TECO ENERGY

Performance, Preservation & Progress

A FOCUS ON OUR UTILITIES AND OPERATIONAL EXCELLENCE

TECO ENERGY INC 2012 ANNUAL REPORT

NYSE
CENTURY CLUB

COMPANY PROFILE

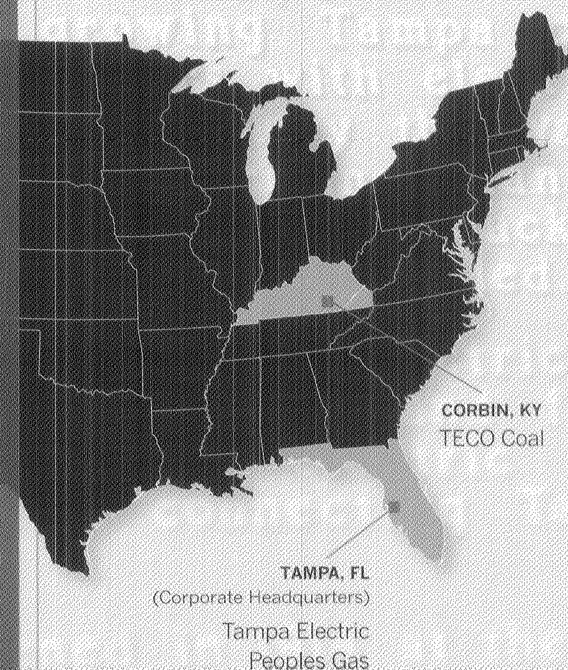
TECO ENERGY INC. (NYSE: TE) is an energy-related holding company in Tampa, Florida. Its regulated Florida operations are Tampa Electric and Peoples Gas, and its other business is engaged in coal production in Kentucky and Virginia.

OUR BUSINESSES

- **TAMPA ELECTRIC** is a regulated electric utility with nearly 4,700 megawatts of capacity. Its 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. Tampa Electric delivers reliable power to more than 687,000 residential, commercial and industrial customers.
- **PEOPLES GAS** is Florida's leading provider of regulated natural gas distribution services, with a presence in most of the state's metropolitan areas. Peoples Gas delivers reliable, clean energy to almost 345,000 residential, commercial and industrial customers.
- **TECO COAL** subsidiaries own and operate low-sulfur coal mines and preparation facilities in Kentucky and Virginia that mine, process and ship more than five million tons of coal per year to domestic utilities, the steel industries in the United States and Europe, and industrial customers.

In December 2012, TECO Energy sold its interests in TECO Guatemala, an electric utility business in Guatemala that operated two power stations, and coal handling and port facilities.

TECO ENERGY COMPANIES



On the cover

TECO Energy's Tampa Electric Company Organized October 1899

In 1899, Colonel Peter O. Knight created Tampa Electric Company to serve the energy needs of a growing Tampa community. Some 28 employees served 1,200 customers with electricity from the region's first power plant, one powered by the water of the Hillsborough River. In 1903, a steam generating plant, renamed the Peter O. Knight Station in 1969, was built on Jackson Street, and by 1906, the first turbo-generator was installed.

At the dawn of the 20th century, Tampa Electric Company promoted such conveniences as electric lights and fans. And for only a nickel, residents could ride electric streetcars over more than 20 miles of track connecting Tampa, Ybor City and Ballast Point.

Modern downtown offices were opened in 1914 at the corner of Cass and Tampa Street. At the end of the century, Tampa Electric and parent company TECO Energy employed more than 5,000 men and women in six states and South America. In its first 100 years, TECO Energy became a major diversified energy company, providing reliable energy services to customers around the state, the nation and the world.

- The above text is from the sign erected at TECO Energy's corporate headquarters, in downtown Tampa, Florida, in cooperation with the Tampa Historical Society in celebration of the Centennial of TECO Energy.

TABLE OF CONTENTS

TECO Energy **Board of Directors**

Left to right: DuBose Ausley, Evelyn Follit, William Rockford, James Ferman, Sherrill Hudson, John Ramil, Loretta Penn, Tom Rankin, Joseph Lacher, Paul Whiting.

Sherrill W. Hudson(3)
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.

Evelyn V. Follit(1)
President, Follit Associates (corporate technology and executive assessment consulting), Tarpon Springs, Florida; former Senior Vice President and Chief Information Officer, Radio Shack Corporation, Fort Worth, Texas.

