TECO ENERGY

DELIVERING VALUE

2010 ANNUAL REPORT

TECO Energy Inc. (NYSE: TE) is an energy-related holding company based in Tampa, Florida. In addition to the regulated Florida operations of Tampa Electric and Peoples Gas, TECO Energy businesses are engaged in coal production in Kentucky and Virginia and electric power generation and related businesses in Guatemala.

OUR BUSINESS

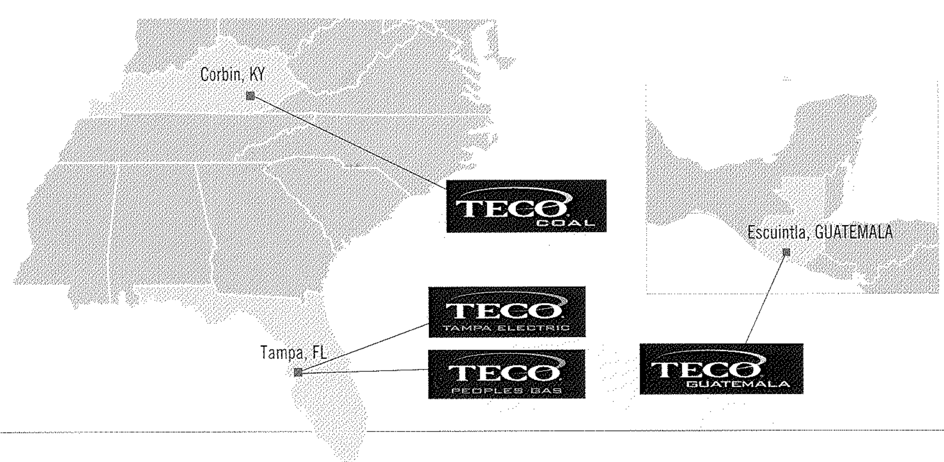
Tampa Electric is a regulated electric utility with more than 4,600 megawatts of generating capacity. The company's service area covers 2,000 square miles in West Central Florida, including nearly all of Hillsborough County and parts of Polk, Pasco and Pinellas counties. More than 672,000 residential, commercial and industrial customers depend on Tampa Electric for reliable power.

Peoples Gas is Florida's leading provider of regulated natural gas distribution services. With a presence in most of the state's major metropolitan areas, Peoples Gas brings reliable, environmentally friendly natural gas service to more than 336,000 residential, commercial and industrial customers.

TECO Coal subsidiaries own and operate low-sulfur coal mines and coal preparation facilities in Kentucky and Virginia. These companies mine, process and ship almost nine million tons of coal annually to domestic utilities, as well as to the United States and European steel industries and other industrial customers.

TECO Guatemala owns two power plants with long-term power purchase agreements in Guatemala: the 120-megawatt, coal-fired San José Power Station and the 78-megawatt, oil-fired Alborada Power Station.

TECO ENERGY COMPANIES



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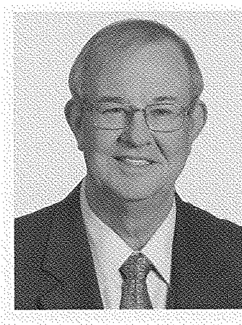
*ON THE COVER: Lineman at sunrise. | We are **Delivering Value** at all hours, day and night, to shareholders, customers and team members.*

To Our Shareholders

Value can be measured in many ways. As a publicly traded company with 4,200 team members working in Florida, Kentucky, Virginia and Guatemala, we deliver value by producing positive results in numerous operating and financial areas. We also provide a work environment where our team members can perform to their highest capabilities and grow in their chosen careers.



Sherrill W. Hudson

John B. Ramil

We are proud to report that in 2010 the TECO Energy team succeeded again in ***delivering value*** by continuing our solid track record and performing well for our shareholders and our customers, and by meeting the needs of TECO Energy team members throughout our operations domestically and in Central America.

Our central focus – ***delivering value*** – produced strong financial results. A financially strong company allows us to provide reliable and reasonably priced services to our customers. A financially strong company also provides us the resources to grow and maintain a multi-talented pool of team members to run our businesses.

We set our expectations high at the beginning of 2010, and we delivered on what we promised – we focused on our utilities and earned in the top half of our allowed return on equity ranges; we maximized the value of our non-regulated businesses; and we improved the strength of our balance sheet.

As a result, in 2010, we delivered the following financial results:

- Increased earnings per share 12 percent
- Provided total shareholder return of 15.4 percent
- Increased the dividend 2.4 percent
- Improved year-end consolidated debt-to-total capital ratio to less than 60 percent
- Reduced the balance and cost of outstanding debt
- Completed the final phase of our 10-year, $1.2 billion investment in environmental improvement

Further, in February, the TECO Energy Board of Directors set a 2011 dividend rate, up an additional 3.7 percent.

These positive results are based on solid business decisions we made throughout the year as we focused our efforts on operating our companies more effectively. As an example, we successfully completed our first full year of operating our Florida electric and gas companies in a more integrated way, and we gained synergies in large operating functions, such as electric and gas delivery and customer service. 2010 also was the first full year of new rates. We also enjoyed a year of favorable weather that sustained higher revenues and saw growth in our utility customer base.

Our operational performance is solid, our energy rates are among the lowest in the state, our balance sheet is much improved, and we have positioned ourselves well with formal business strategies that will guide our future actions and leverage new opportunities. We feel very good about the year, and we are confident about where we are going.

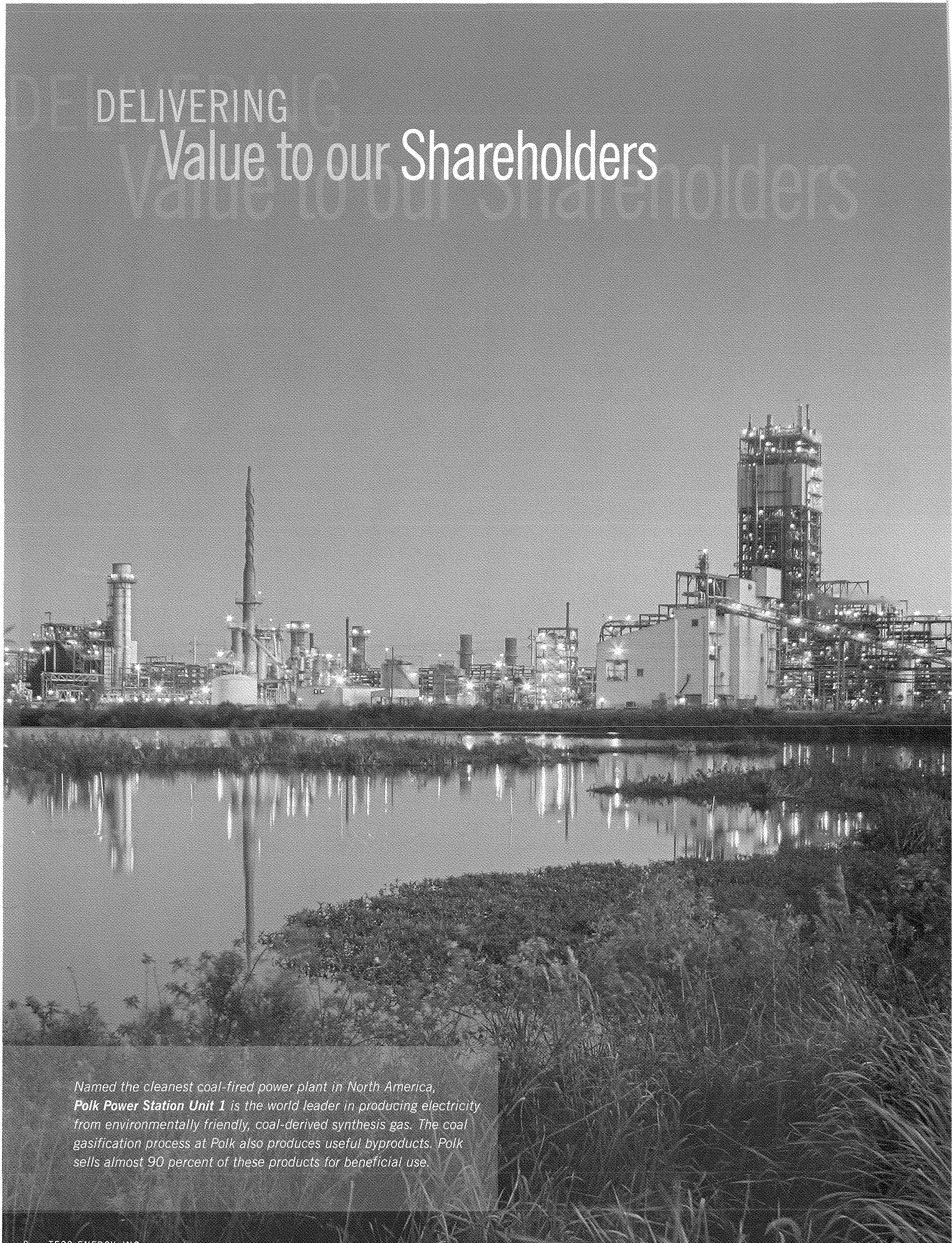
Thank you for your continued support. Our ongoing commitment to you is to continue to focus on ***delivering value*** to all our shareholders, our customers and the TECO Energy global team.

Sincerely,

Sherrill W. Hudson
Executive Chairman of the Board

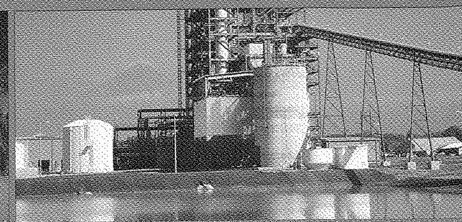
John B. Ramil
President and Chief Executive Officer

DELIVERING Value to our Shareholders



Named the cleanest coal-fired power plant in North America, **_Polk Power Station Unit 1_** is the world leader in producing electricity from environmentally friendly, coal-derived synthesis gas. The coal gasification process at Polk also produces useful byproducts. Polk sells almost 90 percent of these products for beneficial use.

*See the reconciliation table in the Management's Discussion and Analysis of this report.



*Left to right: This **plug-in hybrid** car is one of TECO Energy's "Green Fleet" of vehicles. | TECO Guatemala's **San José Power Station** supplies the base energy needs of Guatemala City and the surrounding area.*

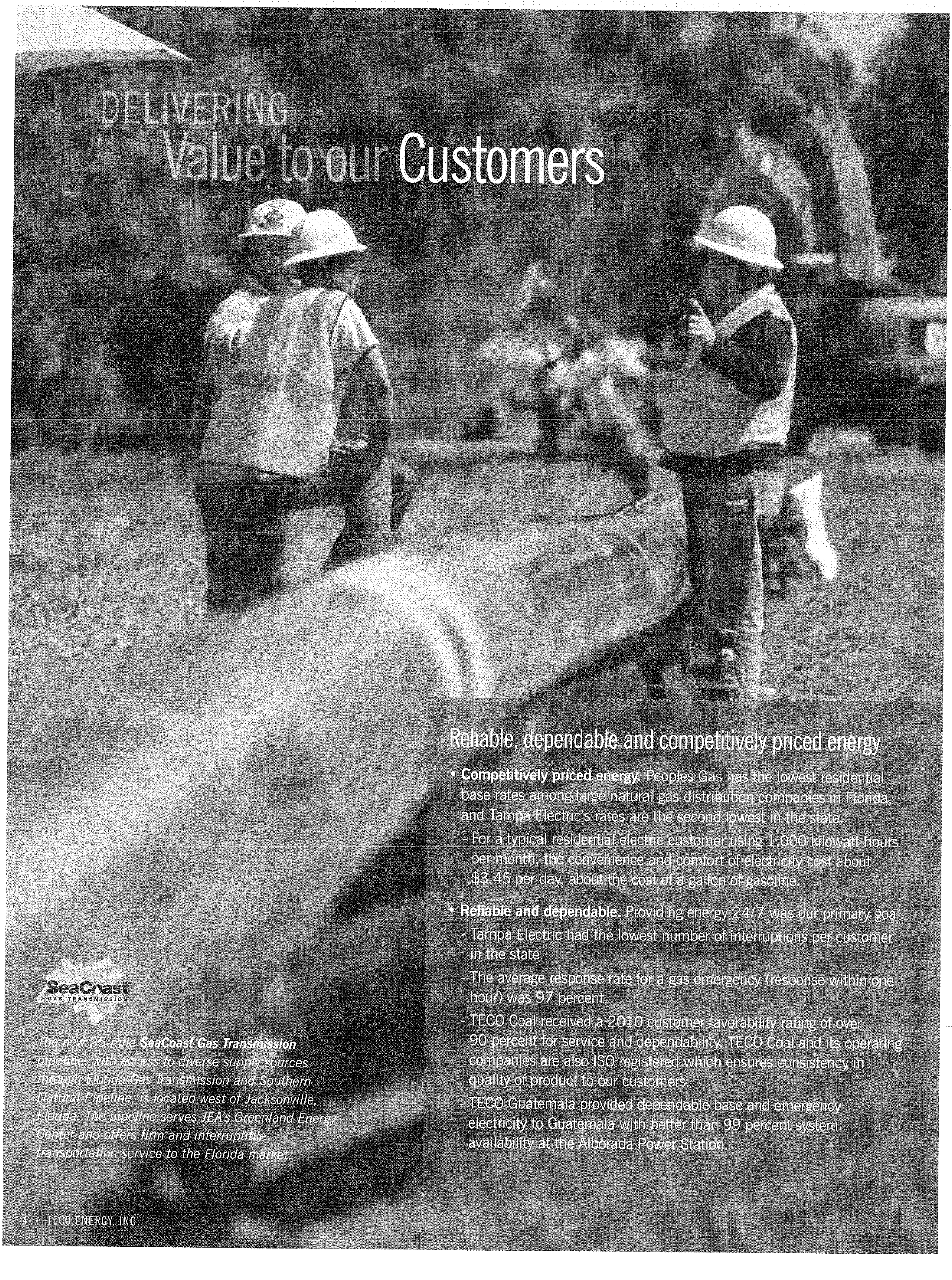
2010 financial accomplishments

- **Positive shareholder returns.**
  - Our annual dividend increased by 2.4 percent.
  - The total shareholder return was 15.4 percent.
- **Improved financial results.**
  - TECO Energy net income increased by $25.1 million (12 percent).
  - TECO Energy non-GAAP results, excluding certain charges and gains, increased by $45.5 million (20 percent).
  - All operating companies achieved higher net income.
    - Tampa Electric +$48.6 million
    - Peoples Gas +$2.2 million
    - TECO Coal +$15.8 million
    - TECO Guatemala +$3.0 million
  - Strong financial results were driven by favorable weather, higher base rates at the Florida utilities, improved coal prices at TECO Coal and better operating performance at TECO Guatemala's San José Power Station.
- **Strengthened our financial position.** Early retirement and refinancing of TECO Energy and TECO Finance debt helped bolster our financial position.
  - The year-end consolidated debt-to-total capital ratio improved to less than 60 percent.
  - The effective interest rate on outstanding debt decreased to less than 6 percent.
  - There are no significant TECO Energy or TECO Finance maturities until 2015.
- **Major environmental capital investment complete.** The final phase of Tampa Electric's 10-year, $1.2 billion environmental investment was completed in April.
  - The project included construction of capital-intensive, state-of-the-art emissions controls and repowering of older, coal-fired generation to combined-cycle natural gas.
  - We continue to earn a return on this investment and recover operating expenses through rates approved by the Florida Public Service Commission.

Our future and 2011 outlook

- **TECO Energy expects 2011 earnings to range between $1.25 and $1.40 per share, excluding charges and gains.****
  - Florida utilities are expected to earn within their allowed returns.
    - Tampa Electric – 10.25 percent to 12.25 percent
    - Peoples Gas – 9.75 percent to 11.75 percent
  - For 2011, the Board of Directors set a dividend rate of $0.85 per share, up 3.7 percent from $0.82 per share.
  - We adopted a new dividend payout ratio target in a range between 60 percent and 70 percent and changed the dividend payout review to better align with providing of annual earnings guidance.
  - TECO Coal sales are expected to be between 8.5 million and 9.0 million tons in 2011, at margins higher than 2010.
  - We expect continued strong results from TECO Guatemala power plants.
  - The overall interest expense is expected to be lower.
- **Evaluating long-term business strategies and growth opportunities.** To potentially take advantage of changing technology and evolving customer usage patterns, the Florida utilities have begun identifying long-term strategies to grow our utility business.
  - Our key areas of focus include alternative fuel vehicles, renewable energy and Smart Grid applications.

*** *This information contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. Actual results may differ materially from those forecasted. The forecasted results are based on the company's current expectations and assumptions, and the company does not undertake to update that information or any other information contained in this report, except as may be required by law. Important factors that could cause actual results to differ materially from those projected in these forward-looking statements are discussed under the "Risk Factors" section of this report.*

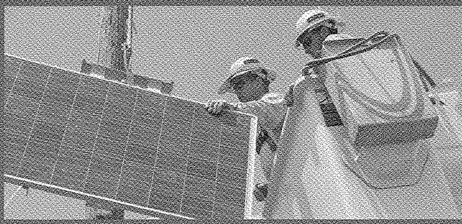


DELIVERING Value to our Customers

Reliable, dependable and competitively priced energy

- **Competitively priced energy.** Peoples Gas has the lowest residential base rates among large natural gas distribution companies in Florida, and Tampa Electric's rates are the second lowest in the state.
  - For a typical residential electric customer using 1,000 kilowatt-hours per month, the convenience and comfort of electricity cost about \$3.45 per day, about the cost of a gallon of gasoline.
- **Reliable and dependable.** Providing energy 24/7 was our primary goal.
  - Tampa Electric had the lowest number of interruptions per customer in the state.
  - The average response rate for a gas emergency (response within one hour) was 97 percent.
  - TECO Coal received a 2010 customer favorability rating of over 90 percent for service and dependability. TECO Coal and its operating companies are also ISO registered which ensures consistency in quality of product to our customers.
  - TECO Guatemala provided dependable base and emergency electricity to Guatemala with better than 99 percent system availability at the Alborada Power Station.

*The new 25-mile **SeaCoast Gas Transmission** pipeline, with access to diverse supply sources through Florida Gas Transmission and Southern Natural Pipeline, is located west of Jacksonville, Florida. The pipeline serves JEA's Greenland Energy Center and offers firm and interruptible transportation service to the Florida market.*



*Left to right: Through the **Energy Planner** program, Tampa Electric helps customers save on electricity through a programmable thermostat that allows customers to take advantage of lower electric prices. | Tampa Electric linemen install **solar panels** on power poles at our Skills Training Center to help the company learn more about renewable energy. | TECO Energy has shifted its commitment to sustainability into high gear and is focused on exploring **alternative fuel vehicles**, like this all-electric car.*

- **Ability to serve under unique and challenging circumstances.** Our electric and gas supply and delivery systems were tested in 2010:
  - Tampa Electric provided uninterrupted power during the company's all-time system peak. Customer demand reached 4,742 megawatts at 7 a.m. Jan. 11. The previous system peak had been 4,327 MW at 5 p.m. on August 20, 2007.
  - Peoples Gas restored gas to customers affected by two major incidents caused by unrelated companies. One incident in May in Jupiter, Florida, affected 10,500 customers and was the result of low gas pressure from the wholesale supplier. The second incident in November affected 7,200 customers in the Fort Myers and Naples areas. It resulted from a road construction crew rupturing a main line.
- **Preparing for our future.** Our companies constantly enhanced maintenance practices, prepared for customer growth and identified areas for continuous improvement.
  - Tampa Electric replaced 700 transmission poles as part of our accelerated maintenance and hardening program and trimmed trees along 2,800 miles of transmission and distribution lines, a preventative measure to ensure reliable service.
  - In November 2010, SeaCoast Gas Transmission LLC, a TECO Energy subsidiary, completed construction of Florida's first intrastate natural gas pipeline near Jacksonville, Florida to serve JEA's Greenland Energy Center.
  - To better serve customers, Tampa Electric and Peoples Gas upgraded nearly 110,000 meters to digital automated meters.

Serving customers and their needs

- **Top-tier customer service.** Tampa Electric and Peoples Gas maintained a combined customer favorability of more than 95 percent, while responding to more than 5.5 million calls and more than 120,000 online requests.
  - About one third of our Florida utility customers (300,000) take advantage of our convenient e-Bill electronic bill payment program.
  - TECO Energy utilized social media to communicate energy savings, outage information and safety tips to our customers.
- **Energy efficiency and conservation.** Tampa Electric received approval to add six new energy-efficiency programs to its already extensive 12 residential and 16 commercial programs.
  - Tampa Electric performed nearly 10,300 free residential energy audits to help customers efficiently use energy.
  - Peoples Gas significantly increased cash rebates for appliance replacement, retention and use in new construction.

Supporting our communities

- **Education.** TECO Energy continued to support educational and cultural institutions.
  - We supported high schools, colleges, museums, performing arts centers and environmental education centers in our Florida service areas.
  - TECO Guatemala built a community education center through Roots and Wings International, built or renovated several other schools and supported the construction of a hospital.
- **Volunteerism.** Team members gave back to our communities in Florida, Guatemala and Kentucky.
  - Our activities ranged from involvement in the Great American Teach-in, Paint Your Heart Out! and Habitat for Humanity to sports, performing arts and school fundraisers.
- **Environmental and sustainability efforts.** We continued focusing on emission reductions and partnerships.
  - In 2010, Tampa Electric completed a 10-year, $1.2 billion environmental investment to reduce emissions from our power plants.
  - We expanded our "Green Fleet" of vehicles to include plug-in hybrid electric cars and started pilot studies on solar and renewable energy.

DELIVERING Value to our Team Members

Team members work on the main transformer for Tampa Electric's ***H.L. Culbreath Bayside Power Station****. The power plant is located on Tampa Bay and provides about 1,800 megawatts of electricity generated from burning natural gas.*

Left to right: Kentucky-based ***TECO Coal*** received multiple safety awards for mining operations. | TECO Energy, in partnership with ***Hillsborough Community College***, offers an associate degree program for team members. Classes are held at our Skills Training Center. | ***Healthy Edge***, TECO Energy's wellness program, helps team members stay fit and helped slow the rate of increase in the company's health care costs.

- **Safety, our number one priority.** We improved our overall safety program by monitoring leading indicators of incidents and watching out for each other.
  - Team members generated over 7,000 proactive, hazard identification reports in 2010.
  - TECO Coal received numerous safety awards for excellence in operations.
  - TECO Energy implemented a companywide policy to eliminate cell phone and texting distractions while driving.
- **Team member wellness.** We encouraged healthy lifestyles and provided a supportive wellness program.
  - We offered wellness-related educational opportunities, events and rewards for healthy living.
  - We offered low-cost membership to 12 work-site fitness centers.
- **A culture of continuous learning.** We enhanced our internal development opportunities.
  - We expanded online learning opportunities, which increased team member participation by over 40 percent.
  - We partnered with Tampa, Florida-based Hillsborough Community College to offer a work-site associate degree program with over 30 team members graduating in 2010.
  - We partnered with local universities to offer a work-site bachelor degree program.
  - We continued to offer a Tuition Assistance Program to support college-level learning for over 250 program participants.
  - We increased the total number of company-sponsored courses from 34 in 2009 to 82 in 2010, and the number of team member facilitators.
- **Balanced program of benefits across the organization.** We reviewed and enhanced team member benefits and compensation to ensure competitive offerings.
  - We continued to provide a medical and prescription drug plan that supports consumerism among team members and their families.
  - We improved engineering job progression to better define the steps to career growth.
  - We integrated the organization's pay structure into a plan that provides for ease in cross-company mobility.
  - We established a new selection of Retirement Savings Plan (401k) funds to better meet the retirement planning needs of our team members.
  - We continued to include an incentive-based component in team member's compensation, allowing team members to share in the companys' success when it achieves its financial, safety and operational goals.
- **Upgraded team member resources for job effectiveness.** We improved the work environment of our team members.
  - Through systematic hardware and software upgrades or replacement of all personal computers, we enhanced our technology capabilities.

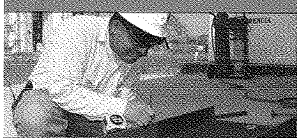
Sherrill W. Hudson
Executive Chairman

A Special Message

As Sherrill Hudson passed the great honor of being CEO of this company on to me last August, I reviewed with our team members the very significant accomplishments during his tenure as CEO. At a most critical time, Sherrill brought a steady hand and guidance to the business, resulting in significant debt reduction, a return to profitability and investment grade credit rating, and a shareholder return better than the S&P Multi-Utility Index and the S&P 500 Index. On behalf of all the constituents of TECO Energy, I offer a well-deserved and sincere thank you to Sherrill.

John B. Ramil, President and CEO

Our Values





Safety

We emphasize a safe work environment and a culture of looking out for the safety and well-being of each other, our customers and our community.

We believe the safety of life outweighs all other considerations.

Integrity

We hold ourselves to the highest ethical behavior in all of our business activities, including legal, regulatory, financial, operational and environmental matters.

We honor our commitments.

Respect and Concern for Others

We value differences, development, teamwork, open communications, care for others and continuous learning.

We treat all stakeholders, including customers, team members, business partners and investors, fairly.

We communicate openly and in a timely way with all stakeholders.

Achievement with a Sense of Urgency

We work, as a team, with speed, sound judgment and diligence toward common goals.

We support the business strategy and accept ownership and personal responsibility for our actions.

Customer Service

We realize customers are why our organization exists.

We treat them fairly and provide high-quality services.

TECO ENERGY

TECO ENERGY | Form 10-K

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

FORM 10-K

☒ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the fiscal year ended December 31, 2010

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

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 ☒ NO ☐

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 ☒

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 ☒ NO ☐

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

Indicate by check mark 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 ☒ Accelerated filer ☐ Non-Accelerated filer ☐ 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 ☒

The aggregate market value of TECO Energy, Inc.'s common stock held by non-affiliates of the registrant as of Jun. 30, 2010 was $3,233,787,526 based on the closing sale price as reported on the New York Stock Exchange.

The number of shares of TECO Energy, Inc.'s common stock outstanding as of Feb. 21, 2011 was 214,890,426. As of Feb. 21, 2011, 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 2011 Annual Meeting of Shareholders of TECO Energy, Inc. are incorporated by reference into Part III.

TECO ENERGY, INC.

ANNUAL REPORT TO SHAREHOLDERS
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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 4,233 employees as of Dec. 31, 2010.

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 through its subsidiary TECO Wholesale Generation, Inc., owns TECO Guatemala, Inc.

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

Tampa Electric Company, a Florida corporation and TECO Energy's largest subsidiary, has two business segments. Its **Tampa Electric** division **(Tampa Electric)** provides retail electric service to more than 672,000 customers in West Central Florida with a net winter system generating capability 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 more than 336,000 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 2010 was almost 1.6 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 consolidated subsidiaries that participate in two contracted Guatemalan power plants, San José and Alborada. In October 2010, TECO Guatemala sold its 30% interest in Distribución Eléctrica Centro Americana II, S.A. (DECA II), which had an ownership interest in Guatemala's largest distribution utility, Empresa Eléctrica de Guatemala, S.A. (EEGSA) and other affiliated energy-related companies.

Revenues from Continuing Operations

(millions)	*2010*	*2009*	*2008*
Tampa Electric	$2,163.2	$2,194.8	$2,091.2
PGS	529.9	470.8	688.4
Total regulated businesses	2,693.1	2,665.6	2,779.6
TECO Coal	690.0	653.0	588.4
TECO Guatemala (1)	124.4	8.3	8.4
	3,507.5	3,326.9	3,376.4
Other and eliminations	(19.6)	(16.4)	(1.1)
Total revenues from continuing operations	$3,487.9	$3,310.5	$3,375.3

(1) Revenues for the years ended Dec. 31, 2009 and 2008 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**. Also, see **Note 19** for additional information regarding the deconsolidation and subsequent reconsolidation of the Guatemala subsidiaries.

TAMPA ELECTRIC—Electric Operations

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

Tampa Electric had 2,300 employees as of Dec. 31, 2010, of which 888 were represented by the International Brotherhood of Electrical Workers and 198 were represented by the Office and Professional Employees International Union.

In 2010, approximately 50% of Tampa Electric's total operating revenue was derived from residential sales, 30% from commercial sales, 9% from industrial sales and 11% 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)	*2010*	*2009*	*2008*
Residential	$1,100.0	$1,082.4	$ 981.7
Commercial	648.4	689.1	639.0
Industrial—Phosphate	84.2	81.2	66.1
Industrial—Other	103.7	111.0	111.2
Other retail sales of electricity	191.6	204.3	185.7
Total retail	2,127.9	2,168.0	1,983.7
Sales for resale	41.6	42.4	69.7
Other	(6.3)	(15.6)	37.8
Total operating revenues	$2,163.2	$2,194.8	$2,091.2

Megawatt-hour Sales

(millions)	*2010*	*2009*	*2008*
Residential	9,185	8,667	8,546
Commercial	6,221	6,274	6,399
Industrial	2,010	1,995	2,205
Other retail sales of electricity	1,797	1,839	1,840
Total retail	19,213	18,775	18,990
Sales for resale	516	440	884
Total energy sold	19,729	19,215	19,874

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 services (rate base). The rate of return on rate base, which is intended to approximate the individual company's weighted cost of capital, primarily includes its costs for debt, deferred income taxes at a zero cost rate and an allowed return on common equity (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 parties.

Tampa Electric's rates and allowed ROE range of 10.25% to 12.25%, with a midpoint of 11.25%, 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 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 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 combustion turbines (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 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 2010, 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 2011. In November 2010, the FPSC approved Tampa Electric's requested rates. The rates include the projected cost for natural gas, oil and coal, including transportation, for 2011 and the net over-recovery of fuel, purchased power and capacity clause expenses, which were collected in 2010 and 2009. Rates in 2010 also reflected 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 $5.22 from $112.73 in 2010 to $107.51 in 2011.

The FPSC determined it was appropriate for Tampa Electric to recover Selective Catalytic Reduction (SCR) operating costs through the Environmental Cost Recovery Clause (ECRC) as well as earn a return on its SCR investment installed on the Big Bend coal fired units for NO_x control in compliance with the environmental consent decree. The SCR for Big Bend Unit 4 was reported in-service in May 2007, the SCR for Big Bend Unit 3 was reported in-service in June 2008, the SCR for Big Bend Unit 2 was reported in-service in May 2009 and the SCR for Big Bend Unit 1 was reported in-service in May 2010, and cost recovery started in the respective in-service years (see the **Environmental Matters** section).

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, to become 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.

A procedural schedule including technical and settlement conference dates has been approved by the settlement judge in each case. Technical and settlement conferences have been held in both cases and the next settlement conference is scheduled for Mar. 15, 2011 in the requirements case.

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).

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.

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.

