liabilities and future earnings of the company's utility operations, management has determined that the net deferred tax assets recorded at Dec. 31, 2011 will be realized in future periods.

The major components of the company's deferred tax assets and liabilities recognized are as follows:

Deferred Income Taxes

(millions) *As of Dec. 31,*	*2011*	*2010*
Deferred tax liabilities [(1)]		
Property related	$ 884.2	$ 715.5
Deferred fuel	3.9	5.5
Total deferred tax liabilities	888.1	721.0
Deferred tax assets [(1)]		
Alternative minimum tax credit carry-forward	196.1	195.1
Loss and credit carry-forwards	503.4	483.1
Other postretirement benefits	69.5	67.1
Other	50.7	71.5
Total deferred tax assets	819.7	816.8
Valuation allowance	(9.7)	(30.2)
Total deferred tax assets, net of valuation allowance	810.0	786.6
Total deferred tax liability (asset), net	78.1	(65.6)
Less: Current portion of deferred tax liability/(asset)	(72.7)	(141.0)
Long-term portion of deferred tax liability, net	$ 150.8	$ 75.4

(1) Certain property related assets and liabilities have been netted.

At Dec. 31, 2011, the company had cumulative unused federal and state (Florida) net operating losses (NOLs) of $1,210.9 million and $399.2 million, respectively, expiring at various times between 2025 and 2028. In addition, the company has unused general business credits of $3.8 million expiring between 2026 and 2030 and unused foreign tax credits of $38.0 million expiring between 2015 and 2021. The company also had available alternative minimum tax credit carryforwards for tax purposes of $196.1 million which may be used indefinitely to reduce federal income taxes.

The company establishes valuation allowances on its deferred tax assets, including losses and tax credits, when the amount of expected future taxable income is not likely to support the use of the deduction or credit. Valuation allowances have been established for state capital loss carryforwards, net of federal tax, and foreign tax credits. During 2011, the valuation allowance decreased by $20.5 million. As a result of amending the 2008 federal income tax return to deduct foreign taxes, the company reclassified the foreign tax credit valuation allowance to current income tax payable. The company's valuation allowance on foreign tax credits and capital loss was $9.7 million at Dec. 31, 2011. The valuation allowances reduce our deferred tax assets to an amount that will more likely than not be realized. The amount of foreign tax credits are considered realizable, however, it could be reduced in the near term if estimates of future foreign source income during the carryforward period are reduced or if the company's projected NOL position extends beyond the carryforward period.

The company accounts for uncertain tax positions in accordance with FASB guidance. This guidance 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 the guidance, 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. The guidance also provides standards on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures. During 2010, the company reached a favorable settlement for certain state items that were under appeal. As a result, the company recorded an after-tax benefit of $4.0 million.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

Unrecognized Tax Benefits

(millions)	*2011*	*2010*
Balance at Jan. 1,	$4.1	$10.2
Decreases due to tax positions related to prior years	0.0	(5.8)
Decreases due to settlements with taxing authorities	0.0	(2.2)
Increases due to expiration of statute of limitations	0.0	1.9
Balance at Dec. 31,	$4.1	$4.1

The company recognizes interest and penalties associated with uncertain tax positions in "Operation other expense – Other" in the Consolidated Statements of Income. In 2011, 2010 and 2009, the company recognized $0.2 million, $(1.1) million and $0.9 million, respectively, of pre-tax charges (benefits) for interest only. Additionally, the company had $4.2 million of interest and penalties accrued at Dec. 31, 2011. As a result of the company reconsolidating TCAE, interest and penalties recorded on TCAE's books for an uncertain tax position are disclosed in the company's totals.

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 2010 consolidated federal income tax return during 2011. The U.S. federal statute of limitations remains open for the year 2008 and forward. The federal income tax return for calendar year 2011 is part of the IRS's Compliance Assurance Program. As a result, the IRS audit of such return is expected to be completed in 2012. Foreign and U.S. 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 taxing authorities in major state and foreign jurisdictions include 2006 and forward.

5. Employee Postretirement Benefits

TECO Energy recognizes in its statement of financial position the over-funded or under-funded status of its postretirement benefit plans. This status is measured as the difference between the fair value of plan assets and the projected benefit obligation (PBO) in the case of its defined benefit plan, or the accumulated postretirement benefit obligation (APBO) in the case of its other postretirement benefit plan. Changes in the funded status are reflected, net of estimated tax benefits, in the benefit liabilities and accumulated other comprehensive loss in the case of the unregulated companies, or the benefit liabilities and regulatory assets in the case of Tampa Electric Company. The results of operations are not impacted.

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.

The Pension Protection Act of 2006 (Pension Protection Act) 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 benefits restrictions, and also provides some technical corrections to the Pension Protection Act. 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%. 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, 2011 estimate reflected the adoption of the asset smoothing methodology under WRERA.

The qualified pension plan's actuarial value of assets, including credit balance, was 90% of the Pension Protection Act funded target as of Jan. 1, 2011 and is estimated at 85% of the Pension Protection Act funded target as of Jan. 1, 2012.

Amounts disclosed for pension benefits also include the unfunded obligations for the supplemental executive retirement plan (SERP). This is a non-qualified, non-contributory defined benefit retirement plan available to certain members of senior management.

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. 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.

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (MMA) 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.

The FASB issued accounting guidance and disclosure requirements related to the MMA. The guidance 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.

In March 2010, the Patient Protection and Affordability Care Act and a companion bill, the Health Care and Education Reconciliation Act, collectively referred to as the Health Care Reform Acts, were signed into law. Among other things, both acts reduce the tax benefits available to an employer that receives the Medicare Part D subsidy, resulting in a write-off of any associated deferred tax asset. As a result, TECO Energy reduced its deferred tax asset by $6.4 million and recorded a corresponding charge of $1.1 million and a regulatory tax asset of $5.3 million in 2010.

Additionally, the Health Care Reform Acts contain other provisions that may impact TECO Energy's obligation for retiree medical benefits. In particular, the Health Care Reform Acts include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. TECO Energy does not currently believe the excise tax or other provisions of the Health Care Reform Acts will materially increase its postretirement benefit obligation. TECO Energy will continue to monitor and assess the impact of the Health Care Reform Acts, including any clarifying regulations issued to address how the provisions are to be implemented, on its future results of operations, cash flows or financial position.

During 2011, the company received subsidy payments under Medicare Part D for the fourth quarter 2010 plan year, along with payments for the first three quarters of the 2011 plan year. The company received the fourth quarter 2011 plan year payment in February 2012.

Obligations and Funded Status	**Pension Benefits**		**Other Benefits**	
(millions)	*2011*	*2010*	*2011*	*2010*
Change in benefit obligation				
Net benefit obligation at prior measurement date (1)	$610.3	$587.7	$222.0	$207.6
Service cost	16.0	16.2	2.1	3.2
Interest cost	30.9	33.2	11.0	10.9
Plan participants' contributions	0.0	0.0	3.9	3.6
Actuarial loss (gain)	26.8	12.3	(7.4)	11.7
Gross benefits paid	(35.2)	(34.2)	(16.2)	(16.7)
Settlements	(2.4)	(4.9)	0.0	0.0
Federal subsidy on benefits paid	n/a	n/a	1.1	1.7
Net benefit obligation at measurement date (1)	$646.4	$610.3	$216.5	$222.0
Change in plan assets				
Fair value of plan assets at prior measurement date (1)	$479.7	$388.9	$0.0	$0.0
Actual return on plan assets (2)	21.8	42.3	0.0	0.0
Employer contributions	3.7	87.6	11.2	11.5
Plan participants' contributions	0.0	0.0	3.9	3.6
Settlements	(2.4)	(4.9)	0.0	0.0
Net benefits paid	(35.2)	(34.2)	(15.1)	(15.1)
Fair value of plan assets at measurement date (1)	$467.6	$479.7	$0.0	$0.0
Funded status				
Fair value of plan assets (3)	$467.6	$479.7	$0.0	$0.0
Benefit obligation (PBO/APBO)	646.4	610.3	216.5	222.0
Funded status at measurement date (1)	(178.8)	(130.6)	(216.5)	(222.0)
Unrecognized net actuarial loss	251.7	220.8	25.5	31.9
Unrecognized prior service (benefit) cost	(1.2)	(1.7)	4.9	5.7
Unrecognized net transition obligation	0.0	0.0	1.9	4.2
Accrued liability at end of year	$71.7	$88.5	($184.2)	($180.2)
Amounts recognized in balance sheet				
Regulatory assets	$199.7	$176.3	$52.7	$61.2
Accrued benefit costs and other current liabilities	(2.9)	(4.4)	(13.2)	(13.8)
Deferred credits and other liabilities	(175.9)	(126.2)	(203.3)	(208.2)
Accumulated other comprehensive loss (income) (pretax)	50.8	42.8	(20.4)	(19.4)
Net amount recognized at end of year	$71.7	$88.5	($184.2)	($180.2)

(1) The measurement dates were Dec. 31, 2011 and Dec. 31, 2010.

(2) The actual return on plan assets differed from expectations due to general market conditions.

(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

	Pension Benefits		Other Benefits	
(millions)	*2011*	*2010*	*2011*	*2010*
Net actuarial loss (gain)	$ 50.3	$ 42.3	$ (20.0)	$ (19.3)
Prior service cost (credit)	0.5	0.5	(0.8)	(1.0)
Transition obligation (asset)	0.0	0.0	0.4	0.9
Amount recognized	$ 50.8	$ 42.8	$ (20.4)	$ (19.4)

The accumulated benefit obligation for all defined benefit pension plans was $596.2 million at Dec. 31, 2011 and $558.4 million at Dec. 31, 2010.

Assumptions used to determine benefit obligations at Dec. 31, 2011 and 2010:

	Pension Benefits		Other Benefits	
	2011	*2010*	*2011*	*2010*
Discount rate	4.80%	5.30%	4.74%	5.25%
Rate of compensation increase - weighted	3.83%	3.88%	3.82%	3.87%
Healthcare cost trend rate				
Immediate rate	n/a	n/a	7.75%	8.00%
Ultimate rate	n/a	n/a	4.50%	4.50%
Year rate reaches ultimate	n/a	n/a	2025	2023

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	$ 7.5	$ (6.3)

The discount rate assumption used to determine the Dec. 31, 2011 benefit obligation was based on a cash flow matching technique developed by outside actuaries and a review of current economic conditions. This technique constructs hypothetical bond portfolios using high-quality (AA or better by Standard & Poor's) corporate bonds available from the Barclays Capital database at the measurement date to meet the plan's year-by-year projected cash flows. The technique calculates all possible bond portfolios that produce adequate cash flows to pay the yearly benefits and then selects the portfolio with the highest yield and uses that yield as the recommended discount rate.

Net periodic benefit cost(1)	Pension Benefits			Other Benefits		
(millions)	*2011*	*2010*	*2009*	*2011*	*2010*	*2009*
Service cost	$ 16.0	$ 16.2	$ 15.7	$ 2.1	$ 3.2	$ 2.9
Interest cost	30.9	33.2	33.6	11.1	10.9	11.3
Expected return on plan assets	(38.4)	(36.3)	(37.8)	0.0	0.0	0.0
Amortization of:						
Actuarial loss	11.3	12.4	8.7	0.1	0.0	0.0
Prior service (benefit) cost	(0.4)	(0.4)	(0.4)	0.8	0.8	0.8
Transition obligation	0.0	0.0	0.0	2.3	2.3	2.3
Curtailment loss (benefit)	0.0	0.0	0.2	0.0	0.0	0.0
Settlement loss	0.9	1.6	0.0	0.0	0.0	0.0
Net periodic benefit cost	$ 20.3	$ 26.7	$ 20.0	$ 16.4	$ 17.2	$ 17.3

(1) Benefit cost was measured for the years ended Dec. 31, 2011, 2010 and 2009.

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 $2.6 million and $0.1 million, respectively. The estimated prior service benefit 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 $0.4 million, respectively.

In addition, the estimated net loss and prior service benefit for the defined benefit pension plans that will be amortized from regulatory assets into net periodic benefit cost over the next fiscal year are $12.1 million and $0.5 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 will be $1.1 million and $1.3 million, respectively.

Assumptions used to determine net periodic benefit cost for years ended Dec. 31,

	Pension Benefits			Other Benefits		
	2011	*2010*	*2009*	*2011*	*2010*	*2009*
Discount rate	5.30%	5.75%	6.05%	5.25%	5.60%	6.05%
Expected long-term return on plan assets	7.75%	8.25%	8.25%	n/a	n/a	n/a
Rate of compensation increase	3.88%	4.25%	4.25%	3.87%	4.25%	4.25%
Healthcare cost trend rate						
Initial rate	n/a	n/a	n/a	8.00%	8.00%	8.50%
Ultimate rate	n/a	n/a	n/a	4.50%	5.00%	5.00%
Year rate reaches ultimate	n/a	n/a	n/a	2023	2017	2016

The discount rate assumption used in calculating the net periodic benefit cost was based on a cash flow matching technique developed by 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 historical returns, fixed income spreads and equity premiums consistent with the portfolio and asset allocation. A change in asset allocations could have a significant impact on the expected return on assets. Additionally, expectations of long-term inflation, real growth in the economy and a provision for active management and expenses paid were incorporated in the assumption. For the year ended Dec. 31, 2011, TECO Energy's pension plan experienced actual asset returns of approximately 4.4%.

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	$ 0.5	$ (0.4)

Pension Plan Assets

Pension plan assets (plan assets) are primarily 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 and funding requirements over the long term. 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.

	Target Allocation	Actual Allocation, End of Year	
Asset Category		*2011*	*2010*
Equity securities	55%	50%	56%
Fixed income securities	45%	50%	44%
Total	100%	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 and funding. The company expects to take additional steps to more closely match plan assets with plan liabilities.

The plan's investments are held by a trust fund administered by JP Morgan Chase Bank, N.A. (JP Morgan). JP Morgan measures fair value using the procedures set forth below for all investments. When available, JP Morgan uses quoted market prices on investments 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 investments are traded in a secondary market, JP Morgan makes use of acceptable practical expedients to calculate fair value, and the company classifies these items as Level 2.

If observable transactions and other market data are not available, fair value is based upon third-party 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 third-party 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.

The following table sets forth by level within the fair value hierarchy the plan's investments as of Dec. 31, 2011 and Dec. 31, 2010. As required by the fair value accounting standards, the investments are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The plan'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 cash equivalents, the cost approach was used in determining fair value. For bonds and U.S. government agencies, the income approach was used. For other investments, the market approach was used.

(millions)	At Fair Value as of Dec. 31, 2011			
	Level 1	Level 2	Level 3	Total
Cash	$4.4	$0.0	$0.0	$4.4
Accounts receivable	39.6	0.0	0.0	39.6
Accounts payable	(20.4)	0.0	0.0	(20.4)
Cash equivalents				
Treasury bills (T bills)	0.0	4.3	0.0	4.3
Short term investment fund (STIF)	13.2	0.0	0.0	13.2
Money markets	0.0	0.3	0.0	0.3
Total cash equivalents	13.2	4.6	0.0	17.8
Equity securities				
Common stocks	114.2	0.0	0.0	114.2
Preferred stocks	0.0	1.0	0.0	1.0
American depository receipt (ADR)	6.5	0.6	0.0	7.1
Real estate investment trust (REIT)	2.0	0.0	0.0	2.0
Commingled fund	0.0	19.8	0.0	19.8
Mutual fund	88.3	0.0	0.0	88.3
Total equity securities	211.0	21.4	0.0	232.4
Fixed income securities				
Municipal bonds	0.0	8.7	0.0	8.7
Government bonds	0.0	31.7	0.0	31.7
Corporate bonds	0.0	29.5	0.0	29.5
Asset backed securities (ABS)	0.0	0.5	0.0	0.5
Mortgage back securities (MBS)	0.0	20.0	0.0	20.0
Collateralized mortgage obligation/real estate mortgage investment conduit (CMO/REMIC)	0.0	2.5	0.0	2.5
Mutual funds	0.0	101.1	0.0	101.1
Total fixed income securities	0.0	194.0	0.0	194.0
Derivatives				
Swaps	0.0	(0.3)	0.0	(0.3)
Written options	0.0	0.1	0.0	0.1
Total derivatives	0.0	(0.2)	0.0	(0.2)
Total	$247.8	$219.8	$0.0	$467.6

(millions)	At Fair Value as of Dec. 31, 2010			
	Level 1	Level 2	Level 3	Total
Accounts receivable	$31.4	$0.0	$0.0	$31.4
Accounts payable	(45.2)	0.0	0.0	(45.2)
Cash equivalents				
Short term investment fund (STIF)	7.9	0.0	0.0	7.9
Repurchase agreements	0.0	14.0	0.0	14.0
Money markets	0.0	0.3	0.0	0.3
Total cash equivalents	7.9	14.3	0.0	22.2
Equity securities				
Common stocks	112.6	0.0	0.0	112.6
Preferred stocks	0.0	1.0	0.0	1.0
American depository receipt (ADR)	4.8	1.3	0.0	6.1
Real estate investment trust (REIT)	2.0	0.0	0.0	2.0
Commingled fund	0.0	24.8	0.0	24.8
Mutual fund	121.5	0.0	0.0	121.5
Total equity securities	240.9	27.1	0.0	268.0
Fixed income securities				
Municipal bonds	0.0	7.9	0.0	7.9
Government bonds	0.0	26.3	0.0	26.3
Corporate bonds	0.0	26.0	0.0	26.0
Asset backed securities (ABS)	0.0	0.6	0.0	0.6
Mortgage back securities (MBS)	0.0	53.6	0.0	53.6
Collateralized mortgage obligation/Real estate mortgage investment conduit (CMO/REMIC)	0.0	3.0	0.0	3.0
Mutual funds	0.0	86.1	0.0	86.1
Total fixed income securities	0.0	203.5	0.0	203.5
Derivatives				
Swaps	0.0	0.1	0.0	0.1
Written options	0.0	(0.3)	0.0	(0.3)
Total derivatives	0.0	(0.2)	0.0	(0.2)
Total	$235.0	$244.7	$0.0	$479.7

- T bills are valued at amortized cost.
- The STIFs are money market mutual funds and are valued using the net asset value (NAV), as determined by the fund's trustee in accordance with U.S. GAAP, at year end. Shares may be sold any day the fund is accepting purchase orders, at the next NAV calculated after the order is accepted. The NAVs are validated with purchases and sales at NAV, making these Level 1 assets.
- Money markets and repurchase agreements valued using cost due to their short term nature. Additionally, money markets are backed by 102% collateral.
- The primary pricing inputs in determining the fair value of the Level 1 assets, excluding the mutual funds and STIFs, are quoted prices in active markets.
- The primary pricing inputs in determining the fair value of Level 2 preferred stock and ADR are prices of similar securities and benchmark quotes.
- The commingled fund invests primarily in international equity securities, normally excluding securities issued in the U.S., with large- and mid-market capitalizations. The fund may invest in "value" or "growth" securities and is not limited to a particular investment style. The fund is valued using the NAV, as determined by the fund's trustee in accordance with U.S. GAAP, at year end. For redemption, written notice of the amount to be withdrawn must be given no later than 4:00 p.m. eastern standard time.
- The primary pricing input in determining the Level 1 mutual fund is the mutual fund's NAV. The Level 1 mutual fund is an open-ended mutual fund and the NAV is validated with purchases and sales at NAV, making this a Level 1 asset.
- The primary pricing inputs in determining the fair value Level 2 municipal bonds are benchmark yields, historical spreads, sector curves, rating updates and prepayment schedules. The primary pricing inputs in determining the fair value of government bonds are the U.S. treasury curve, CPI, and broker quotes, if available. The primary pricing inputs in determining the fair value of corporate bonds are the U.S. treasury curve, base spreads, YTM, and benchmark quotes. ABS and CMO are priced using TBA prices, treasury curves, swap curves, cash flow information and bids and offers as inputs. MBS are priced using TBA prices, treasury curves, average lives, spreads

and cash flow information.

- The primary pricing input in determining the fair value of the Level 2 mutual funds are their NAV at year end. Shares may be purchased at the NAV without sales charges or other fees. Since these mutual funds are private funds, they are Level 2 assets. The funds invest primarily in emerging market fixed income securities. For redemption, written notice of the amount to be withdrawn must be given no later than 4:00 p.m. eastern standard time. Redemption proceeds will normally be received within three business days.
- The Level 2 options are valued using the bid-ask spread and the last price. Swaps are valued using benchmark yields, swap curves and cash flow analyses.

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 Employee Retirement Income Security Act (ERISA) guidelines for minimum annual contributions and minimize Pension Benefit Guarantee Corporation (PBGC) premiums paid by the plan. TECO Energy made no cash contributions in 2011 and $81.3 million of contributions to this plan in 2010, which met the minimum funding requirements for both 2011 and 2010. These amounts are reflected in the "Other" line on the Consolidated Statements of Cash Flows. TECO Energy plans to make a contribution of $35.5 in 2012 to satisfy the funding requirements for 2012. TECO Energy estimates annual contributions to range from $40.0 to $55.0 million per year in 2013 to 2016 based on current assumptions.