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

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

Fuel

Approximately 58% of Tampa Electric's generation of electricity for 2010 was coal-fired, with natural gas representing approximately 42% and oil representing less than 1%. Tampa Electric used its generating units to meet approximately 91% of the total system load requirements, with the remaining 9% coming from purchased power. The following table shows Tampa Electric's average delivered fuel cost per million British thermal unit (Btu) and average delivered cost per ton of coal burned:

Average cost per million Btu	*2010*	*2009*	*2008*	*2007*	*2006*
Coal	$ 3.12	$ 3.05	$ 2.91	$ 2.57	$ 2.49
Oil	$16.43	$16.01	$20.48	$13.87	$13.39
Gas (Natural)	$ 6.74	$ 8.00	$10.61	$ 9.52	$ 9.61
Composite	$ 4.49	$ 5.02	$ 5.56	$ 5.05	$ 4.75
Average cost per ton of coal burned	$75.87	$79.28	$69.14	$60.72	$58.75

Tampa Electric's generating stations burn fuels as follows: Bayside, with units 3 through 6 entering commercial operation in 2009, 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, which entered commercial operation in August 2009; 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 4.4 million tons of coal and petroleum coke during 2010 and estimates that its combined coal and petroleum coke consumption will be about 5.0 million tons for 2011. During 2010, Tampa Electric purchased approximately 75% of its coal under long-term contracts with four suppliers, and approximately 25% 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 67% of its coal and petroleum coke requirements in 2011 under long-term contracts with four suppliers and the remaining 33% 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 2010, 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, 2010, approximately 46% of Tampa Electric's 1,250,000 MMBtu gas storage capacity was full. Tampa Electric has contracted for 60% of the expected gas needs for the April 2011 through September 2011 period, 50% for October 2011 and 20% for November 2011 through March 2012. In early March 2011, Tampa Electric expects to issue an RFP and contract for additional gas to meet its generation requirements for these time periods. 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, and are irrevocable and not subject to amendment without the consent of Tampa Electric (except to the extent certain city ordinances relating to permitting and like matters are modified from time to time), although, in certain events, they are subject to forfeiture.

Florida municipalities are prohibited from granting any franchise for a term exceeding 30 years. 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 $38.6 million in 2010, 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

Among our companies, 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 potential implications due to possible federal and state legislative initiatives. 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. Together, all of these improvements represent an investment in excess of $2 billion since 1994.

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

Consent Decree

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

In 2004, Tampa Electric made its NO_x reduction technology selection and decided to install SCR systems for NO_x control on the four coal-fired Big Bend units. 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 installed on all four of the units at the Big Bend Power Station and pre-SCR projects on Big Bend Units 1–3 (which are early plant improvements to reduce NO_x emissions prior to installing the SCRs) through the ECRC (see the **Regulation** section). Cost recovery for the SCRs began for each unit in the year that the unit entered service.

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

Emission Reductions

Projects committed to under the Consent Decree and Consent Final Judgment have resulted in significant reductions in emissions. Since 1998, Tampa Electric has reduced annual SO_2, NO_x and PM emissions from its facilities by 164,000 tons, 63,000 tons, and 4,500 tons, respectively.

Reductions in SO_2 emissions were accomplished through the installation of scrubber systems on Big Bend Units 1 and 2 in 1999. Big Bend Unit 4 was originally constructed with a scrubber. The Big Bend Unit 4 scrubber system was modified in 1994 to allow it to scrub emissions from Big Bend Unit 3 as well. Currently the scrubbers at the 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. With the completion of the final Big Bend SCR in May 2010, the SCR projects resulted in a total phased reduction of NO_x emissions by 63,000 tons per year from 1998 levels.

In total, Tampa Electric's emission reduction initiatives have resulted in the annual reduction of SO_2, NO_x and PM emissions in 2010 by 94%, 91% and 87%, respectively, below 1998 levels. With these state-of-the-art improvements in place, Tampa Electric's activities have helped to significantly enhance the quality of the air in the community. As a result of 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.

Tampa Electric has reduced mercury emissions through 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 NO_x controls at the Big Bend Power Station, which have led to a reduction of mercury emissions more than 75% from 1998 levels. The Clean Air Mercury Rule (CAMR) Phase I requirements were scheduled for implementation in 2010. The U.S. Court of Appeals for the District of Columbia Circuit vacated CAMR on Feb. 8, 2008. Prior to the court's decision, Tampa Electric expected that it would have been in compliance with CAMR Phase I without additional capital investment.

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, 2010, Tampa Electric Company has estimated its ultimate financial liability to be approximately $21.3 million (primarily related to PGS), and this amount has been reflected in the company's financial statements. This amount is higher than prior estimates to reflect a 2010 study for the costs of remediation primarily related to one site. 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 October 2010, the EPA notified Tampa Electric Company that it is a PRP under the federal Superfund law for the proposed 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 is in the process of responding to such matter, and the scope of its potential liability, if any, and the costs of any required investigations and remediation have not been determined.

Capital Expenditures

Tampa Electric's 2010 capital expenditures included $11.0 million for the installation of the final SCR equipment on the coal-fired Big Bend Unit 1 and $3.0 million for other environmental compliance projects. See the **Liquidity, Capital Expenditures** section of **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 more than 336,000 customers. The system includes approximately 11,000 miles of mains and 6,500 miles of service lines. (See PGS' **Franchises and Other Rights** section below.)

PGS had 537 employees as of Dec. 31, 2010. A total of 79 employees in six of PGS' 14 operating divisions are represented by various union organizations.

In 2010, the total throughput for PGS was almost 1.6 billion therms. Of this total throughput, 9% was gas purchased and resold to retail customers by PGS, 72% was third-party supplied gas that was delivered for retail transportation-only customers and 19% was gas sold off-system. Industrial and power generation customers consumed approximately 49% of PGS' annual therm volume, commercial customers used approximately 26%, off-system sales customers consumed 19% and the balance was consumed by residential customers.

While the residential market represents only a small percentage of total therm volume, residential operations comprised about 30% 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. Four new compressed natural gas stations have been connected in the past year with more planned for 2011.

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

(millions)	*2010*	*Revenues 2009*	*2008*	*2010*	*Therms 2009*	*2008*
Residential	$159.5	$143.4	$150.5	90.5	73.5	74.4
Commercial	143.8	142.2	155.6	407.9	381.7	375.9
Industrial	171.2	125.8	325.7	507.2	448.7	513.3
Power generation	9.7	10.0	12.7	582.2	538.3	455.6
Other revenues	37.2	40.6	36.5	—	—	—
Total	$521.4	$462.0	$681.0	1,587.8	1,442.2	1,419.2

No significant part of PGS' 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' 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' 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 that became effective on Jun. 18, 2009, and reflects a return on equity of 10.75%, which is the middle of a range between 9.75% and 11.75%. The allowed equity in capital structure is 54.7% from all investor sources of capital on an allowed rate base of $560.8 million.

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 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 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 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 2010, the FPSC approved rates under PGS' PGA clause for the period January 2011 through December 2011 for the recovery of the costs of natural gas purchased for its distribution customers.

In addition to its base rates and purchased gas adjustment clause charges, PGS customers (except interruptible customers) also pay a per-therm conservation charge for all gas. This charge is intended to permit PGS to recover 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' 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 15,700 transportation-only customers as of Dec. 31, 2010 out of approximately 32,400 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 60 interconnections (gate stations) serving PGS' operating divisions. In addition, PGS' Jacksonville division receives gas delivered by the South Georgia Natural Gas Company pipeline through two gate stations located northwest of Jacksonville. Gulfstream Natural Gas Pipeline provides delivery through seven gate stations.

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

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

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

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

Franchises and Other Rights

PGS holds franchise and other rights with approximately 100 municipalities throughout Florida. These franchises govern the placement of PGS' 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' 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' property located in the franchise area, if the franchise is not renewed; otherwise, based on judicial precedent, PGS is able to keep its facilities in place subject to reasonable rules and regulations imposed by the municipalities.

PGS' franchise agreements with the incorporated municipalities within its service area have various expiration dates ranging from the present through 2038. PGS expects to negotiate 14 franchises in 2011, the majority of which will be renewals of existing agreements. Franchise fees payable by PGS, which totaled $9.5 million in 2010, are calculated using various formulas which are based principally on natural gas revenues. Franchise fees are collected from only those customers within each franchise area.

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

Environmental Matters

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

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

Capital Expenditures

During the year ended Dec. 31, 2010, PGS did not incur any material capital expenditures to meet environmental requirements, nor are any anticipated for the 2011 through 2015 period.

TECO COAL

TECO Coal, with offices located in Corbin, Kentucky, 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 (collectively referred to herein as TECO Coal) own or control, by lease, mineral rights, and own or operate surface and underground mines and coal processing and loading facilities. TECO Coal produces, processes and sells bituminous, predominately low sulfur coal of steam, industrial and metallurgical grades. TECO Coal uses two distinct extraction techniques: continuous underground mining and dozer and front-end loader surface mining.

TECO Coal currently operates 24 underground mines, which employ the room and pillar mining method, and 10 surface mines. In 2010, TECO Coal sold 8.77 million tons of coal. None of this coal was sold to Tampa Electric. For the reporting period, TECO Coal had a combined estimated 267.6 million tons of proven and probable recoverable reserves. Historically, from time to time, TECO Coal has added to its proven and probable reserves. TECO Coal will continue to explore for additional reserves in and around its existing mining operations to prudently maintain or expand its reserves as appropriate.

History

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

In addition, in that year properties were also acquired in Pike County, Kentucky and Clintwood Elkhorn Mining Company was formed. Premier Elkhorn Coal Company and Pike Letcher Land Company were formed in 1991, when additional property was acquired in Pike and Letcher Counties, Kentucky.

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

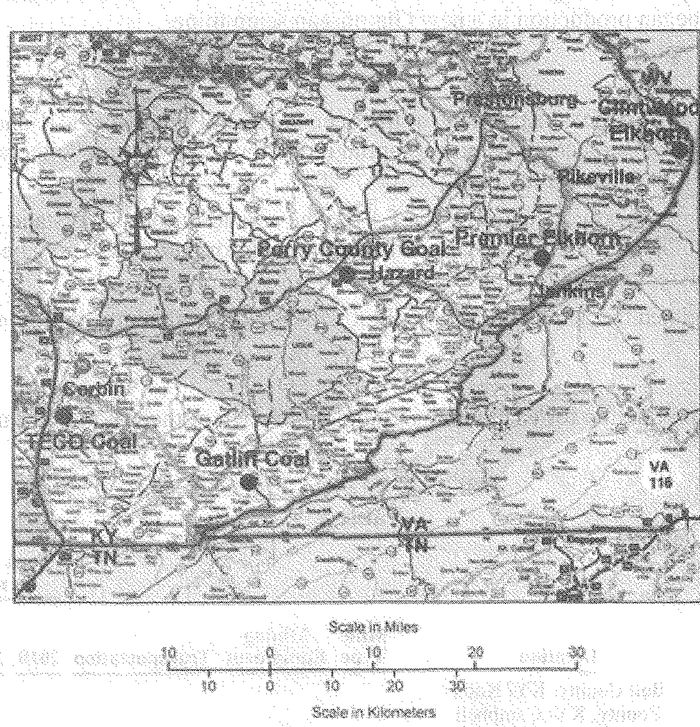
The newest mining company in the TECO Coal family is Perry County Coal Corporation, which was purchased in 2000 and is located in Perry, Knott and Leslie Counties, Kentucky.

In 2004, the acquisition of properties and the Millard Preparation Facilities (currently leased to a non-affiliated company) from American Electric Power and Kentucky Coal, LLC was completed. The property and facility are located in Pike County, Kentucky.

Mining Operations

TECO Coal currently has four mining complexes, all operating in Kentucky with a portion of Clintwood Elkhorn Mining Company operating in Virginia as well. A mining complex is defined as all mines that supply a single wash plant, except in the case of Clintwood Elkhorn Mining Company, which provides production for two active wash plants. Clintwood Elkhorn's Millard Plant is currently leased to a non-affiliated company. 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 12 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 strategic locations in close proximity to the TECO Coal preparation plants and rail shipping facilities. Coal is transported from TECO Coal's mining complexes to customers by means of railroad cars, trucks, barges or vessels, with rail shipments representing approximately 93% of 2010 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 three facilities. The equipment at each facility is in good condition and regularly maintained by qualified personnel. Table 1 below is a summary of the TECO Coal processing facilities:

PROCESSING FACILITIES SUMMARY
Table 1

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

Significant Projects

Significant projects for 2010 included the following:

Clintwood Elkhorn Mining

- Phase I engineering design and planning were completed on a clean coal recovery beltline which is to be installed at the Clintwood Elkhorn #3 Facilities. The project is expected to be completed in the third quarter of 2011. Clintwood Elkhorn also added an underground mine in the Elkhorn Three seam, in Island Creek in Pike County Kentucky.

Premier Elkhorn Coal

- Premier Elkhorn began initial construction on three new deep mine portals. The face-ups should be completed and the mining operations are expected to begin in the second and third quarters of 2011. Premier Elkhorn also completed the portal construction and began production in a new Glamorgan seam mine.

Perry County Coal

- Perry County Coal is finalizing the construction for the Second Creek Portals for E4-1 and E3-1 underground mines. When completed, TECO Coal expects to see a substantial reduction of travel time to the working mine face and more production. Completion is expected in the first quarter of 2011.
- A major exploration program was conducted on the E4-2 mine area to further understand the quality and mineablity of the reserve basin. All geologic modeling was also finalized. This information will now be utilized for mine planning and market analysis for this large boundary of reserves.
- Perry County Coal completed the acquisition of the First Creek reserves that are contiguous to the existing E4-1 mine.

Mining Complexes

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

MINING COMPLEXES
Table 2

	Location	Mine Type	Mining Equipment	Transportation	Tons Produced (in millions) 2010	2009	2008	Tons Sold (in millions) 2010	Year Established or Acquired
Gatliff Coal Company	Bell County, KY/ Knox County, KY/ Campbell County, TN	S	D/L	T	0	0.2	0.3	0	1974
Clintwood Elkhorn Mining	Pike County, KY/ Buchanan County, VA	U, S	CM, D/L, HM, A	R, R/V	2.1	2.0	2.6	2.3	1988
Premier Elkhorn Coal	Pike County, KY/Letcher County, KY/ Floyd County, KY	U, S	CM, D/L	R,T,R/B,T/B	2.6	3.2	3.2	3.4	1991
Perry County Coal	Perry County, KY/ Leslie County, KY/ Knott County, KY	U, S	CM, D/L, HM	R,T,R/B,T/B	3.1	3.1	3.1	3.1	2000
TOTAL					7.8	8.5	9.2	8.8	

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

Gatliff Coal Company

Gatliff Coal Company discontinued surface mine operations in 2009. Poor market conditions and a depletion of the low sulfur content coal that was previously required on its sales contract led to the cessation of mining operations. Gatliff Coal Company had no coal production in 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 or by neighboring competing coal companies for coal royalty considerations. Rich Mountain Coal Company formerly operated as a contractor for Gatliff Coal Company's Tennessee production, but is currently in non-producing reclamation status.

Clintwood Elkhorn Mining Company

Clintwood Elkhorn Mining Company has three facilities. One is located near Biggs, Kentucky in Pike County and is supplied by 11 underground mines and one surface mine. Principal products at the Biggs, Kentucky location include high volatile metallurgical coals and steam coal. The second Clintwood Elkhorn Mining Company facility is located near Hurley, Virginia and is supplied by three underground mines and two surface mines. The Hurley, Virginia operation facility also supplies high-volatile metallurgical coal as well as steam coal products. Products from both locations are shipped domestically to customers in North America via Norfolk Southern Corporation and vessels via the Great Lakes. International customers receive their products via ocean vessels from Lamberts Point, Virginia. The third facility, located at Millard, Kentucky, in Pike County is currently leased. In total, Clintwood Elkhorn Mining Company produced 2.1 million tons of coal in 2010, leaving a reserve base of 47.9 million recoverable tons.

Premier Elkhorn Coal Company

Located near Myra, in Pike County, Kentucky, Premier Elkhorn Coal Company is supplied by production from seven underground mines and five surface mines. Principal products include high-quality steam coal for utilities, specialty stoker products for ferro-silicon and industrial customers and PCI and metallurgical coal for the steel mills. Facilities include a unit train load-out with a 200 car siding capable of loading at 6,000 tons per hour as well as a single car siding. Products from this location are shipped via CSXT Railroad and trucking contractors to destinations in North America and internationally. All production is performed by Premier Elkhorn Coal Company even though Pike Letcher Land Company controls by fee and lease all of the recoverable reserves. Premier Elkhorn Coal Company produced 2.6 million tons of coal in 2010, leaving a reserve base of 70.2 million recoverable tons.

Perry County Coal Corporation

Located in Perry County Kentucky, near Hazard, Perry County Coal Corporation is supplied by three underground mines and two surface mines. Principal products include high quality steam coal for utilities, industrial stoker and PCI products. Facilities include an upgraded 1,350 ton per hour preparation plant and two unit train load-outs, each capable of loading at 5,000 tons per hour. Products from this location are shipped via CSXT Railroad and trucking contractors to destinations in both North America and internationally.

In 2009, Perry County Coal Corporation completed a comparable trade of underground reserves with another mining company of 16.0 million tons. 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 Corporation proved an additional 6.9 million tons of reserves which were previously reported as resource coal. In 2010, Perry County Coal Corporation leased the First Creek reserve which is contiguous to its existing E4-1 underground mine. This new lease will facilitate the mining of approximately 10.0 million tons of high quality reserves. Perry County Coal Corporation produced 3.1 million tons of coal in 2010, leaving a total reserve base of 146.1 million recoverable tons.

Sales and Marketing

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

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

Distribution

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

Competition

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

Employees

As of Dec. 31, 2010, TECO Coal employed a total of 1,126 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 Miner Act of 2006. TECO Coal's subsidiaries are also subject to various Kentucky, Tennessee and Virginia mining laws which require approval of roof control, ventilation, dust control and other facets of the coal mining business. Federal and state inspectors inspect the mines to ensure compliance with these laws. TECO Coal believes it is in substantial compliance with the standards of the various enforcement agencies. It is unaware of any mining laws or regulations that would materially affect the market price of coal sold by its subsidiaries, although mining accidents within the industry could lead to new legislation that could impose additional costs on TECO Coal.

Black Lung Legislation

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

In 2000, the Department of Labor issued amendments to the regulations implementing the federal black lung laws that, among other things, established a presumption in favor of a claimant's treating physician, limited a coal operator's ability to introduce medical evidence, and redefined Coal Workers Pneumoconiosis to include chronic obstructive pulmonary disease.

Under the Patient Protection and Affordable Care Act, signed into law in March 2010, miners with more than 15 years of experience and who have medical evidence of totally disabling lung disease are automatically granted black lung benefits rather than having to go through an application process proving they have black lung caused by being in the mines. Additionally, a surviving spouse is no longer required to reapply to receive the benefits. These changes in the regulations are expected to increase the number of claims, the percentage of claims approved and the overall cost of black lung to coal operators. TECO Coal, with the help of its consulting actuaries, continues to monitor claims very closely.

Workers' Compensation

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

Environmental Laws

Surface Mining Control and Reclamation Act

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

Clean Air Act/Clean Water Act

While conducting their mining operations, TECO Coal's subsidiaries are subject to various federal, state and local air and water pollution standards. In 2010, TECO Coal had expenditures of approximately $4.0 million for environmental protection and reclamation programs. TECO Coal expects to spend a similar amount in 2011 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 the EPA's Toxic Release Inventory process, companies are required to report annually listed toxic materials that exceed defined quantities.

Glossary of Selected Mining Terms:

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

Bituminous Coal. The most common type of coal with moisture content less than 20% by weight and heating value of 10,500 to 14,000 Btu per pound. It is dense and black and often has well-defined bands of bright and dull material.

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

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

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

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

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

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

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

Deep mine. An underground coal mine.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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" ton 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 124 employees as of Dec. 31, 2010.

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

Tampa Centro Americana de Electricidad, Limitada (TCAE), an entity 96.06% owned by TPS Guatemala One, Inc., a subsidiary of TECO Guatemala, and the owner of an oil-fired electric generating facility (the Alborada Power Station), has a U.S. dollar-denominated PPA with EEGSA to provide 78 megawatts of capacity ending in 2015. EEGSA is responsible for providing the fuel for the plant, with a subsidiary of TECO Guatemala providing assistance in fuel administration.

In 1998, DECA II, a consortium whose members included a subsidiary of TECO Guatemala, Iberdrola Energia, S.A. of Spain (Iberdrola), an electric utility in Spain, and Electricidade de Portugal, an electric utility in Portugal, completed the purchase of an 80.9% ownership interest in EEGSA for $520 million. In October 2010, TECO Guatemala sold its 30% interest in DECA II.

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

Our existing plants in Guatemala operate under environmental permits issued by the local environmental authorities. The plants were built in 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	68	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	55	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	51	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	57	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	50	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; Vice President-Regulatory Affairs, Tampa Electric Company, April 2005-April 2006.
Sandra W. Callahan	58	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	62	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	51	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.
J. J. Shackleford	64	President of TECO Coal Corporation, since prior to 2006.

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 4, 2011, 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 to improve could adversely affect Tampa Electric's or PGS' expected performance. Continuation or worsening of the current economic conditions could affect these companies' ability to collect payments from customers.

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

Our electric and gas 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' 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. Recent decisions by the FPSC in investor owned utility rate cases 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 coal combustion by-products, 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. 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.

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 ECRC, Tampa Electric could seek to recover those costs through a base-rate proceeding, but we cannot predict whether the FPSC would grant such recovery.

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

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

The former Governor of Florida signed three Executive Orders in July 2007 aimed at reducing Florida's emissions of GHG. The three orders include directives for reducing GHG emissions by electric utilities to 2000 levels by 2017, to 1990 levels by 2025, and by 80 percent of 1990 levels by 2050.

Also in 2008, the state legislature passed broad energy and climate legislation. However, since that time, the process at the state level has slowed and is likely to be pushed out since the issue has become increasingly active at the federal level. It is unclear if the new Governor of Florida supports the reduction of GHG to the same degree as the former Governor.

However, if Florida does pass final GHG reduction rules that result in increased costs to Tampa Electric its operating results could be adversely affected.

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

In connection with the Executive Orders signed by the former Governor of Florida in July 2007, the FPSC was tasked with evaluating a RPS. The FPSC has made a recommendation to the Florida legislature that the RPS percentage be 7% by Jan. 1, 2013, 12% by Jan. 1, 2016, 18% by Jan. 1, 2019 and 20% by Jan. 1, 2021. The FPSC recommendation is subject to ratification by the Florida legislature, 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. 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 of Tampa Electric's integrated gasification combined cycle (IGCC) unit and the cancellation of numerous proposed coal-fired generating stations in Florida and across the United States in response to GHG emissions concerns is expected to lead to an increasing reliance on natural gas-fired generation to meet the growing demand for electricity. Currently, there is an adequate supply and infrastructure to meet demand for natural gas in Florida and nationally. 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, 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' 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 it 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 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, the 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.

Changes in customer energy usage patterns, the impact of the Florida housing market, and the cost of complying with potential new environmental regulations, may affect sales at our utility companies.

Tampa Electric's weather-normalized residential per customer usage declined in 2010, 2009 and 2008. We believe that mild weather patterns especially in the spring and fall, voluntary conservation in response to the economic conditions, increased appliance efficiency, and increased residential vacancies as a result of higher foreclosures contributed to the declining per customer usage.

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

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 2011-2012 federal budget, as proposed, includes the elimination of the percentage depletion tax deduction for coal mines and other hard mineral 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 2011.

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

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 has four permits on the list of permits subject to enhanced review by the U.S. EPA under its memorandum of understanding with the USACE, which was issued in September 2009. To date, none of these permits have been issued. 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.

In 2010, the EPA issued new water quality standards for discharges from surface mining operations that would be conditions to the issuance of new permits, and may not be technically possible under most circumstances. Compliance with these conditions is projected to be very costly. The cost associated with compliance could make affected surface mining operations unprofitable or make the reserves no longer economic to develop.

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

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

Guatemala, similar to many countries, has been experiencing 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.

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

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

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

Financing Risks

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, 2010, 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 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. In 2010 we were able to access the capital markets on favorable terms to refinance debt and extend maturities. Although we have no significant debt maturities in 2011 Tampa Electric has debt maturing in 2012 and TECO Finance has debt maturing in 2015, and both have credit facilities expiring in 2012. Future financial market conditions could limit our ability to raise the capital we need, or to renew our credit facilities, and could increase our interest costs which could reduce earnings.

We enter into derivative transactions with counterparties, most of which are financial institutions, to hedge our exposure to commodity price changes. Although we believe we have appropriate credit policies in place to manage the non-performance risk associated with these transactions, 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.

Despite the strong financial market recovery in 2010 and 2009, 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, 2010 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 80% as of the next Pension Protection Act measurement date of Jan. 1, 2011. This will require future contributions to the plan ranging from $35 - $50 million annually. 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 2011 will be at levels consistent with 2010. 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, and to maintain coal-fired generating unit reliability and efficiency.

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 positive 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 BBB+ with a positive outlook. Any downgrades by the rating agencies may affect our ability to borrow, may change requirements for future collateral or margin postings, and may increase our financing costs, which may decrease our earnings. We also may experience greater interest expense than we may have otherwise if, in future periods, we replace maturing debt with new debt bearing higher interest rates due to any such downgrades. In addition, downgrades could adversely affect our relationships with customers and counterparties.

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

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

We are a holding company and are dependent on cash flow from our subsidiaries to meet our cash requirements that are not satisfied from external funding sources. Some of our subsidiaries have indebtedness containing restrictive covenants which, if violated, would prevent them from making cash distributions to us. In particular, certain long-term debt at PGS prohibits payment of dividends to us if Tampa Electric Company's consolidated shareholders' equity is lower than $500 million. At Dec. 31, 2010, Tampa Electric Company's consolidated shareholders' equity was approximately $2.2 billion. Also, our wholly-owned subsidiary, TECO Diversified, Inc., the holding company for TECO Coal, has a guarantee related to a coal supply agreement that could limit the payment of dividends by TECO Diversified to us (see the **TECO Energy Significant Financial Covenants** table in the **Liquidity, Capital Resources** sections of **Management's Discussion & Analysis**).

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 2010 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 combustion turbine (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 6MW 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 22,368 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, 2010, there were 672,280 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' distribution system extends throughout the areas it serves in Florida and consists of approximately 17,500 miles of pipe, including approximately 11,000 miles of mains and 6,500 miles of service lines. Mains and service lines are maintained under rights-of-way, franchises or permits.

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

TECO COAL

Property Control

TECO Coal operations are conducted on both owned and leased properties totaling over 265,000 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 are verified during lease or purchase negotiations.

In situations where property is controlled by a lease, the initial lease terms are expected to allow the reserves for the associated operation to be mined. 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 to exhaust the coal from the leased property, provisions are made within the original lease to allow extensions of the lease upon continued payment of minimum royalties.

Coal Reserves

As of Dec. 31, 2010, the TECO Coal operating companies had a combined estimated 267.6 million tons of proven and probable recoverable reserves. All of the reserves consist of High Vol A Bituminous Coal. Reserves are the portion of the proven and probable tonnage that meet TECO Coal's economic criteria regarding mining height, preparation plant recovery, depth of overburden and stripping ratio. Generally, these reserves would be commercially mineable at year-end price and cost levels. Additionally, other controlled areas presently identified as resource now total 60.8 million tons of coal.

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

> **Proven (Measured) Reserves**—Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, working or drill holes: grade and/or quality are computed from the results of detailed sampling; and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established.
>
> **Probable (Indicated) Reserves**—Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but for which the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation.

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

TECO Coal's reserve estimates are prepared by its staff of geologists, with an average experience of 19 years. TECO Coal also has two chief geologists with the responsibility to track changes in reserve estimates, supervise TECO Coal's other geologists and coordinate third party reviews of our reserve estimates by qualified mining consultants. In 2010, a third-party reserve audit was performed by Marshall Miller & Associates on the portion of reserves acquired during 2010. The results of that audit are reflected in the reserve included in this report.

Reserve Estimation Procedure

TECO Coal's reserves are based on over 3,000 data points, including drill holes, prospect measurements and mine measurements. Our reserve estimates also include information obtained from our on-going exploration drilling and in-mine channel sampling programs. Reserve classification is determined by evaluation of engineering and geologic information along with economic analysis. These reserves are adjusted periodically to reflect fluctuations in the economics in the market and/or changes in engineering parameters and/or geologic conditions. Additionally, the information is constantly being updated to reflect new data for existing property as well as new acquisitions and depleted reserves.

This data may include elevation, thickness, and, where samples are available, the quality of the coal from individual drill holes and channel samples. The information is assembled by qualified geologists and engineers located throughout TECO Coal. Information is entered into sophisticated computer modeling programs from which preliminary 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 models and manipulated the grids 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 TECO Coal engineers, geologists and financial management.

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

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

Mining Complex	Location	Total	Proven	Probable	Owned	Leased	Assigned (2) 2011	Assigned (2) 2010	Unassigned (2) 2011	Unassigned (2) 2010
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	47.9	39.9	8.0	3.2	44.7	47.9	50.0	—	—
Premier Elkhorn Coal	Pike County, KY/Letcher County, KY/ Floyd County, KY	70.2	52.8	17.4	38.9	31.3	61.8	64.4	8.4	8.4
Perry County Coal	Perry County, KY/ Leslie County, KY/ Knott County, KY	146.1	81.2	64.9	1.2	144.9	138.8	129.2	7.3	6.8
Total		267.6	176.9	90.7	44.5	223.1	249.0	244.1	18.6	18.1

Notes:

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

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

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

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

Mining Complex	Recoverable Reserves	Sulfur Content < 1% (2)	Sulfur Content >1% (2)	Compliance Tons (3)	Average BTU/lb As received	Coal Type (4)
Gatliff Coal Company	3.4	3.2	0.2	—	13,500	LSU
Clintwood Elkhorn Mining	47.9	22.8	25.1	23.6	13,400	HVM, LSU, PCI
Premier Elkhorn Coal	70.2	40.0	30.2	24.3	13,350	IS, LSU, PCI, HVM
Perry County Coal	146.1	121.9	24.2	74.9	13,195	LSU, PCI, V
Total	267.6	187.9	79.7	122.8		

Notes:

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

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

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

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

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

TECO GUATEMALA

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

Item 3. LEGAL PROCEEDINGS.

From time to time, 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 **8**, **Commitments and Contingencies**, of the TECO Energy, Inc. and Tampa Electric Company **Consolidated Financial Statements**, respectively.

Item 4. SPECIALIZED 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 proposed Item 106 of Regulation S-K (17 CFR 229.106) is included in **Exhibit 99.1** 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*
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	$ 0.20	$0.205	$0.205	$0.205
2009				
High	$12.97	$12.41	$14.64	$16.71
Low	$ 8.41	$10.28	$11.16	$13.45
Close	$11.15	$11.93	$14.08	$16.22
Dividend	$ 0.20	$ 0.20	$ 0.20	$ 0.20

The approximate number of shareholders of record of common stock of TECO Energy as of Feb. 21, 2011 was 13,746.