The SERP is funded annually to meet the benefit obligations. The company made contributions of $3.7 million and $6.3 million to this plan in 2011 and 2010, respectively. In 2012, the company expects to make a contribution of about $2.9 million to this plan.

The other postretirement benefits are funded annually to meet benefit obligations. 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 2012, the company expects to make a contribution of about $13.2 million. Postretirement benefit levels are substantially unrelated to salary.

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**	
(millions)		Gross	Expected Federal Subsidy
2012	$ 46.1	$ 14.7	$ 1.4
2013	45.9	15.4	1.6
2014	46.9	16.2	1.7
2015	48.3	16.8	1.9
2016	52.1	17.3	2.0
2017-2021	279.5	19.6	11.8

Defined Contribution Plan

The company has a defined contribution savings plan covering substantially all employees of TECO Energy and its subsidiaries 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 April 2010, employer matching contributions were 60% of eligible participant contributions with additional incentive match of up to 40% of eligible participant contributions based on the achievement of certain operating company financial goals. Prior to this, the employer matching contributions were 50% of eligible participant contributions, with an additional incentive match of up to 50%. For the years ended Dec. 31, 2011, 2010 and 2009, the company and its subsidiaries recognized expense totaling $9.0 million, $12.6 million and $8.1 million, respectively, related to the matching contributions made to this plan.

6. Short-Term Debt

At Dec. 31, 2011 and Dec. 31, 2010, the following credit facilities and related borrowings existed:

Credit Facilities

	Dec. 31, 2011			*Dec. 31, 2010*		
(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(2)	$325.0	$0.0	$0.7	$325.0	$5.0	$0.7
1-year accounts receivable facility	150.0	0.0	0.0	150.0	7.0	0.0
TECO Energy/TECO Finance:						
5-year facility (2)(3)	200.0	0.0	0.0	200.0	0.0	6.7
Total	$675.0	$0.0	$0.7	$675.0	$12.0	$7.4

(1) Borrowings outstanding are reported as notes payable.

(2) This 5-year facility matures Oct. 25, 2016.

(3) TECO Finance is the borrower and TECO Energy is the guarantor of this facility.

At Dec. 31, 2011, these credit facilities require commitment fees ranging from 17.5 to 35.0 basis points. The weighted-average interest rate on outstanding amounts payable under the credit facilities at Dec. 31, 2010 was 0.64%. There were no outstanding notes payable at Dec. 31, 2011.

Tampa Electric Company Accounts Receivable Facility

On Feb. 17, 2012, Tampa Electric Company and TRC amended their $150 million accounts receivable collateralized borrowing facility, entering into Amendment No. 10 to the Loan and Servicing Agreement with certain lenders named therein and Citibank, N.A., Inc. as Program Agent. The amendment extends the maturity date to Feb. 15, 2013 and makes certain other technical changes. Please refer to **Note 25** for additional information.

TECO Energy/TECO Finance bank credit facility amendment

On Oct. 25, 2011, TECO Energy amended its $200 million bank credit facility, entering into a Third Amended and Restated Credit Agreement. The amendment (i) extended the maturity date of the credit facility from May 9, 2012 to Oct. 25, 2016 (subject to further extension with the consent of each lender); (ii) continues with TECO Energy as Guarantor and its wholly-owned subsidiary, TECO Finance, Inc. (TECO Finance), as Borrower; (iii) allows TECO Finance to borrow funds at an interest rate equal to the London interbank deposit rate plus a margin; (iv) as an alternative to the above interest rate, allows TECO Finance to borrow funds at an interest rate equal to a margin plus the higher of the JPMorgan Chase Bank's prime rate, the federal funds rate plus 50 basis points, or the London interbank deposit rate plus 1.00%; (v) allows TECO Finance to borrow funds on a same-day basis under a new swingline loan provision, which loans mature on the fourth banking day after which any such loans are made and bear interest at an interest rate as agreed by the Borrower and the relevant swingline lender prior to the making of any such loans; (vi) allows TECO Finance to request the lenders to increase their commitments under the credit facility by $100 million in the aggregate (compared to $50 million in the aggregate under the previous agreement); (vii) continues to include a $200 million letter of credit facility; and (viii) makes other technical changes.

Tampa Electric Company $325 million bank credit facility amendment

On Oct. 25, 2011, Tampa Electric Company amended its $325 million bank credit facility, entering into a Third Amended and Restated Credit Agreement. The amendment (i) extended the maturity date of the credit facility from May 9, 2012 to Oct. 25, 2016 (subject to further extension with the consent of each lender); (ii) continues to allow Tampa Electric Company to borrow funds at a rate equal to the London interbank deposit rate plus a margin; (iii) allows Tampa Electric Company to borrow funds at an interest rate equal to a margin plus the higher of Citibank's prime rate, the federal funds rate plus 50 basis points, or the London interbank deposit rate plus 1.00%; (iv) as an alternative to the above interest rate, allows Tampa Electric Company to borrow funds on a same-day basis under a new swingline loan provision, which loans mature on the fourth banking day after which any such loans are made and bear interest at an interest rate as agreed by the Borrower and the relevant swingline lender prior to the making of any such loans; (v) continues to allow Tampa Electric Company to request the lenders to increase their commitments under the credit facility by up to $175 million in the aggregate; (vi) includes a $200 million letter of credit facility (compared to $50 million under the previous agreement); and (vii) makes other technical changes.

7. Long-Term Debt

At Dec. 31, 2011, total long-term debt had a carrying amount of $3,075.8 million and an estimated fair market value of $3,435.3 million. At Dec. 31, 2010, total long-term debt had a carrying amount of $3,229.1 million and an estimated fair market value of $3,451.9 million.

A substantial part of Tampa Electric's tangible assets 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 2012 through 2016 and thereafter are as follows:

Long-Term Debt Maturities

As of Dec. 31, 2011 (millions)	*2012*	*2013*	*2014*	*2015*	*2016*	*Thereafter*	*Total Long-Term Debt*
TECO Energy	$0.0	$0.0	$0.0	$8.8	$0.0	$0.0	$8.8
TECO Finance	0.0	0.0	0.0	191.2	250.0	600.0	1,041.2
Tampa Electric	308.3	60.7	83.3	83.3	83.3	1,150.0	1,768.9
PGS	66.6	0.0	0.0	0.0	0.0	156.8	223.4
TECO Guatemala	11.2	11.2	11.1	0.0	0.0	0.0	33.5
Total long-term debt maturities	$386.1	$71.9	$94.4	$283.3	$333.3	$1,906.8	$3,075.8

Debt Securities

Purchase in Lieu of Redemption of Polk County Industrial Development Authority Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2010

On Mar. 1, 2011, Tampa Electric Company purchased in lieu of redemption $75.0 million Polk County Industrial Development Authority (PCIDA) Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2010 (the PCIDA Bonds). On Nov. 23, 2010, the PCIDA had issued the PCIDA Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. Proceeds of the PCIDA Bonds were used to redeem $75.0 million PCIDA Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007, which previously had been in auction rate mode and had been held by Tampa Electric Company since Mar. 26, 2008. The PCIDA Bonds bore interest at the initial term rate of 1.50% per annum from Nov. 23, 2010 to Mar. 1, 2011.

On Mar. 26, 2008, Tampa Electric Company purchased in lieu of redemption $20.0 million Hillsborough County Industrial Development Authority (HCIDA) Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007C. After the Mar. 1, 2011 purchase of the PCIDA Bonds, $95.0 million in bonds purchased in lieu of redemption were held by the trustee at the direction of Tampa Electric Company as of Dec. 31, 2011 (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.

Refinancing of CGESJ Debt

On Dec. 29, 2010 CGESJ refinanced its $44.7 million loan at a fixed rate of 3.0% for 2011 and a floating rate of 3-month Libor plus 275 basis points for 2012-2014. Payments on the loan are made quarterly with the final payment to be made on Dec. 31, 2014. In connection with this transaction, $0.9 million of unamortized costs were expensed, and are included in "Loss on debt extinguishment" on the Consolidated Statements of Income for the year ended Dec. 31, 2010.

Tampa Electric Company Exchange Offer and Issuance of 5.40% Notes due 2021

On Dec. 14, 2010, Tampa Electric Company completed an exchange offer (the Exchange Offer) which resulted in the exchange of approximately $278.5 million principal amount of Tampa Electric Company notes for approximately $278.5 million principal amount of newly issued Tampa Electric Company 5.40% Notes due 2021.

The Exchange Offer resulted in the exchange and retirement of approximately:

- $131.5 million principal amount of Tampa Electric Company 6.875% Notes due 2012
- $147.0 million principal amount of Tampa Electric Company 6.375% Notes due 2012 for approximately $278.5 million principal amount of newly issued Tampa Electric Company 5.40% Notes due 2021.

The 5.40% Notes bear interest at a rate of 5.40% per year, payable on May 15 and November 15 each year, beginning May 15, 2011 and mature May 15, 2021. Tampa Electric Company may redeem some or all of the 5.40% Notes at a price equal to the greater of (i) 100% of the principal amount of the applicable Tampa Electric Company notes to be redeemed, plus accrued and unpaid interest, or (ii) the net present value of the remaining payments of principal and interest on the Tampa Electric Company 5.40% Notes, discounted at the applicable treasury rate (as defined in the applicable supplemental indenture), plus 25 basis points. Such redemption price would include accrued and unpaid interest to the redemption date. In accordance with allowed regulatory treatment, the unamortized costs are being amortized over the life of the original notes.

After the Exchange Offer, approximately $118.6 million principal amount of Tampa Electric Company 6.875% Notes due 2012 and $253.0 million principal amount of Tampa Electric Company 6.375% Notes due 2012 remain outstanding.

Redemption of TECO Energy, Inc. and TECO Finance, Inc. 7.0% Notes due 2012

On Dec. 2, 2010, TECO Energy and TECO Finance redeemed $73.2 million and $163.1 million, respectively, of 7.0% Notes due May 1, 2012. The redemption price was equal to $1,089.73 per $1,000 principal amount of notes redeemed, plus accrued and unpaid interest on the redeemed notes up to the redemption date. In connection with this transaction, $21.6 million of premiums and fees were expensed, and are included in "Loss on debt extinguishment" on the Consolidated Statements of Income and as part of the "Cash flows from operating activities" in the Consolidated Statements of Cash Flows for the year ended Dec. 31, 2010.

Redemption of TECO Energy, Inc. 7.2% Notes due 2011

On Apr. 22, 2010, TECO Energy redeemed $100.0 million aggregate principal amount of its 7.2% Notes due 2011. The redemption price was equal to $1,066.38 per $1,000 principal amount of notes redeemed, plus accrued and unpaid interest on the redeemed notes up to the redemption date. In connection with this transaction, $6.6 million of premiums and fees were expensed, and are included in "Loss on debt extinguishment" on the Consolidated Statements of Income and as part of the "Cash flows from operating activities" in the Consolidated Statements of Cash Flows for the year ended Dec. 31, 2010.

Redemption of TECO Energy, Inc. Floating Rate Notes due 2010

On Apr. 14, 2010, TECO Energy redeemed all of the outstanding $100.0 million aggregate principal amount of its Floating Rate Notes due 2010. The redemption price was equal to 100% of the principal amount of notes redeemed, plus accrued and unpaid interest on the redeemed notes up to the redemption date.

TECO Energy, Inc. and TECO Finance, Inc. Tender Offers

On Mar. 22, 2010, TECO Energy and TECO Finance completed debt tender offers which resulted in the purchase of approximately $70.0 million principal amount of TECO Energy notes for cash and approximately $230.0 million principal amount of TECO Finance notes for cash.

The tender offers resulted in the purchase and retirement of approximately:

- $43.0 million principal amount of TECO Energy 7.2% Notes due 2011
- $27.0 million principal amount of TECO Energy 7.0% Notes due 2012
- $156.9 million principal amount of TECO Finance 7.2% Notes due 2011
- $73.1 million principal amount of TECO Finance 7.0% Notes due 2012

In connection with these debt tender transactions, $25.5 million of premiums and fees were expensed, and are included in "Loss on debt extinguishment" on the Consolidated Statements of Income and as part of the "Cash flows from operating activities" in the Consolidated Statements of Cash Flows for the twelve months ended Dec. 31, 2010. "Loss on debt extinguishment" also includes remaining unamortized debt issue costs of $0.9 million.

Issuance of TECO Finance, Inc. 4.00% Notes due 2016 and 5.15% Notes due 2020

On Mar. 15, 2010, TECO Finance issued $250.0 million aggregate principal amount of 4.00% Notes due Mar. 15, 2016 and $300.0 million aggregate principal amount of 5.15% Notes due Mar. 15, 2020. The 2016 Notes were priced at 99.594% of the principal amount to yield 4.077% to maturity, and the 2020 Notes were priced at 99.552% of the principal amount to yield 5.208% to maturity. TECO Finance is a wholly–owned subsidiary of TECO Energy whose business activities consist solely of providing funds to TECO Energy for its diversified activities. The TECO Finance notes are fully and unconditionally guaranteed by TECO Energy.

The offering resulted in net proceeds to TECO Finance (after deducting underwriting discounts and commissions and estimated offering expenses) of approximately $543.5 million. TECO Finance used a portion of these net proceeds to fund the cash purchase of the TECO Energy and TECO Finance notes tendered in March 2010 (see *TECO Energy, Inc. and TECO Finance, Inc. Tender Offers* above) and to fund the redemptions of the TECO Energy Floating Rate Notes due 2010 and 7.20% Notes due 2011 in April 2010. TECO Finance may redeem some or all 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 sum of 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 25 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date.

Reconsolidation of TCAE and CGESJ

Effective Jan. 1, 2010, new accounting standards for consolidations amended the determination of the primary beneficiaries for VIEs. As a result of adopting these standards, TECO Guatemala was determined to be the primary beneficiary of, and therefore required to consolidate, both the TCAE and CGESJ projects in Guatemala. The consolidation resulted in a net $44.4 million increase of non–recourse debt.

At Dec. 31, 2011 and 2010, TECO Energy had the following long-term debt outstanding:

Long-Term Debt *(millions) Dec. 31,*		*Due*	*2011*	*2010*
TECO Energy	Notes[1]:			
	7.20% (effective rate of 7.4%) for 2010	2011	$0.0	$48.7
	6.75% (effective rate of 6.9%)[2]	2015	8.8	8.8
Total long-term debt of TECO Energy			8.8	57.5
TECO Finance	Notes[1][3]: 7.2% (effective rate of 7.4%) for 2010	2011	0.0	15.0
	6.75% (effective rate of 6.9%)[2]	2015	191.2	191.2
	4.00% (effective rate of 4.2%)	2016	250.0	250.0
	6.572% (effective rate of 7.3%)	2017	300.0	300.0
	5.15% (effective rate of 5.3%)	2020	300.0	300.0
Total long-term debt of TECO Finance			1,041.2	1,056.2
Tampa Electric	Installment contracts payable[4] :			
	5.10% Refunding bonds (effective rate of 5.6%)	2013	60.7	60.7
	5.65% Refunding bonds (effective rate of 5.9%)	2018	54.2	54.2
	Variable rate bonds repurchased in 2008 [5]	2020	0.0	0.0
	5.50% Refunding bonds (effective rate of 6.2%)	2023	86.4	86.4
	5.15% Refunding bonds (effective rate of 5.4%) [6]	2025	51.6	51.6
	1.50% Term rate bonds repurchased in 2011 [7]	2030	0.0	75.0
	5.00% Refunding bonds (effective rate of 5.8%) [8]	2034	86.0	86.0
	Notes[1]: 6.875% (effective rate of 7.1%)	2012	99.6	99.6
	6.375% (effective rate of 7.9%)	2012	208.7	208.7
	6.25% (effective rate of 6.3%) [2]	2014-2016	250.0	250.0
	6.10% (effective rate of 6.4%)	2018	200.0	200.0
	5.40% (effective rate of 5.9%)	2021	231.7	231.7
	6.55% (effective rate of 6.6%)	2036	250.0	250.0
	6.15% (effective rate of 6.2%)	2037	190.0	190.0
Total long-term debt of Tampa Electric			1,768.9	1,843.9
PGS	Senior Notes[1][2]: 8.00%	2012	3.4	6.8
	Notes[1]: 6.875% (effective rate of 7.1%)	2012	19.0	19.0
	6.375% (effective rate of 7.9%)	2012	44.3	44.3
	6.10% (effective rate of 7.0%)	2018	50.0	50.0
	5.40% (effective rate of 5.8%)	2021	46.7	46.7
	6.15% (effective rate of 6.2%)	2037	60.0	60.0
Total long-term debt of PGS			223.4	226.8
TECO Guatemala	Notes[1][2]: 3.00% Fixed rate for 2011, floating thereafter	2012-2014	33.5	44.7
Total carrying amount of long-term debt			3,075.8	3,229.1
Unamortized debt discount, net			(2.4)	(2.7)
			3,073.4	3,226.3
Less amount due within one year			386.1	78.3
Total long-term debt			$2,687.3	$3,148.0

(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 financial covenants.

(3) Guaranteed by TECO Energy.

(4) Tax-exempt securites.

(5) In March 2008 these bonds, which were in auction rate mode, were purchased in lieu of redemption by Tampa Electric Company. These held variable rate bonds have a par amount of $20.0 million and are due in 2020.

(6) These bonds were converted in March 2008 from auction rate mode to a fixed rate mode for the term ending Sep. 1, 2013.

(7) In March 2011 these bonds, which were in term rate mode, were purchased in lieu of redemption by Tampa Electric Company. These held term rate bonds have a par amount of $75.0 million and are due in 2030.

(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.

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 May 5, 2010, the shareholders approved the 2010 Equity Incentive Plan (2010 Plan) as an amendment and restatement of both the company's 2004 Equity Incentive Plan (2004 Plan) and the 1997 Director Equity Plan (1997 Plan, and together with the 2004 Plan, the Old Plans). The 2010 Plan superseded the Old Plans and no additional grants will be made under the Old Plans. The rights of the holders of outstanding options, unvested restricted stock or other outstanding awards under the Old Plans were not affected. The purpose of the 2010 Plan is to attract and retain key employees and non-employee directors, to enable the company to provide equity-based incentives relating to achieving long-range performance goals and to enable award recipients to participate in the long-term growth of the company. The 2010 Plan is administered by the Compensation Committee of the Board of Directors (Committee), which may grant awards to any employee of the company who is capable of contributing significantly to the successful performance of the company. Only the Board of Directors may grant awards to any non-employee members of the Board of Directors.

The 2010 Plan amended the 2004 Plan to reduce the number of shares of common stock subject to grants to 4.0 million shares (a reduction of 3.0 million shares), remove the cap on shares available for stock grant, place various limitations on the terms of awards granted under the 2010 Plan, remove the ability to make awards to consultants of the company and reapprove the business criteria upon which objective performance goals may be established by the Committee to continue to permit the company to take federal tax deductions for performance-based awards made to certain senior officers under Section 162(m) of the tax code.

The types of awards that can be granted under the 2010 Plan include stock options, stock grants and stock equivalents. Stock options were last awarded in 2006 under the Old Plans. 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. Time-vested restricted stock granted to directors prior to 2011 vest one-third each year. Beginning in 2011, time-vested restricted stock granted to directors vest in one 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 performance-based grants can vest between 0% and 150% of the original grant. Dividends are paid on all time-vested stock grants during the vesting period. Dividends are paid during the vesting period on all performance stock granted prior to 2010. Beginning in 2010, dividends are accrued during the vesting period on all performance stock granted under the 2010 Plan and paid at vesting date on the shares that vest. 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.

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 accounting guidance for the 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.

Assumptions	*2011*	*2010*	*2009*
Assumptions applicable to performance-based restricted stock			
Risk-free interest rate	0.96%	1.37%	1.36%
Expected lives (in years)	3	3	3
Expected stock volatility	34.61%	35.83%	34.11%
Dividend yield	4.48%	4.90%	7.54%

Under the 2010 Plan and the Old Plans 0.8 million, 0.8 million and 0.9 million shares of restricted stock were granted in 2011, 2010 and 2009, respectively, with weighted-average fair values per share of $18.44, $17.22 and $10.63, respectively. The total fair market value of awards vesting during 2011, 2010 and 2009 was $13.4 million, $10.2 million and $7.0 million, respectively, which includes stock grants, time-vested restricted stock and performance-based restricted stock. As of Dec. 31, 2011, there was $14.9 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.

The following table provides additional information on compensation costs and income tax benefits and excess tax benefits related to the stock-based compensation awards.

(millions)	*2011*	*2010*	*2009*
Compensation costs (1)	$ 9.1	$ 7.4	$ 10.4
Income tax benefits (1)	3.5	2.9	4.0
Excess tax benefits (2)	1.7	0.8	0.3

(1) Reflected on the Consolidated Statements of Income.
(2) Reflected as financing activities on the Consolidated Statements of Cash Flows.

The aggregate intrinsic value of stock options exercised was $1.5 million, $0.7 million and $0.1 million for the periods ended Dec. 31, 2011, 2010 and 2009, respectively. Cash received from option exercises under all share-based payment arrangements was $5.0 million, $2.9 million and $0.4 million for the periods ended Dec. 31, 2011, 2010 and 2009, respectively. The income tax benefit realized from stock option exercises was $0.6 million, $0.3 million and $0.1 million for the periods ended Dec. 31, 2011, 2010 and 2009, respectively.

A summary of non-vested shares of restricted stock for the 2010 Plan is shown as follows:

Nonvested Restricted Stock

	Time-Based Restricted Stock(1)		**Performance-Based Restricted Stock(1)**	
	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, 2010	564	$ 14.67	1,299	$ 14.51
Granted	209	19.21	602	18.17
Vested	(186)	16.58	(524)	16.63
Forfeited	(8)	15.92	(20)	16.10
Nonvested balance at Dec. 31, 2011	579	$ 15.68	1,357	$ 15.29

(1) The weighted-average remaining contractual term of restricted stock is two years.

Stock option transactions during 2011 under the 2010 Plan 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, 2010	4,902	$22.04		
Granted	0	0.00		
Exercised	(346)	14.46		
Cancelled	(1,027)	31.55		
Outstanding balance at Dec. 31, 2011 (1)	3,529	$20.01	2	$9.0
Exercisable at Dec. 31, 2011 (1)	3,529	$20.01	2	$9.0
Available for future grant at Dec. 31, 2011	2,584			

(1) Option prices range from $11.09 to $27.97 per share.

As of Dec. 31, 2011, the options outstanding and exercisable under the 2010 Plan are summarized below:

Range of Option Prices (per share)	Option Shares (thousands)	Weighted-Avg. Option Price (per share)	Weighted-Avg. Remaining Contractual Life
$11.09 - $13.64	808	$12.78	2 Years
$16.21 - $19.05	1,357	$16.32	4 Years
$27.97	1,364	$27.97	1 Years
Total	3,529	$20.01	2 Years

Dividend Reinvestment Plan

In 1992, TECO Energy implemented a Dividend Reinvestment and Common Stock Purchase Plan. TECO Energy raised $3.7 million and $3.8 million of common equity from this plan in 2010 and 2009, respectively. TECO Energy purchased shares on the open market for 2011.

10. Other Comprehensive Income

TECO Energy reported the following other comprehensive income (loss) (OCI) for the years ended Dec. 31, 2011, 2010 and 2009, 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 *(millions)*	*Gross*	*Tax*	*Net*
2011			
Unrealized gain on cash flow hedges	$ 1.8	$ (0.6)	$ 1.2
Less: Gain reclassified to net income	(3.1)	1.1	(2.0)
Loss on cash flow hedges	(1.3)	0.5	(0.8)
Amortization of unrecognized benefit costs and other	(6.4)	2.8	(3.6)
Change in benefit obligation due to remeasurement	(1.5)	0.5	(1.0)
Recognized benefit costs due to settlement	0.9	(0.3)	0.6
Total other comprehensive (loss) income	$ (8.3)	$ 3.5	$ (4.8)
2010			
Unrealized gain on cash flow hedges	$ 1.0	$ (0.4)	$ 0.6
Plus: Loss reclassified to net income	3.9	(1.4)	2.5
Gain on cash flow hedges	4.9	(1.8)	3.1
Amortization of unrecognized benefit costs and other	3.7	0.0	3.7
Recognized benefit costs due to settlement	1.7	(0.7)	1.0
Total other comprehensive income (loss)	$ 10.3	$ (2.5)	$ 7.8
2009			
Unrealized gain on cash flow hedges	$ 4.0	$ (1.5)	$ 2.5
Plus: Loss reclassified to net income	24.3	(9.0)	15.3
Gain on cash flow hedges	28.3	(10.5)	17.8
Amortization of unrecognized benefit costs and other	2.1	(0.8)	1.3
Change in benefit obligation due to remeasurement	0.4	(0.2)	0.2
Reclassification to earnings loss on available-for-sale securities(1)	1.7	0.0	1.7
Total other comprehensive income (loss)	$ 32.5	$ (11.5)	$ 21.0

Accumulated Other Comprehensive Loss *(millions) As of Dec. 31,*	*2011*	*2010*
Unrecognized pension losses and prior service costs(2)	$ (31.2)	$ (26.6)
Unrecognized other benefit losses, prior service costs and transition obligations(3)	14.2	13.6
Net unrealized losses from cash flow hedges(4)	(5.0)	(4.2)
Total accumulated other comprehensive loss	$ (22.0)	$ (17.2)

(1) Amount related to an off-shore investment not subject to U.S. Federal income tax.

(2) Net of tax benefit of $19.6 million and $16.2 million as of Dec. 31, 2011 and Dec. 31, 2010, respectively.

(3) Net of tax expense of $6.2 million and $5.8 million as of Dec. 31, 2011 and Dec. 31, 2010, respectively.

(4) Net of tax benefit of $3.2 million and $2.7 million as of Dec. 31, 2011 and Dec. 31, 2010, respectively.

11. Earnings Per Share

In accordance with accounting standards for the calculation of earnings per share (EPS), TECO Energy adopted the two-class method for computing EPS in the first quarter of 2009. These standards define 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. The standards require 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.

Earnings Per Share

(millions, except per share amounts)	*2011*	*2010*	*2009*
Basic earnings per share			
Net income from continuing operations	$272.9	$239.6	$213.9
Less: Income attributable to noncontrolling interest	(0.3)	(0.6)	0.0
Less: Amount allocated to nonvested participating shareholders	(1.4)	(1.7)	(1.8)
Net income attributable to TECO Energy available to common shareholders - basic	$271.2	$237.3	$212.1
Net income attributable to TECO Energy	$272.6	$239.0	$213.9
Amount allocated to nonvested participating shareholders	(1.4)	(1.7)	(1.8)
Net income attributable to TECO Energy available to common shareholders - basic	$271.2	$237.3	$212.1
Average shares outstanding common	213.6	212.6	211.8
Basic earnings per share attributable to TECO Energy available to common shareholders	$1.27	$1.12	$1.00
Diluted earnings per share			
Net income from continuing operations	$272.9	$239.6	$213.9
Less: Income attributable to noncontrolling interest	(0.3)	(0.6)	0.0
Less: Amount allocated to nonvested participating shareholders	(1.4)	(1.7)	(1.8)
Net income attributable to TECO Energy available to common shareholders - diluted	$271.2	$237.3	$212.1
Net income attributable to TECO Energy	$272.6	$239.0	$213.9
Amount allocated to nonvested participating shareholders	(1.4)	(1.7)	(1.8)
Net income attributable to TECO Energy available to common shareholders - diluted	$271.2	$237.3	$212.1
Average shares outstanding common	213.6	212.6	211.8
Assumed conversion of stock options, unvested restricted stock and contingent performance shares, net	1.5	2.2	1.3
Adjusted average shares outstanding common - diluted	215.1	214.8	213.1
Diluted earnings per share attributable to TECO Energy available to common shareholders	$1.27	$1.11	$1.00
Anti-dilutive shares	1.7	2.7	6.0

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 accounting standards for contingencies to provide for matters that are probable of resulting in an estimable 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, financial condition or cash flows.

Merco Group at Aventura Landings v. Peoples Gas System

In a Florida district court case pending in Miami, Merco Group at Aventura Landings I, II and III (Merco) alleged that coal tar from a certain former PGS manufactured gas plant site had been deposited in the early 1960s onto property now owned by Merco. Merco alleged that it incurred approximately $3.9 million in costs associated with the removal of such coal tar and provided testimony claiming approximately $110.0 million plus interest in damages from out-of-pocket development expenses and lost profits due to the delay in its condominium development project allegedly caused by the presence of the coal tar. PGS maintains that it is not liable because the coal tar did not originate from its manufactured gas plant site and filed a third-party complaint against Continental Holdings, Inc. (CHI), which Merco also added as a defendant in its suit, as the owner at the relevant time of the site that PGS believes was the source of the coal tar on Merco's property. In addition, the court will consider PGS's counterclaim against Merco which claims that, because Merco purchased the property with actual knowledge of the presence of coal tar on the property, Merco should contribute toward any damages resulting from the presence of coal tar. The bench trial in this matter was concluded in February 2012 and a ruling is expected in March 2012. Co-defendant CHI reached a settlement with Merco but still remains as a defendant in PGS's third-party complaint.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a 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, 2011, Tampa Electric Company has estimated its ultimate financial liability to be $28.5 million, primarily at PGS. This amount has been accrued and is primarily reflected in "Long-term regulatory liabilities" on the company's Consolidated Balance Sheet. 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 portion of the clean-up 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.

In instances where other PRPs are involved, many of those PRPs are creditworthy and are likely to continue to be creditworthy for the duration of the remediation work. However, in those instances that they are not, Tampa Electric Company could be liable for more than Tampa Electric Company's actual percentage of the remediation costs.

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.

Potentially Responsible Party Notification

In October 2010, the EPA notified Tampa Electric Company that it is a PRP under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, commonly known as Superfund, for the proposed conduct of a contaminated soil removal action and further clean up, if necessary, at a property owned by Tampa Electric Company in Tampa, Florida. The property owned by Tampa Electric Company is undeveloped except for location of transmission lines and poles, and is adjacent to an industrial site, not owned by Tampa Electric Company, which the EPA has studied since 1992 or earlier. The EPA has asserted this potential liability due to Tampa Electric Company's ownership of the property described above but, to the knowledge of Tampa Electric Company, this assertion is not based upon any release of hazardous substances by Tampa Electric Company. Tampa Electric Company has responded to the EPA regarding such matter. The scope and extent of its potential liability, if any, and the costs of any required investigation and remediation have not been determined.

Environmental Protection Agency Administrative Order

In December 2010, Clintwood Elkhorn Mining Company, a subsidiary of TECO Coal, received an Administrative Order from the EPA relating to the discharge of wastewater associated with inactive mining operations in Pike County, Kentucky. TECO Coal responded to the EPA on Feb. 14, 2011. The scope and extent of TECO Coal's potential liability, if any, and the costs of any required investigation and remediation related to these inactive mining operations in the area have not been determined.

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 "Regulated operations - Other", "Operation other expense –

Mining related costs" and "Operation other expense - Other" on the Consolidated Statements of Income for the years ended Dec. 31, 2011, 2010 and 2009, totaled $10.2 million, $11.5 million and $10.7 million, respectively. The following is a schedule of future minimum lease payments with non-cancelable lease terms in excess of one year and capacity payments under power purchase agreements at Dec. 31, 2011:

Future Minimum Lease and Capacity Payments

(millions)	*Capacity Payments*	*Operating Leases*	*Total*
Year ended Dec. 31:			
2012	$ 11.7	$ 6.2	$ 17.9
2013	12.7	3.5	16.2
2014	12.8	3.1	15.9
2015	13.0	2.7	15.7
2016	14.6	2.4	17.0
Thereafter	20.0	18.4	38.4
Total future minimum payments	$ 84.8	$ 36.3	$ 121.1

Guarantees and Letters of Credit

TECO Energy accounts for guarantees in accordance with the applicable accounting standards. 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) are likely to be subject to the recognition and measurement, as well as the disclosure provisions. 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, 2011 are as follows:

Guarantees-TECO Energy

(millions) *Guarantees for the Benefit of:*	*2012*	*2013-2016*	*After (1) 2016*	*Total*	*Liabilities Recognized at Dec. 31, 2011*
TECO Coal					
Fuel purchase related (2)	$0.0	$0.0	$5.4	$5.4	$1.1
Other subsidiaries					
Fuel purchase/energy management (2)	0.0	0.0	109.7	109.7	1.2
Total	$0.0	$0.0	$115.1	$115.1	$2.3

Letters of Credit-Tampa Electric Company

(millions) *Letters of Credit for the Benefit of:*	*2012*	*2013-2016*	*After (1) 2016*	*Total*	*Liabilities Recognized at Dec. 31, 2011*
Tampa Electric(2)	$0.0	$0.0	$0.7	$0.7	$0.2

(1) These letters of credit and guarantees renew annually and are shown on the basis that they will continue to renew beyond 2016.

(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 Dec. 31, 2011. 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 and its subsidiaries must meet certain financial tests as defined in the applicable agreements. In addition, PGS and TECO Diversified have certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2011, TECO Energy, TECO Finance, Tampa Electric Company and the other operating companies were in compliance with all applicable 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 $1.3 million, $1.2 million and $1.6 million for the years ended Dec. 31, 2011, 2010 and 2009, 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, 2011, 2010 and 2009. No material balances were payable as of Dec. 31, 2011 or 2010.

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 the accounting guidance for 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.

Segment Information

(millions)	Tampa Electric	PGS	TECO Coal	TECO [2] Guatemala	Other & Eliminations	TECO Energy
2011						
Revenues - outsiders	$2,019.3	$450.5	$733.0	$133.5	$7.1	$3,343.4
Revenues - affiliates	1.3	3.0	0.0	0.0	(4.3)	0.0
Total revenues	2,020.6	453.5	733.0	133.5	2.8	3,343.4
Depreciation and amortization	222.1	48.4	45.3	7.4	1.4	324.6
Total interest charges [1]	121.8	17.7	6.9	7.6	51.1	205.1
Internally allocated interest [1]	0.0	0.0	6.7	6.2	(12.9)	0.0
Provision (benefit) for taxes	124.8	20.6	15.4	11.1	(18.0)	153.9
Net income attributable to TECO Energy	202.7	32.6	51.5	22.4	(36.6)	272.6
Goodwill, net	0.0	0.0	0.0	55.4	0.0	55.4
Total assets	5,940.9	932.0	385.2 [3]	304.1	(240.0)	7,322.2
Capital expenditures	314.9	71.9	56.6	7.2	3.5	454.1
2010						
Revenues - outsiders	$2,161.9	$510.7	$690.0	$124.4	$0.9	$3,487.9
Revenues - affiliates	1.3	19.2	0.0	0.0	(20.5)	0.0
Total revenues	2,163.2	529.9	690.0	124.4	(19.6)	3,487.9
Earnings from unconsol. affiliates	0.0	0.0	0.0	13.1	(2.7)	10.4
Depreciation and amortization	215.9	46.0	43.5	7.3	0.2	312.9
Restructuring charges	0.0	0.0	0.0	0.0	1.5	1.5
Total interest charges [1]	122.7	18.3	6.8	15.7	67.8	231.3
Internally allocated interest [1]	0.0	0.0	6.6	11.2	(17.8)	0.0
Provision (benefit) for taxes	122.4	21.3	11.8	46.2	(31.7)	170.0
Net income attributable to TECO Energy	208.8	34.1	53.0	41.6	(98.5)	239.0
Goodwill, net	0.0	0.0	0.0	55.4	0.0	55.4
Total assets	5,833.3	918.4	332.2 [3]	292.7	(98.3)	7,278.3
Capital expenditures	331.2	62.4	47.4	0.8	47.9	489.7
2009						
Revenues - outsiders	$2,193.5	$455.6	$653.0	$8.3	$0.1	$3,310.5
Revenues - affiliates	1.3	15.2	0.0	0.0	(16.5)	0.0
Total revenues	2,194.8	470.8	653.0	8.3	(16.4)	3,310.5
Earnings from unconsol. affiliates	0.0	0.0	0.0	47.3	(0.6)	46.7
Depreciation and amortization	200.4	44.2	42.2	0.8	0.3	287.9
Restructuring charges	18.4	4.7	0.0	0.0	2.6	25.7
Total interest charges [1]	116.2	18.7	7.3	12.9	71.9	227.0
Internally allocated interest [1]	0.0	0.0	6.4	12.6	(19.0)	0.0
Provision (benefit) for taxes	98.4	13.3	7.8	10.8	(31.7)	98.6
Net income attributable to TECO Energy	160.2	31.9	37.2	38.6	(54.0)	213.9
Goodwill, net	0.0	0.0	0.0	59.4	0.0	59.4
Investment in unconsolidated affiliates	0.0	0.0	0.0	279.2	0.1	279.3
Total assets	5,697.9	870.1	326.6 [3]	380.7	(55.8)	7,219.5
Capital expenditures	533.0	50.5	47.4	0.2	8.7	639.8

(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 2011 were at a pretax rate of 6.25%, for July through December 2010 were at a pretax rate of 6.50% and for January 2009 through June 2010 were at a pretax rate of 7.15%. 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 2009 are exclusive of entities deconsolidated as a result of the accounting guidance for VIEs. For the San José and Alborada power stations,* total revenues, operating expenses and project level income attributable to TECO Guatemala based on ownership percentages, were $97.3 million, $58.1 million and $31.8 million, respectively, for the twelve months ended Dec. 31, 2009. These entities were consolidated as of Jan. 1, 2010 as a result of accounting guidance effective on that date.

(3) The carrying value of mineral rights as of Dec. 31, 2011, 2010 and 2009 was $15.0 million, $15.8 million and $16.6 million, respectively.

Tampa Electric provides retail electric utility services to more than 678,000 customers in West Central Florida. PGS is engaged in the purchase and distribution of natural gas for approximately 340,000 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 Guatemala includes the San José and Alborada power plants and the TECO Guatemala parent company.

15. Asset Retirement Obligations

TECO Energy accounts for asset retirement obligations (ARO) under the applicable accounting standards. An 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 AROs for reclamation and site restoration obligations principally associated with coal mining, storage and transfer facilities at TECO Coal. The majority of obligations arise from environmental remediation and restoration activities for coal-related operations.

For the years ended Dec. 31, 2011, 2010 and 2009, TECO Energy recognized $1.4 million, $1.4 million and $1.4 million of accretion expense, respectively, associated with AROs in "Depreciation and amortization" on the Consolidated Statements of Income. For the years ended Dec. 31, 2011 and 2010, $2.2 million and $1.8 million, respectively, estimated cash flow revisions at Tampa Electric resulted primarily from the cost of removal of treated wood poles.

Reconciliation of beginning and ending carrying amount of asset retirement obligations:

(millions)	*Dec. 31, 2011*	*2010*
Beginning balance	$55.7	$55.2
Additional liabilities	0.8	0.8
Liabilities settled	(3.6)	(1.5)
Accretion expense	1.4	1.4
Revisions to estimated cash flows	(2.2)	(1.8)
Other[1]	1.7	1.6
Ending balance	$53.8	$55.7

(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. 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. Dispositions

Sale of DECA II

On Oct. 21, 2010, TECO Guatemala Holdings, LLC, (TGH), a TECO Energy subsidiary, sold its 30% interest in DECA II to EPM, a multi-utility company based in Medellín, Colombia[J1], under a[J2] stock purchase agreement.

TGH received $181.5 million of the $605.0 million total purchase price for its 30% interest. In addition, TGH repatriated approximately $25.0 million of cash previously held offshore in a tax deferral structure. During the third quarter of 2010, TECO Guatemala recorded a $24.9 million income tax charge related to the unwinding of the tax deferral structure as the earnings from DECA II were no longer considered indefinitely reinvested. The sale resulted in a fourth quarter 2010 gain of approximately $36.1 million at TECO Guatemala. Also during the fourth quarter of 2010, the company recorded $9.0 million of Guatemalan and U.S. tax expenses as a result of the transaction.

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 gain of $18.3 million and total proceeds of $29.0 million.

17. Goodwill

Under the accounting guidance for goodwill, goodwill is not subject to amortization. Rather, goodwill with an indefinite life is 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.

TECO Energy reviews recorded goodwill at least annually during the fourth quarter for each reporting unit. At Dec. 31, 2011, the company had $55.4 million of goodwill on its balance sheet, which is reflected in the TECO Guatemala segment. The 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 $3.0 million gross amounts at inception, respectively). Since these reporting units 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.

The fair values for the reporting units evaluated are generally determined using discounted cash flows appropriate for the business model of each significant group of assets within each reporting unit. 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 reporting unit.

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. Cash flows through 2017 were based on detailed operating forecasts provided to management. Growth factors of 2.5% for San José and 1.0% for Alborada were applied to predict subsequent year cash flows through the expected plant closings. The growth factors were determined based on each plant's past trends, management's expectations for inflation and each plant's opportunities for growth. The cash flows were discounted to a present value using the risk free rate of return at Dec. 31, 2011, adjusted for an additional risk premium. The additional risk premium included a country risk premium, a relevered beta using each plant's debt/equity ratio, an equity risk premium, and a company specific risk premium. The resulting discount rate was 11.5% for San José and 11.1% for Alborada. Additionally, management performed sensitivity analyses on the model valuation using discount rates up to 15.0%. The resulting calculations did not alter the conclusion of the tests.

The company determined the fair value of its San José and Alborada reporting units supports the book value and related goodwill carrying amounts at Dec. 31, 2011, resulting in no impairment charge.

18. Asset Impairments

The company accounts for long-lived asset impairments in accordance with the accounting guidance for long-lived assets, 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 accounting guidance, 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, 2011, 2010 or 2009.