Dividends on TECO Energy's common stock are declared and paid at the discretion of its Board of Directors. The primary sources of funds to pay dividends to its common shareholders are dividends and other distributions from its operating companies. TECO Energy's $200 million credit facility contains a covenant that could limit the payment of dividends exceeding a calculated amount (initially $50 million) in any quarter under certain circumstances. This covenant is not applicable at TECO Energy's current credit ratings. Certain long-term debt at PGS contains restrictions that limit the payment of dividends and distributions on the common stock of Tampa Electric Company.

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

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

All of Tampa Electric Company's common stock is owned by TECO Energy, Inc. and, therefore, there is no market for the stock. Tampa Electric Company pays dividends on its common stock substantially equal to its net income. Such dividends totaled $239.3 million in 2010, $179.6 million in 2009 and $159.9 million in 2008. 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.

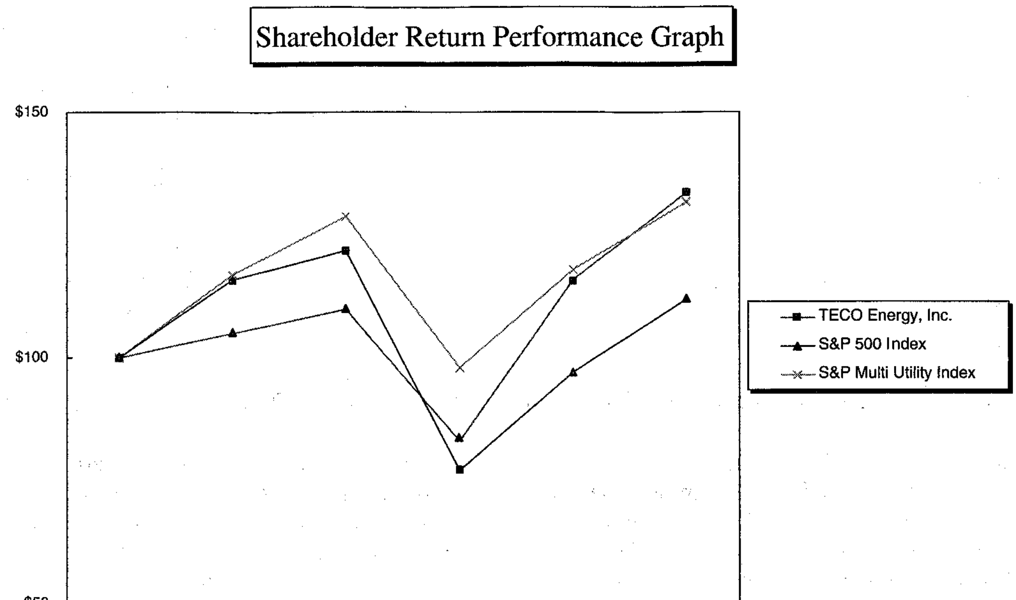
Set forth below is a table showing shares of TECO Energy common stock deemed repurchased by the issuer.

	(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, 2010—Oct. 31, 2010	1,097	$17.59	—	—
Nov. 1, 2010—Nov. 30, 2010	6,957	$16.91	—	—
Dec. 1, 2010—Dec. 31, 2010	1,285	$17.03	—	—
Total 4th Quarter 2010	9,339	$17.01	—	—

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

Shareholder Return Performance Graph

The following graph shows the cumulative total shareholder return on our common stock on a yearly basis over the five-year period ended Dec. 31, 2010, and compares this return with that of the S&P 500 Index and the S&P Multi Utility Index. The graph assumes that the value of the investment in our common stock and each index was $100 on Dec. 31, 2005 and that all dividends were reinvested.



	2005	2006	2007	2008	2009	2010
TECO Energy, Inc.	$100	$105	$110	$83	$116	$134
S&P 500 Index	$100	$116	$122	$77	$97	$112
S&P Multi Utility Index	$100	$117	$129	$98	$118	$132

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

(millions, except per share amounts) *Years ended Dec. 31,*	*2010*	*2009*	*2008*	*2007*	*2006*
Revenues	$3,487.9	$3,310.5	$3,375.3	$3,536.1	$3,448.1
Net income from continuing operations	$ 239.6	$ 213.9	$ 162.4	$ 316.7	$ 174.8
Net income from discontinued operations (1)	—	—	—	$ 14.3	$ 1.9
Net income attributable to TECO Energy (2)	$ 239.0	$ 213.9	$ 162.4	$ 413.2	$ 246.3
Total assets	$7,173.9	$7,219.5	$7,147.4	$6,765.2	$7,361.8
Long-term debt	$3,226.4	$3,309.5	$3,213.5	$3,158.4	$3,212.6
Earnings per share (EPS)—basic;					
From continuing operations (1)	$ 1.12	$ 1.00	$ 0.77	$ 1.90	$ 1.18
From discontinued operations (1)	—	—	—	$ 0.07	$ 0.01
EPS basic	$ 1.12	$ 1.00	$ 0.77	$ 1.97	$ 1.19
Earnings per share (EPS)—diluted;					
From continuing operations (1)	$ 1.11	$ 1.00	$ 0.77	$ 1.89	$ 1.17
From discontinued operations (1)	—	—	—	$ 0.07	$ 0.01
EPS diluted	$ 1.11	$ 1.00	$ 0.77	$ 1.96	$ 1.18
Dividends declared per common share	$ 0.815	$ 0.800	$ 0.795	$ 0.775	$ 0.760

(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 672,000 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 more than 336,000 residential, commercial, industrial and electric power generating customers in all of the major metropolitan areas of the state, with a total natural gas throughput of almost 1.6 billion therms in 2010.

We also have two 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 2010 were 8.8 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. In October 2010, TECO Guatemala sold its 24% ownership interest in Guatemala's largest distribution utility, Empresa Eléctrica de Guatemala (EEGSA), and in affiliated companies (in combination called DECA II).

2010 PERFORMANCE

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

In 2010, our net income and earnings per share attributable to TECO Energy were $239.0 million or $1.12 per share, 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, $0.9 million of the final restructuring charge for the 2009 restructuring described below and a $1.8 million benefit from the recovery of fees related to the previously sold McAdams Power Station.

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

In 2009, our net income and earnings per share attributable to TECO Energy were $213.9 million or $1.00 per share, compared to $162.4 million or $0.77 per share in 2008. Net income in 2009 included $15.8 million of restructuring charges, a $5.2 million write-off of project development costs at Tampa Electric, primarily related to the Polk Unit 6 IGCC plant, a $3.8 million loss on student loan securities held at TECO Energy, and an $8.7 million net gain on the sale of TECO Guatemala's 16.5% interest in the Central American fiber optic telecommunications provider, Navega.

Our non-GAAP results in 2009, which exclude the charges and gains discussed above, were $1.08 on a per share basis, compared to $0.87 in 2008 (see the **2009** and **2008 Reconciliation of GAAP net income from continuing operations to non-GAAP results** tables). Our results in 2009 reflected the benefits of higher base rates at Tampa Electric and PGS effective in

May and June 2009, respectively, and improved margins at TECO Coal as a result of higher selling prices. At TECO Guatemala, results reflected the impact of extended unplanned outages at the San José Power Station in the first half of 2009, the negative impact of lower Value Added Distribution (VAD) tariffs at EEGSA, the Guatemalan distribution utility, and lower net income from the unregulated affiliated companies due to the sale of Navega in the first quarter (see the **TECO Guatemala** section).

In 2010, we focused on managing our utility businesses to earn their allowed Returns on Equity (ROE) following the completion of their respective base rate cases in 2009. We used the proceeds from the sale of DECA II to retire parent debt, and we took advantage of improved financial market conditions to extend the maturities of certain TECO Finance and Tampa Electric Company debt at lower interest rates. In order to potentially take advantage of changing technology and evolving customer usage patterns, we initiated an evaluation of opportunities for our regulated utilities including, among other things, Smart Grid, alternative fueled vehicles and renewable energy sources. This ongoing evaluation is focused on developing longer range plans to take advantage of emerging growth and investment opportunities.

OUTLOOK

We remain focused on our long-term goal of investing in and growing our Florida utility businesses, while maximizing the returns from our other energy-related businesses, TECO Coal and TECO Guatemala. Reduction of parent debt also remains a priority and we expect continued progress at a modest pace, following the substantial debt retirement and debt restructuring achieved in 2010.

Our outlook for 2011 results reflects our expectation that our Florida utilities will continue to earn their authorized returns on equity, TECO Coal will benefit from improved margins due to strong contracted prices, TECO Guatemala will deliver lower earnings, and parent will benefit from substantially lower interest expense and tax impacts. The drivers impacting 2011 are summarized below and discussed in further detail in the individual operating company sections.

Tampa Electric expects customer growth in 2011 to continue at a pace similar to 2010 when the number of customers increased 0.6%. PGS expects customer growth less than Tampa Electric's due to the more pronounced impact of the weak housing market in certain areas of Florida served by PGS, such as the Naples and Ft. Myers areas.

Energy sales at both utilities are likely to be lower in 2011 under an assumption of normal weather conditions. Record cold winter temperatures and, in the case of Tampa Electric, an early start to summer temperatures, boosted energy sales in 2010. At both utilities, however, the positive weather impact in 2010 was substantially offset by the impact of regulatory agreements that resulted in one-time reductions to net income in 2010.

We expect TECO Coal net income to increase in 2011 as higher contracted selling prices boost margins. With more than 90% of its expected 2011 sales contracted, the average contracted selling price across all products of $87 per ton is $11 per ton higher than 2010, while the fully-loaded, all-in cost of production is expected to be in a range between $74 and $78 per ton, or $5-9 per ton higher.

We expect lower results from TECO Guatemala in 2011, largely as a result of the October 2010 sale of its interest in DECA II, which had contributed about $13 million to net income in 2010 prior to its sale. TECO Guatemala expects normal operations and capacity payments and higher spot sales at its San José Power station, and a full year impact of the lower capacity rates that became effective for its Alborada Power Station when the power sales contract was extended in September 2010 at lower prices.

We expect the net costs of parent/other to decline substantially in 2011, reflecting lower interest expense and the absence of $10 million of tax charges that were specific to 2010. In addition to the retirement of $236 million of debt in December 2010, which will favorably impact 2011 results by $10 million, we expect to benefit from a full year of the first quarter 2010 refinancing and the retirement of the May 2011 maturity.

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 reduction of parent debt. In 2011 we expect to make additional equity contributions to Tampa Electric and PGS to support their capital structures and financial integrity, and to retire $64 million of parent debt at maturity. We anticipate moderate capital spending in 2011 of $440 million. (See the **Liquidity, Capital Resources** section).

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)	*2010*	*2009*	*2008*
Net income attributable to TECO Energy	**$239.0**	$213.9	$162.4
Non-GAAP results	**$275.5**	$230.0	$183.3

In 2010, net income and earnings per share attributable to TECO Energy were $239.0 million, or $1.12 per share compared to $213.9 million, or $1.00 per share, in 2009. Our non-GAAP results which exclude charges and gains were $275.5 million, or $1.29 on a per share basis (see the **2010** and **2009 Reconciliation of GAAP net income from continuing operations to non-GAAP results** tables). In 2009, net income and earnings per share attributable to TECO Energy were $213.9, or $1.00 per share, compared to $162.4 million, or $0.77 per share, in 2008. Our non-GAAP results in 2009, which exclude charges and gains, were $230.0 million, or $1.08 on a per share basis, compared to our 2008 non-GAAP results of $183.3 million, or $0.87 on a per share basis (see the **2009** and **2008 Reconciliation of GAAP net income from continuing operations to non-GAAP results** tables).

Compared to 2009, our results in 2010 reflected higher earnings at both of the regulated utilities, Tampa Electric and PGS, and at TECO Coal and TECO Guatemala. In 2010 our net income and earnings per share were reduced by $36.5 million, or $0.17 per share, of net charges and gains, primarily related to early debt retirement costs, taxes on previously undistributed earnings at DECA II and the net loss on the sale of DECA II. Net income 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 FPSC in August that resolved all outstanding issues in the 2008 base rate case (see the **Tampa Electric** section).

Compared to 2008, our results in 2009 reflected higher earnings at both of the regulated utilities, Tampa Electric and PGS, and at TECO Coal and lower earnings from TECO Guatemala. In 2009, our net income and earnings per share were reduced by a net $16.1 million, or $0.08 per share, of charges and gains, primarily related to restructuring actions and the write-off of project development costs at Tampa Electric. In 2008, our net income and earnings per share were reduced by a net $20.9 million of charges and gains consisting primarily of $21.6 million, or $0.10 per share, respectively, for income taxes related to the repatriation of cash and investments from TECO Guatemala, of which $9.6 million was recognized by TECO Guatemala and $12.0 million by TECO Energy parent, (see the **2008 Reconciliation of GAAP net income from continuing operations to non-GAAP results** table).

2010 Earnings Summary

(millions) Except per-share amounts	*2010*	*2009*	*2008*
Consolidated revenues	**$3,487.9**	$3,310.5	$3,375.3
Earnings per share—basic			
Earnings per share attributable to TECO Energy	**$ 1.12**	$ 1.00	$ 0.77
Earnings per share—diluted			
Earnings per share attributable to TECO Energy	**$ 1.11**	$ 1.00	$ 0.77
Net income attributable to TECO Energy	**$ 239.0**	$ 213.9	$ 162.4
Charges and (gains) (1)	**36.5**	16.1	20.9
Non-GAAP results (2)	**$ 275.5**	$ 230.0	$ 183.3
Average common shares outstanding			
Basic	**212.6**	211.8	210.6
Diluted	**214.8**	213.1	211.4

(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:

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
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

2008 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	$135.6	$27.1	$18.0	$36.9	$(55.2)	$162.4
Waterborne transportation dispute settlement	1.9	—	—	—	—	1.9
Final adjustments associated with the sale of TECO Transport recorded at Parent	—	—	—	—	(2.6)	(2.6)
Taxes on repatriation of cash and investments from Guatemala	—	—	—	9.6	12.0	21.6
Total charges and (gains)	1.9	—	—	9.6	9.4	20.9
Non-GAAP results	$137.5	$27.1	$18.0	$46.5	$(45.8)	$183.3

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

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

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

OPERATING RESULTS

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

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

(millions) Except per share amounts		*2010*	*2009*	*2008*
Segment revenues (1)				
Regulated companies	Tampa Electric	**$2,163.2**	$2,194.8	$2,091.2
	Peoples Gas	**529.9**	470.8	688.4
Total regulated		**$2,693.1**	$2,665.6	$2,779.6
Unregulated companies	TECO Coal	**$ 690.0**	$ 653.0	$ 588.4
	TECO Guatemala (2)	**124.4**	8.3	8.4
Total unregulated		**$ 814.4**	$ 661.3	$ 596.8
Net income (3)				
Regulated companies	Tampa Electric	**$ 208.8**	$ 160.2	$ 135.6
	Peoples Gas	**34.1**	31.9	27.1
Total regulated		**242.9**	192.1	162.7
Unregulated companies	TECO Coal	**53.0**	37.2	18.0
	TECO Guatemala	**41.6**	38.6	36.9
Total unregulated		**94.6**	75.8	54.9
Parent/other		**(98.5)**	(54.0)	(55.2)
Net income attributable to TECO Energy		**$ 239.0**	$ 213.9	$ 162.4
Earnings per share—basic (4)				
Regulated companies	Tampa Electric	**$ 0.98**	$ 0.76	$ 0.64
	Peoples Gas	**0.16**	0.15	0.13
Total regulated		**1.14**	0.91	0.77
Unregulated companies	TECO Coal	**0.25**	0.17	0.08
	TECO Guatemala	**0.19**	0.18	0.18
Total unregulated		**0.44**	0.35	0.26
Parent/other		**(0.46)**	(0.26)	(0.26)
Earnings attributable to TECO Energy		**$ 1.12**	$ 1.00	$ 0.77
Average shares outstanding—basic		**212.6**	211.8	210.6

(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 José) 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 financing costs to the non-utility companies. Internally allocated finance costs were 6.5% for July through December 2010, 7.15% for September 2008 through June 2010 and 7.25% for January 2008 through August 2008.
(4) The number of shares used in the earnings-per-share calculations is basic shares.

TAMPA ELECTRIC

Electric Operations Results

Net income in 2010 was $208.8 million, compared to $160.2 million in 2009. There were no charges or gains in 2010. 2009 non-GAAP results were $176.7 million, which excluded the $11.3 million of restructuring charges and the $5.2 million write-off of project development costs primarily related to the Polk Unit 6 IGCC project. Net income and non-GAAP results in 2008 were $135.6 million and $137.5 million, respectively. Non-GAAP results in 2008 excluded the $1.9 million waterborne transportation settlement (see the **2009** and **2008 Reconciliation of GAAP net income from continuing operations to non-GAAP results** table).

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 $24.0 million reduction in base revenues ($14.7 million after tax) associated with the regulatory agreement approved by the FPSC in August 2010, which resolved all outstanding issues in the 2008 base rate case. 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.

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.

In 2010, total retail net energy for load, which is a calendar measurement of retail energy sales rather than a billing cycle measurement, 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.

Compared to 2009, depreciation and amortization expense increased $9.5 million, reflecting the additions to facilities to serve customers discussed above. In 2010, 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.

Net income in 2009 was $160.2 million compared to $135.6 million in 2008. Tampa Electric's full-year non-GAAP results were $176.7 million, which excluded $11.3 million of restructuring charges and the $5.2 million write-off of project development costs primarily related to the Polk Unit 6 IGCC plant, compared to non-GAAP results of $137.5 million in 2008, which excluded the $1.9 million waterborne transportation settlement (see the **2009 and 2008 Reconciliation of GAAP net income from continuing operations to non-GAAP results** table).

Pretax base revenues increased approximately $72 million in 2009 from the higher base rates approved by the FPSC for Tampa Electric effective May 7, 2009. In the 2009 full-year period, there was no reduction in net income due to the waterborne transportation disallowance for the transportation of solid fuel, compared to an $8.9 million reduction in the 2008 period.

The higher 2009 base revenues were partially offset by lower retail energy sales and higher operations and maintenance, depreciation, property tax and interest expense. Results reflect 1.1% lower retail energy sales in 2009, primarily due to lower sales to commercial and industrial customers as a result of the weak Florida economy, and voluntary conservation by residential customers, which we believe was in response to the generally weaker economic conditions. Off-system sales declined due to lower state-wide demand. Total heating and cooling degree days were 4% above normal and 10% above 2008 levels. The average number of retail customers decreased 0.1% for the year.

In 2009, excluding all FPSC-approved cost recovery clause-related expenses, restructuring charges and the Polk 6 write-off, operations and maintenance expense increased $8.7 million, compared to 2008, primarily due to $2.1 million higher spending on generating unit maintenance and repairs, $1.7 million higher expenses to operate the distribution system, $3.0 million higher employee-related expenses, and $0.4 million higher bad debt expense. These increases were partially offset by savings in salaries and other benefits as a result of the restructuring actions taken in 2009. Depreciation and amortization expense increased $9.1 million reflecting additional facilities to serve customers. Interest expense increased due to higher long-term debt balances, and interest income decreased due to lower interest rates on lower under-recovered fuel balances. Net income also included $9.3 million of AFUDC-equity related to the construction of the peaking generation units, rail coal unloading facilities and the installation of NO_x pollution control equipment, compared to $6.3 million in 2008.

Base Rates

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 $34 million 2010 base rate step increase associated with the five peaking combustion turbines (CTs) and the solid-fuel rail unloading facilities at the Big Bend Power Station scheduled to enter service before the end of 2009.

In July 2009, in response to a motion for reconsideration, the FPSC determined that adjustments to the capital structure used to calculate the new rates should have been calculated over all sources of capital rather than only investor sources. This change resulted in $9.3 million higher revenue requirements in 2009. 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 to reject their motion for reconsideration of the 2010 portion of base rates approved in 2009. The FPSC and Tampa Electric opposed this appeal.

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 reduced by $8.4 million to $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 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 is 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 will be in effect.

Summary of Operating Results

(millions)	*2010*	*% Change*	*2009*	*% Change*	*2008*
Revenues	**$2,163.2**	(1.4)	$2,194.8	5.0	$2,091.2
Other operating expenses	**289.5**	18.3	244.7	17.8	207.7
Maintenance	**116.1**	(5.9)	123.4	6.2	116.2
Depreciation	**215.9**	7.7	200.4	8.0	185.6
Taxes, other than income	**145.3**	0.3	144.9	6.2	136.5
Restructuring costs	**—**	—	18.4	—	—
Non-fuel operating expenses	**766.8**	4.8	731.8	13.3	646.0
Fuel	**767.6**	(16.9)	923.3	12.7	819.4
Purchased power	**179.6**	1.1	177.6	(41.8)	305.4
Total fuel expense	**947.2**	(14.0)	1,100.9	(2.1)	1,124.8
Total operating expenses	**1,714.0**	(6.5)	1,832.7	3.5	1,770.8
Operating income	**449.2**	24.1	362.1	13.0	320.4
AFUDC equity	**1.9**	(79.6)	9.3	47.6	6.3
Net income	**$ 208.8**	30.3	$ 160.2	18.1	$ 135.6
Megawatt-Hour Sales (thousands)					
Residential	**9,185**	6.0	8,667	1.4	8,546
Commercial	**6,221**	(0.8)	6,274	(2.0)	6,399
Industrial	**2,010**	0.7	1,995	(9.5)	2,205
Other	**1,797**	(2.3)	1,839	—	1,840
Total retail	**19,213**	2.3	18,775	(1.1)	18,990
Sales for resale	**516**	17.1	440	(50.2)	884
Total energy sold	**19,729**	2.7	19,215	(3.3)	19,874
Retail customers-thousands (average)	**671.0**	0.6	666.7	(0.1)	667.3

Operating Revenues

In 2010, retail megawatt hours, 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, which is a calendar measurement of retail energy sales rather than a billing cycle measurement, increased 3.6%. Off-system sales (Sales for resale) increased 17.1%, primarily due to increased demand throughout Florida in response to cold winter weather.

In 2009 retail megawatt hour sales declined 1.1% primarily due to lower sales to commercial and industrial customers as a result of the weak Florida economy, and voluntary conservation by residential customers, which we believe was in response to the generally weaker economic conditions. Off-system sales declined due to lower state-wide demand. Total heating and cooling degree days were 4% above normal and 10% above 2008 levels. The average number of retail customers decreased 0.1% for the year. Pretax base revenues increased approximately $72 million in 2009 from the higher base rates approved by the FPSC, which were effective in May 2009.

For the past three years, weather-normalized energy consumption per residential customer declined due to the combined effects of voluntary conservation efforts, residential vacancies and changes in appliance efficiency. It is now apparent that some of the robust residential customer growth in the 2005 through mid-2007 period, which was measured by new meter installations, was actually vacant residences with minimal energy usage. The average number of residential customers with minimal usage was approximately 8% of total residential customers in 2010, 2009 and 2008.

Electricity sales to the phosphate industry increased 5.1% in 2010, following a 6.5% decrease in 2009. The 2010 increase in sales to phosphate customers was driven by higher operating rates at the customer's facilities in response to higher demand for their products world wide. The 2009 decline in sales to phosphate customers was partially attributable to planned outages at their production facilities as the producers managed their product inventory levels during the economic downturn. Base revenues from phosphate sales represented about 3% of base revenues in 2010 and less than 3% in 2009. Sales to commercial customers decreased 0.8% in 2010 after a 2.0% decrease in 2009, reflecting the local economic conditions.

Energy sold to other utilities for resale increased 17.1% in 2010 due to increased demand throughout the State of Florida in response to cold winter weather early in the year. Energy sold to other utilities for resale decreased 50.2% in 2009 primarily due to lower energy demand state-wide and to lower natural gas prices through much of the summer, which made Tampa Electric's base-load coal generation not the lowest cost form of energy for spot sales.

Customer and Energy Sales Growth Forecast

The Florida economy has started to recover from the economic downturn, but unemployment remains above the national level and the housing market, which was a major driver of growth in the Florida economy for many years, is not expected to improve until unemployment declines (see the **Risk Factors** section). In general, economists are forecasting a slow improvement in the unemployment rate in 2011, and a stronger improvement in the economy in 2012 and beyond. The forecast used by Tampa Electric reflects a continuation of the modest customer growth trend that was experienced in 2010 in 2011. Following the very strong energy sales in 2010 due to weather, absolute levels of energy sales are expected to decline assuming normal weather. On a weather-normalized basis energy sales are expected to decline slightly due to lower customer usage in response to increased energy efficiency, voluntary conservation and the continued economic weakness. The average number of customers increased 0.6% in 2010 following a 0.1% decline in 2009. Actual average 2008 customer growth was 0.1% reflecting customer growth early in the year that was partially offset by a decline in the number of customers late in the year.

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 at about that same level starting in the 2012 time frame. 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 grew modestly in 2010 after contracting in 2009 and 2008. The growth was lead primarily by the healthcare industry and tourism related businesses, but unemployment remains high. Initially, the contraction was centered in housing and related industries, but spread to the general economy later in 2007. The Tampa metropolitan area's civilian employment increased 0.3% in 2010 after decreasing 5.1% in 2009 and 2.7% in 2008. This level of job creation is slightly higher than the 0.05% increase experienced in Florida. The local Tampa area unemployment rate decreased to 12.0% at year-end 2010, compared to 12.4% at year-end 2009, and 8.3% at the end of 2008. The Tampa area year-end 2010 unemployment rate was the same as the state of Florida, but higher than the 9.4% for the nation, which is contrary to the trends experienced in previous economic slowdowns.

Following the expiration of the home buyer tax credit in June 2010, as in most areas of the country, the housing market in Tampa Electric's service area weakened for the remainder of 2010. As measured by the Case-Shiller Home Price Indices, home prices declined for much of the year and high numbers of foreclosures continued.

Operating Expenses

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. Tampa Electric expects operation and maintenance expense, excluding fuel and purchased power, to decrease in 2011, assuming normal levels of employee incentive compensation accruals.

Total pretax operating expense increased 3.5% in 2009, driven by higher other operating expenses and maintenance expenses, which included the write-off of project development costs, the write-off of disallowed rate case expenses, and restructuring costs. Excluding all FPSC-approved cost recovery clause-related expenses, restructuring charges and the project development write-off, operations and maintenance expense increased $8.7 million, compared to 2008, primarily due to higher spending on generating unit maintenance and repairs, higher expenses to operate the distribution system, higher employee-related expenses, and slightly higher bad debt expense, partially offset by savings in salaries and other benefits as a result of the restructuring actions taken late in the year.

In 2010, depreciation and amortization expense increased $9.5 million, reflecting the additions to facilities to serve customers, which included peaking combustion turbines, NO_x control projects and rail coal unloading facilities. In 2009, depreciation expense increased $9.1 million and taxes other than income, which include property taxes, were higher due to the peaking combustion turbines placed in service in 2009 and normal additions to facilities to serve customers. Depreciation expense is projected to increase in 2011, but at a level of about 50% of the 2010 increase due to routine plant additions to serve Tampa Electric's customer base and maintain system reliability, but without the major incremental project completions as in 2009.

Fuel Prices and Fuel Cost Recovery

In November 2010, the FPSC approved cost recovery rates for fuel and purchased power, capacity, environmental and conservation costs for the period January through December 2011. The rates include the expected cost for natural gas and coal in 2011, and the net over-recovery of fuel, purchased power and capacity clause expenses, which were collected in 2010 and 2009 following the March mid-course adjustment described below.

In November 2009, the FPSC approved cost recovery rates for fuel and purchased power, capacity, environmental and conservation costs for the period January through December 2010. The rates included the expected cost for natural gas and coal in 2010, the net over-recovery of fuel, purchased power and capacity clause expenses, which were collected in 2009 following the March adjustment, and the operating cost for and a return on the capital invested in the fourth SCR project to enter service at the Big Bend Power Station as well as the operation and maintenance expense associated with the projects (see the **Regulation** and **Environmental Compliance** sections).

In November 2008, the FPSC approved Tampa Electric's originally requested 2009 fuel rates. The rates included the costs for natural gas and coal expected in 2009, and the recovery of fuel and purchased power expenses, which were not collected in 2008. In March 2009, Tampa Electric filed a mid-course correction with the FPSC to adjust its projected 2009 fuel and purchased power costs to reflect the decline in commodity fuel prices, primarily natural gas. The revised forecast reduced fuel and purchased power costs by $191 million for 2009, which when combined with $35 million over recovery in late 2008, resulted in $226 million lower projected fuel and purchased power cost (see the **Regulation** section).

Total fuel cost decreased in 2010 due to significantly lower cost for natural gas partially offset by slightly higher cost for coal. Total fuel cost increased in 2009, due to higher cost for coal partially offset by lower cost for natural gas. Purchased power expense increased in 2010 due to higher volumes purchased, but at lower prices due to lower natural gas prices. Purchased power decreased in 2009 due to lower prices for natural gas, which is the primary fuel used by other generators in Florida. Delivered natural gas prices decreased 15.7% in 2010 due to abundant supplies from on-shore domestic natural gas produced from shale formations, and storage inventories above historic averages resulting from lower demand for natural gas from industrial users caused by economic conditions. Delivered coal costs increased 2.3% in 2010. Coal and natural gas prices were $3.12 per million Btu (/MMBtu) and $6.74/MMBtu, respectively, in 2010.

Natural gas futures as traded on the New York Mercantile Exchange (NYMEX) and various forecasts for natural gas prices indicate that natural gas prices will be stable for two to three years due to increased availability of on-shore domestic natural gas produced from shale formations. Coal prices, while less volatile, were relatively stable in 2010 after sharp increases in 2008 and 2007. Coal prices experienced a significant decline in 2009 for spot purchases, due to lower demand for coal fired generation of electricity as a result of the economic conditions. 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. Tampa Electric's coal prices are expected to remain stable in 2011 due to longer-term supply contracts.

Energy Supply

On a retail energy supply basis, Tampa Electric generation accounted for 99%, 98% and 94% of the total retail energy sales in 2010, 2009 and 2008, respectively, with the remainder of the energy supplied by purchased power. Tampa Electric's generation increased in 2010 due to the conclusion of the major coal-fired unit outages for the installation of NO_x control equipment. Purchased power expense increased 1.1%, but purchased power volumes increased 5.0%. The lower prices were driven by lower per-unit prices associated with the purchases as a result of lower natural gas prices. Purchased power expense is expected to decrease in 2011 due to a lower volume of purchases driven by normal generating unit outage schedules compared to a major SCR installation outage for the final unit in 2010.

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. Natural gas prices are expected to remain stable in 2011 and we expect to maintain the generation mix at about 2010 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 $20 million annually for the foreseeable future.

The FPSC also modified its rule regarding the design standards for new and replacement transmission and distribution line construction, including certain critical circuits in a utility's system. Future capital expenditures required under the storm hardening program are expected to average more than $25 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.

Due to the recession experienced in the Florida and national economies and the Florida housing market slowdown in 2008 and 2009, Tampa Electric reassessed its forecast of long-term energy demand and sales growth. Tampa Electric had previously identified a need for new baseload capacity in early 2013; however, the current capital forecast reflects a deferral of construction of new baseload capacity beyond this forecast period. If growth resumes and demand increases above the current projections, Tampa Electric may require peaking capacity in the 2013 time frame. Tampa Electric may seek to purchase power rather than build additional capacity based on the economics of a decision to purchase rather than build new capacity (see the **Capital Expenditures** and **Regulation** sections).

Pending action by the Florida Legislature on a Florida Renewable Energy Portfolio Standard (RPS), the need for additional capital spending on renewable energy sources is likely but not yet defined (see the **Environmental Compliance** section). Depending on the final rules, which the legislature may enact in the 2011 legislative session, Tampa Electric may need to invest capital to develop additional sources of renewable power generation.

PEOPLES GAS (PGS)

Operating Results

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. Increased sales to commercial and industrial customers reflect 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, the total throughput for PGS was almost 1.6 billion therms. Industrial and power generation customers consumed approximately 49% of PGS' annual therm volume, commercial customers used approximately 26%, approximately 19% was sold off-system, and the balance was consumed by residential customers, which are essentially unchanged from 2009 sales.

Residential operations were about 30% of total revenues in 2010 and in 2009. 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.

As a result of the unprecedented cold winter weather in 2010, in the second quarter of 2010 PGS projected that it would earn above the top of its allowed ROE range of 9.75% to 11.75% in 2010. In 2010, PGS recorded a $9.2 million total pretax provision related to the earnings above the top of the range primarily in the second and third quarters. 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 customer's bills in 2011, and the remainder applied to deficiencies in accumulated depreciation reserves. On Jan. 25, 2011, the FPSC approved the stipulation.

PGS reported net income of $31.9 million in 2009, compared to $27.1 million in 2008. Non-GAAP results, which exclude $2.9 million of restructuring charges, were $34.8 million in 2009 (see the **2009 Reconciliation of GAAP net income from continuing operations to non-GAAP results** table). There were no non-GAAP adjustments to the 2008 period. The higher 2009 results reflected a $4.0 million favorable adjustment to previously recorded deferred tax balances, and the new base rates effective in June 2009, partially offset by higher non-fuel operations and maintenance expenses and depreciation. Results reflected a 0.2% lower average number of customers. Residential customer usage increased due to colder winter weather in the first quarter of 2009, compared to the very mild winter weather in 2008. Sales to commercial customers increased, due to several higher volume new customers and conversion of propane customers to natural gas. Lower sales volumes to industrial customers reflected economic conditions and reduced operations by industries sensitive to the housing market, such as cement plants. Gas transported for power generation customers increased over 2008 due to lower natural gas prices, which made it a more economical generating fuel choice. Excluding restructuring charges, non-fuel operations and maintenance expense increased in 2009 compared to 2008 when operations and maintenance expense were reduced by a $1.5 million benefit from the recognition of environmental remediation insurance recoveries and a $0.9 million benefit related to the completion of pipeline installations for power generation customers. PGS experienced higher pipeline integrity costs and higher depreciation expense in 2009 due to routine plant additions.

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

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

Because of lower customer growth, slower energy sales growth, higher levels of operations and maintenance spending, continued investment in the distribution system and higher costs associated with required safety requirements, such as transmission and distribution pipeline integrity management, PGS' 13-month average regulatory ROE was below the bottom of its allowed range at the end of 2007 and was 8.7% at the end of 2008.

Due to the significant decline in ROE, PGS filed for a $26.5 million base rate increase in August 2008. In May 2009, the FPSC awarded a $19.2 million revenue requirements increase that authorized an ROE mid-point of 10.75%, 54.7% equity in the capital structure, and a 2009 13-month average rate base of $561 million. The new rates were effective Jun. 18, 2009.

Summary of Operating Results

(millions)	*2010*	*% Change*	*2009*	*% Change*	*2008*
Revenues	**$ 529.9**	12.6	$ 470.8	(31.6)	$ 688.4
Cost of gas sold	**284.8**	16.5	244.5	(48.7)	476.6
Operating expenses	**171.8**	5.2	163.3	8.6	150.3
Operating income	**73.3**	16.1	63.0	2.4	61.5
Net income	**34.1**	6.9	31.9	17.7	27.1
Therms sold—by customer segment					
Residential	**90.5**	23.2	73.5	(1.2)	74.4
Commercial	**407.9**	6.9	381.7	1.5	375.9
Industrial	**507.2**	13.0	448.7	(12.6)	513.3
Power generation	**582.2**	8.1	538.3	18.1	455.6
Total	**1,587.8**	10.1	1,442.2	1.6	1,419.2
Therms sold—by sales type					
System supply	**451.0**	13.3	398.0	(13.1)	457.8
Transportation	**1,136.8**	8.9	1,044.2	8.6	961.4
Total	**1,587.8**	10.1	1,442.2	1.6	1,419.2
Customer (thousands)—average	**336.0**	0.5	334.4	(0.2)	335.1

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 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 2010, approximately 15,700 out of 32,400 of PGS' eligible non-residential customers had elected to take service under this program.

Since early 2008 at the start of the housing market collapse, customer growth and therm sales growth have been difficult to forecast, due to the state of the national and Florida economies and the uncertainty of the timing of a recovery in the Florida housing market. In 2010, PGS experienced 0.5% customer growth after forecasting no customer growth for the year. In 2009, PGS had a lower average number of customers than in 2008. In 2008, PGS had forecast customer growth of approximately 1.0%; however, actual customer growth was 0.2%, which was significantly lower than the average customer growth experienced for the previous five years. PGS provides service in areas of Florida that experienced some of the most rapid growth in 2005 and 2006, including the Miami, Ft. Myers and Naples areas. These areas continue to experience the most significant impacts of the housing market collapse.

PGS Outlook

In 2011, PGS expects continued modest customer growth, but at a rate lower than Tampa Electric due to the more severe housing market downturn in some of the areas it serves. Assuming normal weather, therm sales to weather sensitive customers, especially residential customers, are expected to be lower than in 2010 when exceptionally cold weather boosted therm sales. Excluding all FPSC-approved cost recovery clause-related expenses, operation and maintenance expense is expected to decrease in 2011 due to the absence of the $6.2 million provision to limit earnings to the top of the allowed ROE range that was recorded as an operating expense. Revenue was also reduced by $3.0 million in 2010 in accordance with this FPSC approved regulatory stipulation. 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 Ft. Myers and Naples areas and the northeast coast in the Jacksonville area. In 2011, PGS expects its capital spending to support modest system expansion in anticipation that the Florida housing market will recover over the next several years. Over time, PGS expects customer additions and related revenues to increase, assuming an economic and housing market recovery throughout the state of Florida and other factors (see the **Risk Factors** section).

Gas Supplies

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

Gas is delivered by the Florida Gas Transmission Company (FGT) through 60 interconnections (gate stations) serving PGS' operating divisions. In addition, PGS' Jacksonville Division receives gas delivered by the South Georgia Natural Gas Company pipeline through two gate stations located northwest of Jacksonville. PGS also receives gas delivered by Gulfstream Natural Gas Pipeline through seven gate stations.

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

TECO COAL

In 2010, TECO Coal recorded full year net income of $53.0 million on sales of 8.8 million tons in 2010, compared to $37.2 million on sales of 8.7 million tons in 2009. These results reflect an average net per-ton selling price, excluding transportation allowances, 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, from increased surface mine reclamation activities and generally higher mining costs due to productivity impacts associated with increased inspection activities. Full year net income includes a $5.3 million favorable net benefit from the settlement of state income tax issues recorded in prior years partially offset by a $1.1 million charge for other tax adjustments. TECO Coal's 2010 effective income tax rate was 22%, excluding the income tax settlements discussed above, compared to 17% in the 2009 full year period.

TECO Coal recorded net income of $37.2 million in 2009, more than double the $18.0 million in 2008, on sales of 8.7 million tons, compared to sales of 9.3 million tons in 2008. Lower volume and the sales mix in 2009 reflected coal market conditions, which included high inventory levels at utility steam coal customers and reduced demand for coal used in the production of steel. At almost $72 per ton, the 2009 full-year average net per-ton selling price was 20% above the 2008 average selling price. At almost $67 per ton, the 2009 all-in total per-ton cost of production was 14% higher than in 2008. In 2009, TECO Coal's effective income tax rate was 17%.

TECO Coal Outlook

We expect TECO Coal's net income to increase in 2011 over 2010 from higher contract selling prices. TECO Coal has more than 90% of its expected 2011 sales of between 8.5 and 9.0 million tons contracted, resulting in an average contracted selling price across all products of $87 per ton. The product mix is expected to be about 40% specialty coal, which includes stoker, metallurgical and PCI coals, and the remainder utility steam coal. The cost of production is expected to increase to a range between $74 and $78 per ton due to expected higher contract miner costs, higher safety-related costs, higher royalties and severance costs, which are a function of selling price, and, due to delays in the issuance of permits, higher surface mining cost, primarily due to longer hauling distances. Diesel fuel prices have been hedged for those contracts that do not have diesel price adjustments in the contract at average prices at about the same level as 2010. TECO Coal's effective income tax rate is expected to be the normal 25% for 2010.

At the end of 2011, an approximately 600,000 ton per year steam coal contract at below-market prices concludes.

Historically, from time to time, TECO Coal has added to its proven and probable reserves. TECO Coal will continue to explore for additional reserves in and around its existing mining operations to prudently maintain or expand its reserves as appropriate.

For the past several years, the issuance of permits by the U.S. Army Corp of Engineers (USACE) under Section 404 of the Clean Water Act required for surface mining activities in the Central and Northern Appalachian mining regions have been challenged in the courts. These challenges have been appealed by various mining companies affected on a number of occasions, but very few permits have been issued over the past several years. TECO Coal had six permits on the list of permits subject to enhanced review by the U.S. EPA under its memorandum of understanding with the USACE, which was issued in September 2009, however, two have been withdrawn. TECO Coal has all of the permits required to meet its 2011 sales projections. However, production from a mine affected by one of those permits that has been delayed is no longer included in the 2011 sales projection due to uncertainty in the ability to obtain a permit or the timing of the issuance of a permit. This mine was previously expected to contribute approximately 300,000 tons to 2011 sales. To date, there has been no progress in granting these permits. TECO Coal is currently producing from other mines, but at a higher cost, to offset the lost production from the delayed permit.

On Apr. 1, 2010, the EPA issued new guidance on environmental permitting requirements for Appalachian mountain top 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. The EPA will 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. 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.

Coal Markets

In the third quarter of 2008, in response to the U.S. economic recession, the prices for many commodities started to drop. The decline in commodity prices, including coal, accelerated in the fourth quarter of 2008 due to the spread of the U.S. economic recession to many other economies around the world. At that time, the U.S. steel industry, which is a large consumer of metallurgical coal, was reported to be operating at a less than 40% utilization rate. In the first half of 2009, coal producers around the world experienced generally depressed demand for their product, which resulted in lower shipments and lower prices. In the second half of 2009, government economic stimulus actions resulted in very strong demand for metallurgical coal in China and India. As the international economies started to emerge from the economic recession in late 2009, demand and prices for metallurgical coal increased, both in the U.S. and in international markets.

In 2010, prices for metallurgical coal remained strong 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. TECO Coal was essentially fully contracted for its metallurgical coal sales by the start of 2010, with virtually no tons available for sale in the spot market.

Demand for coal used by utilities to generate electricity stabilized in 2010 as the economy started to recover and demand for electricity grew following a decline in 2009 due to the economic recession. Natural gas prices, as measured on a cent per million Btu basis, were below coal prices, which allowed utilities to substitute natural gas for coal in the generation of electricity. As a result, utility coal stockpiles were significantly above long-term averages entering 2010. In 2010, utility customers accepted delivery of contracted tons following deferrals of contracted tons into future years in 2009. A cold 2010 winter and a hot summer reduced utility inventories, but not enough to create near-term demand for utility steam coal.

Industry reports indicate that utilities are not expected to purchase significant amounts of coal for 2011 beyond what is already contracted for. Utilities that have indicated an interest in purchasing coal are purchasing tons for delivery after 2011. The industry expects demand for utility steam coal to recover in the second half of 2011 and at that time for prices to improve from the current spot prices of approximately $70 per ton.

The significant factors that could influence TECO Coal's results in 2011 are the cost of production and the ability of the railroads to deliver the contracted volumes. Longer-term factors that could influence results include inventories at steam coal users, weather, 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 in Guatemala both have long-term power sales contracts with the Guatemalan distribution utility EEGSA, the largest Guatemalan distribution utility, which serves Guatemala City, the capital of Guatemala and the surrounding region.

On Oct. 21, 2010, a TECO Guatemala subsidiary sold its 30% interest in DECA II to EPM, a multi-utility company based in Medellín Colombia, for a sale 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 combustion turbines, is a peak-load facility with high availability, but operates at a low capacity factor by design. Guatemala is heavily dependent on hydro-electric sources for baseload power generation. The Alborada Power Station is under contract to EEGSA, but it is designated to be an operating reserve for the country of Guatemala by the country's power dispatcher. The plant runs at peak times or in times of loss of a major generating unit or transmission circuit in the country. In 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.

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.

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 a $27.0 million gain on the sale of its ownership interest in DECA II, and a $24.9 million tax charge related to previously undistributed earnings as a result of the sale. Non-GAAP results in 2009 were $29.9 million, which excluded an $8.7 million net gain on the sale of its minority ownership interest in the telecommunications company, Navega.

These results reflect the absence of earnings from DECA II for most of the fourth quarter, a $2.0 million reduction, 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 the extended unplanned outages in 2009.

In 2009, TECO Guatemala's net income was $38.6 million, compared to $36.9 million in 2008. TECO Guatemala's full-year 2009 non-GAAP results, which exclude the $8.7 million gain on the sale of Navega were $29.9 million, compared to 2008 non-GAAP results of $46.5 million, which exclude $9.6 million of taxes related to the December cash repatriation. Results in 2009 reflected lower results at the San José Power Station due to unplanned outages for much of the first half of the year and lower capacity payments under the power sales contract as a result of lower availability due to the unplanned outages, partially offset by a $1.7 million net insurance recovery related to the unplanned outages. Results also reflected the reduction in the VAD tariff at EEGSA, which reduced 2009 earnings at TECO Guatemala by approximately $5.0 million. The effect of the VAD more than offset the benefit of 2.9% customer growth, higher energy sales, and cost control measures at EEGSA. The earnings from the DECA II unregulated EEGSA-affiliated companies, which provide, among other things, electricity transmission services, wholesale power sales to unregulated electric customers and engineering services, decreased due to the loss of the earnings from the telecommunications service provider, Navega, which was sold in the first quarter of 2009. The 2009 results for EEGSA and affiliated companies also included a $2.5 million benefit related to an adjustment to previously estimated year-end equity balances, compared to a similar $3.1 million benefit in 2008.

TECO Guatemala Outlook

In 2011, we expect normal operations for the Alborada and San José power stations. Earnings from the Alborada Power Station will be at the lower rates under the contract extension described above. TECO Guatemala's results will reflect the absence of earnings from DECA II, which was sold in October 2010. Prior to the sale, DECA II contributed $13.1 million to 2010 net income at TECO Guatemala.

PARENT/OTHER

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 $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).

Non-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 reflect $3.4 million lower interest expense as a result of debt restructuring and retirement.

In 2009, Parent/other cost was $54.0 million, compared to a cost of $55.2 million in 2008. Non-GAAP Parent/other cost was $48.6 million in 2009, compared to $45.8 million in 2008. Results in 2009 reflected a $2.6 million unfavorable valuation adjustment to foreign tax credits, a $1.5 million gain on the sale of a lease, the final asset held in a leveraged lease portfolio, and a $2.6 million benefit from a sale of property by TECO Properties. Results in 2009 also reflected negative tax return adjustments that normally occur, compared to 2008 when the tax return adjustments were favorable. Non-GAAP Parent/other cost in 2009 excluded $1.6 million of restructuring costs and a $3.8 million charge associated with the sale of student-loan securities held at TECO Energy parent (see the **2009** and **2008 Reconciliation of GAAP net income from continuing operations to non-GAAP results** tables).

OTHER ITEMS IMPACTING NET INCOME

Other income (expense)

In 2010, Other income (expense) of $14.1 million included a $55.5 million charge related to early debt retirement; $13.1 million from DECA II prior to its sale, which was accounted for as an equity investment; and $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 the $18.3 million pretax gain on the sale of Navega, from the Guatemalan operations, which are accounted for as equity investments, and a net $3.3 million charge related to the sale of various investments.

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

AFUDC equity at Tampa Electric, which is included in Other income (expense), was $1.9 million, $9.3 million and $6.3 million in 2010, 2009 and 2008, respectively. AFUDC is expected to decrease in 2011 due to the completion of the installation of the fourth and final NO_x control unit at the Big Bend Power Station in 2010 (see the **Environmental Compliance** and **Liquidity, Capital Resources** sections).

Interest Expense

In 2010, total interest expense was $231.3 million compared to $227.0 million in 2009 and $228.9 million in 2008. In 2010, interest expense increased 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. In 2009, interest expense was reduced by lower interest rates on floating rate debt and higher AFUDC debt at Tampa Electric.

Interest expense is expected to be lower in 2011 due to the retirement of $236 million of TECO Energy and TECO Finance debt in December 2010, and the retirement of $64 million of TECO Energy debt at maturity in April 2011 (see the **Liquidity, Capital Resources** section).

Income Taxes

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, and an increase to the foreign tax credit valuation allowance. The provision for income taxes increased in 2009 due to higher operating income, partially offset by lower foreign tax credit valuation allowances, lower taxes on cash repatriated from Guatemala, and increased depletion and AFUDC equity. Income tax expense as a percentage of income from continuing operations before taxes was 41.5% in 2010, 31.6% in 2009 and 36.8% in 2008. For 2011, we expect the effective tax rate to be in the range of 30% to 35%.

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 $5.5 million, $4.1 million, and $6.0 million in 2010, 2009, and 2008, respectively.

On Dec. 17, 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 was signed into law. The legislation provides 100% bonus depreciation for capital investments placed in service after Sep. 8, 2010 and through Dec. 31, 2011 and 50% bonus for equipment placed in service after Dec. 31, 2011 and through Dec. 31, 2012. Based on the company's preliminary estimate, additional bonus depreciation will extend our NOL.

Due to the NOL carryforward position resulting from the disposition of the generating assets formerly held by TWG Merchant, 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. We currently expect to utilize these NOLs through 2015, at which time we expect to start using more than $195 million of AMT carryforward to limit future cash tax payments for federal income taxes to the level of AMT. We currently project cash tax payments of between $30 and $35 million over the next five years.

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

LIQUIDITY, CAPITAL RESOURCES

The table below sets forth the Dec. 31, 2010 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, 2010			
(millions)	**Consolidated**	**Tampa Electric Company**	**Unregulated Companies**	**Parent**
Credit facilities	$675.0	$475.0	$ —	$200.0
Drawn amounts/LCs	19.4	12.7	—	6.7
Available credit facilities	655.6	462.3	—	193.3
Cash and short-term investments	82.3	3.7	38.9	39.7
Total liquidity	$737.9	$466.0	$38.9	$233.0

In 2010, we met our cash flow 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 and $8 million from the sale of common stock, primarily through dividend reinvestment. 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 flow needs primarily from a mix of internal sources supplemented with net borrowings of $57 million, of which $102 million represented notes issued by Tampa Electric Company. Cash from operations was $725 million. Other sources of cash included $32 million of proceeds from the sale of businesses, primarily the sale of our ownership interest in the Guatemalan telecommunications provider, Navega, $5 million from the sale of common stock, primarily through dividend reinvestment, and $16 million from the sale of student loan securities and other investments. We paid dividends of $171 million in 2009, and capital expenditures were $640 million.

In 2008, we met our cash needs primarily from a mix of internal sources and cash on hand at the beginning of the year, including cash held offshore which was repatriated in December 2008. We supplemented this with net borrowings of $102 million, of which $68 million represented borrowings under bank credit facilities. Cash from operations was $388 million in 2008.

Cash from Operations

In 2010, consolidated cash flow from operations was $664 million, which was positively impacted by $55 million associated with net recoveries of deferred costs, primarily fuel and purchased power, under FPSC-approved recovery clauses. Cash from operations reflects an $81 million contribution to the pension plans in 2010, which included a $47 million pre-funding of our 2011 required contribution. 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 Tax** section).

We expect cash from operations in 2011 to be higher than the 2010 level. We expect higher net income in 2011, but due to the over-recovery of fuel and purchased power costs in 2010, we expect the net recoveries under various regulatory clauses to reduce cash from operations. In November 2010, the FPSC approved recovery clause rates that provide for refunds to customers of estimated 2010 net over-recoveries of fuel and purchased power over 12 months beginning Jan. 1, 2011 (see the **Regulation** section). Like 2010, we expect our NOL carryforwards to result in minimal state and federal income tax payments in 2011 (see the **Income Tax** section).

Cash from Investing Activities

Our investing activities in 2010 resulted in a net use of cash of $296 million, including capital expenditures totaling $490 million. In 2010 we received $183 million representing the proceeds from the sale of businesses and other assets, primarily the sale of our ownership interest in DECA II.

We expect capital spending for the next several years to be below 2010 levels primarily due to the completion of the SeaCoast Gas Transmission, LLC (SeaCoast LLC) intrastate pipeline and the NO_x control projects at Tampa Electric (see the **Capital Expenditures** section).

Cash from Financing Activities

Our financing activities in 2010 resulted in a net use of cash of $347 million. Major items included the net repayment of $189 million of TECO Parent and TECO Finance long-term debt, $75 million of proceeds from Tampa Electric Company's remarketing of tax-exempt notes previously held in lieu of redemption, and the repayment of $43 million of short-term debt (see the **Financing** section). We paid $175 million in common stock dividends, and we received almost $8 million from the sale of common stock from our dividend reinvestment program and exercises of stock options.

In 2011, Tampa Electric Company expects to utilize internally generated funds, equity contributions from TECO Energy, and short-term borrowings under its credit facilities to support its capital spending program and for normal working capital fluctuations. We have $64 million of TECO Energy parent and TECO Finance notes maturing in 2011 which we expect to retire at maturity. See the **Cash and Liquidity Outlook** section below for a discussion of financing expectations in 2011 and beyond.

Cash and Liquidity Outlook

In general, we target to maintain consolidated liquidity (unrestricted cash on hand plus undrawn credit facilities) of at least $500 million. At Dec. 31, 2010 our consolidated liquidity was $738 million, consisting of $466 million at Tampa Electric Company, $233 million at TECO Energy parent and $39 million at the other operating companies.

We expect our sources of cash in 2011 to include cash from operations at levels above 2010, due in large part to higher net income from the operating companies and lower pension contributions, due to prefunding the expected 2011 contribution in 2010, partially offset by lower net recoveries under various regulatory clauses in 2011 as described above. We plan to use cash generated in 2011 to fund capital spending estimated at $440 million, for dividends to shareholders and to retire maturing debt.

Tampa Electric Company expects to utilize cash from operations and equity contributions from TECO Energy to support its capital spending program, supplemented with minimal 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 2011 and remain within the covenant restrictions.

Beyond 2011, 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. Tampa Electric Company has two series of notes totaling $372 million maturing in 2012 and will need to issue replacement debt to fund some or all of those maturities. The existing bank credit facilities for both Tampa Electric Company and TECO Energy/TECO Finance expire in 2012. We expect to renew these facilities in late 2011 under similar terms, but at higher cost.

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

TECO Energy expects 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. Through 2015, we expect to realize significant cash benefits from the utilization of net operating loss carryforwards generated in 2004 and 2005 upon the disposition of merchant power assets to reduce federal and certain state income taxes. We currently project cash tax payments between $30 and $35 million over the next five years.

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, 2010, we could have been required to post additional collateral or settle existing positions with counterparties totaling $29.7 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, which 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, 2010 and 2009, the following credit facilities and related borrowings existed:

	Dec. 31, 2010			Dec. 31, 2009		
(millions)	**Credit Facilities**	**Borrowings Outstanding**	**Letters of Credit Outstanding**	**Credit Facilities**	**Borrowings Outstanding**	**Letters of Credit Outstanding**
Tampa Electric						
5-year facility	$325.0	$ 5.0	$ 0.7	$325.0	$55.0	$ 0.7
1-year accounts receivable facility	150.0	7.0	—	150.0	—	—
TECO Finance :						
5-year facility	200.0	—	6.7	200.0	—	6.9
Total	$675.0	$12.0 (1)	$ 7.4	$675.0	$55.0 (1)	$ 7.6

(1) Borrowings outstanding are reported as notes payable.

These credit facilities, including the one-year accounts receivable facility which was renewed in February 2011, require commitment fees ranging from 7.0 to 35.0 basis points. The weighted average interest rates on outstanding notes payable under the credit facilities at Dec. 31, 2010 and 2009 were 0.64% and 0.66%, respectively.

At Dec. 31, 2010, TECO Finance had a $200 million bank credit facility in place guaranteed by TECO Energy with a maturity date in May 2012. Tampa Electric Company had a bank credit facility totaling $325 million, also maturing in May 2012. In addition, Tampa Electric Company had a $150 million accounts receivable securitized borrowing facility which was renewed in February 2011 with a maturity date of February 2012. The TECO Finance and Tampa Electric Company bank credit facilities include sub-limits for letters of credit of $200 million and $50 million, respectively. At Dec. 31, 2010, the TECO Finance credit facility was undrawn and $6.7 million of letters of credit were outstanding. At Dec. 31, 2010, $12.0 million was drawn on the Tampa Electric Company credit facilities and $0.7 million of letters of credit were outstanding.

	2010 Credit Facility Utilization			
(millions)	**Maximum drawn amount**	**Minimum drawn amount**	**Average drawn amount**	**Average interest rate**
TECO Finance	$ 35.0	—	$ 3.0	0.85%
Tampa Electric	$102.0	—	$26.3	0.71%

At current ratings, TECO Finance's and Tampa Electric Company's bank credit facilities require commitment fees of 12.5 basis points and 7.0 basis points, respectively, and drawn amounts are charged interest at LIBOR plus 55.0 – 60.0 basis points and 35.0 – 40.0 basis points, respectively. At Dec. 31, 2010, the LIBOR interest rate was 0.26%.

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

Under a Loan and Servicing Agreement, TRC may borrow up to $150 million to fund its acquisition of the receivables under the facility, and TRC secures such borrowings with a pledge of all of its assets, including the receivables. Tampa Electric Company acts as the servicer to service the collection of the receivables. TRC pays program and liquidity fees based on Tampa Electric Company's credit ratings, which total 70 basis points at its current ratings under its renewed facility. Interest rates on the borrowings are based on prevailing asset-backed commercial paper rates, unless such rates are not available from conduit lenders, or under certain circumstances upon a change of accounting rules applicable to the lenders, in which case the rates will be at an interest rate equal to, at Tampa Electric Company's option, either Citibank's prime rate (or the federal funds rate plus 50 basis points, if higher) or a rate based on the London interbank deposit rate (if available) plus a margin. The facility includes the following financial covenants: (1) at each quarter-end, Tampa Electric Company's debt-to-capital ratio, as defined in the agreement, must not exceed 65%; and (2) certain dilution and delinquency ratios with respect to the receivables (see the **Covenants in Financing Agreements** section). Tampa Electric Company renewed this facility Feb. 18, 2011 with a Feb. 17, 2012 maturity date (see **Note 25** to the TECO Energy **Consolidated Financial Statements**).

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, 2010, 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, 2010. 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, 2010*
Tampa Electric Company			
Credit facility (2)	Debt/capital	Cannot exceed 65%	49.1%
Accounts receivable credit facility (2)	Debt/capital	Cannot exceed 65%	49.1%
6.25% senior notes	Debt/capital	Cannot exceed 60%	49.1%
	Limit on liens (3)	Cannot exceed $700	$0 liens outstanding
Insurance agreement relating to certain pollution bonds	Limit on liens (3)	Cannot exceed $441 (7.5% of net assets)	$0 liens outstanding
TECO Energy/TECO Finance			
Credit facility (2)	EBITDA/interest (4)	Minimum of 2.6 times	4.6 times
TECO Energy 6.75% notes and TECO Finance 6.75% notes	Restrictions on secured debt (5)	(6)	(6)

(1) As defined in each applicable instrument.
(2) See **Note 6** to the **TECO Energy Consolidated Financial Statements** for a description of the credit facilities.
(3) If the limitation on liens is exceeded the company is required to provide ratable security to the holders of these notes.
(4) EBITDA generally represents EBIT before depreciation and amortization. However, the term is subject to the definition prescribed under the relevant agreement.
(5) These limitations would not include first mortgage bonds of Tampa Electric Company if any were outstanding.
(6) The indentures for these notes contain restrictions which limit secured debt of TECO Energy if secured by Principal Property or Capital Stock or indebtedness of directly held subsidiaries (with exceptions as defined in the indentures) without equally and ratably securing these notes.

Credit Ratings of Senior Unsecured Debt at Dec. 31, 2010

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

On Oct. 22, 2010, Fitch Ratings placed TECO Energy, TECO Finance and Tampa Electric Company on Rating Watch Positive following the announcement of the sale of DECA II (see **TECO Guatemala** section). The Rating Watch Positive reflects Fitch's expectation that previously anticipated parent level debt reduction would be accelerated by the DECA II sale and the use of the resulting cash proceeds to retire parent level debt (see the **Financing Activities** section). This followed Fitch's revision of the long-term Rating Outlook to positive on Jun. 25, 2010.

Standard & Poor's, Moody's and Fitch describe credit ratings in the BBB or Baa category as representing adequate capacity for payment of financial obligations. The lowest investment grade credit ratings for Standard & Poor's is BBB-, for Moody's is Baa3 and for Fitch is BBB-; thus all three credit rating agencies assign 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 an 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, 2010

	Payments Due by Period					
(millions)	**Total**	**2011**	**2012**	**2013**	**2014-2015**	**After 2015**
Long-term debt (1)						
Recourse	$3,184.4	$ 67.1	$375.0	$ 60.7	$366.6	$2,315.0
Non-recourse (2)	44.7	11.2	11.2	11.2	11.1	—
Operating leases/rentals (3)	117.5	17.3	14.3	12.0	23.5	50.4
Net purchase obligations/commitments (4)	201.7	74.4	40.5	30.5	56.2	0.1
Interest payment obligations	1,871.0	179.4	172.6	160.1	279.0	1,079.9
Pension plans (5)	171.4	—	35.7	47.1	88.6	—
Total contractual obligations	$5,590.7	$349.4	$649.3	$321.6	$825.0	$3,445.4

(1) Includes debt at TECO Energy, TECO Finance, Tampa Electric, PGS and the other operating companies (see **Note 7** to the TECO Energy **Consolidated Financial Statements** for a list of long-term debt and the respective due dates).

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

(3) 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 the accounting guidance for 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 2010, these commitments include Tampa Electric's outstanding commitments for major projects and long-term capitalized maintenance agreements for its combustion turbines.

(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, 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 Contractual Cash Obligations table above and not otherwise included in our Consolidated Financial Statements.