19. Variable Interest Entities

Effective Jan. 1, 2010, the accounting standards for consolidation of VIEs were amended. The most significant amendment was the determination of a VIE's primary beneficiary. Under the amended standard, the primary beneficiary is the enterprise that has both 1) the power to direct the activities of a VIE that most significantly impact the entity's economic performance and 2) the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

Tampa Electric Company 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 range in size from 117 MW to 370 MW of available capacity, are with similar entities and contain similar provisions. Because some of these provisions provide for the transfer or sharing of a number of risks inherent in the generation of energy, these agreements meet the definition of being VIEs. These risks include: operating and maintenance, regulatory, credit, commodity/fuel and energy market risk. Tampa Electric 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, have the power to direct the most significant activities, the obligation or right to absorb losses or benefits and hence remain the primary beneficiaries. As a result, Tampa Electric Company is not required to consolidate any of these entities. Tampa Electric Company purchased $81.2 million, $108.8 million and $105.5 million, under these PPAs for the three years ended Dec. 31, 2011, 2010 and 2009, respectively.

In one instance, Tampa Electric Company's agreement with the entity for 370 MW of capacity was entered into prior to Dec. 31, 2003, the effective date of these standards. Under these standards, 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. Under this PPA, Tampa Electric Company purchased $34.4 million, $52.8 million and $31.7 million, for the three years ended Dec. 31, 2011, 2010 and 2009, respectively.

Tampa Electric Company does not provide any material financial or other support to any of the VIEs it is involved with, nor is it under any obligation to absorb losses associated with these VIEs. In the normal course of business, Tampa Electric Company's involvement with the remaining VIEs does not affect its Consolidated Balance Sheets, Statements of Income or Cash Flows.

20. Restructuring Charges

On Jul. 30, 2009, TECO Energy, Inc. announced organizational changes and a new senior management structure as part of its response to industry changes, economic uncertainties and its commitment to maintain a lean and efficient organization. As a second step in response to these factors, on Aug. 31, 2009, the company decided on a total reduction in force of 229 jobs. The reduction in force was substantially completed by Dec. 31, 2009. In connection with this reduction in force, the company incurred total costs of $26.6 million related to severance and other benefits. For the three months ended Mar. 31, 2010, the remaining $1.5 million of these costs were recognized on the Consolidated Statements of Income under "Restructuring Charges". The company's wholly-owned subsidiary, Tampa Electric Company, incurred $23.1 million of such costs, all of which were recognized in the year ended Dec. 31, 2009. The total cash payments related to these actions were $28.4 million, including $4.9 million for the settlement of pension obligations.

Restructuring Charges Incurred

(millions)	*Termination of Benefits*	*Other Costs*	*Total*
Total costs expected to be incurred	$26.6	$0.6	$27.2
Costs incurred in 2009	(25.1)	(0.6)	(25.7)
Costs incurred in 2010	(1.5)	$0.0	(1.5)
Total costs remaining	$0.0	$0.0	$0.0

Accrued Liability for Restructuring Charges

(millions)	*Termination of Benefits*	*Other Costs*	*Total*
Beginning balance, Jul. 1, 2009	$0.0	$0.0	$0.0
Costs incurred and charged to expense	26.6	0.6	27.2
Costs paid/settled	(22.9)	(0.6)	(23.5)
Non-cash expense	(3.7)	0.0	(3.7)
Ending balance, Dec. 31, 2010	$0.0	$0.0	$0.0

Restructuring Charges by Segment

(millions)	*Tampa Electric*	*PGS*	*Other (1)*	*Total*
Total costs expected to be incurred	$ 18.4	$ 4.7	$ 4.1	$ 27.2
Costs incurred in 2009	(18.4)	(4.7)	(2.6)	(25.7)
Costs incurred in 2010	0.0	0.0	(1.5)	(1.5)
Total costs remaining	$0.0	$0.0	$0.0	$0.0

(1) Restructuring costs incurred at the parent company.

21. 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 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 accounting standards for 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 (see **Note 22**). 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.

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

The 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 Dec. 31, 2011, 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 Dec. 31, 2011 and Dec. 31, 2010:

Total Derivatives

(millions)	*Dec. 31, 2011*	*Dec. 31, 2010*
Current assets	$ 0.9	$ 2.7
Long-term assets	0.0	0.2
Total assets	$ 0.9	$ 2.9
Current liabilities	$ 58.4	$ 27.2
Long-term liabilities	8.6	2.6
Total liabilities	$ 67.0	$ 29.8

The following table presents the derivative cash flow hedges of diesel fuel contracts at Dec. 31, 2011 and 2010 to limit the exposure to changes in the market price for diesel fuel:

Diesel Fuel Derivatives

(millions)	*Dec. 31, 2011*	*Dec. 31, 2010*
Current assets	$0.9	$1.6
Long-term assets	0.0	0.2
Total assets	$0.9	$1.8
Current liabilities	$0.0	$0.0
Long-term liabilities	1.2	0.0
Total liabilities	$1.2	$0.0

The following table presents the derivative cash flow hedges of natural gas contracts at Dec. 31, 2011 and 2010 to limit the exposure to changes in market price for natural gas used to produce energy, natural gas purchased for resale to customers:

Natural Gas Derivatives [1]

(millions)	*Dec. 31, 2011*	*Dec. 31, 2010*
Current assets	$0.0	$1.1
Long-term assets	0.0	0.0
Total assets	$0.0	$1.1
Current liabilities	$58.4	$27.2
Long-term liabilities	7.4	2.6
Total liabilities	$65.8	$29.8

(1) Amounts presented above are on a gross basis, with asset and liability positions netted by counterparty in accordance with accounting standards for derivatives and hedging.

The ending balance in accumulated other comprehensive income (AOCI) related to the cash flow hedges and previously settled interest rate swaps at Dec. 31, 2011 is a net loss of $5.0 million after tax and accumulated amortization. This compares to a net loss of $4.2 million in AOCI after tax and accumulated amortization at Dec. 31, 2010.

The following table presents the fair values and locations of derivative instruments recorded on the balance sheet at Dec. 31, 2011 and 2010:

Derivatives Designated As Hedging Instruments

	Asset Derivatives		Liability Derivatives	
(millions) at Dec. 31, 2011	*Balance Sheet Location*	*Fair Value*	*Balance Sheet Location*	*Fair Value*
Commodity Contracts:				
Diesel fuel derivatives:				
Current	Derivative assets	$0.9	Derivative liabilities	$0.0
Long-term	Derivative assets	0.0	Derivative liabilities	1.2
Natural gas derivatives:				
Current	Derivative assets	0.0	Derivative liabilities	58.4
Long-term	Derivative assets	0.0	Derivative liabilities	7.4
Total derivatives designated as hedging instruments		$0.9		$67.0

	Asset Derivatives		Liability Derivatives	
(millions) at Dec. 31, 2010	*Balance Sheet Location*	*Fair Value*	*Balance Sheet Location*	*Fair Value*
Commodity Contracts:				
Diesel fuel derivatives:				
Current	Derivative assets	$1.6	Derivative liabilities	$0.0
Long-term	Derivative assets	0.2	Derivative liabilities	0.0
Natural gas derivatives:				
Current	Derivative assets	1.1	Derivative liabilities	27.2
Long-term	Derivative assets	0.0	Derivative liabilities	2.6
Total derivatives designated as hedging instruments		$2.9		$29.8

The following table presents the effect of energy related derivatives on the fuel recovery clause mechanism on the

Consolidated Balance Sheets as of Dec. 31, 2011 and 2010:

(millions) at Dec. 31, 2011	*Balance Sheet Location* [(1)]	*Fair Value*	*Balance Sheet Location* [(1)]	*Fair Value*
Commodity Contracts:				
Natural gas derivatives:				
Current	Regulatory liabilities	$0.0	Regulatory assets	$58.4
Long-term	Regulatory liabilities	0.0	Regulatory assets	7.4
Total		$0.0		$65.8

(millions) at Dec. 31, 2010	*Balance Sheet Location* [(1)]	*Fair Value*	*Balance Sheet Location* [(1)]	*Fair Value*
Commodity Contracts:				
Natural gas derivatives:				
Current	Regulatory liabilities	$1.1	Regulatory assets	$27.2
Long-term	Regulatory liabilities	0.0	Regulatory assets	2.6
Total		$1.1		$29.8

(1) Natural gas derivatives are deferred in accordance with accounting standards for regulated operations 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 Statements of Income.

Based on the fair value of the instruments at Dec. 31, 2011, net pretax losses of $58.4 million are expected to be reclassified from regulatory assets or liabilities to the Consolidated Statements of Income within the next twelve months.

The following table presents the effect of hedging instruments on OCI and income for the years ended Dec. 31:

(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 Cash Flow Hedging Relationships	Effective Portion[(1)]	Effective Portion[(1)]	
2011			
Interest rate contracts:	$0.0	Interest expense	($0.7)
Commodity contracts:			
Diesel fuel derivatives	1.2	Mining related costs	2.7
Total	$1.2		$2.0
2010			
Interest rate contracts:	$0.0	Interest expense	($1.7)
Commodity contracts:			
Diesel fuel derivatives	0.6	Mining related costs	(0.8)
Total	$0.6		($2.5)
2009			
Interest rate contracts:	($0.3)	Interest expense	($2.0)
Commodity contracts:			
Diesel fuel derivatives	2.8	Mining related costs	(13.3)
Total	$2.5		($15.3)

(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 years ended Dec. 31, 2011, 2010 and 2009, all hedges were effective.

The following table presents the derivative activity for instruments classified as qualifying cash flow hedges for the years ended Dec. 31:

(millions)	Fair Value Asset/(Liability)	Amount of Gain/(Loss) Recognized in OCI[1]	Amount of Gain/(Loss) Reclassified From AOCI Into Income [1]
2011			
Interest rate swaps	$0.0	$0.0	($0.7)
Diesel fuel derivatives	(0.3)	1.2	2.7
Total	($0.3)	$1.2	$2.0
2010			
Interest rate swaps	$0.0	$0.0	($1.7)
Diesel fuel derivatives	1.8	0.6	(0.8)
Total	$1.8	$0.6	($2.5)
2009			
Interest rate swaps	$0.0	($0.3)	($2.0)
Diesel fuel derivatives	(0.7)	2.8	(13.3)
Total	($0.7)	$2.5	($15.3)

(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, 2014 for both financial natural gas and financial diesel fuel contracts. The following table presents by commodity type the company's derivative volumes, as of Dec. 31, 2011, that are expected to settle during the 2012, 2013 and 2014 fiscal years:

(millions)	Diesel Fuel Contracts (Gallons)		Natural Gas Contracts (MMBtus)	
Year	Physical	Financial	Physical	Financial
2012	0.0	2.7	0.0	39.5
2013	0.0	1.8	0.0	7.2
2014	0.0	1.0	0.0	0.0
Total	0.0	5.5	0.0	46.7

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 Dec. 31, 2011, substantially all of the counterparties with transaction amounts outstanding in the company's energy portfolio were rated investment grade by the major 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 Dec. 31, 2011, substantially all positions with counterparties were 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 Dec. 31, 2011:

Contingent Features

(millions)	Fair Value Asset/ (Liability)	Derivative Exposure Asset/ (Liability)	Posted Collateral
Credit Rating	($67.0)	($67.0)	$0.0

22. Fair Value Measurements

Items Measured at Fair Value on a Recurring Basis

The following tables set 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, 2011 and 2010. As required by accounting standards for fair value measurements, 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 diesel fuel swaps, the market approach was used in determining fair value.

Recurring Fair Value Measures

	At fair value as of Dec. 31, 2011			
(millions)	*Level 1*	*Level 2*	*Level 3*	*Total*
Assets				
Natural gas swaps	$0.0	$0.0	$0.0	$0.0
Diesel fuel swaps	0.0	0.9	0.0	0.9
Total	$0.0	$0.9	$0.0	$0.9
Liabilities				
Natural gas swaps	$0.0	$65.8	$0.0	$65.8
Diesel fuel swaps	0.0	1.2	0.0	1.2
Total	$0.0	$67.0	$0.0	$67.0

	At fair value as of Dec. 31, 2010			
(millions)	*Level 1*	*Level 2*	*Level 3*	*Total*
Assets				
Natural gas swaps	$0.0	$1.1	$0.0	$1.1
Diesel fuel swaps	0.0	1.8	0.0	1.8
Total	$0.0	$2.9	$0.0	$2.9
Liabilities				
Natural gas swaps	$0.0	$29.8	$0.0	$29.8
Diesel fuel swaps	0.0	0.0	0.0	0.0
Total	$0.0	$29.8	$0.0	$29.8

Natural gas and diesel fuel 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 (see **Note 21**).

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, the intent of the parties, indications of credit deterioration and whether the markets in which the company transacts have experienced dislocation. At Dec. 31, 2011, the fair value of derivatives was not materially affected by nonperformance risk. The company's net positions with substantially all counterparties were liability positions. There were no Level 3 assets or liabilities during the 2011 or 2010 fiscal years.

23. 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).

24. 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*
2011				
Revenues	$ 750.2	$ 911.4	$ 885.7	$ 796.1
Income from operations	$ 130.3	$ 189.4	$ 171.1	$ 130.9
Net income	$ 53.2	$ 90.2	$ 77.5	$ 51.7
Earnings per share (EPS) — basic	$ 0.25	$ 0.42	$ 0.36	$ 0.24
Earnings per share (EPS) — diluted	$ 0.25	$ 0.42	$ 0.36	$ 0.24
Dividends paid per common share	$ 0.215	$ 0.215	$ 0.215	$ 0.205

Quarter ended	*Dec. 31*	*Sep. 30*	*Jun. 30*	*Mar. 31*
2010				
Revenues	$ 775.0	$ 901.8	$ 898.8	$ 912.3
Income from operations	$ 128.3	$ 159.7	$ 169.9	$ 168.9
Net income	$ 56.7	$ 51.0	$ 75.5	$ 55.8
Earnings per share (EPS) — basic	$ 0.27	$ 0.24	$ 0.35	$ 0.26
Earnings per share (EPS) — diluted	$ 0.26	$ 0.24	$ 0.35	$ 0.26
Dividends paid per common share	$ 0.205	$ 0.205	$ 0.205	$ 0.20

25. Subsequent Events

Tampa Electric Company Accounts Receivable Facility

On Feb. 17, 2012, Tampa Electric Company and TEC Receivables Corporation (TRC), a wholly-owned subsidiary of Tampa Electric Company, amended their $150 million accounts receivable collateralized borrowing facility, entering into Amendment No. 10 to the Loan and Servicing Agreement with certain lenders named therein and Citibank, N.A. as Program Agent. The amendment (i) extends the maturity date to Feb. 15, 2013, (ii) provides that TRC will pay program and liquidity fees, which will total 60 basis points, (iii) continues to provide 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, 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 offered rate (if available) plus a margin and (iv) makes other technical changes.

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 (the Company) at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 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 the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the 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.

/s/ PricewaterhouseCoopers LLP

Tampa, Florida

February 24, 2012

TAMPA ELECTRIC COMPANY
Consolidated Balance Sheets

Assets (millions)	*Dec. 31, 2011*	*Dec. 31, 2010*
Property, plant and equipment		
Utility plant in service		
Electric	$ 6,516.0	$ 6,343.4
Gas	1,113.5	1,060.6
Construction work in progress	239.2	206.8
Property, plant and equipment, at original costs	7,868.7	7,610.8
Accumulated depreciation	(2,230.3)	(2,093.9)
	5,638.4	5,516.9
Other property	6.5	4.7
Total property, plant and equipment (net)	5,644.9	5,521.6
Current assets		
Cash and cash equivalents	13.9	3.7
Receivables, less allowance for uncollectibles of $1.3 and $3.2 at Dec. 31, 2011 and 2010, respectively	216.8	264.6
Inventories, at average cost		
Fuel	97.9	119.0
Materials and supplies	67.7	59.1
Current regulatory assets	87.3	62.7
Current derivative assets	0.0	1.1
Taxes receivable	14.6	24.6
Deferred tax assets	30.4	37.7
Prepayments and other current assets	10.5	10.0
Total current assets	539.1	582.5
Deferred debits		
Unamortized debt expense	14.1	17.8
Long-term regulatory assets	364.5	341.9
Other	8.8	10.9
Total deferred debits	387.4	370.6
Total assets	$ 6,571.4	$ 6,474.7

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, 2011*	*Dec. 31, 2010*
Capital		
Common stock	$ 1,852.4	$ 1,852.4
Accumulated other comprehensive loss	(4.6)	(5.3)
Retained earnings	305.7	311.1
Total capital	2,153.5	2,158.2
Long-term debt, less amount due within one year	1,616.3	2,066.1
Total capitalization	3,769.8	4,224.3
Current liabilities		
Long-term debt due within one year	374.9	3.4
Notes payable	0.0	12.0
Accounts payable	191.3	219.0
Customer deposits	159.5	156.5
Current regulatory liabilities	86.2	110.0
Current derivative liabilities	58.4	27.2
Interest accrued	25.6	24.6
Taxes accrued	11.9	14.0
Other	11.6	12.2
Total current liabilities	919.4	578.9
Deferred credits		
Non-current deferred income taxes	833.0	667.7
Investment tax credits	10.0	10.4
Long-term derivative liabilities	7.4	2.6
Long-term regulatory liabilities	647.8	630.8
Other	384.0	360.0
Total deferred credits	1,882.2	1,671.5
Total liabilities and capital	$ 6,571.4	$ 6,474.7

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,*	*2011*	*2010*	*2009*
Revenues			
Electric (includes franchise fees and gross receipts taxes of $85.6 in 2011, $89.8 in 2010 and $92.2 in 2009)	$ 2,020.1	$ 2,162.8	$ 2,194.3
Gas (includes franchise fees and gross receipts taxes of $23.7 in 2011, $26.3 in 2010 and $23.5 in 2009)	450.5	510.8	455.6
Total revenues	2,470.6	2,673.6	2,649.9
Expenses			
Operations			
Fuel	731.4	748.9	909.9
Purchased power	125.9	179.6	177.6
Cost of natural gas sold	210.4	284.5	242.7
Other	322.3	369.6	318.3
Maintenance	114.1	122.8	128.9
Depreciation and amortization	270.5	261.9	244.6
Restructuring	0.0	0.0	23.1
Taxes, federal and state	144.5	143.1	110.9
Taxes, other than income	179.7	183.9	179.7
Total expenses	2,098.8	2,294.3	2,335.7
Income from operations	371.8	379.3	314.2
Other income			
Allowance for other funds used during construction	1.0	1.9	9.3
Taxes, non-utility federal and state	(0.9)	(0.6)	(0.8)
Other income, net	2.9	3.3	4.3
Total other income	3.0	4.6	12.8
Interest charges			
Interest on long-term debt	128.6	130.9	128.2
Other interest	11.5	11.2	11.2
Allowance for borrowed funds used during construction	(0.6)	(1.1)	(4.5)
Total interest charges	139.5	141.0	134.9
Net income	235.3	242.9	192.1
Other comprehensive income, net of tax			
Net unrealized gains on cash flow hedges	0.7	0.8	0.7
Other comprehensive income, net of tax	0.7	0.8	0.7
Comprehensive income	$ 236.0	$ 243.7	$ 192.8

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,*	*2011*	*2010*	*2009*
Cash flows from operating activities			
Net income	$ 235.3	$ 242.9	$ 192.1
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	270.5	261.9	244.6
Deferred income taxes	173.6	70.4	73.2
Investment tax credits, net	(0.4)	(0.4)	(0.4)
Allowance for other funds used during construction	(1.0)	(1.9)	(9.3)
Gain on sale of business/assets, pretax	(0.3)	(0.3)	(0.6)
Deferred recovery clause	(9.0)	55.0	136.6
Receivables, less allowance for uncollectibles	47.8	(36.0)	7.5
Inventories	12.6	(36.5)	(3.0)
Prepayments	(0.5)	2.0	2.1
Taxes accrued	7.9	(5.8)	(24.6)
Interest accrued	1.0	(3.1)	0.6
Accounts payable	(42.2)	36.6	(41.8)
Other	29.4	(31.9)	54.0
Cash flows from operating activities	724.7	552.9	631.0
Cash flows from investing activities			
Capital expenditures	(386.8)	(393.6)	(583.5)
Allowance for other funds used during construction	1.0	1.9	9.3
Net proceeds from sale of assets	2.8	0.0	2.2
Cash flows used in investing activities	(383.0)	(391.7)	(572.0)
Cash flows from financing activities			
Common stock	0.0	50.0	0.0
Proceeds from long-term debt	0.0	73.0	102.0
Repayment of long-term debt/Purchase in-lieu-of redemption	(78.8)	(3.7)	(5.5)
Net (decrease) increase in short-term debt	(12.0)	(43.0)	26.0
Dividends	(240.7)	(239.3)	(179.6)
Cash flows used in financing activities	(331.5)	(163.0)	(57.1)
Net increase (decrease) in cash and cash equivalents	10.2	(1.8)	1.9
Cash and cash equivalents at beginning of period	3.7	5.5	3.6
Cash and cash equivalents at end of period	$ 13.9	$ 3.7	$ 5.5

Supplemental disclosure of cash flow information			
Cash paid (received) during the year for:			
Interest	$ 129.0	$ 135.6	$ 127.7
Income taxes	$ (31.1)	$ 81.6	$ 62.3

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,*	*2011*	*2010*	*2009*
Balance, beginning of year	$ 311.1	$ 307.5	$ 295.0
Add: Net income	235.3	242.9	192.1
	546.4	550.4	487.1
Deduct:			
Cash dividends on capital stock			
Common	240.7	239.3	179.6
Balance, end of year	$ 305.7	$ 311.1	$ 307.5

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

TAMPA ELECTRIC COMPANY
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					
2011	N/A	10	$ 1,852.4	[(2)]	$ 240.7
2010	N/A	10	$ 1,852.4	[(2)]	$ 239.3
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 27, Aug. 26 and Nov. 28 during 2011.
Quarterly dividends paid on Feb. 26, May 28, Aug. 27 and Nov. 26 during 2010.