Contingent Obligations at Dec. 31, 2010

(millions)		Commitment Expiration Total	2011	2013	2013	2014 - 2015	After 2015 (1)
Letters of credit		$ 7.4	$—	$—	$—	$—	$ 7.4
Guarantees	Fuel purchase (2)	129.7	—	—	—	—	129.7
	Other	5.4	—	—	—	—	5.4
Total contingent obligations		$142.5	$—	$—	$—	$—	$142.5

(1) These letters of credit and guarantees renew annually and are shown on the basis that they will continue to renew beyond 2015.
(2) The amounts shown are the maximum theoretical amounts guaranteed under current agreements.

Capital Expenditures

(millions)	Actual 2010	Forecast 2011	2012	2013 – 2015	2011 – 2015 Total
Tampa Electric					
Transmission	$ 40	$ 45	$ 40	$ 90	$ 175
Distribution	90	90	90	295	475
Generation	135	135	140	360	635
Other	20	30	35	115	180
NO_x control projects	15	—	—	—	—
Other environmental	5	25	40	45	110
Tampa Electric total	305	325	345	905	1,575
Net cash effect of accruals and Retentions	25	—	—	—	—
Tampa Electric net	330	325	345	905	1,575
PGS	60	60	60	180	300
Unregulated companies (1)	100	55	60	155	270
Total	$490	$440	$465	$1,240	$2,145

(1) Represents the capital expenditures of TECO Coal, SeaCoast LLC and the consolidated operations of TECO Guatemala.

TECO Energy's 2010 capital expenditures of $490 million included $330 million at Tampa Electric, including $3 million of AFUDC—debt and equity, and $25 million of amounts paid in 2010 but incurred in a prior period. Capital expenditures at PGS were $60 million in 2010. Tampa Electric's capital expenditures in 2010 were primarily for equipment and facilities to meet modest customer growth, generating equipment maintenance, environmental compliance, and completion of the final NO_x control project (see the **Environmental Compliance** section). Capital expenditures for PGS were approximately $30 million for system expansion and approximately $30 million for maintenance of the existing system. TECO Coal's capital expenditures included $30 million primarily for normal mining equipment replacement, and $20 million for new mine development. SeaCoast LLC invested approximately $50 million for the construction of the SeaCoast LLC natural gas pipeline in northeast Florida, which was completed in late 2010. SeaCoast LLC, an indirect wholly-owned Subsidiary of TECO Energy, owns a 24 mile intrastate natural gas pipeline in northeast Florida that began serving the Jacksonville Electric Authority Greenland Energy Center in late 2010 under a long-term contract. Currently the Greenland Energy Center is the sole customer of SeaCoast LLC; however, we are seeking other customers for the existing capacity on this pipeline.

TECO Energy estimates capital spending for ongoing operations to be $440 million for 2011 and approximately $1.7 billion during the 2012 – 2015 period.

For 2011, Tampa Electric expects to spend $325 million. For the transmission and distribution systems Tampa Electric expects to spend $135 million in 2011, including approximately $90 million for normal transmission and distribution system expansion and reliability, and $30 million for transmission and distribution system storm hardening. Capital expenditures for the existing generating facilities of $135 million include approximately $25 million for repair and refurbishments of combustion turbines under long-term agreements with equipment manufacturers, approximately $50 million for generating unit outages, $15 million for a reclaimed water pipeline to eliminate ground water usage at the Polk Power Station, and $45 million for other improvements and refurbishments to generating units. In addition, Tampa Electric expects to spend $25 million for environmental compliance programs in 2011.

In the 2012 – 2015 period, Tampa Electric expects to spend $35 million for the completion of the reclaimed water pipeline project at the Polk Power Station. Capital spending for environmental compliance is expected to average approximately $20 million annually in the same period. In addition to the above amounts, Tampa Electric expects to spend approximately $285 million annually to support normal system growth and reliability in the 2012 – 2015 period. This level of ongoing capital expenditures reflects the costs for materials and contractors, long-term regulatory requirements for storm hardening, and an active program of transmission and distribution system upgrades which will occur over the forecast period. These programs and requirements include: approximately $20 million annually for repair and refurbishments of combustion turbines under long-term agreements with equipment manufacturers; average annual expenditures of more than $90 million to support generating unit availability and reliability; average annual expenditures of $35 million for general infrastructure to support customers; average annual expenditures of more than $25 million for transmission and distribution system storm hardening; approximately $30 million annually for transmission system reliability and capacity improvements; and an average of approximately $85 million annually for distribution system reliability and to meet the expected customer growth.

Capital expenditures for PGS are expected to be about $60 million in 2011 and $240 million during the 2012 – 2015 period. Included in these amounts is an average of approximately $35 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing renewal, replacement and system safety.

The unregulated companies expect to invest $55 million in 2011 and $215 million during the 2012 – 2015 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.

Tampa Electric—Generating Capacity Additions

In 2009, Tampa Electric completed the construction of five peaking capacity combustion turbines at the Bayside and Big Bend power stations. These units were used to meet the summer peak demand requirements in 2009 and the new winter peak experienced in January 2010. One combustion turbine at each of the facilities is configured to meet the North American Electric Reliability Council (NERC) black start requirements for system reliability.

Due to the 2008 and 2009 financial crisis and the slowdown in the Florida and national economies, Tampa Electric has deferred new baseload capacity until beyond the 2015 forecast period. Tampa Electric may require peaking capacity in the 2013 period, after the expiration of the purchased power agreement with the Hardee Power Station in Central Florida. If demand growth resumes and additional generating capacity is required, Tampa Electric may construct this additional peaking capacity or seek to purchase power rather than build based on the economics (see the **Tampa Electric** and **Regulation** sections). If Tampa Electric builds this capacity, capital expenditures would start in 2012.

If the U.S. Congress or the Florida Legislature enacted a national or Florida Renewable Energy Portfolio Standard (RPS), the need for additional capital spending for renewable generating resources to meet the requirements of a RPS is likely but not yet defined (see the **Environmental Compliance** section). Depending on the final federal or state rules, which may be enacted in 2011, Tampa Electric may need to invest capital to develop additional sources of renewable power generation.

The forecast of capital expenditures shown above are based on our current estimates and assumptions for normal maintenance capital at the operating companies; capital expenditures to support normal system reliability and growth at Tampa Electric and PGS; the programs for transmission and distribution system storm hardening and transmission system reliability requirements; and incremental investments above normal maintenance capital to expand the PGS system 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 2010 consolidated capital structure was 60% debt and 40% common equity. The debt-to-total-capital ratio has improved significantly over the past four years, primarily due to the repayment of more than $900 million of parent and parent guaranteed debt, consisting of $765 million in 2007 and a net $189 million in 2010, as well as the increase in retained earnings. At Dec. 31, 2010, Tampa Electric Company's year-end capital structure was 49% debt and 51% common equity.

In 2010, we raised $3.6 million of equity primarily through our dividend reinvestment plan.

In December 2010, Tampa Electric Company completed an exchange offer (the Exchange Offer) which resulted in the exchange of $278.5 million principal amount of Tampa Electric Company notes for $278.5 million principal amount of Tampa Electric Company 5.40% Notes due 2021. The Exchange Offer resulted in the exchange of $131.5 million principal amount of Tampa Electric Company 6.875% Notes due 2012 and $147.0 million principal amount of Tampa Electric Company 6.375% Notes due 2012 for $278.5 million principal amount of Tampa Electric Company 5.40% Notes due 2021. After the Exchange Offer, $118.5 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.

In December 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, a $13.2 million charge for premiums and fees was recorded at TECO Energy Parent & other (see the **2010 Reconciliation of GAAP net income from continuing operations to non-GAAP results** table).

In November 2010, the Polk County Industrial Development Authority (PCIDA) issued $75.0 million Solid Waste Disposal Revenue Refunding Bonds (Tampa Electric Company Project), Series 2010, in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. Proceeds of the bonds were used to redeem $75.0 million PCIDA Solid Waste Disposal Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 bonds, which previously had been in auction rate mode and were held by Tampa Electric Company since Mar. 26, 2008. The Series 2010 bonds bear interest at 1.50% per annum and are subject to mandatory tender for purchase on Mar. 1, 2011. Tampa Electric Company entered into a Loan and Trust Agreement with the PCIDA, as issuer, and The Bank of New York Trust Company, N.A., as trustee, in connection with the issuance of the Series 2010 Bonds. Tampa Electric Company is responsible for payment of the interest and principal associated with the bonds.

On Mar. 26, 2008, Tampa Electric Company purchased in lieu of redemption $75.0 million PCIDA Solid Waste Disposal Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 and $20 million Hillsborough County Industrial Development Authority (HCIDA) Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007C (collectively, the "2007 Bonds"). After the Nov. 15, 2010 issuance of the Series 2010 PCIDA Bonds, $20 million of bonds purchased in lieu of redemption were held by the trustee at the direction of Tampa Electric Company as of Dec. 31, 2010 (the "Held Bonds") to provide an opportunity to evaluate refinancing alternatives. The Held Bonds effectively offset the outstanding debt balances and are presented net on the balance sheet.

In April 2010, TECO Energy redeemed $100 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, a $4.1 million charge for premiums and fees was recorded at TECO Energy Parent & other (see the **2010 Reconciliation of GAAP net income from continuing operations to non-GAAP results** table).

In April 2010, TECO Energy redeemed all of the outstanding $100 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.

In March, 2010, TECO Energy and TECO Finance completed debt tender offers which resulted in the purchase of $70 million principal amount of TECO Energy notes for cash and approximately $230 million principal amount of TECO Finance notes for cash. The tender offers resulted in the purchase and retirement of: $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 this transaction, a $16.2 million charge for premiums and fees was recorded at TECO Energy Parent & other (see the **2010 Reconciliation of GAAP net income from continuing operations to non-GAAP results** table).

In March 2010, TECO Finance, Inc. issued $250 million aggregate principal amount of 4.00% Notes due Mar. 15, 2016 and $300 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 $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" described above) and to fund the redemptions of the TECO Energy Floating Rate Notes due 2010 and 7.20% Notes due 2011 in April 2010.

In July 2009, Tampa Electric Company completed an offering of $100 million aggregate principal amount of 6.10% Notes due May 15, 2018. These notes were sold at 102.988% of par. The offering resulted in net proceeds (after deducting underwriting discounts and commissions and estimated offering expenses) of $102.0 million. Net proceeds were used to repay short-term debt and for general corporate purposes.

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

At Dec. 31, 2010, we had net deferred income tax assets of $57.3 million, attributable primarily to property-related items, alternative minimum tax credit carryforwards, operating loss carryforwards, 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 net deferred tax assets recorded at Dec. 31, 2010 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 IRS or the U.S. Treasury or changes in law or regulation could change our deferred tax levels, including the potential for elimination or reduction of our ability to utilize the deferred tax assets (see **Note 4** to the **TECO Energy Consolidated Financial Statements**).

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 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 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 is 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 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 decreased 2010 net income by approximately $4.4 million. Likewise, a 1% decrease in the discount rate assumption would have resulted in an approximately $5.3 million decrease in 2010 net income. For 2011, a 1% decrease in the discount rate assumption would result in an approximately $3.2 million 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 increase in expected pension cost.

Unrecognized actuarial gains and losses are being recognized over a period of up to 9 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 and a regulatory tax asset of $5.3 million.

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. In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (MMA) was enacted. MMA established a prescription drug benefit under Medicare, known as Medicare Part D, and a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription benefit, which is at least actuarially equivalent to Medicare Part D. In May 2004, the FASB issued guidance that required: 1) that the effects of the federal subsidy be considered an actuarial gain and recognized in the same manner as other actuarial gains and losses and 2) certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits.

We adopted the guidance retroactive to the second quarter of 2004 for benefits provided that we believe to be actuarially equivalent to Medicare Part D. The expected subsidy reduced the accumulated postretirement benefit obligations (APBO) at Dec. 31, 2010 by $35.3 million and increased net income for 2010 by $1.8 million. In 2010, we filed for and received a Part D subsidy of $0.8 million for the first three quarters of 2010. Payments for the fourth quarter of 2010 have not been received yet. The Health Care Reform Acts eliminated the tax-free status of those subsidies beginning in 2013.

The assumed health care cost trend rate for medical costs was 8.0% in 2010 and decreases to 4.50% in 2023 and thereafter. A 1% increase in the health care trend rates would have produced a 3.1% increase in the aggregate service and interest cost for 2010, which would have decreased net income $0.5 million, and a 3.8% increase in the accumulated postretirement benefit obligation as of Dec. 31, 2010, the measurement date.

A 1% decrease in the health care trend rates would have produced a 3.2% decrease in the aggregate service and interest cost for 2010, which would have increased net income $0.4 million, and a 3.2% decrease in the accumulated postretirement benefit obligation as of Dec. 31, 2010, the measurement date.

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, 2010, 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, 2010, 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 ($52.3 million and $3.1 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, 2010, there was no impairment of this goodwill.

Regulatory Accounting

Tampa Electric's and PGS' retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by the Federal Energy Regulatory Commission (FERC). As a result, the regulated utilities qualify for the application of 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 generally accepted accounting principles and the accounting principles imposed by the regulatory authorities. Regulatory assets generally represent incurred costs that have been deferred, as their future recovery in customer rates is probable. Regulatory liabilities generally represent obligations to make refunds to customers from previous collections for costs that are not likely to be incurred.

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

We periodically assess the probability of recovery of the regulatory assets by considering factors such as regulatory environment changes, recent rate orders to other regulated entities in the same jurisdiction, the current political climate in the state, and the status of any pending or potential deregulation legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate earned on invested capital and the timing and amount of assets to be recovered by rates. 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

Disclosures about the Credit Quality of Financing Receivables and the Allowance for Credit Losses

In July 2010, the Financial Accounting Standards Board (FASB) issued guidance requiring improved disclosures about the credit quality of a company's financing receivables and their associated credit reserves. The guidance is effective for interim and annual periods that end after Dec. 15, 2010. This guidance did not have any effect on the company's results of operations, statement of position or cash flows.

Subsequent Events

In February 2010, the FASB issued additional guidance related to subsequent event disclosure. The guidance was effective upon issuance and has no effect on the company's results of operations, statement of position or cash flows.

Fair Value Measures and Disclosures

In January 2010, the FASB issued guidance that requires entities to disclose more information regarding the movements between Levels 1 and 2 of the fair value hierarchy. The guidance was effective for fiscal years that begin after Dec. 15, 2010, and for interim periods within that year. This guidance will not have any effect on the company's results of operations, statement of position or cash flows.

INFLATION

The effects of general inflation on our results have not been significant for the past several years. The annual average rate of inflation, as measured by the Consumer Price Index (CPI-U), all items, all urban consumers, as reported by the U.S. Department of Labor, was 1.5%, 2.7% and 3.8% in 2010, 2009 and 2008, respectively. The current economic situation and the state of the economic recovery cause the outlook for 2011 to be stronger than 2010. Reports published by the Federal Reserve Bank of Atlanta indicate that CPI-U is expected to rise 1.7% in 2011.

ENVIRONMENTAL COMPLIANCE

Environmental Matters

Among our companies, 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 that may be impacted by possible federal and state legislative initiatives. Tampa Electric has undertaken major steps to dramatically reduce its air emissions through a series of voluntary actions, including technology selection (e.g., IGCC and conversion of coal-fired units to natural-gas fired combined cycle); 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. Together, these improvements represent an investment in excess of $2 billion since 1994.

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

Air Quality Control

Consent Decree

Tampa Electric, through voluntary negotiations with the U.S. Environmental Protection Agency (EPA), the U.S. Department of Justice (DOJ) and the Florida Department of Environmental Protection (FDEP), signed a Consent Decree, which became effective Feb. 29, 2000, and a Consent Final Judgment, which became effective Dec. 6, 1999, as settlement of federal and state litigation. Pursuant to these agreements, allegations of violations of New Source Review requirements of the Clean Air Act were resolved, 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 included specific detail with respect to the availability of flue gas desulfurization systems (scrubbers) to help reduce SO_2, projects for NO_x reduction on Big Bend Units 1 through 4, and the repowering of the coal-fired Gannon Power Station to natural gas, which was renamed as the H. L. Culbreath Bayside Power Station (Bayside Power Station), in 2003 and 2004. Upon completion of the conversion, the station capacity was approximately 1,800 megawatts (nominal) of natural gas-fueled, combined-cycle electric generation. The repowering has reduced the facility's NO_x and SO_2 emissions by approximately 99% and particulate matter (PM) emissions by approximately 92% from 1998 levels.

In 2004, Tampa Electric made its NO_x reduction technology selection and decided to install SCR systems for NO_x control on the four coal-fired Big Bend units. The units were reported in-service in May 2007, June 2008, May 2009 and May 2010.

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

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

Emission Reductions

Projects committed to under the Consent Decree and Consent Final Judgment have resulted in significant reductions in emissions. Since 1998, Tampa Electric has reduced annual SO_2, NO_x and PM emissions from its facilities by 164,000 tons, 63,000 tons and 4,500 tons, respectively.

Reductions in SO_2 emissions were accomplished through the installation of scrubber systems on Big Bend Units 1 and 2 in 1999. Big Bend Unit 4 was originally constructed with a scrubber. The Big Bend Unit 4 scrubber system was modified in 1994 to allow it to scrub emissions from Big Bend Unit 3 as well. Currently the scrubbers at the 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. With the completion of the final Big Bend SCR in May 2010, the SCR projects resulted in a total phased reduction of NO_x emissions by 63,000 tons per year from 1998 levels.

In total, Tampa Electric's emission reduction initiatives have resulted in the annual reduction of SO_2, NO_x and PM emissions by 94%, 91% and 87% in 2010, respectively, below 1998 levels. With these state-of-the-art improvements in place, Tampa Electric's activities have helped to significantly enhance the quality of the air in the community. As a result of all its 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, 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.

On Sep. 16, 2009, the EPA announced it would reconsider its 2008 decision setting national standards for ground-level ozone. The EPA is reconsidering the standards to ensure they are grounded in science, protect public health with an adequate margin of safety, and are sufficient to protect the environment. Much of the State of Florida is not expected to meet the current ground-level ozone standards and will most likely be deemed non-attainment. A non-attainment area is an area that does not meet National Ambient Air Quality Standards under the Clean Air Act. States not in compliance will establish State Implementation Plans (SIP). Compliance with a Florida SIP may be accomplished by utilizing existing controls to a greater extent or installing new control technology to make further reductions. Future power generation expansion in a non-attainment classification would require purchasing emissions offsets or making reductions in existing Tampa Electric facilities to generate offsets.

In July 2010, the EPA proposed a new rule, Clean Air Transport Rule (CATR) to replace CAIR. CATR is focused on reducing SO_2 and NO_X in 31 eastern states and the District of Columbia. Compliance with CATR, which would be measured at the individual power plant level, would most likely require the additions of scrubbers or SCRs on coal-fired power plants. In addition, the rule proposes intrastate emissions allowance trading and limited interstate emissions allowance trading to achieve compliance. The final rules are expected in 2011 with implementation in the 2012 to 2014 time frame. It is likely that the EPA will propose new ozone and particulate rules and would incorporate them into CATR. 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 is under a court order to issue rules in March 2011 to reduce Hazardous Air Pollutants (HAPS). These rules are expected to reduce mercury, acid gas, organics, and heavy metals emissions and require Maximum Achievable Control Technology

(MACT). The final HAPS MACT rules are expected in late 2011 with implementation in 2014 or 2015. A potential outcome of the HAPS 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, therefore Tampa Electric expects the co-benefits of these control devices to minimize the impact of this rule.

Reductions in mercury emissions 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 NO_x controls at Big Bend Power Station, which have led to a reduction of mercury emissions of more than 75% from 1998 levels. The Clean Air Mercury Rule (CAMR) Phase I requirements were scheduled for implementation in 2010. CAMR was vacated by the U.S. Court of Appeals for the District of Columbia Circuit on Feb. 8, 2008. Prior to the court's decision Tampa Electric expected that it would have been in compliance with CAMR Phase I without additional capital investment.

Carbon Reductions

Tampa Electric has historically supported voluntary efforts to reduce carbon emissions and has taken significant steps to reduce overall emissions at Tampa Electric's facilities. Since 1998, Tampa Electric has reduced its system-wide emissions of CO_2 by approximately 20%, bringing emissions to near 1990 levels. Tampa Electric expects emissions of CO_2 to remain near 1990 levels until the addition of the next baseload unit, which is not expected until after 2014 (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's voluntary activities to reduce carbon emissions also include membership in the U.S. Department of Energy's Climate Challenge (now Power Partners) program since 1994, voluntary annual reporting of greenhouse gas (GHG) emissions through the Energy Information Agency (EIA) EIA-1605(b) Report beginning in 1995 and participation in the Chicago Climate Exchange (CCX), a voluntary but legally binding cap and trade program dedicated to reducing GHG emissions since 2003. Because of Tampa Electric's membership in the CCX, its reported CO_2 emissions are audited annually by the Financial Industry Regulatory Authority (formerly National Association of Securities Dealers), which has certified the results thus far. In January 2008, the CCX recognized Tampa Electric for achieving its Phase I GHG participation targets for CO_2 reduction. While the commitment required in Phase I was a reduction of 4% below the average of the year 1998 – 2001, Tampa Electric surpassed this level with an actual reduction of approximately 20%.

Recently 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 Mar. 31, 2011. Tampa Electric expects to comply with the mandatory reporting requirement, in large part utilizing the same methods and procedures utilized for the voluntary activities.

Climate Change

There are pending legislative and regulatory initiatives on the federal and state levels to establish programs that would require reductions in GHG emissions. While the timing of passage of any federal legislation into law remains uncertain, we will participate in the debate in an effort to encourage a comprehensive environmental approach to carbon emission reductions that maintains a reliable energy supply at affordable prices. In order to meet the reduction contemplated, Tampa Electric could be required to make significant additional capital investments in technologies to reduce GHG that are not yet commercially viable.

On Dec. 15, 2009, the EPA published the final Endangerment Finding in the Federal Register. Although the finding is technically being made in the context of GHG emissions from new motor vehicles and does not in itself impose any requirements on industry or other entities, the finding will trigger GHG regulation of a variety of sources under the CAA. Related to utility sources, the EPA's "tailoring rule" 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 on-going operations, it will factor into any permitting activities for new and modified fossil-fuel fired electric generating units going forward.

At the state level, activities aimed at reducing Florida's GHG emissions were initiated through the former Governor's Executive Orders in 2007 and broad energy and climate legislation was passed by the state legislature. However, the process has since slowed and is likely to be pushed out since the issue has become increasingly active at the federal level.

The company is examining various options relating to its carbon emissions. At this time, Tampa Electric expects to meet its needs for its next baseload generating capacity with natural gas fired combined-cycle technology, as well as energy efficiency programs and renewable resources (see the **Tampa Electric** section). While natural gas has lower carbon emissions than coal, fuel price changes have the potential to make natural gas generating facilities less economic than coal-fired facilities. Large-scale fuel switching from coal to natural gas by utilities could increase natural gas prices, which would reduce the economic efficiency of natural gas generation facilities. Increased costs for electricity may cause customers to change usage patterns, which would impact Tampa Electric's sales.

Tampa Electric currently emits approximately 16.6 million tons of CO_2 per year. Assuming a projected long-term average annual load growth of 1.0% - 2.0%, Tampa Electric may emit approximately 19.8 million tons of CO_2 (an increase of approximately 19%) by 2020 if natural gas-fired peaking and combined-cycle generation additions are used to meet growing customer needs.

Tampa Electric expects that the costs to comply with new environmental regulations would be eligible for recovery through the ECRC. If approved as prudent, the costs required to comply with CO_2 emissions reductions would be reflected in customers' bills. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the ECRC, Tampa Electric could seek to recover those costs through a base-rate proceeding, but can not predict whether the FPSC would grant such recovery. Although Tampa Electric's current coal-based generation has declined to less than 60% of its output in 2010 from 95% of its output in 2002, due primarily to the conversion of the coal-fired Gannon Power Station into the natural gas-fired Bayside Power Station, coal fired facilities remain a significant part of Tampa Electric's generation fleet and additional coal units could be used in the future.

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

In the case of TECO Coal, it is unclear if the requirements for GHG emissions reductions would directly impact it as a carbon-based fuel provider or the user. 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, 39 million kWh of renewable energy have been produced to support participating customer requirements.

Tampa Electric has installed 81.7 kilowatts of solar panels to generate electricity from the sun at two 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 kilowatts, 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. In the area of biomass, which is organic plant material from yard clippings and other vegetation, Tampa Electric has tested bahia grass as a fuel to generate electricity at the Polk Power Station, where it was ground and mixed with the pulverized coal slurry used in the plant's gasifier.

Despite the emphasis on the use of renewable energy sources, an FPSC study conducted by Navigant Consulting in 2008 indicates that only under the most favorable conditions of high customer incentives, a mature Renewable Energy Credit (REC) market and a high revenue rate cap would allow utilities to achieve the former Governor's renewable energy target. The Navigant study also found that solar photovoltaic power generation and biomass were the most viable sources of renewable energy and that Florida was a poor location for either significant land based wind generation or concentrating solar generation. While support for tax incentives for renewable energy development specific to regional disparities may facilitate the development of new sources, mandates for renewable portfolios at high percentages create concerns that RECs will have to be purchased to meet the mandate, rates for customers will grow rapidly and such mandates are not likely to result in significant quantities of renewable energy sources to be developed in the state. A mandatory renewable energy portfolio standard could add to Tampa Electric's costs and adversely affect its operating results.

In Florida, the Executive Orders tasked the FPSC with evaluating a renewable portfolio target of 20% by 2020. The 2008 Energy Bill directed the FPSC to draft a rule for a RPS to be presented to the Florida Legislature for ratification, but did not specify targets and timeframes. Under this direction, the FPSC submitted recommendations for ratification, but ultimately the Legislature did not ratify the rule in the 2009 session and is not expected to do so going forward. While renewable energy issues remain a part of the discussion in Florida, and many groups are emphasizing the need for renewable energy legislation, the Legislature may take up the issue of renewables in the upcoming legislative session in 2011, but prospects are uncertain.

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

Water Supply and Quality

The EPA's final Clean Water Act Section 316(b) rule became effective Jul. 9, 2004. The rule established aquatic protection requirements for existing facilities that withdraw 50 million gallons or more of water per day from rivers, streams, lakes, reservoirs, estuaries, oceans, or other U.S. waters for cooling purposes. Tampa Electric uses water from Tampa Bay at its Bayside and Big Bend facilities 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. On Jan. 25, 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule to the EPA for revisions. Among other things, the court rejected the EPA's use of "cost-benefit" analysis and suggested some ways to incorporate cost considerations. The Supreme Court agreed to review the Second Circuit's decision and heard arguments in December 2008. The EPA decided to rewrite the rule, and expects to propose a new rule in 2011. 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 final rule is being challenged in the courts by numerous parties, including the State of Florida. The final 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 Agency 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 will 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 adopted, 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. Also pursuant to the aforementioned consent decree, the EPA will propose numeric criteria for estuaries and coastal waters by November 2011, and finalize the rules by August 2012 pending the outcome of the previously described legal challenges.

The Big Bend, Bayside and Polk Power stations also use water on a daily basis to generate electricity with steam and to operate emission control devices (e.g. its scrubbers to reduce SO_2 emissions, water injection to reduce NO_x emissions). Water recycling and beneficial reuse programs are widely employed in the fresh water systems at all three power stations to reduce demand on higher-cost water sources such as municipal water systems.

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 is in the process of responding 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, 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.

On Apr. 1, 2010, the EPA issued new guidance on environmental permitting requirements for Appalachian mountain top 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. The EPA will decide whether to modify the guidance after consideration of public comments and the results of the SAB technical review of the EPA scientific reports, which is expected in April 2011. 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.

Conservation

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

During 2010, Tampa Electric offered customers 27 comprehensive programs to conserve energy. These programs were designed to reduce peak energy demand which allows Tampa Electric to delay construction of future generation facilities. Since their inception, these conservation programs have reduced the summer peak demand by 273 megawatts, and the winter peak demand by 687 megawatts. These programs and their costs are approved annually by the FPSC with the costs recovered through a clause on the customer's bill. In 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.

In December 2009, the FPSC established new 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 megawatts, respectively, and the annual energy goal is 360 gigawatt hours. These goals are very aggressive and represent as much as a 300 percent increase over the company's previous goals.

Tampa Electric developed its DSM plan designed to meet the new goals and filed the plan with the FPSC in March 2010. The plan contained 36 programs that include two offerings promoting the renewable technologies of photovoltaics and solar water heating. Final approval of the plan occurred in November 2010. The company is actively developing the infrastructure necessary to support and promote the new plan and expects to make the programs available to customers during the second quarter of 2011.

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, 2010, Tampa Electric Company has estimated its ultimate financial liability to be approximately $21.3 million (primarily related to PGS), and this amount has been reflected in the company's financial statements. This amount is higher than prior estimates to reflect a 2010 study for the costs of remediation primarily related to one site. 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 October 2010, the EPA notified Tampa Electric Company that it is a PRP under the federal Superfund law for the proposed 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 is in the process of responding to such matter, and the scope of its potential liability, if any, and the costs of any required investigations and remediation have not been determined.

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 is 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. Trial in this matter is scheduled for April 2011. At this time, the ultimate resolution of this proceeding is uncertain and no potential loss has been accrued (see **Footnote 12** to the TECO Energy **Consolidated Financial Statements**).

Coal Combustion Byproducts 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 byproducts, collectively known as Coal Combustion Byproducts (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 2010.

In response to the TVA Kingston 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, 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' 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 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, PGS, the FPSC or other parties.

Tampa Electric is also subject to regulation by the Federal Energy Regulatory Commission (FERC) in various respects, including wholesale power sales, certain wholesale power purchases, transmission 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%, 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 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 $8.4 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, 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.

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 2010, 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 2011. In November 2010, the FPSC approved Tampa Electric's requested rates. The rates include the projected cost for natural gas, oil and coal, including transportation, for 2011 and the net over-recovery of fuel, purchased power and capacity clause expenses, which were collected in 2010 and 2009. Rates in 2010 also reflected 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 $5.22 from $112.73 in 2010 to $107.51 in 2011.

The FPSC determined it was appropriate for Tampa Electric to recover SCR operating costs through the ECRC as well as earn a return on its SCR investment installed on the Big Bend coal fired units for NO_x control in compliance with the environmental consent decree. The SCR for Big Bend Unit 4 was reported in-service in May 2007, the SCR for Big Bend Unit 3 was reported in-service in June 2008, the SCR for Big Bend Unit 2 was reported in-service in May 2009 and the SCR for Big Bend Unit 1 was reported in-service in May 2010, and cost recovery started in the respective in-service years (see the **Environmental Compliance** section).

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, to become 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.

A procedural schedule including technical and settlement conference dates has been approved by the settlement judge in each case. Technical and settlement conferences have been held in both cases, and the next settlement conference is scheduled for Mar. 15, 2011 in the requirements case.

Coal Transportation Contract

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

Tampa Electric issued an RFP for solid fuel transportation services in October 2007. Tampa Electric structured the RFP to comply with the FPSC order issued in October 2004. New contracts for solid fuel deliveries were executed with United Maritime, AEP Memco and CSX Railroad prior to the expiration of the then existing contract with United Maritime on Dec. 31, 2008. The rail service contract provides Tampa Electric with bimodal capability for solid fuel transportation, which the FPSC had encouraged Tampa Electric to pursue, with the 2009 completion of construction of rail unloading facilities at the Big Bend Power Station (see the **Liquidity, Capital Resources** section). In its November 2010 fuel hearings, the FPSC approved the full recovery of rates for 2011 that included the costs associated with the contracts described above.

Hardening of Transmission and Distribution Facilities

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

The FPSC subsequently issued an order requiring all IOUs to implement a 10-point storm preparedness plan designed to improve the statewide electric infrastructure to better withstand severe storms and expedite recovery from future storms. Tampa Electric has implemented its plan and estimates the average incremental non-fuel operation and maintenance expense of this plan to be approximately $20 million annually. The FPSC also modified its rule regarding the design standards for new and replacement transmission and distribution line construction, including certain critical circuits in a utility's system. Future capital expenditures required under the storm hardening program are expected to average approximately $25 million annually for the foreseeable future.

Utility Competition—Electric

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

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

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

PGS Rates

PGS' 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.

PGS' previous base rates became effective in January 2003. PGS' 2003 authorized rates provided an allowed ROE range from 10.25% to 12.25% with an 11.25% midpoint. At the end of 2007, PGS' 13-month average regulatory ROE was below the bottom of its allowed range as a result of higher operating costs, continued investment in the distribution system and higher costs associated with required safety requirements, such as transmission and distribution pipeline integrity management.

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 Commission 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 2010, the FPSC approved rates under PGS' PGA for the period January 2011 through December 2011 for the recovery of the costs of natural gas purchased for its distribution customers.

In addition to its base rates and purchased gas adjustment clause charges, PGS customers (except interruptible customers) also pay a per-therm conservation charge for all gas. This charge is intended to permit PGS to recover 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 15,700 transportation-only customers as of Dec. 31, 2010 out of approximately 32,400 eligible customers.

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

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:

- 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 other comprehensive income or net income, depending on the designation of those instruments.

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

Fair Value Measurements

Effective Jan. 1, 2008, the company adopted accounting standards for fair value measurement. These standards define fair value, establish a framework for measuring fair value under generally accepted accounting principles, 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 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, 2010 was $29.8 million, all of which were Tampa Electric Company positions. If the credit-risk-related contingent features underlying these agreements were triggered as of Dec. 31, 2010, we could have been required to post collateral or settle existing positions with counterparties totaling $29.8 million. In the unlikely event that this situation would occur, we believe that we maintain adequate lines of credit to meet these obligations. At Dec. 31, 2010 all other positions held by TECO Energy, Inc. were asset positions.

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, 2010 and 2009, 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 2.7% at Dec. 31, 2010 and 2.7% at Dec. 31, 2009 (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' commodity price risk is largely mitigated by the fact that increases in the price of fuel and purchased power are recovered through cost recovery clauses, with no anticipated effect on earnings. However, increasing fuel cost recovery has the potential to affect total energy usage and the relative attractiveness of electricity and natural gas to consumers. To moderate the impacts of fuel price changes on customers, both Tampa Electric and PGS manage commodity price risk by entering into long-term fuel supply agreements, prudently operating plant facilities to optimize cost, and entering into derivative transactions designated as cash flow hedges of anticipated purchases of wholesale natural gas. At Dec. 31, 2010 and 2009, 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, 2010, TECO Coal had derivative instruments in place to reduce the price variability for its anticipated 2011 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 (millions)

Net fair value of derivatives as of Dec. 31, 2009	$(36.6)
Additions and net changes in unrealized fair value of derivatives	(75.1)
Changes in valuation techniques and assumptions	—
Realized net settlement of derivatives	84.8
Net fair value of derivatives as of Dec. 31, 2010	$ (26.9)

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

Total energy contract net assets (liabilities) as of Dec. 31, 2009	$(36.6)
Change in fair value of net derivative assets (liabilities):	
Recorded as regulatory assets and liabilities or other comprehensive income	(75.1)
Recorded in earnings	—
Realized at settlement of derivatives	84.8
Net option premium payments	—
Net purchase (sale) of existing contracts	—
Total energy contract net assets (liabilities) as of Dec. 31, 2010	$ (26.9)

Maturity and Source of Energy Derivative Contracts Net Assets (Liabilities) at Dec. 31, 2010

(millions)	Current	Non-current	Total Fair Value
Source of fair value			
Actively quoted prices	$ —	$—	$ —
Other external price sources (1)	(24.5)	(2.4)	(26.9)
Model prices (2)	—	—	—
Total	$(24.5)	$(2.4)	$(26.9)

(1) Information from external sources includes information obtained from OTC brokers, industry price services or surveys and multiple-party on-line platforms. This information is reviewed by management for reasonableness by comparing it to prices quoted on NYMEX.

(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.

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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 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, 2010, 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 25, 2011

TECO ENERGY, INC.

Consolidated Balance Sheets

Assets

(millions)	*Dec. 31, 2010*	*Dec. 31, 2009*
Current assets		
Cash and cash equivalents	$ 67.5	$ 46.0
Short-term investments	14.8	0.8
Receivables, less allowance for uncollectibles of $4.5 and $3.0 at Dec. 31, 2010 and 2009, respectively	333.4	277.4
Inventories, at average cost		
Fuel	169.5	124.3
Materials and supplies	78.1	65.7
Current derivative assets	2.7	0.8
Income tax receivables	0.4	1.7
Prepayments and other current assets	28.5	25.7
Current regulatory assets	62.7	109.2
Total current assets	757.6	651.6
Property, plant and equipment		
Utility plant in service		
Electric	6,558.9	6,079.5
Gas	1,115.0	1,017.2
Construction work in progress	212.4	304.5
Other property	398.5	377.2
Property, plant and equipment	8,284.8	7,778.4
Accumulated depreciation	(2,443.8)	(2,234.3)
Total property, plant and equipment, net	5,841.0	5,544.1
Other assets		
Deferred income taxes	57.3	222.7
Long-term regulatory assets	341.9	335.6
Investment in unconsolidated affiliates	0.0	279.3
Goodwill	55.4	59.4
Long-term derivative assets	0.2	0.2
Deferred charges and other assets	141.2	126.6
Total other assets	596.0	1,023.8
Total assets	$ 7,194.6	$ 7,219.5

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, 2010*	*Dec. 31, 2009*
Current liabilities		
Long-term debt due within one year		
Recourse	$ 67.1	$ 106.5
Non-recourse	11.2	1.4
Notes payable	12.0	55.0
Accounts payable	281.5	251.4
Customer deposits	156.5	151.2
Current regulatory liabilities	110.0	85.4
Current derivative liabilities	27.2	34.0
Interest accrued	42.4	45.3
Taxes accrued	26.2	20.5
Other current liabilities	18.2	20.6
Total current liabilities	752.3	771.3
Other liabilities		
Investment tax credits	10.4	10.8
Long-term regulatory liabilities	630.8	602.6
Long-term derivative liabilities	2.6	3.6
Deferred credits and other liabilities	479.8	544.2
Long-term debt, less amount due within one year		
Recourse	3,114.6	3,195.4
Non-recourse	33.5	6.2
Total other liabilities	4,271.7	4,362.8
Commitments and contingencies (see Note 12)		
Capital		
Common equity (400.0 million shares authorized; par value $1; 214.9 million shares and 213.9 million shares outstanding at Dec. 31, 2010 and 2009, respectively)	214.9	213.9
Additional paid in capital	1,542.0	1,530.8
Retained earnings	430.0	365.7
Accumulated other comprehensive loss	(17.2)	(25.0)
TECO Energy stockholder's equity	2,169.7	2,085.4
Noncontrolling interest	0.9	0.0
Total capital	2,170.6	2,085.4
Total liabilities and capital	$7,194.6	$7,219.5

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,*	*2010*	*2009*	*2008*
Revenues			
Regulated electric and gas (includes franchise fees and gross receipts taxes of $116.1 in 2010, $115.7 in 2009 and $109.2 in 2008)	$2,672.6	$2,649.1	$2,778.2
Unregulated	815.3	661.4	597.1
Total revenues	3,487.9	3,310.5	3,375.3
Expenses			
Regulated operations			
Fuel	748.9	909.9	819.4
Purchased power	179.6	177.6	305.4
Cost of natural gas sold	284.5	242.7	476.6
Other	370.0	318.7	277.7
Operation other expense			
Mining related costs	482.7	458.7	440.6
Guatemalan power generation	65.1	12.3	14.3
Other	6.6	4.8	3.9
Maintenance	184.8	187.6	173.9
Depreciation and amortization	312.9	287.9	266.1
Restructuring charges	1.5	25.7	0.0
Loss (gain) on sale, net of transaction related costs	0.0	0.0	0.9
Recoveries from previously impaired assets	(2.9)	0.0	0.0
Taxes, other than income	227.4	224.4	211.5
Total expenses	2,861.1	2,850.3	2,990.3
Income from operations	626.8	460.2	385.0
Other income (expense)			
Allowance for other funds used during construction	1.9	9.3	6.3
Other income	57.3	23.3	21.5
Loss on debt extinguishment	(55.5)	0.0	0.0
Income from equity investments	10.4	46.7	72.9
Total other income	14.1	79.3	100.7
Interest charges			
Interest expense	232.4	231.5	231.3
Allowance for borrowed funds used during construction	(1.1)	(4.5)	(2.4)
Total interest charges	231.3	227.0	228.9
Income before provision for income taxes	409.6	312.5	256.8
Provision for income taxes	170.0	98.6	94.4
Net income	239.6	213.9	162.4
Less: Net income attributable to noncontrolling interest	(0.6)	0.0	0.0
Net income attributable to TECO Energy	$ 239.0	$ 213.9	$ 162.4
Average common shares outstanding—Basic	212.6	211.8	210.6
—Diluted	214.8	213.1	211.4
Earnings per share—Basic	$ 1.12	$ 1.00	$ 0.77
—Diluted	$ 1.11	$ 1.00	$ 0.77
Dividends declared and paid per common share outstanding	$ 0.815	$ 0.800	$ 0.795

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,*	*2010*	*2009*	*2008*
Net income	$239.6	$213.9	$162.4
Other comprehensive income (loss), net of tax			
Net unrealized gains (losses) on cash flow hedges	3.1	17.8	(18.9)
Amortization of unrecognized benefit costs and other	3.7	1.3	2.6
Change in benefit obligation due to annual remeasurement	0.0	0.2	(10.8)
Recognized benefit costs due to settlement	1.0	0.0	0.0
Reclassification to earnings - loss on available-for-sale securities	0.0	1.7	(1.7)
Other comprehensive income, net of tax	7.8	21.0	(28.8)
Comprehensive income			
Comprehensive income attributable to noncontrolling interests	(0.6)	0.0	0.0
Comprehensive income attributable to TECO Energy, Inc.	$246.8	$234.9	$133.6

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,*	*2010*	*2009*	*2008*
Cash flows from operating activities			
Net income	$ 239.6	$ 213.9	$ 162.4
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	312.9	287.9	266.1
Deferred income taxes	162.9	98.5	95.4
Investment tax credits, net	(0.4)	(0.4)	(1.0)
Allowance for other funds used during construction	(1.9)	(9.3)	(6.3)
Non-cash stock compensation	7.4	10.3	9.7
Gain on sales of business / assets, pretax	(39.6)	(16.0)	(1.7)
Equity in earnings of unconsolidated affiliates, net of cash distributions on earnings	6.9	(4.3)	(22.8)
Non-cash debt extinguishment / exchange	2.2	0.0	0.0
Deferred recovery clause	55.0	136.6	(115.8)
Receivables, less allowance for uncollectibles	(43.9)	8.5	10.0
Inventories	(41.4)	(27.0)	(9.0)
Prepayments and other deposits	(1.3)	0.1	(2.8)
Taxes accrued	4.9	0.2	(14.8)
Interest accrued	(6.0)	0.1	12.4
Accounts payable	51.0	(38.7)	(8.3)
Other	(43.9)	64.3	14.3
Cash flows from operating activities	664.4	724.7	387.8
Cash flows from investing activities			
Capital expenditures	(489.7)	(639.8)	(589.5)
Allowance for other funds used during construction	1.9	9.3	6.3
Net proceeds from sales of business / assets	183.1	31.6	0.6
Net cash increase from consolidation	24.1	0.0	0.0
Restricted cash	0.0	0.5	(0.1)
(Investments in)/Distributions from unconsolidated affiliates	(1.7)	(0.2)	13.2
Other investments	(14.0)	16.3	76.1
Cash flows used in investing activities	(296.3)	(582.3)	(493.4)
Cash flows from financing activities			
Dividends	(174.7)	(170.8)	(168.6)
Proceeds from sale of common stock	7.8	5.1	21.8
Proceeds from long-term debt	661.2	102.0	327.8
Repayment of long-term debt	(797.2)	(6.9)	(293.8)
Dividends to noncontrolling interests	(0.7)	0.0	0.0
Net (decrease) increase in short-term debt	(43.0)	(38.0)	68.0
Cash flows used in financing activities	(346.6)	(108.6)	(44.8)
Net increase (decrease) in cash and cash equivalents	21.5	33.8	(150.4)
Cash and cash equivalents at beginning of the year	46.0	12.2	162.6
Cash and cash equivalents at end of the year	$ 67.5	$ 46.0	$ 12.2
Supplemental disclosure of cash flow information			
Cash paid during the year for:			
Interest	$ 219.0	$ 216.4	$ 203.0
Income taxes paid	$ 5.5	$ 4.1	$ 6.0

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, 2007	210.9	$210.9	$1,489.2	$ 334.1	$(17.2)	$ 0.0	$2,017.0
Net income				162.4			162.4
Other comprehensive loss, after tax					(28.8)		(28.8)
Common stock issued	2.0	2.0	19.3				21.3
Cash dividends declared				(168.6)			(168.6)
Stock compensation expense			9.7				9.7
Implementation of guidance for employer's post-retirement benefits				(5.3)			(5.3)
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
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

(1) TECO Energy had a Maximum of 400 Million Shares of $1 par value Common Stock authorized as of Dec. 31, 2010, 2009, 2008 and 2007

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

1. Significant Accounting Policies

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

Principles of Consolidation

The consolidated financial statements include the accounts of TECO Energy, Inc. and its majority-owned subsidiaries (TECO Energy or the company). All significant inter-company balances and inter-company transactions have been eliminated in consolidation. Generally, the equity method of accounting is used to account for investments in partnerships or other arrangements in which TECO Energy or its subsidiary companies do not have majority ownership or exercise control.

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

Use of Estimates

The use of estimates is inherent in the preparation of financial statements in accordance with generally accepted accounting principles (GAAP). Actual results could differ from these estimates.

Cash Equivalents

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

Restricted Cash

Restricted cash included in "Deferred charges and other assets" included $8.4 million at Dec. 31, 2010 and $7.0 million at Dec. 31, 2009 of cash held in escrow related to the 2003 sale of Hardee Power Partners (HPP). The cash will be released from escrow in 2012, upon maturity of debt financing currently held by the purchaser of HPP. The $1.4 million change reflects the amortization 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 Peoples Gas System (PGS) expense major maintenance costs as incurred. For Tampa Electric and PGS, concurrent with a planned major maintenance outage, the cost of adding or replacing retirement units-of-property is capitalized in conformity with Florida Public Service Commission (FPSC) and Federal Energy Regulatory Commission (FERC) regulations.

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

Depreciation

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

Total depreciation expense for the years ended Dec. 31, 2010, 2009 and 2008 was $297.1 million, $275.2 million and $257.3 million, respectively. The provision for total regulated utility plant in service, expressed as a percentage of the original cost of depreciable property was 3.6% for 2010, 2009 and 2008.

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 2010 and 7.79% for January 2008 through April 2009. Total AFUDC for 2010, 2009 and 2008 was $3.0 million, $13.8 million and $8.7 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, 2010*	*Dec. 31, 2009*
Tampa Electric	$119.0	$ 85.8
TECO Coal	33.9	38.5
TECO Guatemala (1)	16.6	0.0
	$169.5	$124.3

(1) TECO Guatemala fuel was consolidated effective Jan.1, 2010. See **Note 19**.

Investments in Unconsolidated Affiliates

Investments in unconsolidated affiliates are accounted for using the equity method of accounting. The percentage ownership interests for each investment at Dec. 31, 2010 and 2009 are presented in the following table:

TECO Energy's Percent Ownership in Unconsolidated Affiliates (1)

Dec. 31,	*2010*	*2009*
TECO Guatemala		
Distribućion Eléctrica CentroAmericana II, S.A.(DECA II)	0%(2)	30%
Central Generadora Electrica San José, Limitada (San José or CGESJ)	N/A(3)	100%
Tampa Centro Americana de Electricidad, Limitada (Alborada or TCAE)	N/A(3)	96%

(1) TECO Energy, Inc. received $15.6 million, $42.2 million and $63.3 million during the years ended Dec. 31, 2010, 2009 and 2008, respectively, as dividends from unconsolidated affiliates.
(2) In October 2010, TECO Guatemala sold its 30% interest in DECA II.
(3) Effective Jan. 1, 2010, the accounting standards for consolidation of VIEs were amended. As a result of adopting this amendment, the company reconsolidated both TCAE and CGESJ. See **Note 19** for more information.

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 asset will not be realized. If management determines that it is likely that some or all of a deferred tax asset will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized.

Investment Tax Credits

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

Revenue Recognition

TECO Energy recognizes revenues consistent with 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. Revenues for any financial or hedge transactions that do not result in physical delivery are reported on a net basis.

The regulated utilities' (Tampa Electric and PGS) retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by 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 via rail are recognized when title and risk of loss transfer to the customer. For coal shipments via ocean vessel, revenue is recognized under international shipping standards as defined by Incoterms 2000 when title and risk of loss transfer to the customer.

Revenues for 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, 2010, 2009 and 2008 were $8.7 million, $1.9 million and $17.3 million, respectively.

Shipping and Handling

TECO Coal includes the costs to ship product to customers in "Operation other expense - Mining related costs" on the Consolidated Statements of Income for the periods ended Dec. 31, 2010, 2009 and 2008 of $27.3 million, $24.3 million and $30.1 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 heating oil 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, 2010 and 2009, unbilled revenues of $65.5 million and $51.6 million, respectively, are included in the "Receivables" line item on TECO Energy's Consolidated Balance Sheets.

Tampa Electric purchases power on a regular basis primarily to meet the needs of its retail customers. Tampa Electric purchased power from non-TECO Energy affiliates at a cost of $179.6 million, $177.6 million and $305.4 million, for the years ended Dec. 31, 2010, 2009 and 2008, respectively. The prudently incurred purchased power costs at Tampa Electric have historically been recovered through an FPSC-approved cost recovery clause.

Accounting for Excise Taxes, Franchise Fees and Gross Receipts

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

The regulated utilities are allowed to recover certain costs incurred from customers through prices approved by the FPSC. The amounts included in customers' bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Statements of Income. These amounts totaled $116.1 million, $115.7 million and $109.2 million for the years ended Dec. 31, 2010, 2009 and 2008, respectively. Franchise fees and gross receipt taxes payable by the regulated utilities are included as an expense on the Consolidated Statements of Income in "Taxes, other than income". For the years ended Dec. 31, 2010, 2009 and 2008, these totaled $115.7 million, $115.6 million and $109.0 million, 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, 2010 and 2009 ranged from 4.00% 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. TECO Energy's $200 million credit facility contains a covenant that could limit the payment of dividends exceeding a calculated amount (initially $50 million) in any quarter under certain circumstances. This covenant is not applicable at TECO Energy's current credit ratings. 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 2010, 2009 and 2008 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 doubtful accounts is established based on Tampa Electric's and PGS' collection experience. Circumstances that could affect Tampa Electric's and PGS' estimates of uncollectible receivables include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

2. New Accounting Pronouncements

Disclosures about the Credit Quality of Financing Receivables and the Allowance for Credit Losses

In July 2010, the Financial Accounting Standards Board (FASB) issued guidance requiring improved disclosures about the credit quality of a company's financing receivables and their associated credit reserves. The guidance is effective for interim and annual periods that end after Dec. 15, 2010. This guidance did not have any effect on the company's results of operations, statement of position or cash flows.

Subsequent Events

In February 2010, the FASB issued additional guidance related to subsequent event disclosure. The guidance was effective upon issuance and has no effect on the company's results of operations, statement of position or cash flows.

Fair Value Measures and Disclosures

In January 2010, the FASB issued guidance that requires entities to disclose more information regarding the movements between Levels 1 and 2 of the fair value hierarchy. The guidance was effective for fiscal years that begin after Dec. 15, 2010, and for interim periods within that year. This guidance will not have any effect on the company's results of operations, statement of position or cash flows.

3. Regulatory

Tampa Electric's and PGS' 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 now resolves 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 is reflected in the third quarter 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 will be 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, to become 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.

Storm Damage Cost Recovery

Tampa Electric accrues $8.0 million annually effective May 2009 to a FERC-authorized and FPSC-approved self-insured storm damage reserve. This reserve was created after Florida's investor owned utilities (IOUs) were unable to obtain transmission and distribution insurance coverage due to destructive acts of nature. Tampa Electric's storm reserve was $37.4 million and $29.3 million as of Dec. 31, 2010 and Dec. 31, 2009, 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 return on common equity (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.

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: 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, 2010 and Dec. 31, 2009 are presented in the following table:

Regulatory Assets and Liabilities

(millions)	*Dec. 31, 2010*	*Dec. 31, 2009*
Regulatory assets:		
Regulatory tax asset (1)	$ 66.6	$ 69.0
Other:		
Cost recovery clauses	41.9	89.4
Postretirement benefit asset	237.5	229.1
Deferred bond refinancing costs (2)	15.4	18.0
Environmental remediation	23.6	21.2
Competitive rate adjustment	3.3	3.1
Other	16.3	15.0
Total other regulatory assets	338.0	375.8
Total regulatory assets	404.6	444.8
Less: Current portion	62.7	109.2
Long-term regulatory assets	$341.9	$335.6
Regulatory liabilities:		
Regulatory tax liability (1)	$ 17.7	$ 19.6
Other:		
Cost recovery clauses	76.2	61.4
Environmental remediation	21.2	19.9
Transmission and delivery storm reserve	37.4	29.3
Deferred gain on property sales (3)	6.3	2.8
Provision for stipulation and other (4)	9.8	0.7
Accumulated reserve-cost of removal	572.2	554.3
Total other regulatory liabilities	723.1	668.4
Total regulatory liabilities	740.8	688.0
Less: Current portion	110.0	85.4
Long-term regulatory liabilities	$630.8	$602.6

(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' 2010 earnings above 11.75%. A one-time credit to customer bills totaling $3.0 million will be applied in March 2011 and the remaining balance of the 2010 earnings above 11.75% will be credited to its accumulated depreciation reserves.

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, 2010*	*Dec. 31, 2009*
Clause recoverable (1)	$ 45.2	$ 92.5
Components of rate base (2)	248.1	238.1
Regulatory tax assets (3)	66.6	69.0
Capital structure and other (3)	44.7	45.2
Total	$404.6	$444.8

(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 loan costs, which are amortized over the life of the related debt instruments. See footnotes 1 and 2 in the prior table for additional information.

4. Income Tax Expense

Income tax expense consists of the following components:

Income Tax Expense (Benefit)

(millions) *For the year ended Dec. 31,*	*2010*	*2009*	*2008*
Current income taxes			
Federal	$ 5.7	$ 0.0	$ 0.0
Foreign	7.0	0.6	0.5
State	(5.2)	(0.1)	(0.6)
Deferred income taxes			
Federal	147.4	86.0	90.9
Foreign	0.0	0.0	0.1
State	15.5	12.5	4.4
Amortization of investment tax credits	(0.4)	(0.4)	(0.9)
Total income tax expense	$170.0	$98.6	$94.4

As discussed in **Note 1**, TECO Energy uses the liability method to determine deferred income taxes. Based primarily on the reversal of deferred income tax liabilities and future earnings of the company's core utility operations, management has determined that the net deferred tax assets recorded at Dec. 31, 2010 will be realized in future periods.

The principal components of the company's deferred tax assets and liabilities recognized in the balance sheet are as follows:

Deferred Income Tax Assets and Liabilities

(millions) Dec. 31,	*2010*	*2009*
Deferred income tax assets (1)		
Alternative minimum tax credit carryforward	$195.1	$197.2
Losses and credit carryforwards	483.1	553.2
Other	131.1	119.8
Gross deferred income tax assets	809.3	870.2
Valuation allowance	(30.2)	(14.6)
Total deferred income tax assets	779.1	855.6
Deferred income tax liabilities (1)		
Property related	716.3	611.4
Deferred fuel	5.5	21.5
Total deferred income tax liabilities	721.8	632.9
Net deferred income tax assets	$ 57.3	$222.7

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

At Dec. 31, 2010, the company had cumulative unused federal and state (Florida) net operating losses (NOLs) of $1,085.0 million and $407.9 million, respectively, expiring at various times between 2025 and 2028. In addition, the company has unused general business credits of $3.7 million expiring between 2026 and 2029 and unused foreign tax credits of $61.4 million expiring between 2015 and 2020. The company also had available alternative minimum tax credit carryforwards for tax purposes of $195.1 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 2010, our valuation allowance increased $15.6 million. The increase includes a $1.9 million valuation allowance established against state capital loss carryforwards that will more likely than not expire before the company has sufficient capital gains to offset the losses within the remaining carryforward period. The valuation allowance on foreign tax credits increased $13.7 million due to an increase in the estimated amount of unrealizable foreign tax credits. Our valuation allowance on foreign tax credits was $28.3 million at Dec. 31, 2010. 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 considered realizable, however, 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.

Effective Income Tax Rate

(millions) *For the years ended Dec. 31,*	*2010*	*2009*	*2008*
Income tax expense at the federal statutory rate of 35%	$143.4	$109.4	$ 89.9
Increase (decrease) due to			
State income tax, net of federal income tax	6.7	8.0	2.5
Foreign income taxed at different rates	(20.1)	(18.0)	(18.6)
Equity portion of AFUDC	(0.7)	(3.2)	(2.2)
Tax on repatriation of foreign earnings	37.1	12.5	14.8
Valuation allowance	15.6	2.6	12.0
Depletion	(9.1)	(7.3)	(4.6)
Other	(2.9)	(5.4)	0.6
Total income tax expense on consolidated statements of income	$170.0	$ 98.6	$ 94.4
Income tax expense as a percent of income from continuing operations, before income taxes	41.5%	31.6%	36.8%

For the three years presented, the company experienced a number of events that have 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 increase in the company's 2010 effective tax rate compared to 2009 was primarily due to the increased tax on the repatriation of foreign earnings as a result of TECO Guatemala's sale of its ownership interest in DECA II and the 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.

During 2008, the company repatriated $98.2 million of foreign earnings resulting in $14.7 million additional tax expense, net of foreign tax credits. Of this amount, $71.7 million represented a one-time repatriation from certain foreign subsidiaries whose remaining earnings at the end of the year were considered indefinitely reinvested.

The actual cash paid for income taxes as required for the alternative minimum tax, state income taxes and prior year audits in 2010, 2009 and 2008 was $5.5 million, $4.1 million and $6.0 million, respectively.

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 guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures.

During the first and second quarters of 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)	*2010*	*2009*	*2008*
Balance at Jan. 1,	$10.2	$14.9	$14.9
Increases due to tax positions related to prior years	—	0.7	—
Decreases due to tax positions related to prior years	(5.8)	(0.9)	—
Decreases due to settlements with taxing authorities	(2.2)	—	—
Decreases due to payments to taxing authorities	—	(4.5)	—
Increases due to expiration of statute of limitations	1.9	—	—
Balance at Dec. 31,	$ 4.1	$10.2	$14.9

The company recognizes interest and penalties associated with uncertain tax positions in "Operation other expense – Other" in the Consolidated Statements of Income. In 2010, 2009 and 2008 the company recognized ($1.1) million, $0.9 million and $1.4 million, respectively, of pre-tax (benefits) charges for interest only. Additionally, the company had $4.0 million of interest and penalties accrued at Dec. 31, 2010. As a result of the company reconsolidating TCAE (see **Note 19**), 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 2009 consolidated federal income tax return during 2010. During the fourth quarter, the company finalized a settlement with the IRS related to the only outstanding issue for the 2008 tax return with no material impact on earnings and operating cash flows. The U.S. federal statute of limitations remains open for the year 2007 and forward. Year 2010 is currently under examination by the IRS under the Compliance Assurance Program, a program in which the company is a participant. Foreign and U.S. state jurisdictions have statutes of limitations generally ranging from 3 to 5 years from the filing of an income tax return. The state impact of any federal changes remains subject to examination by various states for a period of up to one year after formal notification to the states. Years still open to examination by taxing authorities in major state and foreign jurisdictions include 2005 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 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 PPA. There are two primary provisions that impact funding results for TECO Energy. First, for plans funded less than 100%, required shortfall contributions will be based on a percentage of the funding target until 2011, rather than the funding target of 100%. These percentages are 94% and 96% in 2009 and 2010, respectively. Second, one of the technical corrections, referred to as asset smoothing, allows the use of asset averaging subject to certain limitations in the determination of funding requirements. The Jan. 1, 2010 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, 2010 and is estimated at 80% of the Pension Protection Act funded target as of Jan. 1, 2011.

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 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.

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.

The company received subsidy payments under Part D for the 2008 and 2009 plan years, along with payments for the first three quarters of the 2010 plan year. The company expects to receive the fourth quarter 2010 plan year payment later in 2011.