(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*	*2011*	*2010*
Tampa Electric	Installment contracts payable[1] :			
	5.10% Refunding bonds (effective rate of 5.6%)	2013	$60.7	$60.7
	5.65% Refunding bonds (effective rate of 5.9%)	2018	54.2	54.2
	Variable rate bonds repurchased in 2008 [2]	2020	0.0	0.0
	5.50% Refunding bonds (effective rate of 6.2%)	2023	86.4	86.4
	5.15% Refunding bonds (effective rate of 5.4%) [3]	2025	51.6	51.6
	1.50% term rate bonds repurchased in 2011 [4]	2030	0.0	75.0
	5.00% Refunding bonds (effective rate of 5.8%) [5]	2034	86.0	86.0
	Notes[6]: 6.875% (effective rate of 7.1%)	2012	99.6	99.6
	6.375% (effective rate of 7.9%)	2012	208.7	208.7
	6.25% (effective rate of 6.3%) [7]	2014-2016	250.0	250.0
	6.10% (effective rate of 6.4%)	2018	200.0	200.0
	5.40% (effective rate of 5.9%)	2021	231.7	231.7
	6.55% (effective rate of 6.6%)	2036	250.0	250.0
	6.15% (effective rate of 6.2%)	2037	190.0	190.0
Total long-term debt of Tampa Electric			1,768.9	1,843.9
PGS	Senior Notes[6][7]: 8.00%	2012	3.4	6.8
	Notes[6]: 6.875% (effective rate of 7.1%)	2012	19.0	19.0
	6.375% (effective rate of 7.9%)	2012	44.3	44.3
	6.10% (effective rate of 7.0%)	2018	50.0	50.0
	5.40% (effective rate of 5.8%)	2021	46.7	46.7
	6.15% (effective rate of 6.2%)	2037	60.0	60.0
Total long-term debt of PGS			223.4	226.8
			1,992.3	2,070.7
Unamortized debt discount, net			(1.1)	(1.2)
			1,991.2	2,069.5
Less amount due within one year			374.9	3.4
Total long-term debt			$1,616.3	$2,066.1

(1) Tax-exempt securities.
(2) In March 2008 these bonds, which were in auction rate mode, were purchased in lieu of redemption by Tampa Electric Company. These held variable rate bonds have a par amount of $20.0 million due in 2020.
(3) These bonds were converted in March 2008 from an auction rate mode to a fixed rate mode for the term ending Sep. 1, 2013.
(4) In March 2011 these bonds, which were in term rate mode, were purchased in lieu of redemption by Tampa Electric Company. These held term rate bonds have a par amount of $75.0 million due in 2030.
(5) These bonds were converted in March 2008 from an auction rate mode to a fixed rate mode for the term ending Mar. 15, 2012.
(6) These securities are subject to redemption in whole or in part, at any time, at the option of the company.
(7) These long-term debt agreements contain various restrictive financial covenants.

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

TAMPA ELECTRIC COMPANY
Consolidated Statements of Capitalization -continued

At Dec. 31, 2011, total long-term debt had a carrying amount of $1,992.3 million and an estimated fair market value of $2,291.5 million. At Dec. 31, 2010, total long-term debt had a carrying amount of $2,070.7 million and an estimated fair market value of $2,218.1 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 14**).

A substantial part of Tampa Electric's tangible assets are pledged as collateral to secure its first mortgage bonds. 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 2012 through 2016 and thereafter are as follows:

Long-Term Debt Maturities

As of Dec. 31, (millions)	*2012*	*2013*	*2014*	*2015*	*2016*	*Thereafter*	*Total Long-term debt*
Tampa Electric	$308.3	$60.7	$83.3	$83.3	$83.3	$1,150.0	$1,768.9
PGS	66.6	0.0	0.0	0.0	0.0	156.8	223.4
Total long-term debt maturities	$374.9	$60.7	$83.3	$83.3	$83.3	$1,306.8	$1,992.3

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 FPSC and the FERC. These policies conform with GAAP in all material respects.

The impact of the accounting guidance for the effects of certain types of regulation 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 this guidance.

Tampa Electric 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, 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 GAAP. Actual results could differ from these estimates.

For entities that are determined to meet the definition of a 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 15**).

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 Company 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, 2011, 2010 and 2009 was $263.7 million, $255.4 million and $239.5 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% for 2011, 2010 and 2009. Construction work in progress is not depreciated until the asset is completed or placed in service.

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, the cash inflows and outflows are included in the operating section of the Consolidated Statements of Cash Flows.

Allowance for Funds Used During Construction

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. The rate used to calculate AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. The rate was 8.16% for May 2009 through December 2011 and 7.79% for January 2009 through April 2009. Total AFUDC for 2011, 2010 and 2009 was $1.6 million, $3.0 million and $13.8 million, respectively.

Deferred Income Taxes

Tampa Electric Company utilizes the asset and liability method in the measurement of deferred income taxes. Under the asset and 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 accounting standards for revenue recognition. 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 the FERC. See **Note 3** for a discussion of significant regulatory matters and the applicability of the accounting for the effects of certain types of regulation 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, 2011 and 2010, unbilled revenues of $50.2 million and $65.5 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 $125.9 million, $179.6 million and $177.6 million, for the years ended Dec. 31, 2011, 2010 and 2009, 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 on a dollar-for-dollar basis 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. 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". These amounts totaled $109.3 million, $116.1 million and $115.7 million, for the years ended Dec. 31, 2011, 2010 and 2009, respectively. Excise taxes paid by the regulated utilities are not material and are expensed as incurred.

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 9** 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 uncollectible 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.

Reclassifications

Certain reclassifications were made to prior year amounts to conform to current period presentation. None of the reclassifications affected our net income in any period.

2. New Accounting Pronouncements

Offsetting Assets and Liabilities

In December 2011, the FASB issued guidance enhancing disclosures of financial instruments and derivative instruments that are offset in the statement of financial position or subject to enforceable master netting agreements. The guidance is effective for interim and annual reporting periods beginning on or after Jan. 1, 2013. The company will adopt this guidance as required. It will have no effect on the company's results of operations, financial position or cash flows.

Presentation of Comprehensive Income

In June 2011, the FASB issued guidance requiring companies to present the total of comprehensive income, the components of net income and the components of other comprehensive income, in a single continuous statement of comprehensive income or in two separate but consecutive statements. The guidance is effective for interim and annual periods beginning after Dec. 15, 2011. The company will adopt this guidance as required. It will have no effect on the company's results of operations, financial position or cash flows.

Additionally, in December 2011, the FASB issued guidance that indefinitely delayed the effective date of the requirement to present the reclassification adjustment out of AOCI. The guidance is effective for interim and annual periods beginning after Dec. 15, 2011. The company will adopt this guidance as required. It will have no effect on the company's results of operations, financial position or cash flows.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards

In May 2011, the FASB issued guidance to more closely align its fair value measurement and disclosure requirements with IFRS. The guidance relates to: measuring the fair value of financial instruments that are managed in a portfolio; the application of premiums and discounts in fair value measurement; and disclosures for items required to be disclosed, but not reported on the statement of financial position, at fair value and Level 3 measures. The guidance is effective for interim and annual periods beginning after Dec. 15, 2011. The company will adopt the guidance as required. It will have no effect on the company's results of operations, financial position or cash flows.

3. Regulatory

Tampa Electric's and PGS's retail businesses are regulated by the FPSC. Tampa Electric also is subject to regulation by the FERC under the PUHCA 2005. However, pursuant to a waiver granted in accordance with the FERC's regulations, Tampa Electric Company is not subject to certain accounting, record-keeping and reporting requirements prescribed by the FERC's regulations under PUHCA 2005. 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 utilities such as Tampa Electric and PGS to collect total revenues (revenue requirements) equal to their cost of providing service, plus a reasonable return on invested capital.

Stipulation with Intervenors – Tampa Electric

The FPSC, in connection with Tampa Electric's 2008 base rate request, approved a $25.7 million increase in base rates effective Jan. 1, 2010 (step increase), subject to refund, for certain capital additions placed in service in 2009.

In connection with the base rate request, the FPSC had rejected the intervenors' arguments that the approved 2010 increase violated the intervenors' due process rights, Florida Statutes or FPSC rules. The intervenors filed an appeal with the Florida Supreme Court in September 2009, which Tampa Electric opposed.

In July 2010, Tampa Electric entered into a stipulation with the intervenors to resolve all issues related to the 2008 base rate case, including the 2010 step increase, as well as the intervenors' appeal to the Florida Supreme Court. Under the terms of the stipulation, the $25.7 million step increase would remain in effect for 2010, and Tampa Electric would make a one-time reduction of $24.0 million to customers' bills in 2010.

In August 2010, the FPSC voted to approve the July stipulation, which was contained in their Docket No. 090368-EI "Review of the continuing need and cost associated with Tampa Electric Company's 5 Combustion Turbines and Big Bend Rail Facility". This stipulation resolved all issues in the above docket and all issues in the intervenors' appeal of the FPSC's 2009 decision in Tampa Electric's base rate proceeding pending before the Florida Supreme Court. The docket related to the base rate proceeding is now closed. The one-time reduction of $24.0 million to customers' bills in 2010 was reflected in the operating results as a reduction in revenue.

Effective Jan. 1, 2011, and for subsequent years, rates of $24.4 million (a $1.3 million reduction from the $25.7 million in effect for 2010) related to the step increase were in effect.

Wholesale and Transmission Rate Cases

In July 2010, Tampa Electric filed wholesale requirements and transmission rate cases with the FERC. Tampa Electric's last wholesale requirements rate case was in 1991 and the associated service agreements were approved by the FERC in the mid-1990s. The FERC approved Tampa Electric's proposed transmission rates as filed, which became effective Sep. 14, 2010, subject to refund. The FERC also approved Tampa Electric's proposed wholesale requirements rates as filed, which became effective Mar. 1, 2011, subject to refund. The proposed wholesale requirements and transmission rates did not have a material impact on Tampa Electric's results.

Storm Damage Cost Recovery

Tampa Electric accrues $8.0 million annually to a FERC-authorized and FPSC-approved self-insured storm damage reserve. This reserve was created after Florida's IOUs were unable to obtain transmission and distribution insurance coverage due to destructive acts of nature. Tampa Electric's storm reserve was $43.6 million and $37.4 million as of Dec. 31, 2011 and 2010, respectively.

Stipulation with the Office of Public Counsel - PGS

On Jun. 9, 2010, PGS filed a letter with the FPSC agreeing to cap its earned ROE for the year ending Dec. 31, 2010 at 11.75%, the maximum of the ROE range established in its last base rate proceeding.

On Dec. 16, 2010, PGS and the Office of Public Counsel filed a joint motion for FPSC approval of a proposed stipulation resolving all issues relating to any 2010 overearnings of PGS.

On Jan. 25, 2011, the FPSC approved the stipulation for PGS to provide a one-time credit to customer bills totaling $3.0 million for 2010 earnings above 11.75%, excluding the portion of the company's share of net revenues derived from off-system sales, and credit the remaining balance to its accumulated depreciation reserves. This one-time credit was applied to customer bills in April 2011 and the $6.2 million remaining balance was credited to the accumulated depreciation reserves in June 2011.

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 standards for regulated operations. Areas of applicability include: the 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, 2011 and 2010 are presented in the following table:

Regulatory Assets and Liabilities

(millions)		*Dec. 31, 2011*		*Dec. 31, 2010*
Regulatory assets:				
Regulatory tax asset[1]	$	63.6	$	66.6
Other:				
Cost-recovery clauses		73.3		41.9
Postretirement benefit asset		252.4		237.5
Deferred bond refinancing costs[2]		11.1		15.4
Environmental remediation		30.5		23.6
Competitive rate adjustment		3.5		3.3
Other		17.4		16.3
Total other regulatory assets		388.2		338.0
Total regulatory assets		451.8		404.6
Less: Current portion		87.3		62.7
Long-term regulatory assets	$	364.5	$	341.9
Regulatory liabilities:				
Regulatory tax liability[1]	$	16.0	$	17.7
Other:				
Cost-recovery clauses		61.4		76.2
Environmental remediation		28.4		21.2
Transmission and delivery storm reserve		43.6		37.4
Deferred gain on property sales[3]		5.0		6.3
Provision for stipulation and other[4]		0.8		9.8
Accumulated reserve-cost of removal		578.8		572.2
Total other regulatory liabilities		718.0		723.1
Total regulatory liabilities		734.0		740.8
Less: Current portion		86.2		110.0
Long-term regulatory liabilities	$	647.8	$	630.8

(1) Primarily related to plant life and derivative positions.
(2) Amortized over the term of the related debt instruments.
(3) Amortized over a 4- or 5-year period with various ending dates.
(4) Includes a provision to reflect the FPSC-approved PGS stipulation regarding PGS's 2010 earnings above 11.75%. A one-time credit to customer bills totaling $3.0 million was applied in April 2011 and the $6.2 million remaining balance of the 2010 earnings above 11.75% was credited to accumulated depreciation reserves in June 2011.

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)		*Dec. 31, 2011*		*Dec. 31, 2010*
Clause recoverable [1]	$	76.8	$	45.2
Components of rate base [2]		264.9		248.1
Regulatory tax assets [3]		63.6		66.6
Capital structure and other [3]		46.5		44.7
Total	$	451.8	$	404.6

(1) To be recovered through cost-recovery clauses approved by the FPSC on a dollar-for-dollar basis in the next year.
(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 debt 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. For the three years presented, Tampa Electric Company's effective tax rate differs from the statutory rate principally due to state income taxes, domestic production deduction and AFUDC equity benefit. The increase in the 2011 effective tax rate compared to 2010 is principally due to decreased AFUDC equity benefit and decreased domestic production deduction.

Income tax expense consists of the following components:

Income Tax Expense (Benefit)

(millions) *For the year ending Dec. 31,*	2011	2010	2009
Current income taxes			
Federal	$ (30.7)	$ 60.1	$ 24.4
State	2.9	13.6	14.5
Deferred income taxes			
Federal	155.6	63.0	71.7
State	18.0	7.4	1.5
Amortization of investment tax credits	(0.4)	(0.4)	(0.4)
Total income tax expense	145.4	143.7	111.7
Included in other income, net	(0.9)	(0.6)	(0.8)
Included in operating expenses	$ 144.5	$ 143.1	$ 110.9

The total income tax provisions differ from amounts computed by applying the federal statutory tax rate to income before income taxes as follows:

Effective Income Tax Rate

(millions) *For the years ended Dec. 31,*	2011	2010	2009
Income tax expense at the federal statutory rate of 35%	$ 133.2	$ 135.3	$ 106.3
Increase (decrease) due to			
State income tax, net of federal income tax	13.6	13.6	10.3
Equity portion of AFUDC	(0.4)	(0.7)	(3.2)
Domestic production deduction	(1.5)	(3.2)	0.0
Other	0.5	(1.3)	(1.7)
Total income tax expense on consolidated statements of income	$ 145.4	$ 143.7	$ 111.7
Income tax expense as a percent of income from continuing operations, before income taxes	38.2%	37.2%	36.8%

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 Taxes

(millions) As of Dec. 31,	*2011*	*2010*
Deferred tax liabilities [1]		
Property related	$ 879.1	$ 711.8
Deferred fuel	3.9	5.5
Pension and postretirement benefits	99.0	93.2
Pension	31.7	27.2
Other	14.3	8.7
Total deferred tax liabilities	1,028.0	846.4
Deferred tax assets [1]		
Medical benefits	50.0	48.1
Insurance reserves	28.2	25.7
Investment tax credits	5.7	5.9
Hedging activities	2.9	3.4
Pension and postretirement benefits	99.0	93.2
Unbilled revenue	19.6	17.2
Capitalized energy conservation assistance costs	20.0	22.9
Total deferred tax assets	225.4	216.4
Total deferred tax liability, net	802.6	630.0
Less: Current portion of deferred tax liability/(asset)	(30.4)	(37.7)
Long-term portion of deferred tax liability, net	$ 833.0	$ 667.7

(1) Certain property related assets and liabilities have been netted.

Tampa Electric Company accounts for uncertain tax positions as required by FASB accounting guidance. This guidance 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 the guidance, 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. 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 50% likelihood of being realized upon ultimate settlement. The guidance also provides standards on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures.

As of Dec. 31 2011 and 2010, Tampa Electric Company did not have a liability for unrecognized tax benefits. Based on current information, Tampa Electric Company does not anticipate that this will change materially in 2012. As of Dec. 31, 2011, Tampa Electric Company does not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

Unrecognized Tax Benefits

(millions)	*2011*	*2010*
Balance at Jan. 1,	$0.0	$0.7
Decreases due to tax positions related to prior years	0.0	(0.2)
Decreases due to settlements with taxing authorities	0.0	(0.5)
Balance at Dec. 31,	$0.0	$0.0

The IRS concluded its examination of federal income tax returns for the year 2010 during 2011. The U.S. federal statute of limitations remains open for the year 2008 and onward. The federal income tax return for calendar year 2011 is part of the IRS's Compliance Assurance Program. As a result, the IRS audit of such return is expected to be completed in 2012. Florida's statute of limitations is three 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 Florida's tax authorities include 2008 and onward. Tampa Electric Company does not expect the settlement of audit examinations to significantly change the total amount of unrecognized tax benefits within the next 12 months.

5. Employee Postretirement Benefits

Tampa Electric Company recognizes in its statement of financial position the over-funded or under-funded status of its postretirement benefit plans. This status is measured as the difference between the fair value of plan assets and the projected benefit obligation (PBO) in the case of its defined benefit plan, or the accumulated postretirement benefit obligation (APBO) in the case of its other postretirement benefit plan. As a result of the application of the accounting guidance for certain types of regulation, changes in the funded status are reflected in benefit liabilities and regulatory assets. The results of operations are not impacted.

Pension Benefits

Tampa Electric Company is a participant in the comprehensive retirement plans of TECO Energy, including a non-contributory defined benefit retirement plan that covers substantially all employees. Benefits are based on the employees' age, years of service and final average earnings. 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.

The Pension Protection Act of 2006 (Pension Protection Act) 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 benefits restrictions, and also provides some technical corrections to the Pension Protection Act. 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%. 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, 2011 estimate reflected the adoption of the asset smoothing methodology under WRERA.

The qualified pension plan's actuarial value of assets, including credit balance, was 90% of the Pension Protection Act funded target as of Jan. 1, 2011 and is estimated at 85% of the Pension Protection Act funded target as of Jan. 1, 2012.

Amounts disclosed for pension benefits also include the unfunded obligations for the supplemental executive retirement plan (SERP). This is a non-qualified, non-contributory defined benefit retirement plan available to certain members of senior management.

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. 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 postretirement health care and life insurance plans. 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.

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (MMA) 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.

The FASB issued accounting guidance and disclosure requirements related to the MMA. The guidance 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.

In March 2010, the Patient Protection and Affordability Care Act and a companion bill, the Health Care and Education Reconciliation Act, collectively referred to as the Health Care Reform Acts, were signed into law. Among other things, both acts reduce the tax benefits available to an employer that receives the Medicare Part D subsidy, resulting in a write-off of any associated deferred tax asset. As a result, Tampa Electric Company reduced its deferred tax asset by $5.3 million and recorded a regulatory tax asset of $5.3 million in 2010.

Additionally, the Health Care Reform Acts contain other provisions that may impact TECO Energy's obligation for retiree medical benefits. In particular, the Health Care Reform Acts include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. TECO Energy does not currently believe the excise tax or other provisions of the Health Care Reform Acts will materially increase its postretirement benefit obligation. TECO Energy will continue to monitor and assess the impact of the Health Care Reform

Acts, including any clarifying regulations issued to address how the provisions are to be implemented, on its future results of operations, cash flows or financial position.