Obligations and Funded Status *(millions)*	Pension Benefits 2010	Pension Benefits 2009	Other Benefits 2010	Other Benefits 2009
Change in benefit obligation				
Net benefit obligation at prior measurement date (1)	$ 587.7	$ 555.4	$ 207.6	$ 188.9
Service cost	16.1	15.7	3.1	2.9
Interest cost	33.2	33.7	10.9	11.2
Plan participants' contributions	0.0	0.0	3.6	3.5
Actuarial loss	12.4	29.6	11.8	16.6
Plan amendments	0.0	0.4	0.0	0.0
Curtailment	0.0	(0.8)	0.0	0.0
Gross benefits paid	(34.2)	(46.3)	(16.7)	(16.4)
Settlements	(4.9)	0.0	0.0	0.0
Federal subsidy on benefits paid	n/a	n/a	1.7	0.9
Net benefit obligation at measurement date (1)	$ 610.3	$ 587.7	$ 222.0	$ 207.6
Change in plan assets				
Fair value of plan assets at prior measurement date (1)	$ 388.9	$ 360.7	$ 0.0	$ 0.0
Actual return on plan assets (2)	42.3	66.3	0.0	0.0
Employer contributions	87.6	8.2	11.5	12.9
Plan participants' contributions	0.0	0.0	3.6	3.5
Settlements	(4.9)	0.0	0.0	0.0
Gross benefits paid	(34.2)	(46.3)	(15.1)	(16.4)
Fair value of plan assets at measurement date (1)	$ 479.7	$ 388.9	$ 0.0	$ 0.0
Funded status				
Fair value of plan assets (3)	$ 479.7	$ 388.9	$ 0.0	$ 0.0
Benefit obligation (PBO/APBO)	610.3	587.7	222.0	207.6
Funded status at measurement date (1)	(130.6)	(198.8)	(222.0)	(207.6)
Unrecognized net actuarial loss	220.8	228.7	31.9	18.3
Unrecognized prior (benefit) service cost	(1.7)	(2.1)	5.7	6.5
Unrecognized net transition obligation	0.0	0.0	4.2	6.5
Accrued liability at end of year	$ 88.5	$ 27.8	($ 180.2)	($ 176.3)
Amounts recognized in balance sheet				
Regulatory assets	$ 176.3	$ 181.7	$ 61.2	$ 47.4
Accrued benefit costs and other current liabilities	(4.4)	(7.2)	(13.8)	(13.4)
Deferred credits and other liabilities	(126.2)	(191.6)	(208.2)	(194.2)
Accumulated other comprehensive loss (income) (pretax)	42.8	44.9	(19.4)	(16.1)
Net amount recognized at end of year	$ 88.5	$ 27.8	($ 180.2)	($ 176.3)

(1) The measurement dates were Dec. 31, 2010 and Dec. 31, 2009.
(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

(millions)	Pension Benefits 2010	Pension Benefits 2009	Other Benefits 2010	Other Benefits 2009
Net actuarial loss (gain)	$42.3	$44.3	$(19.3)	$(16.3)
Prior service cost (credit)	0.5	0.6	(1.0)	(1.2)
Transition obligation (asset)	0.0	0.0	0.9	1.4
Amount recognized	$42.8	$44.9	$(19.4)	$(16.1)

The accumulated benefit obligation for all defined benefit pension plans was $558.4 million at Dec. 31, 2010 and $530.1 million at Dec. 31, 2009.

Assumptions used to determine benefit obligations at Dec. 31, 2010 and 2009:

	Pension Benefits		Other Benefits	
	2010	*2009*	*2010*	*2009*
Discount rate	5.30%	5.75%	5.25%	5.60%
Rate of compensation increase—weighted	3.88%	4.25%	3.87%	4.25%
Healthcare cost trend rate				
Initial rate	n/a	n/a	8.00%	8.00%
Ultimate rate	n/a	n/a	4.50%	5.00%
Year rate reaches ultimate	n/a	n/a	2023	2016

A one-percentage-point change in assumed health care cost trend rates would have the following effect on the benefit obligation:

(millions)	Increase	Decrease
Effect on postretirement benefit obligation	$8.4	$(7.0)

	Pension Benefits			Other Benefits		
Net periodic benefit cost [1] *(millions)*	*2010*	*2009*	*2008*	*2010*	*2009*	*2008*
Service cost	$ 16.2	$ 15.7	$ 15.4	$ 3.2	$ 2.9	$ 4.1
Interest cost	33.2	33.6	31.9	10.9	11.3	12.0
Expected return on plan assets	(36.3)	(37.8)	(39.0)	—	—	—
Amortization of:						
Actuarial loss	12.4	8.7	4.0	—	—	—
Prior service (benefit) cost	(0.4)	(0.4)	(0.4)	0.8	0.8	1.8
Transition obligation	—	—	—	2.3	2.3	2.3
Curtailment loss (benefit)	—	0.2	—	—	—	—
Settlement loss	1.6	—	0.9	—	—	—
Net periodic benefit cost	$ 26.7	$ 20.0	$ 12.8	$17.2	$17.3	$20.2

(1) Benefit Cost was measured for the twelve months ended Dec. 31, 2010, 2009 and 2008. The company elected a 15-month transition approach allowed by accounting standards for employer's defined benefit pension and other post-retirement plans to move from an early measurement date of Sep. 30, 2007 to a year-end measurement date of Dec. 31, 2008. In connection with this election, the company recorded after-tax charges to retained earnings of $2.2 million for pensions and $3.1 million for other postretirement benefits in the fourth quarter of 2008.

The estimated net loss and prior service net cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are $1.9 million and $0.1 million, respectively. The estimated net loss, prior service credit and transition obligation for the other postretirement benefit plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are $0.5 million, $0.2 million and $0.1 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 $9.3 million and $0.5 million. The estimated net loss, 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 $0.4 million, $1.0 million and $1.8 million, respectively.

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

	Pension Benefits			Other Benefits		
	2010	*2009*	*2008*	*2010*	*2009*	*2008*
Discount rate	5.75%	6.05%	6.20%	5.60%	6.05%	6.20%
Expected long-term return on plan assets	8.25%	8.25%	8.25%	n/a	n/a	n/a
Rate of compensation increase	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%
Healthcare cost trend rate						
Initial rate	n/a	n/a	n/a	8.00%	8.50%	9.25%
Ultimate rate	n/a	n/a	n/a	5.00%	5.00%	5.25%
Year rate reaches ultimate	n/a	n/a	n/a	2017	2016	2016

The discount rate assumption was based on a cash flow matching technique developed by our outside actuaries and a review of current economic conditions. This technique matches the yields from high-quality (Aa-graded, non-callable) corporate bonds to the company's projected cash flows for the benefit plans to develop a present value that is converted to a discount rate.

The expected return on assets assumption was based on historical returns, fixed income spreads and equity premiums consistent with our 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, 2010, TECO Energy's pension plan experienced actual asset returns of approximately 11%.

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)	Increase	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.

Asset Category	Target Allocation	Actual Allocation, End of Year 2010	2009
Equity securities	55%	56%	66%
Fixed income securities	45%	44%	34%
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, 2010 and Dec. 31, 2009. 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, 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

(millions)	At Fair Value as of Dec. 31, 2009			
	Level 1	Level 2	Level 3	Total
Accounts receivable	$ 72.8	$ 0.0	$0.0	$ 72.8
Accounts payable	(35.6)	0.0	0.0	(35.6)
Cash equivalents				
Treasury bill	0.0	0.3	0.0	0.3
Certificate of deposit	0.0	3.6	0.0	3.6
STIF	6.7	0.0	0.0	6.7
Total cash equivalents	6.7	3.9	0.0	10.6
Equity securities				
Common stocks	94.1	0.0	0.0	94.1
Preferred stocks	0.0	1.0	0.0	1.0
ADR	7.1	1.1	0.0	8.2
REIT	1.1	0.0	0.0	1.1
Commingled fund	0.0	22.8	0.0	22.8
Mutual fund	127.2	0.0	0.0	127.2
Total equity securities	229.5	24.9	0.0	254.4
Fixed income securities				
Municipal bonds	0.7	3.2	0.0	3.9
Government bonds	0.0	27.5	0.0	27.5
Corporate bonds	0.0	24.3	0.0	24.3
MBS	0.0	25.7	0.0	25.7
ABS	0.0	0.7	0.0	0.7
CMO/REMIC	0.0	3.9	0.0	3.9
Mutual fund	0.0	0.9	0.0	0.9
Total fixed income securities	0.7	86.2	0.0	86.9
Options	0.0	(0.3)	0.0	(0.3)
Miscellaneous	0.0	0.1	0.0	0.1
Total	$274.1	$114.8	$0.0	$388.9

- Cash equivalents, excluding the STIF, are valued using cost due to their short term nature. Additionally, cash equivalents are backed by 102% collateral.
- The STIF is a money market mutual fund and is 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 NAV is validated with purchases and sales at NAV, making this a Level 1 asset.
- The primary pricing inputs in determining the fair value of the Level 1 assets, excluding the mutual fund, 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, Consumer price index (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, yield to maturity (YTM), and benchmark quotes. ABS and CMO are priced using to be announced (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 fund is its NAV at year end. Shares may be purchased at the NAV without sales charges or other fees. Since this mutual fund is a private fund, it is a Level 2 asset. The fund invests 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 contributed $81.3 million in 2010 and $6.7 million to this plan in 2009, which met the minimum funding requirements for both 2010 and 2009. These amounts are reflected in the "Other" line item on the Consolidated Statements of Cash Flows. TECO Energy does not plan to make a contribution in 2011 since the contributions made in 2010 satisfy the funding requirements for 2011. TECO Energy estimates annual contributions to range from $35 - $50 million per year in 2012 to 2015 based on current assumptions.

The SERP is funded annually to meet the benefit obligations. The company made contributions of $6.3 million and $1.5 million to this plan in 2010 and 2009, respectively. In 2011, the company expects to make a contribution of about $4.4 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 2011, the company expects to make a contribution of about $13.8 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	
Expected benefit payments (millions):		Gross	Expected Federal Subsidy
2011	$ 41.7	$15.1	$ 1.3
2012	$ 44.7	$15.9	$ 1.4
2013	$ 45.0	$16.7	$ 1.6
2014	$ 46.7	$17.5	$ 1.8
2015	$ 47.5	$18.0	$ 1.9
2016-2020	$273.5	$96.4	$11.7

Defined Contribution Plan

The company has a defined contribution savings plan covering substantially all employees of TECO Energy and its subsidiaries (the Employers) that enables participants to save a portion of their compensation up to the limits allowed by IRS guidelines. The company and its subsidiaries match up to 6% of the participant's payroll savings deductions. Effective 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, 2010, 2009 and 2008, the company and its subsidiaries recognized expense totaling $12.6 million, $8.1 million and $7.1 million, respectively, related to the matching contributions made to this plan.

6. Short-Term Debt

At Dec. 31, 2010 and 2009, the following credit facilities and related borrowings existed:

Credit Facilities

(millions)	*Dec. 31, 2010* Credit Facilities	Borrowings Outstanding (1)	Letters of Credit Outstanding	*Dec. 31, 2009* Credit Facilities	Borrowings Outstanding (1)	Letters of Credit Outstanding
Tampa Electric Company:						
5-year facility (2)	$325.0	$ 5.0	$0.7	$325.0	$55.0	$0.7
1-year accounts receivable facility	150.0	7.0	0.0	150.0	0.0	0.0
TECO Energy/TECO Finance:						
5-year facility (2)(3)	200.0	0.0	6.7	200.0	0.0	6.9
Total	$675.0	$12.0	$7.4	$675.0	$55.0	$7.6

(1) Borrowings outstanding are reported as notes payable.
(2) These 5-year facilities mature May 9, 2012.
(3) TECO Finance is the borrower and TECO Energy is the guarantor of this facility.

At Dec. 31, 2010, these credit facilities require commitment fees ranging from 7.0 to 60.0 basis points. The weighted average interest rate on outstanding notes payable at Dec. 31, 2010 and 2009 was 0.64% and 0.66%, respectively.

Tampa Electric Company Accounts Receivable Facility

On Feb. 18, 2011, Tampa Electric Company and TEC Receivables Corp. (TRC), a wholly-owned subsidiary of Tampa Electric Company, amended their $150 million accounts receivable collateralized borrowing facility, entering into Omnibus Amendment No. 9 to the Loan and Servicing Agreement with certain lenders named therein and Citicorp North America, Inc. as Program Agent. The amendment extends the maturity date to Feb. 17, 2012. Please refer to **Note 25** for additional information.

7. Long-Term Debt

At Dec. 31, 2010, total long-term debt had a carrying amount of $3,229.1 million and an estimated fair market value of $3,449.3 million. At Dec. 31, 2009, total long-term debt had a carrying amount of $3,309.7 million and an estimated fair market value of $3,500.3 million.

A substantial part of the tangible assets of Tampa Electric are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under Tampa Electric's first mortgage bond indenture.

TECO Energy's maturities and annual sinking fund requirements of long-term debt for 2011 through 2015 and thereafter are as follows:

Long-Term Debt Maturities

Dec. 31, 2010 (millions)	*2011*	*2012*	*2013*	*2014*	*2015*	*Thereafter*	*Total Long-Term Debt*
TECO Energy	$48.7	$ 0.0	$ 0.0	$ 0.0	$ 8.8	$ 0.0	$ 57.5
TECO Finance	15.0	0.0	0.0	0.0	191.2	850.0	1,056.2
Tampa Electric	0.0	308.3	60.7	83.3	83.3	1,308.3	1,843.9
PGS	3.4	66.7	0.0	0.0	0.0	156.7	226.8
TECO Guatemala	11.2	11.2	11.2	11.1	0.0	0.0	44.7
Total long-term debt maturities	$78.3	$386.2	$71.9	$94.4	$283.3	$2,315.0	$3,229.1

Debt Securities

Refinancing of CGESJ Debt

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 Cash Flows for the twelve months 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 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 twelve months ended Dec. 31, 2010.

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

On Nov. 23, 2010, the Polk County Industrial Development Authority (PCIDA) issued $75.0 million Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2010, in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. Proceeds of the bonds were used to redeem $75.0 million PCIDA Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 bonds, which previously had been in auction rate mode and were held by Tampa Electric Company since Mar. 26, 2008. The Series 2010 bonds bear interest at the initial term rate of 1.50% per annum and are subject to mandatory tender for purchase on Mar. 1, 2011, at which time the interest rate on the Series 2010 bonds may be converted to another interest rate mode or another term interest rate of the same or different duration. Tampa Electric Company is responsible for payment of the interest and principal associated with the bonds. Tampa Electric Company entered into a Loan and Trust Agreement with the PCIDA, as issuer, and The Bank of New York Trust Company, N.A., as trustee, in connection with the issuance of the Series 2010 bonds.

On Mar. 26, 2008, Tampa Electric Company purchased in lieu of redemption $75.0 million PCIDA Solid Waste Disposal Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 and $20.0 million Hillsborough County Industrial Development Authority (HCIDA) Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007C (collectively, the "2007 Bonds"). After the Nov. 15, 2010 issuance of the Series 2010 PCIDA Bonds, $20.0 million in bonds purchased in lieu of redemption were held by the trustee at the direction of Tampa Electric Company as of Dec. 31, 2010 (the "Held Bonds") to provide an opportunity to evaluate refinancing alternatives. The Held Bonds effectively offset the outstanding debt balances and are presented net on the balance sheet.

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 twelve months 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, Inc. 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 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 TCAE and CGESJ projects in Guatemala. (See **Note 19**.) The consolidation resulted in a net $44.4 million increase of non-recourse debt.

At Dec. 31, 2010 and 2009, TECO Energy had the following long-term debt outstanding:

Long-Term Debt (millions) Dec. 31,		*Due*	*2010*	*2009*
TECO Energy	Notes [1]:			
	Floating rate 2.3% (effective rate 2.5%) for 2009	2010	$ —	$ 100.0
	7.50% (effective rate of 7.8%) for 2009	2010	—	2.8
	7.20% (effective rate of 7.4%)	2011	48.7	191.7
	7.00% (effective rate of 7.1%) for 2009	2012	—	100.2
	6.75% (effective rate of 6.9%)[2]	2015	8.8	8.8
			57.5	403.5
TECO Finance	Notes [1][3]: 7.2% (effective rate of 7.4%)	2011	15.0	171.8
	7.00% (effective rate of 7.1%) for 2009	2012	—	236.2
	6.75% (effective rate of 6.9%)[2]	2015	191.2	191.2
	4.00% (effective rate of 4.2%)	2016	250.0	—
	6.572% (effective rate of 7.3%)	2017	300.0	300.0
	5.15% (effective rate of 5.3%)	2020	300.0	—
			1,056.2	899.2
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	—	—
	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
	Variable rate bonds (effective rate of 4.3%) [7]	2030	75.0	—
	5.00% Refunding bonds (effective rate of 5.9%) [8]	2034	86.0	86.0
	Notes[1]: 6.875% (effective rate of 7.0%)	2012	99.6	210.0
	6.375% (effective rate of 7.4%)	2012	208.7	330.0
	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 5.8%)	2021	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
			1,843.9	1,768.9
Peoples Gas System	Senior Notes [1][2]: 9.93%	2010	—	1.0
	8.00%	2011-2012	6.8	9.5
	Notes[1]: 6.875% (effective rate of 7.1%)	2012	19.0	40.0
	6.375% (effective rate of 7.4%)	2012	44.3	70.0
	6.10% (effective rate of 7.0%)	2018	50.0	50.0
	5.40% (effective rate of 5.4%)	2021	46.7	—
	6.15% (effective rate of 6.2%)	2037	60.0	60.0
			226.8	230.5
TECO Guatemala	Notes[1][2]: 3.00% Fixed rate for 2011, floating thereafter	2011-2014	44.7	—
	3.00% Fixed rate	2010-2014	—	7.6
			44.7	7.6
Unamortized debt discount, net			(2.7)	(0.2)
			3,226.4	3,309.5
Less amount due within one year			78.3	107.9
Total long-term debt			$3,148.1	$3,201.6

(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 securities.
(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) These bonds were converted in December 2010 from an auction rate mode to a term rate mode ending Mar. 1, 2011.
(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 vests one-third each year. Performance-based restricted stock has been granted to officers and employees, with shares potentially vesting after three years. The total awards for performance-based restricted stock vest based on the total return of TECO Energy common stock compared to a peer group of utility stocks. The 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 on all performance stock granted prior to 2010 during the vesting period. Dividends are accrued during the vesting period on all performance stock granted in 2010 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	2010	2009	2008
Assumptions applicable to performance-based restricted stock			
Risk-free interest rate	1.37%	1.36%	2.46%
Expected lives (in years)	3	3	3
Expected stock volatility	35.83%	34.11%	18.38%
Dividend yield	4.90%	7.54%	4.80%

Under the 2010 Plan and the Old Plans 0.8 million, 0.9 million and 0.7 million shares of restricted stock were granted in 2010, 2009 and 2008, respectively, with weighted average fair values of $17.22, $10.63 and $16.85, respectively. The total fair market value of awards vesting during 2010, 2009 and 2008 was $10.2 million, $7.0 million and $2.6 million, respectively, which includes stock grants, time-vested restricted stock and performance-based restricted stock. As of Dec. 31, 2010, there was $11.6 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)	*2010*	*2009*	*2008*
Compensation costs (1)	$7.4	$10.4	$9.8
Income tax benefits (1)	2.9	4.0	3.8
Excess tax benefits (2)	0.8	0.3	1.9

(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 $0.7 million, $0.1 million and $8.4 million for the periods ended Dec. 31, 2010, 2009 and 2008, respectively. Cash received from option exercises under all share-based payment arrangements was $2.9 million, $0.4 million and $18.2 million for the periods ended Dec. 31, 2010, 2009 and 2008, respectively. The income tax benefit realized from stock option exercises was $0.3 million, $0.1 million and $3.2 million for the periods ended Dec. 31, 2010, 2009 and 2008, 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, 2009	582	$14.44	1,161	$14.39
Granted	195	16.73	573	17.38
Vested	(208)	15.96	(423)	18.05
Forfeited	(5)	14.62	(12)	14.70
Nonvested balance at Dec. 31, 2010	564	$14.67	1,299	$14.51

(1) The weighted average remaining contractual term of restricted stock is 2 years.

Stock option transactions during 2010 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, 2009	6,002	$21.66		
Granted	—	—		
Exercised	(213)	13.71		
Cancelled	(887)	21.49		
Outstanding balance at Dec. 31, 2010 (1)	4,902	$22.04	3	$7.3
Exercisable at Dec. 31, 2010 (1)	4,902	$22.04	3	$7.3
Available for future grant at Dec. 31, 2010	3,374			

(1) Option prices range from $11.09 to $31.58.

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

	Stock Options Outstanding and Exercisable		
Range of Option Prices	Option Shares (thousands)	Weighted Avg. Option Price	Weighted Avg. Remaining Contractual Life
\$11.09 - \$13.64	985	\$12.78	3 Years
\$16.21 - \$19.05	1,526	\$16.31	5 Years
\$27.97 - \$31.58	2,391	\$29.50	1 Years
Total	4,902	\$22.04	3 Years

Dividend Reinvestment Plan

In 1992, TECO Energy implemented a Dividend Reinvestment and Common Stock Purchase Plan. TECO Energy raised \$3.7 million, \$3.8 million and \$3.6 million of common equity from this plan in 2010, 2009 and 2008, respectively.

Shareholder Rights Plan

The Shareholder Rights Plan expired according to its terms in May 2009.

Other

In February 2009, the Committee awarded eight senior officers time-vested restricted common stock in-lieu of cash for 50% of their annual incentive award; the remaining balances of these 2008 incentive awards were paid in cash. The full cost of these incentives were reflected in the 2008 income statement under the caption "Operation other expense-Other." In connection with these restricted stock awards, 72,342 shares were issued at a grant-date value of \$12.15. These awards vested one year from the date of grant.

10. Other Comprehensive Income

TECO Energy reported the following other comprehensive income (loss) (OCI) for the years ended Dec. 31, 2010, 2009 and 2008, 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*
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	\$ 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	\$ 32.5	\$(11.5)	\$ 21.0
2008			
Unrealized loss on cash flow hedges	\$(25.2)	\$ 9.4	\$(15.8)
Less: Gain reclassified to net income	(4.9)	1.8	(3.1)
Loss on cash flow hedges	(30.1)	11.2	(18.9)
Amortization of unrecognized benefit costs and other	4.2	(1.6)	2.6
Unrecognized loss on available-for-sale securities (1)	(1.7)	0.0	(1.7)
Unrecognized benefits due to remeasurement	(17.7)	6.9	(10.8)
Total other comprehensive loss	\$(45.3)	\$ 16.5	\$(28.8)

Accumulated Other Comprehensive Loss

(millions)	*Dec. 31, 2010*	*Dec. 31, 2009*
Unrecognized pension losses and prior service costs (2)	$(26.6)	$(27.8)
Unrecognized other benefit losses, prior service costs and transition obligations (3)	13.6	10.1
Net unrealized losses from cash flow hedges (4)	(4.2)	(7.3)
Total accumulated other comprehensive loss	$(17.2)	$(25.0)

(1) Amount relates to an off-shore investment not subject to U.S. Federal income tax.
(2) Net of tax benefit of $16.2 million and $17.1 million as of Dec. 31, 2010 and Dec. 31, 2009, respectively.
(3) Net of tax expense of $5.8 million and $6.0 million as of Dec. 31, 2010 and Dec. 31, 2009, respectively.
(4) Net of tax benefit of $2.7 million and $4.5 million as of Dec. 31, 2010 and Dec. 31, 2009, 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)	*2010*	*2009*	*2008*
Basic earnings per share			
Net income from continuing operations	$239.6	$213.9	$162.4
Less: Income attributable to noncontrolling interest	(0.6)	0.0	0.0
Less: Amount allocated to nonvested participating shareholders	(1.7)	(1.8)	(1.1)
Net income attributable to TECO Energy available to common shareholders—basic	$237.3	$212.1	$161.3
Net income attributable to TECO Energy	$239.0	$213.9	$162.4
Amount allocated to nonvested participating shareholders	(1.7)	(1.8)	(1.1)
Net income attributable to TECO Energy available to common shareholders—basic	$237.3	$212.1	$161.3
Average shares outstanding common	212.6	211.8	210.6
Basic earnings per share attributable to TECO Energy available to common shareholders	$ 1.12	$ 1.00	$ 0.77
Diluted earnings per share			
Net income from continuing operations	$239.6	$213.9	$162.4
Less: Income attributable to noncontrolling interest	(0.6)	0.0	0.0
Less: Amount allocated to nonvested participating shareholders	(1.7)	(1.8)	(1.1)
Net income attributable to TECO Energy available to common shareholders—diluted	$237.3	$212.1	$161.3
Net income attributable to TECO Energy	$239.0	$213.9	$162.4
Amount allocated to nonvested participating shareholders	(1.7)	(1.8)	(1.1)
Net income attributable to TECO Energy available to common shareholders—diluted	$237.3	$212.1	$161.3
Average shares outstanding common	212.6	211.8	210.6
Assumed conversion of stock options, unvested restricted stock and contingent performance shares, net	2.2	1.3	0.8
Adjusted average shares outstanding common—diluted	214.8	213.1	211.4
Diluted earnings per share attributable to TECO Energy available to common shareholders	$ 1.11	$ 1.00	$ 0.77
Anti-dilutive shares	2.7	6.0	4.3

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, 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.

TECO Coal Corporation and Premier Elkhorn Coal Corporation v. Orlando Utilities Commission (OUC)

TECO Coal Corporation and Premier Elkhorn Coal Corporation (collectively, TECO Coal), wholly-owned subsidiaries of TECO Energy, Inc., filed a declaratory judgment suit on Dec. 21, 2007, in the U.S. District Court for the Eastern District of Kentucky. The dispute stems from a 1995 coal supply contract with OUC that contains a mechanism to adjust the contract price every six months based on changes in government-published indexes intended to track changes in unit costs in TECO Coal's cost of production for supplying the coal. TECO Coal maintains that it is commercially impractical to continue the contract because that mechanism has not worked as intended and has resulted in an unintended windfall for OUC. OUC has filed a counterclaim unrelated to the commercial impracticability claim that seeks damages for TECO Coal's failure to deliver coal in 2008 when TECO Coal notified OUC of its inability to deliver coal as a result of force majeure.

On Sep. 17, 2010, the Court granted OUC's motion for summary judgment against TECO Coal's claim and denied OUC's motion for summary judgment on its breach of contract counterclaim against TECO Coal. On Jan. 6, 2011, the Court on joint motion from both parties dismissed the case without either party making payment to the other. TECO Coal will deliver the remaining tons provided on the contract that expires at the end of 2011.

Merco Group at Adventura Landings v. Peoples Gas System

In October 2004, Merco Group at Adventura Landings I, II and III (together, "Merco"), filed suit against Peoples Gas System in Dade County Circuit Court, and in its second amended complaint under that action, Merco alleges that coal tar from a certain former Peoples Gas manufactured gas plant site had been deposited in the early 1960s onto property now owned by Merco. Merco alleges that it incurred approximately $2.5 million in costs associated with the removal of such coal tar, and recently provided expert testimony claiming $110 million plus interest in damages from lost profits due to the delay in its condominium development project allegedly caused by the presence of the coal tar. Peoples Gas maintains that the coal tar did not originate from its manufactured gas plant site and has filed a third-party complaint against Continental Holdings, Inc., which Merco also added as a defendant in its suit, as the owner at the relevant time of the site that Peoples Gas believes was the source of the coal tar on Merco's property. Additionally, Peoples Gas has filed a counterclaim against Merco for contribution for its portion of the damages, in the event Peoples Gas is found liable any damages associated with the coal tar, alleging Merco is a responsible party based in part on its purchasing the property with knowledge of the presence of the coal tar. In February 2011, the trial judge granted partial summary judgment to Merco and shifted the burden of proof to Peoples Gas and Continental Holdings to prove the coal tar did not come from their respective manufactured gas plant sites. Trial is scheduled for April 2011. As of the filing of this report, the ultimate resolution of this proceeding is uncertain and no potential loss has been accrued.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party (PRP) for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2010, Tampa Electric Company has estimated its ultimate financial liability to be $21.3 million, primarily at PGS. This amount has been accrued and is primarily reflected in "Regulatory liabilities" on the company's consolidated balance sheet. This amount is higher than prior estimates to reflect a 2009 study for the costs of remediation primarily related to one site. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

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

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

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

Potentially Responsible Party Notification

In October 2010, the U.S. Environmental Protection Agency (EPA) notified Tampa Electric Company that it is a potentially responsible party 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 is in the process of responding to such matter, and the scope and extent of its potential liability, if any, and the costs of any required investigation and remediation have not been determined.

EPA Administrative Order

In December 2010, Clintwood Elkhorn Mining Company, a subsidiary of TECO Coal Corporation, received an Administrative Order from the EPA relating to the discharge of wastewater associated with inactive mining operations in Pike County, Kentucky. TECO Coal Corporation is in the process of responding 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.

Long-Term Commitments

TECO Energy has commitments under long-term leases, primarily for building space, capacity payments, office equipment and heavy equipment.

Total rental expense for these leases, included in "Operation other expense - Other" on the Consolidated Statements of Income for the years ended Dec. 31, 2010, 2009 and 2008, was $11.5 million, $10.7 million and $9.9 million, respectively. The following is a schedule of future minimum lease payments at Dec. 31, 2010 for all leases with non-cancelable lease terms in excess of one year:

Future Minimum Lease Payments

(millions)	*Capacity Payments* (1)	*Operating Leases*	*Total*
Year ended Dec. 31:			
2011	$ 8.8	$ 8.5	$ 17.3
2012	9.0	5.3	14.3
2013	9.1	2.9	12.0
2014	9.3	2.4	11.7
2015	9.5	2.3	11.8
Thereafter	29.7	20.7	50.4
Total future minimum lease payments	$75.4	$42.1	$117.5

(1) This schedule includes the fixed capacity payments required under a capacity and tolling agreement of Tampa Electric which commenced Jan. 1, 2009. In accordance with accounting standards on arrangements that contain a lease, the company evaluated the agreement and concluded based on the criteria that the agreement met the lease definition. Prudently incurred capacity payments are recoverable under an FPSC-approved cost recovery clause (See **Note 3**).

Guarantees and Letters of Credit

TECO Energy accounts for guarantees in accordance with 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, 2010 are as follows:

Letters of Credit and Guarantees-TECO Energy

(millions) *Letters of Credit and Guarantees for the Benefit of:*	*2011*	*2012-2015*	*After (1) 2015*	*Total*	*Liabilities Recognized at Dec. 31, 2010*
Tampa Electric					
Guarantees:					
Fuel purchase/energy management (2)	$0.0	$0.0	$ 20.0	$ 20.0	$3.0
	0.0	0.0	20.0	20.0	3.0
TECO Coal					
Letters of credit	0.0	0.0	6.7	6.7	0.0
Guarantees: Fuel purchase related (2)	0.0	0.0	5.4	5.4	1.9
	0.0	0.0	12.1	12.1	1.9
Other subsidiaries					
Guarantees:					
Fuel purchase/energy management (2)	0.0	0.0	109.7	109.7	0.0
Total	$0.0	$0.0	$141.8	$141.8	$4.9

Letters of Credit-Tampa Electric Company

(millions) *Letters of Credit for the Benefit of:*	*2011*	*2012-2015*	*After (1) 2015*	*Total*	*Liabilities Recognized at Dec. 31, 2010*
Tampa Electric					
Letters of credit	$0.0	$0.0	$0.7	$0.7	$0.0
Total	$0.0	$0.0	$0.7	$0.7	$0.0

(1) These letters of credit and guarantees renew annually and are shown on the basis that they will continue to renew beyond 2015.
(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, 2010. 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, TECO Energy, TECO Finance, Tampa Electric Company and other operating companies have certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2010, 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 $1.2 million, $1.6 million and $1.9 million for the years ended Dec. 31, 2010, 2009 and 2008, 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, 2010, 2009 and 2008. No material balances were payable as of Dec. 31, 2010 or 2009.

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*
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	(182.0)	7,194.6
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
2008						
Revenues—outsiders	$2,089.8	$688.4	$588.4	$ 8.4	$ 0.3	$3,375.3
Revenues—affiliates	1.4	0.0	0.0	0.0	(1.4)	0.0
Total revenues	2,091.2	688.4	588.4	8.4	(1.1)	3,375.3
Earnings from unconsol. affiliates	0.0	0.0	0.0	72.5	0.4	72.9
Depreciation and amortization	185.6	41.9	37.6	0.8	0.2	266.1
Total interest charges (1)	114.7	18.2	8.1	15.4	72.5	228.9
Internally allocated interest (1)	0.0	0.0	6.7	15.1	(21.8)	0.0
Provision (benefit) for taxes	81.9	17.3	2.3	14.8	(21.9)	94.4
Net income attributable to TECO Energy	135.6	27.1	18.0	36.9	(55.2)	162.4
Goodwill, net	0.0	0.0	0.0	59.4	0.0	59.4
Investment in unconsolidated affiliates	0.0	0.0	0.0	284.0	0.0	284.0
Other non-current investments	0.0	0.0	0.0	0.0	21.3	21.3
Total assets	5,538.8	878.0	309.1 (3)	383.1	38.4	7,147.4
Capital expenditures	479.7	69.0	40.3	0.5	0.0	589.5

(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 July through December 2010 were at a pretax rate of 6.50%, for September 2008 through June 2010 were at a pretax rate of 7.15% and for January 2008 through August 2008 were at a pretax rate of 7.25%. 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) Revenues for 2009 and 2008 are exclusive of entities deconsolidated as a result of the accounting guidance for variable interest entities. Total revenues for the San José and Alborada power stations, attributable to TECO Guatemala based on ownership percentages, were $97.3 million and $117.1 million for the twelve months ended Dec. 31, 2009 and 2008, respectively. These entities were consolidated as of Jan. 1, 2010 as a result of accounting guidance effective that date. See **Note 19** for more information.
(3) The carrying value of mineral rights as of Dec. 31, 2010, 2009 and 2008 was $15.8 million, $16.6 million and $18.1 million, respectively.

Tampa Electric provides retail electric utility services to more than 672,000 customers in West Central Florida. PGS is engaged in the purchase and distribution of natural gas for more than 336,000 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. The majority of obligations arise from environmental remediation and restoration activities for coal-related operations.

For the years ended Dec. 31, 2010, 2009 and 2008, 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 year ended Dec. 31, 2010, a $1.8 million estimated cash flow revision at Tampa Electric resulted primarily from the decreased cost of removal of treated wood poles of nearly 50%.

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

(millions)	*Dec. 31,* *2010*	*2009*
Beginning balance	$55.2	$52.9
Additional liabilities	0.8	0.4
Liabilities settled	(1.5)	(1.0)
Accretion expense	1.4	1.4
Revisions to estimated cash flows	(1.8)	0.0
Other (1)	1.6	1.5
Ending balance	$55.7	$55.2

(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, a TECO Energy subsidiary, TPSU, sold its 30% interest in DECA II to EPM, a multi-utility company based in Medellín Colombia, under a stock purchase agreement (SPA), for a sale price of $181.5 million. TPSU is a subsidiary of TGH.

DECA II is a holding company in which, prior to the sale, TGH held a 30% interest, Iberdrola Energia, S.A. held a 49% interest and EDP—Energias de Portugal, S.A. held a 21% interest. Each of these parties sold its interest in DECA II pursuant to the SPA. DECA II holds an 80.9% ownership interest in EEGSA and affiliated companies. EEGSA is the largest Guatemalan distribution utility, which serves Guatemala City, the capital of Guatemala and the surrounding region.

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, 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 gain of approximately $36.1 million at TECO Guatemala. Also during the fourth quarter, 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. The fair value for the reporting units evaluated is 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.

At Dec. 31, 2010, 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.

While quoted prices in active markets provide the best evidence of fair value, these are not available since TECO Guatemala has not received any offers for the purchase of its power plants. Additionally, multiples of earnings or another performance measure to determine fair value is not available since there are no comparable entities in Guatemala that have recently been sold. While there may have been similar sales in Central America, these sales are not comparable to TECO Guatemala's investment due to the differing regulatory, economic and growth environments throughout Central America. Therefore, in conducting the impairment assessment for the reporting units, the company used discounted cash flows of the business model of 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. Cash flows through 2015 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, 2010, 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 10.8% for San José and 10.3% 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 support the book value and related goodwill carrying amounts at Dec. 31, 2010, 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, 2010, 2009 or 2008.

19. Variable Interest Entities

The company formed TCAE to own and construct the Alborada Power Station and the company formed CGESJ to own and construct the San José Power Station. Both power stations are located in Guatemala and both projects obtained long-term PPAs with EEGSA, a distribution utility in Guatemala. The terms of the two separate PPAs included EEGSA's right to the full capacity of the plants for 15 years, U.S. dollar based capacity payments, certain terms for providing fuel, and certain other terms including the right to extend the Alborada and San José contracts. Under prior accounting standards for consolidation, management believed that EEGSA was the primary beneficiary of the variable interests in TCAE and CGESJ due to the terms of the PPAs. Accordingly, both entities were deconsolidated as of Jan. 1, 2004. The TCAE deconsolidation resulted in the initial removal of $25.0 million of debt and $15.1 million of net assets from TECO Energy's Consolidated Balance Sheet. The CGESJ deconsolidation resulted in the initial removal of $65.5 million of debt and $106.6 million of net assets from TECO Energy's Consolidated Balance Sheet. The results of operations for the two projects were classified as "Income from equity investments" on TECO Energy's Consolidated Statements of Income since the date of deconsolidation through Dec. 31, 2009.

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. As a result of adopting this amendment, the company reconsolidated both TCAE and CGESJ.

The following table summarizes combined income statement information for the TCAE and CGESJ projects for the years ended Dec. 31, 2009 and 2008, which were not consolidated:

Summary Results for TCAE and CGESJ

For the years ended Dec. 31, (millions)	*2009*	*2008*
Revenues	$97.2	$117.1
Operating expenses	58.1	56.8
Project level income (1)	31.8	49.0

(1) Excludes taxes, allocated interest expense and administrative and general expenses. Includes project level interest.

The following table summarizes combined balance sheet information for the TCAE and CGESJ projects for the periods ended Dec. 31, 2010, which were consolidated, and Dec. 31, 2009, which were not consolidated:

Summary Results for TCAE and CGESJ

(millions)	*Dec. 31, 2010*	*Dec. 31, 2009*
Current assets	$ 71.9	$ 58.1
Long-term assets and other deferred debits	152.7	161.2
Total assets	$224.6	$219.3
Current liabilities	$ 22.5	$ 17.6
Long-term liabilities and other deferred credits	37.1	51.2
Equity	165.0	150.5
Total liabilities and equity	$224.6	$219.3

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 121 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 variable interest entities. 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 $108.8 million, $105.5 million and $167.2 million, under these PPAs for the three years ended Dec. 31, 2010, 2009 and 2008, 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 the 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. Tampa Electric Company purchased $52.8 million, $31.7 million and $71.6 million, under this PPA for the three years ended Dec. 31, 2010, 2009 and 2008, respectively.

The company does not provide any material financial or other support to any of the VIEs it is involved with, nor is the company under any obligation to absorb losses associated with these VIEs. Other than the Guatemalan projects previously mentioned, in the normal course of business, our involvement with the remaining VIEs does not affect our Consolidated Balance Sheets, Statements of Income or Cash Flows.

20. 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. As of Mar. 31, 2010, all restructuring charges were paid or settled.

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 to reflect the impact of hedging activities on the fuel recovery clause. As a result, these changes are not recorded in OCI (see **Note 3**).

A company's physical contracts qualify for the normal purchase/normal sale (NPNS) exception to derivative accounting rules, provided they meet certain criteria. Generally, NPNS applies if the company deems the counterparty creditworthy, if the counterparty owns or controls resources within the proximity to allow for physical delivery of the commodity, if the company intends to receive physical delivery and if the transaction is reasonable in relation to the company's business needs. As of Dec. 31, 2010, 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, 2010 and Dec. 31, 2009:

Total Derivatives

(millions)	*Dec. 31, 2010*	*Dec. 31, 2009*
Current assets	$ 2.7	$ 0.8
Long-term assets	0.2	0.2
Total assets	$ 2.9	$ 1.0
Current liabilities	$27.2	$34.0
Long-term liabilities	2.6	3.6
Total liabilities	$29.8	$37.6

The following table presents the derivative cash flow hedges of heating oil contracts at Dec. 31, 2010 and Dec. 31, 2009 to limit the exposure to changes in the market price for diesel fuel:

Heating Oil Derivatives

(millions)	*Dec. 31, 2010*	*Dec. 31, 2009*
Current assets	$1.6	$0.0
Long-term assets	0.2	0.2
Total assets	$1.8	$0.2
Current liabilities	$0.0	$0.9
Long-term liabilities	0.0	0.0
Total liabilities	$0.0	$0.9

The following table presents the derivative cash flow hedges of natural gas contracts at Dec. 31, 2010 and Dec. 31, 2009 to limit the exposure to changes in market price for natural gas used to produce energy, natural gas purchased for resale to customers and natural gas used as a component price for explosives purchased:

Natural Gas Derivatives

(millions)	*Dec. 31, 2010*	*Dec. 31, 2009*
Current assets	$ 1.1	$ 0.8
Long-term assets	0.0	0.0
Total assets	$ 1.1	$ 0.8
Current liabilities	$27.2	$33.1
Long-term liabilities	2.6	3.6
Total liabilities	$29.8	$36.7

The ending balance in accumulated other comprehensive income (AOCI) related to the cash flow hedges and previously settled interest rate swaps at Dec. 31, 2010 is a net loss of $4.2 million after tax and accumulated amortization. This compares to a net loss of $7.3 million in AOCI after tax and accumulated amortization at Dec. 31, 2009.

The following table presents the fair values and locations of derivative instruments recorded on the balance sheet at Dec. 31, 2010 and 2009:

Derivatives Designated As Hedging Instruments

(millions) *at Dec. 31, 2010*	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	*Fair Value*	*Balance Sheet Location*	*Fair Value*
Commodity Contracts:				
Heating oil 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

(millions) *at Dec. 31, 2009*	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	*Fair Value*	*Balance Sheet Location*	*Fair Value*
Commodity Contracts:				
Heating oil derivatives:				
Current	Derivative assets	$0.0	Derivative liabilities	$ 0.9
Long-term	Derivative assets	0.2	Derivative liabilities	0.0
Natural gas derivatives:				
Current	Derivative assets	0.8	Derivative liabilities	33.1
Long-term	Derivative assets	0.0	Derivative liabilities	3.6
Total derivatives designated as hedging instruments		$1.0		$37.6

The following table presents the effect of energy related derivatives on the fuel recovery clause mechanism in the Consolidated Balance Sheet as of Dec. 31, 2010 and 2009:

(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

(millions) *at Dec. 31, 2009*	*Balance Sheet Location* (1)	*Fair Value*	*Balance Sheet Location* (1)	*Fair Value*
Commodity Contracts:				
Natural gas derivatives:				
Current	Regulatory liabilities	$0.8	Regulatory assets	$33.1
Long-term	Regulatory liabilities	0.0	Regulatory assets	3.6
Total		$0.8		$36.7

(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, 2010, net pretax losses of $26.1 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]	
2010			
Interest rate contracts:	$ 0.0	Interest expense	($ 1.7)
Commodity contracts:			
Heating oil 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:			
Heating oil derivatives	2.8	Mining related costs	(13.3)
Total	$ 2.5		($ 15.3)
2008			
Interest rate contracts:	($ 3.4)	Interest expense	($ 1.0)
Commodity contracts:			
Heating oil derivatives	(12.4)	Mining related costs	4.1
Total	($ 15.8)		$ 3.1

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

For derivative instruments that meet cash flow hedge criteria, the effective portion of the gain or loss on the derivative is reported as a component of OCI and reclassified into earnings in the same period or period during which the hedged transaction affects earnings. Gains and losses on the derivatives representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings. For the years ended Dec. 31, 2010, 2009 and 2008, 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
2010			
Interest rate swaps	$ 0.0	$ 0.0	($ 1.7)
Heating oil derivatives	1.8	0.6	(0.8)
Total	$ 1.8	$ 0.6	($ 2.5)
2009			
Interest rate swaps	$ 0.0	($ 0.3)	($ 2.0)
Heating oil derivatives	(0.7)	2.8	(13.3)
Total	($ 0.7)	$ 2.5	($ 15.3)
2008			
Interest rate swaps	$ 0.0	($ 3.4)	($ 1.0)
Heating oil derivatives	(26.3)	(12.4)	4.1
Total	($ 26.3)	($ 15.8)	$ 3.1

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

The maximum length of time over which the company is hedging its exposure to the variability in future cash flows extends to Dec. 31, 2012 for both financial natural gas and financial heating oil fuel contracts. The following table presents by commodity type the company's derivative volumes that, as of Dec. 31, 2010, are expected to settle during the 2011 and 2012 fiscal years:

(millions)	Heating Oil Contracts (Gallons)		Natural Gas Contracts (MMBTUs)	
Year	**Physical**	**Financial**	**Physical**	**Financial**
2011	0.0	7.0	0.0	31.9
2012	0.0	0.5	0.0	9.6
Total	0.0	7.5	0.0	41.5

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, 2010, 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, 2010, 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, 2010:

Contingent Features

(millions) **At Dec. 31, 2010**	**Fair Value Asset/ (Liability)**	**Derivative Exposure Asset/ (Liability)**	**Posted Collateral**
Credit Rating	($29.8)	($29.8)	$0.0

22. Fair Value Measurements

Determination of Fair Value

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

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

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

Items Measured at Fair Value on a Recurring Basis

The following table sets forth by level within the fair value hierarchy the company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of Dec. 31, 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 heating oil swaps, the market approach was used in determining fair value. For other investments, the income approach was used.

Recurring Fair Value Measures

	At fair value as of Dec. 31, 2010			
(millions)	*Level 1*	*Level 2*	*Level 3*	*Total*
Assets				
Natural gas swaps	$0.0	$ 1.1	$0.0	$ 1.1
Heating oil 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
Heating oil swaps	0.0	0.0	0.0	0.0
Total	$0.0	$29.8	$0.0	$29.8

	At fair value as of Dec. 31, 2009			
(millions)	*Level 1*	*Level 2*	*Level 3*	*Total*
Assets				
Natural gas swaps	$0.0	$ 0.8	$0.0	$ 0.8
Heating oil swaps	0.0	0.2	0.0	0.2
Total	$0.0	$ 1.0	$0.0	$ 1.0
Liabilities				
Natural gas swaps	$0.0	$36.7	$0.0	$36.7
Heating oil swaps	0.0	0.9	0.0	0.9
Total	$0.0	$37.6	$0.0	$37.6

Natural gas and heating oil swaps are over-the-counter swap instruments. The primary pricing inputs in determining the fair value of these swaps are the New York Mercantile Exchange (NYMEX) quoted closing prices of exchange-traded instruments. These prices are applied to the notional amounts of active positions to determine the reported fair value (See **Note 21**).

The table below details the change in value and eventual sale of auction rate securities backed by pools of student loans. These securities were recorded in the "Other investments" line of the Consolidated Balance Sheets. As a result of auction failures and the lack of an alternative active market, the valuation technique for this security was an income approach using a discounted cash flow model and was considered Level 3 within the three tier fair value hierarchy. The model assumed a continuation of failed auctions and interest payments at the default rate. Cash flows were discounted at a rate approximating current market spreads for similar securities.

Based on the protracted disruption of the market for these securities and the uncertain potential for its recovery, the company no longer expected to hold the securities indefinitely to recover the original value. Accordingly, the impairment was deemed other-than-temporary and recognized in "Other income" on the Consolidated Statement of Income for the year ended Dec. 31, 2009. During the second quarter of 2009, one of the two securities was sold for the remaining fair value of $7.3 million. During the third quarter of 2009, the second security was sold for its remaining fair value of $2.5 million.

There were no Level 3 assets or liabilities during the 2010 fiscal year.

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

(millions)	*Auction Rate Securities*
Balance at Dec. 31, 2008	$13.3
Transfers to Level 3	0.0
Change in fair market value included in earnings	(4.1)
Balance at Mar. 31, 2009	$ 9.2
Transfers to Level 3	0.0
Change in fair market value included in earnings	0.0
Settled	(7.3)
Balance at Jun. 30, 2009	$ 1.9
Transfers to Level 3	0.0
Change in fair market value	0.6
Settled	(2.5)
Included in earnings	0.0
Balance at Sep. 30, 2009	$ 0.0
Transfers to Level 3	0.0
Change in fair market value	0.0
Settled	0.0
Included in earnings	0.0
Balance at Dec. 31, 2009	$ 0.0

23. TECO Finance, Inc.

TECO Finance, Inc. (TECO Finance) is a 100% 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**). See also **Restrictions on Dividend Payments and Transfer of Assets** in **Note 1**.

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*
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
Stock price per common share (1)				
High	$18.11	$17.65	$17.35	$16.54
Low	$16.58	$14.78	$14.46	$14.46
Close	$17.80	$17.32	$15.07	$15.89

Quarter ended	*Dec. 31*	*Sep. 30*	*Jun. 30*	*Mar. 31*
2009				
Revenues	$765.0	$896.3	$825.2	$824.0
Income from operations	$119.4	$135.0	$123.1	$ 82.7
Net income	$ 53.5	$ 64.8	$ 60.9	$ 34.7
Earnings per share (EPS)—basic	$ 0.25	$ 0.30	$ 0.29	$ 0.16
Earnings per share (EPS)—diluted	$ 0.25	$ 0.30	$ 0.29	$ 0.16
Dividends paid per common share	$ 0.20	$ 0.20	$ 0.20	$ 0.20
Stock price per common share (1)				
High	$16.71	$14.64	$12.41	$12.97
Low	$13.45	$11.16	$10.28	$ 8.41
Close	$16.22	$14.08	$11.93	$11.15

(1) Trading prices for common shares

25. Subsequent Events

Tampa Electric Company Accounts Receivable Facility

On Feb. 18, 2011, Tampa Electric Company and TRC, a wholly-owned subsidiary of Tampa Electric Company, amended their $150 million accounts receivable collateralized borrowing facility, entering into Omnibus Amendment No. 9 to the Loan and Servicing Agreement with certain lenders named therein and Citicorp North America, Inc. as Program Agent. The amendment (i) extends the maturity date to Feb. 17, 2012, (ii) provides that TRC will pay program and liquidity fees, which will total 70 basis points, (iii) provides that the interest rates on the borrowings will be based on prevailing asset-backed commercial paper rates, unless such rates are not available from conduit lenders, in which case the rates will be at an interest rate equal to, at Tampa Electric Company's option, either Citibank's prime rate (or the federal funds rate plus 50 basis points, if higher) or a rate based on the London interbank offer rate (if available) plus a margin and (iv) makes other technical changes.

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 (the "Exchange Act")) as of the end of the period covered by this annual report, Dec. 31, 2010 (the "Evaluation Date"). Based on such evaluation, TECO Energy's principal executive officer and principal financial officer have concluded that, as of the Evaluation Date, TECO Energy's disclosure controls and procedures are effective.

Management's Report on Internal Control over Financial Reporting.

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, 2010 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, 2010.

TECO Energy's internal control over financial reporting as of Dec. 31, 2010 has been audited by PricewaterhouseCoopers LLP, an independent registered certified public accounting firm, as stated in their report which is on page 73 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.

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 4, 2011 (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 18 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 Discussion and Analysis" and ending with "Executive Chairman Employment Agreement" just above the caption "Ratification of Appointment of Independent Auditor", and under the caption "Compensation of Directors" and is incorporated herein by reference.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by Item 12 is included under the caption "Share Ownership" in the Proxy Statement, and is incorporated herein by reference.

Equity Compensation Plan Information

(thousands, except per share price) *Plan Category*	*(a)* *Number of securities to be issued upon exercise of outstanding options, warrants and rights* (1)	*(b)* *Weighted-average exercise price of outstanding options, warrants and rights*	*(c)* *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)	4,902	$22.04	3,374
Equity compensation plans/arrangements not approved by the stockholders			
None	—	—	—
Total	4,902	$22.04	3,374

(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, performance units, dividend equivalents and other forms of award available for grant under the plan.

(3) The 2010 Equity Incentive Plan amends, restates and supersedes the 2004 Equity Incentive Plan and the 1997 Director Equity 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.

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 72

2. Financial Statement Schedules

   Condensed Parent Company Financial Statements Schedule I—page 125-128

   TECO Energy, Inc. Schedule II—page 129

(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, 2010*	*Dec. 31, 2009*
Current assets		
Cash and cash equivalents	$ 39.7	$ 21.9
Advances to affiliates	96.2	213.4
Accounts receivable from affiliates	8.1	7.2
Interest receivable from affiliates	1.0	1.6
Other current assets	0.6	0.9
Total current assets	145.6	245.0
Property, plant and equipment		
Property, plant and equipment	0.7	0.6
Accumulated depreciation	(0.3)	(0.2)
Total property, plant and equipment, net	0.4	0.4
Other assets		
Investment in subsidiaries	2,661.8	2,641.3
Deferred income taxes	563.4	657.6
Other assets	9.4	8.4
Total other assets	3,234.6	3,307.3
Total assets	$3,380.6	$3,552.7
Liabilities and capital		
Current liabilities		
Long-term debt due within one year	$ 48.8	$ 102.8
Accounts payable to affiliates	0.4	0.4
Accounts payable	5.3	3.6
Interest payable	0.7	3.9
Taxes accrued	6.0	0.2
Advances from affiliates	1,111.2	1,030.8
Other current liabilities	0.5	0.6
Total current liabilities	1,172.9	1,142.3
Other liabilities		
Long-term debt, less amount due within one year	8.8	301.0
Other liabilities	29.2	24.0
Total other liabilities	38.0	325.0
Capital		
Common equity	214.9	213.9
Additional paid in capital	1,542.0	1,530.8
Retained earnings	430.0	365.7
Accumulated other comprehensive loss	(17.2)	(25.0)
Total capital	2,169.7	2,085.4
Total liabilities and capital	$3,380.6	$3,552.7

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

For the years ended Dec. 31, (millions)	*2010*	*2009*	*2008*
Revenues	$ 0.0	$ 0.0	$ 0.0
Expenses			
Administrative and general expenses	5.2	4.5	4.2
Other taxes	0.9	0.7	0.8
Transaction (gain) costs related to sale of business	0.0	0.0	(0.2)
Sale of previously impaired assets	(2.9)	0.0	0.0
Restructuring charges	1.5	2.6	0.0
Depreciation and amortization	0.2	0.2	0.2
Total expenses	4.9	8.0	5.0
Loss from operations	(4.9)	(8.0)	(5.0)
Other income (expense)			
Loss on debt extinguishment	(19.8)	0.0	0.0
Interest income	0.2	0.2	0.0
Other income	1.0	(5.2)	2.0
Earnings from investments in subsidiaries	281.4	243.0	192.1
Total other income	262.8	238.0	194.1
Interest income (expense)			
Interest expense			
Others	(13.5)	(25.2)	(28.1)
Total interest expense	(13.5)	(25.2)	(28.1)
Income before income taxes	244.4	204.8	161.0
Income tax expense (benefit)	5.4	(9.1)	(1.4)
Net income	$239.0	$213.9	$162.4

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

SCHEDULE I—CONDENSED PARENT COMPANY FINANCIAL STATEMENTS

TECO ENERGY, INC.

PARENT COMPANY ONLY
Condensed Statements of Cash Flows

For the years ended Dec. 31, (millions)	*2010*	*2009*	*2008*
Cash flows from operating activities	$ 383.2	$ 311.7	$ 428.0
Cash flows from investing activities			
Restricted cash	0.0	0.4	(0.1)
Capital expenditures	(0.1)	0.0	0.0
Investment in subsidiaries	(50.0)	0.0	(271.0)
Net change in affiliate advances	197.6	(134.5)	(67.4)
Other non-current investments	0.0	9.8	(42.3)
Cash flows from (used in) investing activities	147.5	(124.3)	(380.8)
Cash flows from financing activities			
Dividends to shareholders	(174.7)	(170.8)	(168.6)
Common stock	7.8	5.1	21.8
Repayment of long-term debt	(346.0)	0.0	0.0
Cash flows used in financing activities	(512.9)	(165.7)	(146.8)
Net increase (decrease) in cash and cash equivalents	17.8	21.7	(99.6)
Cash and cash equivalents at beginning of period	21.9	0.2	99.8
Cash and cash equivalents at end of period	$ 39.7	$ 21.9	$ 0.2
Supplemental Data			
Dividends from subsidiaries included in cash flows from operating activities	$ 318.4	$ 254.2	$ 408.4

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 due to their net assets exceeding 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 and 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, 2010, 2009 and 2008
(millions)

	Balance at Beginning of Period	Additions: Charged to Income	Additions: Other Charges	Payments & Deductions (1)	Balance at End of Period
Allowance for Uncollectible Accounts:					
2010	$3.0	$10.7	$—	$9.2	$4.5
2009	$3.5	$ 9.1	$—	$9.6	$3.0
2008	$3.3	$ 8.1	$—	$7.9	$3.5

(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 28, 2011

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 25, 2011:

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/ TOM L. RANKIN **TOM L. RANKIN**	Director
/s/ JAMES L. FERMAN, JR. **JAMES L. FERMAN, JR.**	Director	/s/ WILLIAM D. ROCKFORD **WILLIAM D. ROCKFORD**	Director
/s/ JOSEPH P. LACHER **JOSEPH P. LACHER**	Director	/s/ PAUL L. WHITING **PAUL L. WHITING**	Director
/s/ LORETTA A. PENN **LORETTA A. PENN**	Director		

Corporate Officers

TECO ENERGY EXECUTIVE OFFICERS

Sherrill W. Hudson
Executive Chairman of the Board

John B. Ramil
President and Chief Executive Officer

Charles A. Attal III
Senior Vice President - General Counsel and Chief Legal Officer

Phil L. Barringer
President, TECO Guatemala Inc. and Vice President - Human Resources, TECO Energy Inc.

Deirdre A. Brown
Vice President - Business Strategy & Compliance and Chief Ethics and Compliance Officer

Sandra W. Callahan
Senior Vice President - Finance and Accounting and Chief Financial Officer (Chief Accounting Officer)

Clinton E. Childress
Senior Vice President - Corporate Services and Chief Human Resources Officer

Gordon L. Gillette
President, Tampa Electric Company and Peoples Gas System

J. J. Shackleford
President and Chief Operating Officer, TECO Coal Corporation
(Mr. Shackleford will retire April 1 and Mr. Clark Taylor will succeed Shackleford as President.)

TECO ENERGY AND OPERATING COMPANY OFFICERS

Kim M. Caruso
Treasurer, TECO Energy Inc.

Thomas L. Hernandez
Vice President - Energy Supply, Tampa Electric Company

Charles O. Hinson III
Vice President - Government Affairs, TECO Energy Inc.

Joe W. Lee
Vice President - Sales, TECO Coal Corporation

D. Bruce Meece
Vice President - Administration & Strategic Planning, TECO Coal Corporation

Karen M. Mincey
Vice President - Information Technology and Chief Information Officer, TECO Energy Inc.

Bruce Narzissenfeld
Vice President - Customer Care & Fuels Management, Tampa Electric Company

David E. Schwartz
Vice President - Governance, Associate General Counsel and Corporate Secretary, TECO Energy Inc.

Clark Taylor
Vice President - Controller, TECO Coal Corporation
(Mr. Taylor will succeed Mr. J. J. Shackleford as President on April 1.)

Victor Urrutia
Vice President - Operations, TECO Guatemala Inc.

William T. Whale
Vice President - Electric & Gas Delivery, Tampa Electric Company

Robert J. Zik
Vice President - Operations, TECO Coal Corporation

Board of Directors

Sherrill W. Hudson[(3)]
Executive Chairman of the Board, TECO Energy Inc.

DuBose Ausley[(3)]
Attorney and former Chairman, Ausley & McMullen, P.A. (attorneys), Tallahassee, Florida.

James L. Ferman Jr.[(2)(4)]
President, Ferman Motor Car Company Inc. (automobile dealerships), Tampa, Florida.

Joseph P. Lacher[(1)(4)]
Former President of Florida Operations for BellSouth Telecommunications Inc., (telecommunications services), Miami, Florida.

Loretta A. Penn[(2)(4)]
President, Spherion Staffing Services, a division of SFN Group Inc. (staffing and professional services), McLean, Virginia.

John B. Ramil[(3)]
President and Chief Executive Officer, TECO Energy Inc.

Tom L. Rankin[(1)(3)]
Independent Investment Manager, Tampa, Florida; former Chairman of the Board and Chief Executive Officer, Lykes Energy Inc. (the former holding company for Peoples Gas System).

William D. Rockford[(2)(3)]
Former President, Primary Energy Ventures LLC (power generation), Oak Brook, Illinois; also former Managing Director, Chase Securities Inc. (financial services), New York, New York.

Paul L. Whiting[(1)(2)]
President, Seabreeze Holdings Inc. (consulting and private investments), Tampa, Florida, and Chairman of the Board, Sykes Enterprises Inc. (outsourcing and consulting), Tampa, Florida.

(1) Member of the Audit Committee
(2) Member of the Compensation Committee
(3) Member of the Finance Committee
(4) Member of the Governance and Nominating Committee

P. O. Box 111 Tampa, FL 33601 tecoenergy.com

Information for Investors

INTERNET

Current information about TECO Energy is available on the Internet at **tecoenergy.com**

TECO Energy is listed on the New York Stock Exchange under the symbol **TE**.

TECO ENERGY OFFICES

702 N. Franklin Street
Tampa, FL 33602
813-228-1111
813-228-4262 fax

TECO ENERGY SHAREHOLDER SERVICES

813-228-1326
800-810-2032

AUDITORS

PricewaterhouseCoopers LLP
Tampa, FL

ANNUAL MEETING

The Annual Meeting of Shareholders will be held at 11:00 a.m. May 4, 2011 at:

TECO Plaza
702 N. Franklin Street
Tampa, FL 33602

SHAREHOLDER INQUIRIES

Communication concerning transfer requirements, lost certificates, dividends and change of address should be directed to the Transfer Agent:

By phone: 1-800-650-9222 or 201-680-6578 (outside the U.S.and Canada)

By e-mail: **shrrelations@bnymellon.com**

By Web: **bnymellon.com/shareowner/equityaccess**

TRANSFER AGENT & REGISTRAR

BNY Mellon Shareowner Services
P.O. Box 358015
Pittsburgh, PA 15252-8015
or
480 Washington Boulevard
Jersey City, N J 07310-1900

DIVIDEND REINVESTMENT

The company offers a Dividend Reinvestment and Common Stock Purchase Plan, which allows common shareholders of record to purchase additional shares of common stock. All correspondence concerning this plan should be directed to the Plan Agent:

BNY Mellon Shareowner Services
P.O. Box 358035
Pittsburgh, PA 15252-8035

FORM 10-K AVAILABLE

TECO Energy's Annual Report on Form 10-K, which is filed with the Securities and Exchange Commission, is available on the Internet at sec.gov or through the "Investors" section of our website at **tecoenergy.com**. A printed copy is available to shareholders at no charge, upon a written request addressed to:

TECO Energy, Inc.
Investor Relations
P.O. Box 111
Tampa, FL 33601-0111

ANALYST CONTACTS

Sandra W. Callahan
Senior Vice President and Chief Financial Officer

Mark M. Kane
Director - Investor Relations
813-228-1111

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