During 2011, TECO Energy, Inc. received subsidy payments under Medicare Part D for the fourth quarter of the 2010 plan year, along with payments for the first three quarters of the 2011 plan year. TECO Energy, Inc. received the fourth quarter 2011 plan year payment in February 2012.

Obligations and Funded Status *(millions)*	**Pension Benefits** *2011*	*2010*	**Other Benefits** *2011*	*2010*
Change in benefit obligation				
Net benefit obligation at prior measurement date (1)	$610.3	$587.7	$222.0	$207.6
Service cost	16.0	16.2	2.1	3.2
Interest cost	30.9	33.2	11.0	10.9
Plan participants' contributions	0.0	0.0	3.9	3.6
Actuarial loss (gain)	26.8	12.3	(7.4)	11.7
Gross benefits paid	(35.2)	(34.2)	(16.2)	(16.7)
Settlements	(2.4)	(4.9)	0.0	0.0
Federal subsidy on benefits paid	n/a	n/a	1.1	1.7
Net benefit obligation at measurement date (1)	$646.4	$610.3	$216.5	$222.0
Change in plan assets				
Fair value of plan assets at prior measurement date (1)	$479.7	$388.9	$0.0	$0.0
Actual return on plan assets (2)	21.8	42.3	0.0	0.0
Employer contributions	3.7	87.6	11.2	11.5
Plan participants' contributions	0.0	0.0	3.9	3.6
Settlements	(2.4)	(4.9)	0.0	0.0
Gross benefits paid	(35.2)	(34.2)	(15.1)	(15.1)
Fair value of plan assets at measurement date (1)	$467.6	$479.7	$0.0	$0.0
Funded status				
Fair value of plan assets (3)	$467.6	$479.7	$0.0	$0.0
Benefit obligation (PBO/APBO)	646.4	610.3	216.5	222.0
Funded status at measurement date (1)	(178.8)	(130.6)	(216.5)	(222.0)
Unrecognized net actuarial loss	251.7	220.8	25.5	31.9
Unrecognized prior service (benefit) cost	(1.2)	(1.7)	4.9	5.7
Unrecognized net transition obligation	0.0	0.0	1.9	4.2
Accrued liability at end of year	$71.7	$88.5	($184.2)	($180.2)
Amounts recognized in balance sheet				
Regulatory assets	$199.7	$176.3	$52.7	$61.2
Accrued benefit costs and other current liabilities	(2.9)	(4.4)	(13.2)	(13.8)
Deferred credits and other liabilities	(175.9)	(126.2)	(203.3)	(208.2)
Accumulated other comprehensive loss (income) (pretax)	50.8	42.8	(20.4)	(19.4)
Net amount recognized at end of year	$71.7	$88.5	($184.2)	($180.2)

(1) The measurement dates were Dec. 31, 2011 and Dec. 31, 2010.

(2) The actual return on plan assets differed from expectations due to general market conditions.

(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 **Amounts recognized in balance sheet** *(millions)*	Pension Benefits *2011*	Pension Benefits *2010*	Other Benefits *2011*	Other Benefits *2010*
Regulatory assets	$ 199.7	$ 176.3	$ 52.7	$ 61.2
Accrued benefit costs and other current liabilities	(1.0)	(0.1)	(10.6)	(11.2)
Deferred credits and other liabilities	(133.2)	(97.4)	(163.6)	(167.8)
	$ 65.5	$ 78.8	$ (121.5)	$ (117.8)

The accumulated benefit obligation for TECO Energy Consolidated defined benefit pension plans was $596.2 million at Dec. 31, 2011 and $558.4 million at Dec. 31, 2010.

Assumptions used to determine benefit obligations at Dec. 31, 2011 and 2010:

	Pension Benefits 2011	Pension Benefits 2010	Other Benefits 2011	Other Benefits 2010
Discount rate	4.80%	5.30%	4.74%	5.25%
Rate of compensation increase-weighted average	3.83%	3.88%	3.82%	3.87%
Healthcare cost trend rate				
Immediate rate	n/a	n/a	7.75%	8.00%
Ultimate rate	n/a	n/a	4.50%	4.50%
Year rate reaches ultimate	n/a	n/a	2025	2023

A one-percentage-point change in assumed health care cost trend rates would have the following effect on Tampa Electric Company's benefit obligation:

(millions)	Increase	Decrease
Effect on postretirement benefit obligation	$ 6.0	$ (4.9)

The discount rate assumption used to determine the Dec. 31, 2011 benefit obligation was based on a cash flow matching technique developed by outside actuaries and a review of current economic conditions. This technique constructs hypothetical bond portfolios using high-quality (AA or better by Standard & Poor's) corporate bonds available from the Barclays Capital database at the measurement date to meet the plan's year-by-year projected cash flows. The technique calculates all possible bond portfolios that produce adequate cash flows to pay the yearly benefits and then selects the portfolio with the highest yield and uses that yield as the recommended discount rate.

Components of TECO Energy Consolidated net periodic benefit cost

(millions)	Pension Benefits *2011* (1)	Pension Benefits *2010* (1)	Pension Benefits *2009* (1)	Other Benefits *2011* (1)	Other Benefits *2010* (1)	Other Benefits *2009* (1)
Service cost	$ 16.0	$ 16.2	$ 15.7	$ 2.1	$ 3.2	$ 2.9
Interest cost	30.9	33.2	33.6	11.1	10.9	11.3
Expected return on plan assets	(38.4)	(36.3)	(37.8)	0.0	0.0	0.0
Amortization of:						
Actuarial loss	11.3	12.4	8.7	0.1	0.0	0.0
Prior service (benefit) cost	(0.4)	(0.4)	(0.4)	0.8	0.8	0.8
Transition obligation	0.0	0.0	0.0	2.3	2.3	2.3
Curtailment loss (benefit)	0.0	0.0	0.2	0.0	0.0	0.0
Settlement loss	0.9	1.6	0.0	0.0	0.0	0.0
Net periodic benefit cost	$ 20.3	$ 26.7	$ 20.0	$ 16.4	$ 17.2	$ 17.3

(1) Benefit cost was measured for the years ended Dec. 31, 2011, 2010 and 2009.

Tampa Electric Company's portion of the net periodic benefit costs for pension benefits was $13.1 million, $18.6 million and $15.4 million for 2011, 2010 and 2009, respectively. Tampa Electric Company's portion of the net periodic benefit costs for other benefits was $10.0 million, $13.8 million and $13.6 million for 2011, 2010 and 2009, respectively.

The estimated net loss and prior service benefit 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 are $12.1 million and $0.5 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 total $1.1 million and $1.3 million, respectively.

Assumptions used to determine net periodic benefit cost for years ended Dec. 31,

	Pension Benefits			Other Benefits		
	2011	*2010*	*2009*	*2011*	*2010*	*2009*
Discount rate	5.30%	5.75%	6.05%	5.25%	5.60%	6.05%
Expected long-term return on plan assets	7.75%	8.25%	8.25%	n/a	n/a	n/a
Rate of compensation increase	3.88%	4.25%	4.25%	3.87%	4.25%	4.25%
Healthcare cost trend rate						
Immediate rate	n/a	n/a	n/a	8.00%	8.00%	8.50%
Ultimate rate	n/a	n/a	n/a	4.50%	5.00%	5.00%
Year rate reaches ultimate	n/a	n/a	n/a	2023	2017	2016

The discount rate assumption was based on a cash flow matching technique developed by 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 historical returns, fixed income spreads and equity premiums consistent with the portfolio and asset allocation. A change in asset allocations could have a significant impact on the expected return on assets. Additionally, expectations of long-term inflation, real growth in the economy and a provision for active management and expenses paid were incorporated in the assumption. For the year ended Dec. 31, 2011, TECO Energy's pension plan experienced actual asset returns of approximately 4.4%.

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 Tampa Electric Company's expense:

(millions)	1% Increase	1% Decrease
Effect on periodic cost	$ 0.4	$ (0.3)

Pension Plan Assets

Pension plan assets (plan assets) are invested in a mix of equity and fixed income securities. TECO Energy's investment objective is to obtain above-average returns while minimizing volatility of expected returns and funding requirements over the long term. TECO Energy'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.

	Target Allocation	Actual Allocation, End of Year	
Asset Category		*2011*	*2010*
Equity securities	55%	50%	56%
Fixed income securities	45%	50%	44%
Total	100%	100%	100%

TECO Energy 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 and funding. TECO Energy, Inc. expects to take additional steps to more closely match plan assets with plan liabilities.

The plan's investments are held by a trust fund administered by JP Morgan Chase Bank, N.A. (JP Morgan). JP Morgan measures fair value using the procedures set forth below for all investments. When available, JP Morgan uses quoted market prices on investments 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 investments are traded in a secondary market, JP Morgan makes use of acceptable practical expedients to calculate fair value, and the company classifies these items as Level 2.

If observable transactions and other market data are not available, fair value is based upon third-party 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 third-party 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.

The following table sets forth by level within the fair value hierarchy the plan's investments as of Dec. 31, 2011 and 2010. As required by the fair value accounting standards, the investments are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The plan'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 cash equivalents, the cost approach was used in determining fair value. For bonds and U.S. government agencies, the income approach was used. For other investments, the market approach was used.

(millions)	At Fair Value as of Dec. 31, 2011			
	Level 1	Level 2	Level 3	Total
Cash	$4.4	$0.0	$0.0	$4.4
Accounts receivable	39.6	0.0	0.0	39.6
Accounts payable	(20.4)	0.0	0.0	(20.4)
Cash equivalents				
Treasury bills (T bills)	0.0	4.3	0.0	4.3
Short term investment fund (STIF)	13.2	0.0	0.0	13.2
Money markets	0.0	0.3	0.0	0.3
Total cash equivalents	13.2	4.6	0.0	17.8
Equity securities				
Common stocks	114.2	0.0	0.0	114.2
Preferred stocks	0.0	1.0	0.0	1.0
American depository receipt (ADR)	6.5	0.6	0.0	7.1
Real estate investment trust (REIT)	2.0	0.0	0.0	2.0
Commingled fund	0.0	19.8	0.0	19.8
Mutual fund	88.3	0.0	0.0	88.3
Total equity securities	211.0	21.4	0.0	232.4
Fixed income securities				
Municipal bonds	0.0	8.7	0.0	8.7
Government bonds	0.0	31.7	0.0	31.7
Corporate bonds	0.0	29.5	0.0	29.5
Asset backed securities (ABS)	0.0	0.5	0.0	0.5
Mortgage back securities (MBS)	0.0	20.0	0.0	20.0
Collateralized mortgage obligation/real estate mortgage investment conduit (CMO/REMIC)	0.0	2.5	0.0	2.5
Mutual funds	0.0	101.1	0.0	101.1
Total fixed income securities	0.0	194.0	0.0	194.0
Derivatives				
Swaps	0.0	(0.3)	0.0	(0.3)
Written options	0.0	0.1	0.0	0.1
Total derivatives	0.0	(0.2)	0.0	(0.2)
Total	$247.8	$219.8	$0.0	$467.6

(millions)	At Fair Value as of Dec. 31, 2010			
	Level 1	**Level 2**	**Level 3**	**Total**
Accounts receivable	$31.4	$0.0	$0.0	$31.4
Accounts payable	(45.2)	0.0	0.0	(45.2)
Cash equivalents				
Short term investment fund (STIF)	7.9	0.0	0.0	7.9
Repurchase agreements	0.0	14.0	0.0	14.0
Money markets	0.0	0.3	0.0	0.3
Total cash equivalents	7.9	14.3	0.0	22.2
Equity securities				
Common stocks	112.6	0.0	0.0	112.6
Preferred stocks	0.0	1.0	0.0	1.0
American depository receipt (ADR)	4.8	1.3	0.0	6.1
Real estate investment trust (REIT)	2.0	0.0	0.0	2.0
Commingled fund	0.0	24.8	0.0	24.8
Mutual fund	121.5	0.0	0.0	121.5
Total equity securities	240.9	27.1	0.0	268.0
Fixed income securities				
Municipal bonds	0.0	7.9	0.0	7.9
Government bonds	0.0	26.3	0.0	26.3
Corporate bonds	0.0	26.0	0.0	26.0
Asset backed securities (ABS)	0.0	0.6	0.0	0.6
Mortgage back securities (MBS)	0.0	53.6	0.0	53.6
Collateralized mortgage obligation/real estate mortgage investment conduit (CMO/REMIC)	0.0	3.0	0.0	3.0
Mutual funds	0.0	86.1	0.0	86.1
Total fixed income securities	0.0	203.5	0.0	203.5
Derivatives				
Swaps	0.0	0.1	0.0	0.1
Written options	0.0	(0.3)	0.0	(0.3)
Total Derivatives	0.0	(0.2)	0.0	(0.2)
Total	$235.0	$244.7	$0.0	$479.7

- T bills are valued at amortized cost.
- The STIFs are money market mutual funds and are valued using the net asset value (NAV), as determined by the fund's trustee in accordance with U.S. GAAP, at year end. Shares may be sold any day the fund is accepting purchase orders, at the next NAV calculated after the order is accepted. The NAVs are validated with purchases and sales at NAV, making these Level 1 assets.
- Money markets and repurchase agreements valued using cost due to their short term nature. Additionally, money markets are backed by 102% collateral.
- The primary pricing inputs in determining the fair value of the Level 1 assets, excluding the mutual funds and STIFs, are quoted prices in active markets.
- The primary pricing inputs in determining the fair value of Level 2 preferred stock and ADR are prices of similar securities and benchmark quotes.
- The commingled fund invests primarily in international equity securities, normally excluding securities issued in the U.S., with large- and mid-market capitalizations. The fund may invest in "value" or "growth" securities and is not limited to a particular investment style. The fund is valued using the NAV, as determined by the fund's trustee in accordance with U.S. GAAP, at year end. For redemption, written notice of the amount to be withdrawn must be given no later than 4:00 p.m. eastern standard time.
- The primary pricing input in determining the Level 1 mutual fund is the mutual fund's NAV. The Level 1 mutual fund is an open-ended mutual fund and the NAV is validated with purchases and sales at NAV, making this a Level 1 asset.
- The primary pricing inputs in determining the fair value Level 2 municipal bonds are benchmark yields, historical spreads, sector curves, rating updates and prepayment schedules. The primary pricing inputs in determining the fair value of government bonds are the U.S. treasury curve, CPI, and broker quotes, if available. The primary pricing inputs in determining the fair value of corporate bonds are the U.S. treasury curve, base spreads, YTM, and benchmark quotes. ABS and CMO are priced using TBA prices, treasury curves, swap curves, cash flow information and bids and offers as inputs. MBS are priced using TBA prices,

treasury curves, average lives, spreads and cash flow information.

- The primary pricing input in determining the fair value of the Level 2 mutual funds are their NAV at year end. Shares may be purchased at the NAV without sales charges or other fees. Since these mutual funds are private funds, they are Level 2 assets. The funds invest primarily in emerging market fixed income securities. For redemption, written notice of the amount to be withdrawn must be given no later than 4:00 p.m. eastern standard time. Redemption proceeds will normally be received within three business days.
- The Level 2 options are valued using the bid-ask spread and the last price. Swaps are valued using benchmark yields, swap curves and cash flow analyses.

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 made no cash contribution to this plan in 2011 and $81.3 million in 2010, which met the minimum funding requirements for both 2011 and 2010. Tampa Electric Company's portion of the contribution in 2010 was $65.7 million. This amount is reflected in the "Other" line item on the Consolidated Statements of Cash Flows. TECO Energy plans on making a contribution in 2012 of $35.5 million, with Tampa Electric Company's portion being $27.6 million. TECO Energy estimates annual contributions to range from $40.0 to $55.0 million per year in 2013 to 2016 based on current assumptions. Tampa Electric Company's portion of the contributions range from $30.0 to $40.0 million per year in 2013 to 2016.

The SERP is funded annually to meet the benefit obligations. TECO Energy made contributions of $3.7 million and $6.3 million to this plan in 2011 and 2010, respectively. Tampa Electric Company's portion of the contributions in 2011 and 2010 were $1.0 million and $5.9 million, respectively. In 2012, TECO Energy expects to make a contribution of about $2.9 million to this plan. Tampa Electric Company's portion of the expected contribution is about $1.0 million.

The other postretirement benefits are funded annually to meet benefit obligations. TECO Energy'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. TECO Energy's 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 2012, TECO Energy expects to make a contribution of about $13.2 million. Tampa Electric Company's portion of the expected contribution is $10.6 million. Postretirement benefit levels are substantially unrelated to salary.

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**	
(millions)		Gross	Expected Federal Subsidy
2012	$ 46.1	$ 14.7	$ 1.4
2013	45.9	15.4	1.6
2014	46.9	16.2	1.7
2015	48.3	16.8	1.9
2016	52.1	17.3	2.0
2017-2021	279.5	19.6	11.8

Defined Contribution Plan

TECO Energy has a defined contribution savings plan covering substantially all employees of TECO Energy and its subsidiaries that enables participants to save a portion of their compensation up to the limits allowed by IRS guidelines. TECO Energy and its subsidiaries match up to 6% of the participant's payroll savings deductions. Effective April 2010, employer matching contributions were 60% of eligible participant contributions with additional incentive match of up to 40% of eligible participant contributions based on the achievement of certain operating company financial goals. Prior to this, the employer matching contributions were 50% of eligible participant contributions, with an additional incentive match of up to 50%. For the years ended Dec. 31, 2011, 2010 and 2009, TECO Energy and its subsidiaries recognized expense totaling $9.0 million, $12.6 million and $8.1 million, respectively, related to the matching contributions made to this plan. Tampa Electric Company's portion of expense totaled $5.8 million, $8.8 million and $6.5 million for 2011, 2010 and 2009, respectively.

6. Short-Term Debt

At Dec. 31, 2011 and 2010, the following credit facilities and related borrowings existed:

Credit Facilities	*Dec. 31, 2011*			*Dec. 31, 2010*		
(millions)	*Credit Facilities*	*Borrowings Outstanding (1)*	*Letters of Credit Outstanding*	*Credit Facilities*	*Borrowings Outstanding (1)*	*Letters of Credit Outstanding*
Recourse:						
Tampa Electric Company:						
5-year facility(2)	$ 325.0	$ 0.0	$ 0.7	$ 325.0	$ 5.0	$ 0.7
1-year accounts receivable facility	150.0	0.0	0.0	150.0	7.0	0.0
Total	$ 475.0	$ 0.0	$ 0.7	$ 475.0	$ 12.0	$ 0.7

(1) Borrowings outstanding are reported as notes payable.
(2) This 5-year facility matures Oct. 25, 2016.

At Dec. 31, 2011, these credit facilities require commitment fees ranging from 17.5 to 35.0 basis points. The weighted-average interest rate on outstanding notes payable at Dec. 31, 2010 was 0.64%. There were no outstanding notes payable at Dec. 31, 2011.

Tampa Electric Company Accounts Receivable Facility

On Feb. 17, 2012, Tampa Electric Company and TRC amended their $150 million accounts receivable collateralized borrowing facility, entering into Amendment No. 10 to the Loan and Servicing Agreement with certain lenders named therein and Citibank, N.A., Inc. as Program Agent. The amendment extends the maturity date to Feb. 15, 2013 and makes certain other technical changes. Please refer to **Note 18** for additional information.

Tampa Electric Company $325 million bank credit facility amendment

On Oct. 25, 2011, Tampa Electric Company amended its $325 million bank credit facility, entering into a Third Amended and Restated Credit Agreement. The amendment (i) extended the maturity date of the credit facility from May 9, 2012 to Oct. 25, 2016 (subject to further extension with the consent of each lender); (ii) continued to allow Tampa Electric Company to borrow funds at a rate equal to the London interbank deposit rate plus a margin; (iii) allows Tampa Electric Company to borrow funds at an interest rate equal to a margin plus the higher of Citibank's prime rate, the federal funds rate plus 50 basis points, or the London interbank deposit rate plus 1.00%; (iv) as an alternative to the above interest rate, allows Tampa Electric Company to borrow funds on a same-day basis under a new swingline loan provision, which loans mature on the fourth banking day after which any such loans are made and bear interest at an interest rate as agreed by the Borrower and the relevant swingline lender prior to the making of any such loans; (v) continues to allow Tampa Electric Company to request the lenders to increase their commitments under the credit facility by up to $175 million in the aggregate; (vi) includes a $200 million letter of credit facility (compared to $50 million under the previous agreement); and (vii) made other technical changes.

7. Long-Term Debt

Purchase in Lieu of Redemption of Polk County Industrial Development Authority Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2010

On Mar. 1, 2011, Tampa Electric Company purchased in lieu of redemption $75.0 million PCIDA Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2010 (the PCIDA Bonds). On Nov. 23, 2010, the PCIDA had issued the PCIDA Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. Proceeds of the PCIDA Bonds were used to redeem $75.0 million PCIDA Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007, which previously had been in auction rate mode and had been held by Tampa Electric Company since Mar. 26, 2008. The PCIDA Bonds bore interest at the initial term rate of 1.50% per annum from Nov. 23, 2010 to Mar. 1, 2011.

On Mar. 26, 2008, Tampa Electric Company purchased in lieu of redemption $20.0 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007C. After the Mar. 1, 2011 purchase of the PCIDA Bonds, $95.0 million in bonds purchased in lieu of redemption were held by the trustee at the direction of Tampa Electric Company as of Dec. 31, 2011 (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.

Tampa Electric Company Exchange Offer and Issuance of 5.40% Notes due 2021

On Dec. 14, 2010, Tampa Electric Company completed an exchange offer (the Exchange Offer) which resulted in the exchange of approximately $278.5 million principal amount of Tampa Electric Company notes for approximately $278.5 million principal amount of newly issued Tampa Electric Company 5.40% Notes due 2021.

The Exchange Offer resulted in the exchange and retirement of approximately:

- $131.5 million principal amount of Tampa Electric Company 6.875% Notes due 2012
- $147.0 million principal amount of Tampa Electric Company 6.375% Notes due 2012 for approximately $278.5 million principal amount of newly issued Tampa Electric Company 5.40% Notes due 2021.

The 5.40% Notes bear interest at a rate of 5.40% per year, payable on May 15 and November 15 each year, beginning May 15, 2011 and mature May 15, 2021. Tampa Electric Company may redeem some or all of the 5.40% Notes at a price equal to the greater of (i) 100% of the principal amount of the applicable Tampa Electric Company notes to be redeemed, plus accrued and unpaid interest, or (ii) the net present value of the remaining payments of principal and interest on the Tampa Electric Company 5.40% Notes, discounted at the applicable treasury rate (as defined in the applicable supplemental indenture), plus 25 basis points. Such redemption price would include accrued and unpaid interest to the redemption date. In accordance with allowed regulatory treatment, the unamortized costs are being amortized over the life of the original notes.

After the Exchange Offer, approximately $118.6 million principal amount of Tampa Electric Company 6.875% Notes due 2012 and $253.0 million principal amount of Tampa Electric Company 6.375% Notes due 2012 remain outstanding.

8. 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, 2011	10	$ 1,852.4	$ 0.0	$ 1,852.4
Balance Dec. 31, 2010[(1)]	10	$ 1,852.4	$ 0.0	$ 1,852.4

(1) TECO Energy, Inc. made equity contributions to Tampa Electric Company of $50.0 million in 2010.

9. 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 accounting standards for contingencies to provide for matters that are probable of resulting in an estimable loss. While the outcome of such proceedings is uncertain, management does not believe that their ultimate resolution will have a material adverse effect on Tampa Electric Company's results of operations, financial condition or cash flows.

Merco Group at Aventura Landings v. Peoples Gas System

In a Florida district court case pending in Miami, Merco Group at Aventura Landings I, II and III (Merco) alleged that coal tar from a certain former PGS manufactured gas plant site had been deposited in the early 1960s onto property now owned by Merco. Merco alleged that it incurred approximately $3.9 million in costs associated with the removal of such coal tar and provided testimony claiming approximately $110.0 million plus interest in damages from out-of-pocket development expenses and lost profits due to the delay in its condominium development project allegedly caused by the presence of the coal tar. PGS maintains that it is not liable because the coal tar did not originate from its manufactured gas plant site and filed a third-party complaint against Continental Holdings, Inc. (CHI), which Merco also added as a defendant in its suit, as the owner at the relevant time of the site that PGS believes was the source of the coal tar on Merco's property. In addition, the court will consider PGS's counterclaim against Merco which claims that, because Merco purchased the property with actual knowledge of the presence of coal tar on the property, Merco should contribute toward any damages resulting from the presence of coal tar. The bench trial in this matter was concluded in February 2012 and a ruling is expected in March 2012. Co-defendant CHI reached a settlement with Merco but still remains as a defendant in PGS's third-party complaint.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a 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, 2011, Tampa Electric Company has estimated its ultimate financial liability to be $28.5 million, primarily at PGS. This amount has been accrued and is primarily reflected in "Long-term regulatory liabilities" on Tampa Electric Company's Consolidated Balance Sheet. 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 clean-up 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.

In instances where other PRPs are involved, many of those PRPs are creditworthy and are likely to continue to be creditworthy for the duration of the remediation work. However, in those instances that they are not, Tampa Electric Company could be liable for more than Tampa Electric Company's actual percentage of the remediation costs.

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.

Potentially Responsible Party Notification

In October 2010, the EPA notified Tampa Electric Company that it is a PRP under the federal Superfund law for the proposed conduct of a contaminated soil removal action and further clean up, if necessary, at a property owned by Tampa Electric Company in Tampa, Florida. The property owned by Tampa Electric Company is undeveloped except for location of transmission lines and poles, and is adjacent to an industrial site, not owned by Tampa Electric Company, which the EPA has studied since 1992 or earlier. The EPA has asserted this potential liability due to Tampa Electric Company's ownership of the property described above but, to the knowledge of Tampa Electric Company, is not based upon any release of hazardous substances by Tampa Electric Company. Tampa Electric Company has responded to the EPA regarding such matter. The scope and extent of its potential liability, if any, and the costs of any required investigation and remediation have not been determined.

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, 2011, 2010 and 2009 was $2.2 million, $2.3 million and $2.3 million, respectively. The following is a schedule of future minimum lease payments with non-cancelable lease terms in excess of one year and capacity payments under PPAs at Dec. 31, 2011:

Future Minimum Lease and Capacity Payments

(millions)	*Capacity Payments*	*Operating Leases*	*Total*
Year ended Dec. 31:			
2012	$ 11.7	$ 2.3	$ 14.0
2013	12.7	2.1	14.8
2014	12.8	2.1	14.9
2015	13.0	2.1	15.1
2016	14.6	2.2	16.8
Thereafter	20.0	17.2	37.2
Total future mimimum payments	$ 84.8	$ 28.0	$ 112.8

Guarantees and Letters of Credit

Tampa Electric Company accounts for guarantees in accordance with the applicable accounting standards. 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) are likely to be subject to the recognition and measurement, as well as the disclosure provisions. 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, 2011, Tampa Electric Company was not obligated under guarantees, but had $0.7 million of letters of credit outstanding.

Letters of Credit -Tampa Electric Company

(millions) Letters of Credit for the Benefit of:	*2012*	*2013-2016*	*After [1] 2016*	*Total*	*Liabilities Recognized at Dec. 31, 2011*
Tampa Electric [2]					
Letters of credit	$ 0.0	$ 0.0	$ 0.7	$ 0.7	$ 0.2

(1) These letters of credit and guarantees renew annually and are shown on the basis that they will continue to renew beyond 2016.

(2) The amounts shown are the maximum theoretical amounts guaranteed under current agreements. Liabilities recognized represent the associated obligation of Tampa Electric Company under these agreements at Dec. 31, 2011. The obligations under these letters of credit and guarantees include net accounts payable and net derivative liabilities.

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, PGS has certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2011, Tampa Electric Company was in compliance with applicable financial covenants.

10. Related Party Transactions

A summary of activities between Tampa Electric Company and its affiliates follows:

Net transactions with affiliates:			
(millions)	*2011*	*2010*	*2009*
Administrative and general, net	$ 17.5	$ 19.9	$ 19.8
Amounts due from or to affiliates at Dec. 31,			
(millions)	*2011*	*2010*	
Accounts receivable [1]	$ 0.9	$ 0.9	
Accounts payable [1]	$ 7.9	$ 7.2	
Taxes receivable	$ 14.6	$ 24.6	
Taxes payable	$ 0.1	$ 0.9	

(1) Accounts receivable and accounts payable were incurred in the ordinary course of business and do not bear interest.

Tampa Electric Company had certain transactions, in the ordinary course of business, with entities in which directors of Tampa Electric Company had interests. Tampa Electric Company paid legal fees of $1.3 million, $1.2 million and $1.6 million for the years ended Dec. 31, 2011, 2010 and 2009, respectively, to Ausley McMullen, P.A. of which Mr. Ausley (a director of Tampa Electric Company) is an employee.

11. 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 678,000 customers in West Central Florida. Its PGS division is engaged in the purchase, distribution and marketing of natural gas for approximately 340,000 residential, commercial, industrial and electric power generation customers in the state of Florida.

Segment Information

(millions)	*Tampa Electric*	*PGS*	*Other & eliminations*	*Tampa Electric Company*
2011				
Revenues – outsiders	$ 2,020.1	$ 450.5	$ 0.0	$2,470.6
Revenues – affiliates	0.5	3.0	(3.5)	0.0
Total revenues	2,020.6	453.5	(3.5)	2,470.6
Depreciation and amortization	222.1	48.4	0.0	270.5
Total interest charges	121.8	17.7	0.0	139.5
Provision for taxes	124.8	20.6	0.0	145.4
Net income	202.7	32.6	0.0	235.3
Total assets	5,693.0	888.4	(10.0)	6,571.4
Capital expenditures	314.9	71.9	0.0	386.8
2010				
Revenues – outsiders	$ 2,162.8	$ 510.8	$ 0.0	$2,673.6
Revenues – affiliates	0.4	19.1	(19.5)	0.0
Total revenues	2,163.2	529.9	(19.5)	2,673.6
Depreciation and amortization	215.9	46.0	0.0	261.9
Total interest charges	122.7	18.3	0.0	141.0
Provision for taxes	122.4	21.3	0.0	143.7
Net income	208.8	34.1	0.0	242.9
Total assets	5,614.8	876.2	(16.3)	6,474.7
Capital expenditures	331.2	62.4	0.0	393.6
2009				
Revenues – outsiders	$2,194.3	$ 455.6	$ 0.0	$2,649.9
Revenues – affiliates	0.5	15.2	(15.7)	0.0
Total revenues	2,194.8	470.8	(15.7)	2,649.9
Depreciation and amortization	200.4	44.2	0.0	244.6
Restructuring charges	18.4	4.7	0.0	23.1
Total interest charges	116.2	18.7	0.0	134.9
Provision for taxes	98.4	13.3	0.0	111.7
Net income	160.2	31.9	0.0	192.1
Total assets	5,457.5	826.0	(9.7)	6,273.8
Capital expenditures	533.0	50.5	0.0	583.5

12. Asset Retirement Obligations

Tampa Electric Company accounts for AROs under the applicable accounting standards. An 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, 2011 and 2010, $2.2 million and $1.8 million, respectively, estimated cash flow revisions at Tampa Electric resulted primarily from the cost of removal of treated wood poles.

Reconciliation of beginning and ending carrying amount of asset retirement obligations:

(millions)	*Dec. 31, 2011*	*2010*
Beginning balance	$ 31.3	$ 31.5
Revisions to estimated cash flows	(2.2)	(1.8)
Other[1]	1.7	1.6
Ending balance	$ 30.8	$ 31.3

(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.

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.

13. 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 accounting standards for derivatives and hedging. 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 (see **Note 14**). 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.

Tampa Electric Company applies accounting standards for regulated operations to financial instruments used to hedge the purchase of natural gas for the regulated companies. These standards, 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**).

Tampa Electric Company's physical contracts qualify for the NPNS exception to derivative accounting rules, provided they meet certain criteria. Generally, NPNS applies if Tampa Electric Company deems the counterparty creditworthy, if the counterparty owns or controls resources within the proximity to allow for physical delivery of the commodity, if Tampa Electric Company intends to receive physical delivery and if the transaction is reasonable in relation to Tampa Electric Company's business needs. As of Dec. 31, 2011, 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 Dec. 31, 2011 and Dec. 31, 2010 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 [(1)]

(millions)	*Dec. 31, 2011*	*Dec. 31, 2010*
Current assets	$0.0	$1.1
Long-term assets	0.0	0.0
Total assets	$0.0	$1.1
Current liabilities	$58.4	$27.2
Long-term liabilities	7.4	2.6
Total liabilities	$65.8	$29.8

(1) Amounts presented above are on a gross basis, with asset and liability positions netted by counterparty in accordance with accounting standards for derivatives and hedging.

The ending balance in accumulated other comprehensive income (AOCI) related to previously settled interest rate swaps at Dec. 31, 2011 is a net loss of $4.6 million after tax and accumulated amortization. This compares to a net loss of $5.3 million in AOCI after tax and accumulated amortization at Dec. 31, 2010.

The following table presents the effect of energy related derivatives on the fuel recovery clause mechanism on the Consolidated Balance Sheets as of Dec. 31, 2011 and 2010:

Energy Related Derivatives

	Asset Derivatives		Liability Derivatives	
(millions) *at Dec. 31, 2011*	Balance Sheet Location[(1)]	Fair Value	Balance Sheet Location[(1)]	Fair Value
Commodity Contracts:				
Natural gas derivatives:				
Current	Regulatory liabilities	$0.0	Regulatory assets	$58.4
Long-term	Regulatory liabilities	0.0	Regulatory assets	7.4
Total		$0.0		$65.8

(millions) *at Dec. 31, 2010*	Balance Sheet Location[(1)]	Fair Value	Balance Sheet Location[(1)]	Fair Value
Commodity Contracts:				
Natural gas derivatives:				
Current	Regulatory liabilities	$1.1	Regulatory assets	$27.2
Long-term	Regulatory liabilities	0.0	Regulatory assets	2.6
Total		$1.1		$29.8

(1) Natural gas derivatives are deferred in accordance with accounting standards for regulated operations 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 Statements of Income.

Based on the fair value of the instruments at Dec. 31, 2011, net pretax losses of $58.4 million are expected to be reclassified from regulatory assets to the Consolidated Statements of Income within the next twelve months.

The following table presents the effect of hedging instruments on OCI and income for the years ended Dec. 31, 2011 and 2010:

(millions) *For the years ended Dec. 31:*	Location of Gain/(Loss) Reclassified From AOCI Into Income	Amount of Gain/(Loss) Reclassified From AOCI Into Income *2011*	*2010*	*2009*
Derivatives in Cash Flow Hedging Relationships	Effective Portion[(1)]			
Interest rate contracts:	Interest expense	($0.7)	($0.8)	($0.7)
Total		($0.7)	($0.8)	($0.7)

(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 years ended Dec. 31, 2011 and 2010, 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, 2013 for the financial natural gas contracts. The following table presents by commodity type the company's derivative volumes that, as of Dec. 31, 2011, are expected to settle during the 2012 and 2013 fiscal years:

(millions)	Natural Gas Contracts (MMBtus)	
Year	Physical	Financial
2012	0.0	39.5
2013	0.0	7.2
Total	0.0	46.7

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. Tampa Electric 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 Tampa Electric 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, Tampa Electric Company could suffer a material financial loss. However, as of Dec. 31, 2011, substantially all of the counterparties with transaction amounts outstanding in Tampa Electric Company's energy portfolio were rated investment grade by the major 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. Tampa Electric Company generally enters into the following master arrangements: (1) EEI - standardized power sales contracts in the electric industry; (2) ISDA - standardized financial gas and electric contracts; and (3) 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 its 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 Dec. 31, 2011, substantially all positions with counterparties were net liabilities.

Certain Tampa Electric Company 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 Dec. 31, 2011:

Contingent Features

(millions)	Fair Value Asset/ (Liability)	Derivative Exposure Asset/ (Liability)	Posted Collateral
Credit Rating	($65.8)	($65.8)	$0.0

14. Fair Value Measurements

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, 2011 and 2010. As required by accounting standards for fair value measurements, 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, 2011			
(millions)	*Level 1*	*Level 2*	*Level 3*	*Total*
Assets				
Natural gas swaps	$ 0.0	$0.0	$ 0.0	$0.0
Total	$ 0.0	$0.0	$ 0.0	$0.0
Liabilities				
Natural gas swaps	$ 0.0	$65.8	$ 0.0	$65.8
Total	$ 0.0	$65.8	$ 0.0	$65.8

	At fair value as of Dec. 31, 2010			
(millions)	*Level 1*	*Level 2*	*Level 3*	*Total*
Assets				
Natural gas swaps	$ 0.0	$1.1	$ 0.0	$1.1
Total	$ 0.0	$1.1	$ 0.0	$1.1
Liabilities				
Natural gas swaps	$ 0.0	$29.8	$ 0.0	$29.8
Total	$ 0.0	$29.8	$ 0.0	$29.8

Natural gas swaps are over-the-counter swap instruments. The primary pricing inputs in determining the fair value of natural gas swaps are the 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 (see **Note 13**).

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, the intent of the parties, indications of credit deterioration, and whether the markets in which Tampa Electric Company transacts have experienced dislocation. At Dec. 31, 2011, 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. There were no Level 3 assets or liabilities during the 2011 or 2010 fiscal years.

15. Variable Interest Entities

Effective Jan. 1, 2010, the accounting standards for consolidation of VIEs were amended. The most significant amendment was the determination of a VIE's primary beneficiary. Under the amended standard, the primary beneficiary is the enterprise that has both 1) the power to direct the activities of a VIE that most significantly impact the entity's economic performance and 2) the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

Tampa Electric Company 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 range in size from 117 MW to 370 MW of available capacity, are with similar entities and contain similar provisions. Because some of these provisions provide for the transfer or sharing of a number of risks inherent in the generation of energy, these agreements meet the definition of being VIEs. These risks include: operating and maintenance, regulatory, credit, commodity/fuel and energy market risk. Tampa Electric 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, have the power to direct the most significant activities, the obligation or right to absorb losses or benefits and hence remain the primary beneficiaries. As a result, Tampa Electric Company is not required to consolidate any of these entities. Tampa Electric Company purchased $81.2 million, $108.8 million and $105.5 million, under these PPAs for the three years ended Dec. 31, 2011, 2010 and 2009, respectively.

In one instance, Tampa Electric Company's agreement with the entity for 370 MW of capacity was entered into prior to Dec. 31, 2003, the effective date of these standards. Under these standards, Tampa Electric 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, Tampa Electric Company 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 Company has no obligation to this entity beyond the purchase of capacity; therefore, the maximum exposure for Tampa Electric Company is the obligation to pay for such capacity under terms of the PPA at rates that could be unfavorable to the wholesale market. Under this PPA, Tampa Electric Company purchased $34.4 million, $52.8 million and $31.7 million, for the three years ended Dec. 31, 2011, 2010 and 2009, respectively.

Tampa Electric Company does not provide any material financial or other support to any of the VIEs it is involved with, nor is it under any obligation to absorb losses associated with these VIEs. In the normal course of business, Tampa Electric Company's involvement with the remaining VIEs does not affect its Consolidated Balance Sheets, Statements of Income or Cash Flows.

16. Other Comprehensive Income

Tampa Electric Company reported the following other comprehensive income (loss) for the years ended Dec. 31, 2011, 2010 and 2009, 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*
2011			
Unrealized loss on cash flow hedges	$ 0.0	$ 0.0	$ 0.0
Plus: Loss reclassified to net income	1.2	(0.5)	0.7
Gain on cash flow hedges	1.2	(0.5)	0.7
Total other comprehensive income (loss)	$ 1.2	$ (0.5)	$ 0.7
2010			
Unrealized loss on cash flow hedges	$ 0.0	$ 0.0	$ 0.0
Plus: Loss reclassified to net income	1.2	(0.4)	0.8
Gain on cash flow hedges	1.2	(0.4)	0.8
Total other comprehensive income (loss)	$ 1.2	$ (0.4)	$ 0.8
2009			
Unrealized loss on cash flow hedges	$ 0.0	$ 0.0	$ 0.0
Plus: Loss reclassified to net income	1.2	(0.5)	0.7
Gain on cash flow hedges	1.2	(0.5)	0.7
Total other comprehensive income (loss)	$ 1.2	$ (0.5)	$ 0.7

Accumulated other comprehensive (loss) *(millions) As of Dec. 31,*	*2011*	*2010*
Net unrealized loss from cash flow hedges [(1)]	$ (4.6)	$ (5.3)
Total accumulated other comprehensive loss	$ (4.6)	$ (5.3)

(1) Net of tax benefit of $2.9 million and $3.4 million as of Dec. 31, 2011 and 2010, respectively.

17. Restructuring Charges

On Jul. 30, 2009, TECO Energy, Inc. announced organizational changes and a new senior executive team structure as part of its response to industry changes, economic uncertainties and its commitment to maintain a lean and efficient organization. As a second step in response to these factors, on Aug. 31, 2009, the company decided on a total reduction in force which included approximately 216 jobs at Tampa Electric Company. The reduction in force was substantially completed by Dec. 31, 2009. In connection with this reduction in force, Tampa Electric Company incurred $23.1 million related to severance and benefits recognized on the Consolidated Statements of Income under "Restructuring charges" for the year ended Dec. 31, 2009. The total cash payments related to these actions were $26.2 million, including $4.9 million for the settlement of pension obligations (see **Note 5**), paid during 2009 and early 2010.

Restructuring Charges Incurred

(millions)	*Termination of Benefits*	*Other Costs*	*Total*
Total costs expected to be incurred	$23.1	$0.0	$23.1
Costs incurred in 2009	(23.1)	0.0	(23.1)
Total costs remaining	$0.0	$0.0	$0.0

Accrued Liability for Restructuring Charges

(millions)	*Termination of Benefits*	*Other Costs*	*Total*
Beginning balance, Jul. 1, 2009	$0.0	$0.0	$0.0
Costs incurred and charged to expense	23.1	0.0	23.1
Costs paid/settled	(21.3)	0.0	(21.3)
Non-cash expense	(1.8)	0.0	(1.8)
Ending balance, Dec. 31, 2010	$0.0	$0.0	$0.0

Restructuring Charges by Segment

(millions)	*Tampa Electric*	*PGS*	*Total*
Total costs expected to be incurred	$18.4	$4.7	$23.1
Costs incurred in 2009	(18.4)	(4.7)	(23.1)
Total costs remaining	$0.0	$0.0	$0.0

18. Subsequent Events

Tampa Electric Company Accounts Receivable Facility

On Feb. 17, 2012, Tampa Electric Company and TEC Receivables Corporation (TRC), a wholly-owned subsidiary of Tampa Electric Company, amended their $150 million accounts receivable collateralized borrowing facility, entering into Amendment No. 10 to the Loan and Servicing Agreement with certain lenders named therein and Citibank, N.A. as Program Agent. The amendment (i) extends the maturity date to Feb. 15, 2013, (ii) provides that TRC will pay program and liquidity fees, which will total 60 basis points, (iii) continues to provide 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, 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 offered rate (if available) plus a margin and (iv) makes other technical changes.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.
None.

Item 9A. CONTROLS AND PROCEDURES.

TECO Energy, Inc.

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 (Exchange Act)) as of the end of the period covered by this annual report, Dec. 31, 2011 (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.
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, 2011 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, 2011.

TECO Energy's internal control over financial reporting as of Dec. 31, 2011 has been audited by PricewaterhouseCoopers LLP, an independent registered certified public accounting firm, as stated in their report which is on page 85 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

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, 2011 (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.
Tampa Electric Company's 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, 2011 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, 2011.

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 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 May 2, 2012 (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 24 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 *Code of Ethics and Business Conduct* is available in the Corporate Governance section of the Investors page of the company's website at www.tecoenergy.com. Any amendments to or waivers of the *Code of Ethics and Business Conduct* 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 Committee Report" and ending with "Executive Chairman Employment Agreement" just above the caption "Ratification of Appointment of Independent Auditor" 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 caption "Share Ownership" in the Proxy Statement, and is incorporated herein by reference.

Equity Compensation Plan Information

(thousands, except per share price)	*(a)*	*(b)*	*(c)*
Plan Category	*Number of securities to be issued upon exercise of outstanding options, warrants and rights* [1]	*Weighted-average exercise price per share of outstanding options, warrants and rights*	*Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)* [2]
Equity compensation plans/arrangements approved by the stockholders			
2010 Equity Incentive Plan	3,529	$20.01	2,584
Equity compensation plans/arrangements not approved by the stockholders			
None	0	0.00	0
Total	3,529	$20.01	2,584

(1) The reported amount for the 2010 Equity Incentive Plan excludes performance shares which have been issued or may potentially be issued due to performance, subject to a performance-based vesting schedule. Because of the nature of these awards, these shares have also not been taken into account in calculating the weighted-average exercise price under column (b) of this table.

(2) The reported amount for the 2010 Equity Incentive Plan includes shares which may be issued as restricted stock, performance shares, performance-accelerated restricted stock, bonus stock, phantom stock, performanc units, dividend equivalents and other forms of award available for grant under the plan.

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 Independent Auditor" in the Proxy Statement and is incorporated herein by reference.

Tampa Electric Company incurred $0.7 million in audit-related fees rendered by PricewaterhouseCoopers for each of the years 2011, 2010 and 2009, including $0.3 million related to Sarbanes-Oxley in each of those three years. No other fees for services rendered by PricewaterhouseCoopers were incurred by Tampa Electric Company in those years.

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 83
   Tampa Electric Company Financial Statements – See index on page 129
2. Financial Statement Schedules
   Condensed Parent Company Financial Statements Schedule I – pages 167 - 170
   TECO Energy, Inc. Schedule II – page 171
   Tampa Electric Company Schedule II – page 172
3. Exhibits – See index beginning on page 176

(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, 2011*	*Dec. 31, 2010*
Current assets		
Cash and cash equivalents	$ 0.1	$ 39.7
Restricted cash	8.7	0.0
Advances to affiliates	145.6	96.2
Accounts receivable from affiliates	9.7	8.1
Interest receivable from affiliates	1.3	1.0
Deferred income taxes	38.8	98.7
Other current assets	0.5	0.6
Total current assets	204.7	244.3
Property, plant and equipment		
Property, plant and equipment	1.2	0.7
Accumulated depreciation	(0.3)	(0.3)
Total property, plant and equipment, net	0.9	0.4
Other assets		
Investment in subsidiaries	2,635.4	2,661.8
Deferred income taxes	628.0	464.8
Other assets	1.0	9.4
Total other assets	3,264.4	3,136.0
Total assets	$ 3,470.0	$ 3,380.7

Liabilities and capital		
Current liabilities		
Long-term debt due within one year	$ 0.0	$ 48.8
Accounts payable to affiliates	0.4	0.4
Accounts payable	4.3	5.3
Interest payable	0.1	0.7
Taxes accrued	0.3	6.0
Advances from affiliates	1,153.9	1,111.2
Other current liabilities	2.0	0.5
Total current liabilities	1,161.0	1,172.9
Other liabilities		
Long-term debt, less amount due within one year	8.8	8.8
Other liabilities	33.6	29.3
Total other liabilities	42.4	38.1
Capital		
Common equity	215.8	214.9
Additional paid in capital	1,553.4	1,542.0
Retained earnings	519.4	430.0
Accumulated other comprehensive loss	(22.0)	(17.2)
Total capital	2,266.6	2,169.7
Total liabilities and capital	$ 3,470.0	$ 3,380.7

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

(millions) *For the years ended Dec. 31,*	*2011*	*2010*	*2009*
Revenues	$ 0.0	$ 0.0	$ 0.0
Expenses			
Administrative and general expenses	5.7	5.2	4.5
Other taxes	0.8	0.9	0.7
Sale of previously impaired assets	0.0	(2.9)	0.0
Restructuring charges	0.0	1.5	2.6
Depreciation and amortization	0.2	0.2	0.2
Total expenses	6.7	4.9	8.0
Loss from operations	(6.7)	(4.9)	(8.0)
Other income (expense)			
Loss on debt extinguishment	0.0	(19.8)	0.0
Interest income	0.1	0.2	0.2
Other income	0.0	1.0	(5.2)
Earnings from investments in subsidiaries	280.7	281.4	243.0
Total other income	280.8	262.8	238.0
Interest income (expense)			
Interest expense			
Others	(1.6)	(13.5)	(25.2)
Total interest expense	(1.6)	(13.5)	(25.2)
Income before income taxes	272.5	244.4	204.8
Income tax expense (benefit)	(0.1)	5.4	(9.1)
Net income	$ 272.6	$ 239.0	$ 213.9

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

(millions) *For the years ended Dec. 31,*	*2011*	*2010*	*2009*
Cash flows from operating activities	$ 198.6	$ 383.2	$ 311.7
Cash flows from investing activities			
Restricted cash	0.0	0.0	0.4
Capital expenditures	(0.5)	(0.1)	0.0
Investment in subsidiaries	0.0	(50.0)	0.0
Net change in affiliate advances	(12.7)	197.6	(134.5)
Other non-current investments	0.0	0.0	9.8
Cash flows from (used in) investing activities	(13.2)	147.5	(124.3)
Cash flows from financing activities			
Dividends to shareholders	(183.2)	(174.7)	(170.8)
Common stock	7.0	7.8	5.1
Repayment of long-term debt	(48.8)	(346.0)	0.0
Cash flows used in financing activities	(225.0)	(512.9)	(165.7)
Net increase (decrease) in cash and cash equivalents	(39.6)	17.8	21.7
Cash and cash equivalents at beginning of period	39.7	21.9	0.2
Cash and cash equivalents at end of period	$ 0.1	$ 39.7	$ 21.9
Supplemental Data			
Dividends from subsidiaries included in cash flows from operating activities	$ 308.8	$ 318.4	$ 254.2

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 as restricted net assets at its consolidated subsidiaries were approximately 25% of the consolidated net assets of TECO Energy, Inc.

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. 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.

3. Restructuring Charges

On Jul. 30, 2009, TECO Energy, Inc. announced organizational changes and a new senior executive team structure as part of its response to industry changes, economic uncertainties and its commitment to maintain a lean and efficient organization. As a second step in response to these factors, on Aug. 31, 2009, the company decided on a total reduction in force, which included approximately 13 jobs at the parent company. The reduction in force was substantially completed by Dec. 31, 2009. In connection with this reduction in force, for the years ended Dec. 31, 2010 and 2009, the parent company incurred $1.5 million and $2.6 million, respectively, related to severance and benefits recognized on the Condensed Statements of Income under "Restructuring charges". The total cash payments related to these actions were $2.1 million which were paid during 2009 and early 2010.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

TECO ENERGY, INC.
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
For the Years Ended Dec. 31, 2011, 2010 and 2009
(millions)

	Balance at Beginning of Period	Additions		Payments & Deductions (1)	Balance at End of Period
		Charged to Income	Other Charges		
Allowance for Uncollectible Accounts:					
2011	$ 4.5	$ 3.8	$ 0.0	$ 5.7	$ 2.6
2010	$ 3.0	$ 10.7	$ 0.0	$ 9.2	$ 4.5
2009	$ 3.5	$ 9.1	$ 0.0	$ 9.6	$ 3.0

(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, 2011, 2010 and 2009
(millions)

	Balance at Beginning of Period	Additions		Payments & Deductions [1]	Balance at End of Period
		Charged to Income	Other Charges		
Allowance for Uncollectible Accounts:					
2011	$ 3.2	$ 3.8	$ 0.0	$ 5.7	$ 1.3
2010	$ 1.6	$ 10.7	$ 0.0	$ 9.1	$ 3.2
2009	$ 1.6	$ 9.0	$ 0.0	$ 9.0	$ 1.6

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(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 24, 2012

By: /s/ JOHN B. RAMIL
JOHN B. RAMIL
President, Chief Executive Officer and Director
(Principal 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 24, 2012:

Signature	Title
/s/ SHERRILL W. HUDSON SHERRILL W. HUDSON	Executive Chairman of the Board and Director
/s/ JOHN B. RAMIL JOHN B. RAMIL	President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ SANDRA W. CALLAHAN SANDRA W. CALLAHAN	Senior Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer) (Principal Financial and Principal Accounting Officer)

Signature	Title	Signature	Title
/s/ C. DUBOSE AUSLEY C. DUBOSE AUSLEY	Director	/s/ LORETTA A. PENN LORETTA A. PENN	Director
/s/ JAMES L. FERMAN, JR. JAMES L. FERMAN, JR.	Director	/s/ TOM L. RANKIN TOM L. RANKIN	Director
/s/ EVELYN V. FOLLIT EVELYN V. FOLLIT	Director	/s/ WILLIAM D. ROCKFORD WILLIAM D. ROCKFORD	Director
/s/ JOSEPH P. LACHER JOSEPH P. LACHER	Director	/s/ PAUL L. WHITING PAUL L. WHITING	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 24, 2012

By: /s/ JOHN B. RAMIL
JOHN B. RAMIL
President, Chief Executive Officer and Director
(Principal 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 24, 2012:

Signature	Title
/s/ SHERRILL W. HUDSON SHERRILL W. HUDSON	Executive Chairman of the Board and Director
/s/ JOHN B. RAMIL JOHN B. RAMIL	Chief Executive Officer and Director (Principal Executive Officer)
/s/ SANDRA W. CALLAHAN SANDRA W. CALLAHAN	Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer) (Principal Financial and Principal Accounting Officer)

Signature	Title	Signature	Title
/s/ C. DUBOSE AUSLEY C. DUBOSE AUSLEY	Director	/s/ LORETTA A. PENN LORETTA A. PENN	Director
/s/ JAMES L. FERMAN, JR. JAMES L. FERMAN, JR.	Director	/s/ TOM L. RANKIN TOM L. RANKIN	Director
/s/ EVELYN V. FOLLIT EVELYN V. FOLLIT	Director	/s/ WILLIAM D. ROCKFORD WILLIAM D. ROCKFORD	Director
/s/ JOSEPH P. LACHER JOSEPH P. LACHER	Director	/s/ PAUL L. WHITING PAUL L. WHITING	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	
2.1	Stock Purchase Agreement dated as of October 21, 2010, among Iberdrola Energia, S.A., TPS de Ultramar Ltd., EDP – Energias de Portugal, S.A., Empresas Públicas de Medellín E.S.P., and EPM Inversiones S.A. (Exhibit 2.1, Form 10-K for 2010 of TECO Energy, Inc. and Tampa Electric Company).	*
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 May 4, 2011 (Exhibit 3.1, Form 8-K dated May 4, 2011 of TECO Energy, Inc.).	*
3.3	Restated Articles of Incorporation of Tampa Electric Company, as amended on Nov. 30, 1982 (Exhibit 3 to Registration Statement No. 2-70653 of Tampa Electric Company).	*
3.4	Bylaws of Tampa Electric Company, as amended effective Feb. 2, 2011 (Exhibit 3.4, Form 10-K for 2011 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 November 15, 2010 among Tampa Electric Company, Polk County Industrial Development Authority and The Bank of New York Mellon Trust Company, N.A., as trustee (including the form of Bond) (Exhibit 4.1, Form 8-K dated Nov. 23, 2010 of Tampa Electric Company).	*
4.11	Sixth Supplemental Indenture dated as of May 1, 2007 between Tampa Electric Company and The Bank of New York, as trustee (Exhibit 4.18, Form 8-K dated May 25, 2007 of Tampa Electric Company).	*
4.12	Seventh Supplemental Indenture dated as of May 1, 2008 between Tampa Electric Company and The Bank of New York, as trustee (Exhibit 4.20, Form 8-K dated May 16, 2008 of Tampa Electric Company).	*
4.13	Eighth Supplemental Indenture dated as of Nov. 15, 2010 between Tampa Electric Company, as issuer, and The Bank of New York Mellon, as trustee (including the form of 5.40% notes due 2021) (Exhibit 4.1, Form 8-K dated Dec. 9, 2010 of Tampa Electric Company).	*
4.14	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).	
4.15	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).	*
4.16	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.).	*
4.17	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. 20, 2000 of TECO Energy, Inc.).	*
4.18	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.).	*
4.19	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.).	*
4.20	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.).	*
4.21	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.).	*
4.22	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.).	*
4.23	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.)	*
4.24	Indenture dated as of Dec. 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.).	*
4.25	First Supplemental Indenture dated as of Dec. 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 (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.).	*
4.26	Second Supplemental Indenture dated as of Dec. 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 (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.).	*
4.27	Third Supplemental Indenture dated as of Mar. 15, 2010 by and among TECO Finance, Inc., as issuer, TECO Energy, Inc., as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee, (including the form of TECO Finance 4.00% Notes due 2016 and 5.15% Notes due 2020) (Exhibit 4.26, Form 8-K dated Mar. 15, 2010 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 (Exhibit 10.3, Form 10-K for 2008 of TECO Energy, Inc. and Tampa Electric Company).	*
10.4	Annual Incentive Compensation Plan for TECO Energy and subsidiaries, revised as of Feb. 2, 2011 (Exhibit 10.4, Form 10-K for 2011 of TECO Energy, Inc. and Tampa Electric Company).	*
10.5	Form of Change-in-Control Severance Agreement between TECO Energy, Inc. and certain Executive Officers (Exhibit 10.1, Form 10-Q for the quarter ended Sep. 30, 2008 of TECO Energy, Inc. and Tampa Electric Company).	*
10.6	Change-in-Control Severance Agreement between TECO Energy, Inc. and certain Executive Officers (Exhibit 10.1, Form 8-K dated Feb. 5, 2010 of TECO Energy, Inc.).	*
10.7	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).	*
10.8	Amendment No. 1 to TECO Energy Directors' Deferred Compensation Plan, effective as of Apr. 29, 2009 (Exhibit 10.1, Form 10-Q for the quarter ended Jun. 30, 2009 of TECO Energy, Inc. and	*

	Tampa Electric Company).	
10.9	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.).	*
10.10	TECO Energy, Inc. 1997 Director Equity Plan (Exhibit 10.1, Form 8-K dated Apr. 16, 1997 of TECO Energy, Inc.).	*
10.11	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).	*
10.12	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).	*
10.13	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).	*
10.14	Form of Restricted Stock 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, 2008 of TECO Energy, Inc. and Tampa Electric Company).	*
10.15	Form of Restricted Stock 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, 2009 of TECO Energy, Inc. and Tampa Electric Company).	*
10.16	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).	*
10.17	Form of Performance Shares Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.3, Form 10-Q for the quarter ended Jun. 30, 2009 of TECO Energy, Inc. and Tampa Electric Company).	*
10.18	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).	*
10.19	TECO Energy, Inc. 2010 Equity Incentive Plan (Exhibit 10.1, Post-Effective Amendment No. 1 to Form S-8 Registration Statement No. 333-115954 dated May 5, 2010 of TECO Energy, Inc.).	*
10.20	Form of Performance Shares Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2010 Equity Incentive Plan (Exhibit 10.2, Form 10-Q for the quarter ended Jun. 30, 2010 of TECO Energy, Inc. and Tampa Electric Company).	*
10.21	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2010 Equity Incentive Plan (Exhibit 10.3, Form 10-Q for the quarter ended Jun. 30, 2010 of TECO Energy, Inc. and Tampa Electric Company).	*
10.22	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain directors under the TECO Energy, Inc. 2010 Equity Incentive Plan (Exhibit 10.4, Form 10-Q for the quarter ended Jun. 30, 2010 of TECO Energy, Inc. and Tampa Electric Company).	*
10.23	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain directors under the TECO Energy, Inc. 2010 Equity Incentive Plan.	
10.24	Compensatory Arrangements with Executive Officers of TECO Energy, Inc.	
10.25	Compensatory Arrangements with Non-Management Directors of TECO Energy, Inc.	
10.26	Employment Agreement between TECO Energy, Inc. and Sherrill W. Hudson dated Aug. 4, 2010 (Exhibit 10.1, Form 8-K dated Aug. 4, 2010 of TECO Energy, Inc.).	*
10.27	Change-in-Control Severance Agreement between TECO Energy, Inc. and Clark Taylor (Exhibit 10.1, Form 10-Q for the quarter ended Mar. 31, 2011 of TECO Energy, Inc. and Tampa Electric Company).	*
10.28	Change-in-Control Severance Agreement between TECO Coal Corporation and Clark Taylor (Exhibit 10.2, Form 10-Q for the quarter ended Mar. 31, 2011 of TECO Energy, Inc. and Tampa Electric Company).	*
10.29	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).	*
10.30	Third Amended and Restated Credit Agreement dated as of Oct. 25, 2011, 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 Oct. 25, 2011 of TECO Energy, Inc.).	*
10.31	Third Amended and Restated Credit Agreement dated as of Oct. 25, 2011, 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 Oct. 25, 2011 of Tampa Electric Company).	*

10.32	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).	*
10.33	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).	*
10.34	Omnibus Amendment No. 3 to Loan and Servicing Agreement dated as of Dec. 22, 2006, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citicorp North America, Inc. as Program Agent (also amending the agreement identified in Exhibit 10.26 herein) (Exhibit 10.28.1, Form 10-K for 2009 of TECO Energy, Inc. and Tampa Electric Company).	*
10.35	Amendment No. 6 to Loan and Servicing Agreement dated as of Dec. 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).	*
10.36	Amendment No. 8 to Loan and Servicing Agreement dated as of Feb. 19, 2010, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citicorp North America, Inc. as Program Agent. (Exhibit 10.28.3, Form 10-K for 2009 of TECO Energy, Inc. and Tampa Electric Company).	*
10.37	Omnibus Amendment No. 9 to Loan and Servicing Agreement dated as of Feb. 18, 2011, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citibank, North America, Inc. as Program Agent. (Exhibit 10.37, Form 10-K for 2010 of TECO Energy, Inc. and Tampa Electric Company).	*
10.38	Amendment No. 10 to Loan and Servicing Agreement dated as of Feb. 17, 2012, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citibank, North America, Inc. as Program Agent.	
10.39	Registration Rights Agreement dated as of Dec. 9, 2010 by and among Tampa Electric Company, CitiGroup Global Markets Inc., J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. Incorporated (Exhibit 10.1, Form 8-K dated Dec. 9, 2010 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 TECO Energy, Inc.	
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]	
95	Mine Safety Disclosure	
101.INS	XBRL Instance Document	
101.SCH	XBRL Taxonomy Extension Schema Document	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document	
101.LAB	XBRL Taxonomy Extension Label Linkbase Document	

101.PRE XBRL Taxonomy Extension Presentation Linkbase Document

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(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 10.28, above are management contracts or compensatory plans or arrangements in which executive officers or directors of TECO Energy, Inc. participate.