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

Loretta A. Penn(2)(4)
Former 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)
Investor, 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. (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

Of Special Note

***DuBose Ausley**, a member of our Board of Directors for 21 years, is retiring May 1, 2013. Please join me in thanking Mr. Ausley for his leadership, service and dedication. His many contributions will be missed.*

***Sherrill Hudson,** on December 31, 2012, retired as an active employee of TECO Energy. As you know, Sherrill has been a most valuable and accomplished team member. I am most pleased that Sherrill has graciously agreed to continue on our Board and serve as Chair. Sherrill was named Chairman of the Board, effective January 1, 2013.*

– **John B. Ramil**, President and Chief Executive Officer

To Our Shareholders

I am pleased to report that TECO Energy delivered value in 2012 to our shareholders and customers while continuing to execute strategies that allowed us to focus on our core domestic utility businesses. We also set operational performance records and continued to deliver the solid returns you've come to expect from our company. And all of this was accomplished despite the challenges and uncertainties in our nation, state and industries.

John B. Ramil
President and Chief Executive Officer

2013 marked the 89th straight year that TECO Energy has paid dividends to our shareholders. Our total shareholder performance outpaced the S&P Multi-Utility Index and the S&P 500 Index over the past five years. Considering the coal sector was down by about 40 percent, this translates to remarkably stable performance especially since TECO Coal has recently contributed almost 30 percent of overall earnings.

Florida's idyllic weather and slow but positive economic recovery played significant roles in the performance of our utility businesses. Despite growth in the number of customers and other positive signs of economic recovery, mild weather impacted revenues for Tampa Electric and Peoples Gas. And like most other electric utilities, Tampa Electric saw a slowdown in average customer usage per household. Fortunately, soft revenues were offset by the good work of our employees, who continued to find ways to manage costs and perform more efficiently and innovatively.

I am extremely proud of our utilities' safety and reliability performance. In 2012, we had our safest year ever at TECO Energy, with both Tampa Electric and Peoples Gas landing in the top quartile of their respective regional peers. At the same time, we operated both utilities with some of the best reliability metrics in Florida and, at Tampa Electric, we improved our customer satisfaction rankings for the third year in a row as measured by J.D. Power and Associates.

Our two unregulated businesses, TECO Coal and TECO Guatemala, managed their businesses well and continued to deliver value for shareholders. TECO Coal delivered strong results, even with a depressed and challenged market. Over the past few years, that business has shifted sales to higher-margin metallurgical coal and has delivered three years of record income. In Guatemala, we capitalized on an opportunity to create future value by selling our two power plants and related facilities. The sale marked our exit from Central America, and allows us to stay keenly focused on growing our core electric and gas utilities.

We were honored by the New York Stock Exchange inviting us to its inaugural Century Club meeting. TECO Energy was one of about 350 publicly traded businesses recognized in 2012 for thriving for more than a century. The NYSE acknowledged companies such as TECO Energy for their ability to innovate, transform and grow through decades of economic and social progress.

I want to assure you that our leadership team is never complacent nor fully satisfied with the company's overall performance. We are working diligently to position our businesses for better growth, taking advantage of our strong cash position and solid credit ratings to support future utility investments and growth aspirations.

Peoples Gas is doing well with increasing customer interest in natural gas as a reasonably priced and viable long-term energy solution. In early 2013, Tampa Electric notified the Florida Public Service Commission that it needs a base rate increase beginning in 2014 to better reflect costs of providing safe and reliable service. And the PSC recently approved our Polk Power Station expansion project, an investment that will drive our electric business growth and benefit customers for decades to come. I am confident our core utility businesses have strong futures.

At TECO Coal, our commitment remains – to provide value by generating cash to invest in the utilities and improve our financial position. As the worldwide demand for metallurgical coal has softened, we have taken actions to be profitable, even in difficult markets, and our strong leadership team is keenly focused on ensuring operations continue to be positioned to generate overall value to the corporation.

As always, your team at TECO Energy remains dedicated and committed to success. We are investors in our company and we are very much aligned with the interests of you, our shareholders. We have and continue to set our sights on future success and we very much like the view. Thank you for your investments, continued support, and interest in our company.

Sincerely,

John B. Ramil, President and Chief Executive Officer

Sharpening our focus on core electric operations - generation addition

In March 2012, Tampa Electric announced plans to expand the **Polk Power Station** in 2017 to accommodate customer growth and to replace expiring purchased-power agreements.

- **The expansion would add about 460 megawatts**, or enough electricity to power more than 100,000 homes.
- The project includes **converting four existing simple-cycle natural gas peaking units** to a more efficient combined-cycle unit by January 2017. It will add heat recovery steam generators to capture energy from the existing combustion turbine exhausts and use them to produce additional electric power.


Polk Power Station

- **The $700 million project also would improve transmission reliability** and dramatically reduce emissions of nitrogen oxide and carbon dioxide.

"As Florida's economy recovers from the downturn, Tampa Electric anticipates growth in energy use in coming years, and we also will need to replace other sources of power. Expanding the Polk Power Station provides the best value to customers based on cost, reliability and flexibility, as well as environmental performance."

– **Gordon Gillette**, President, Tampa Electric

Maximizing value - the sale of TECO Guatemala operations

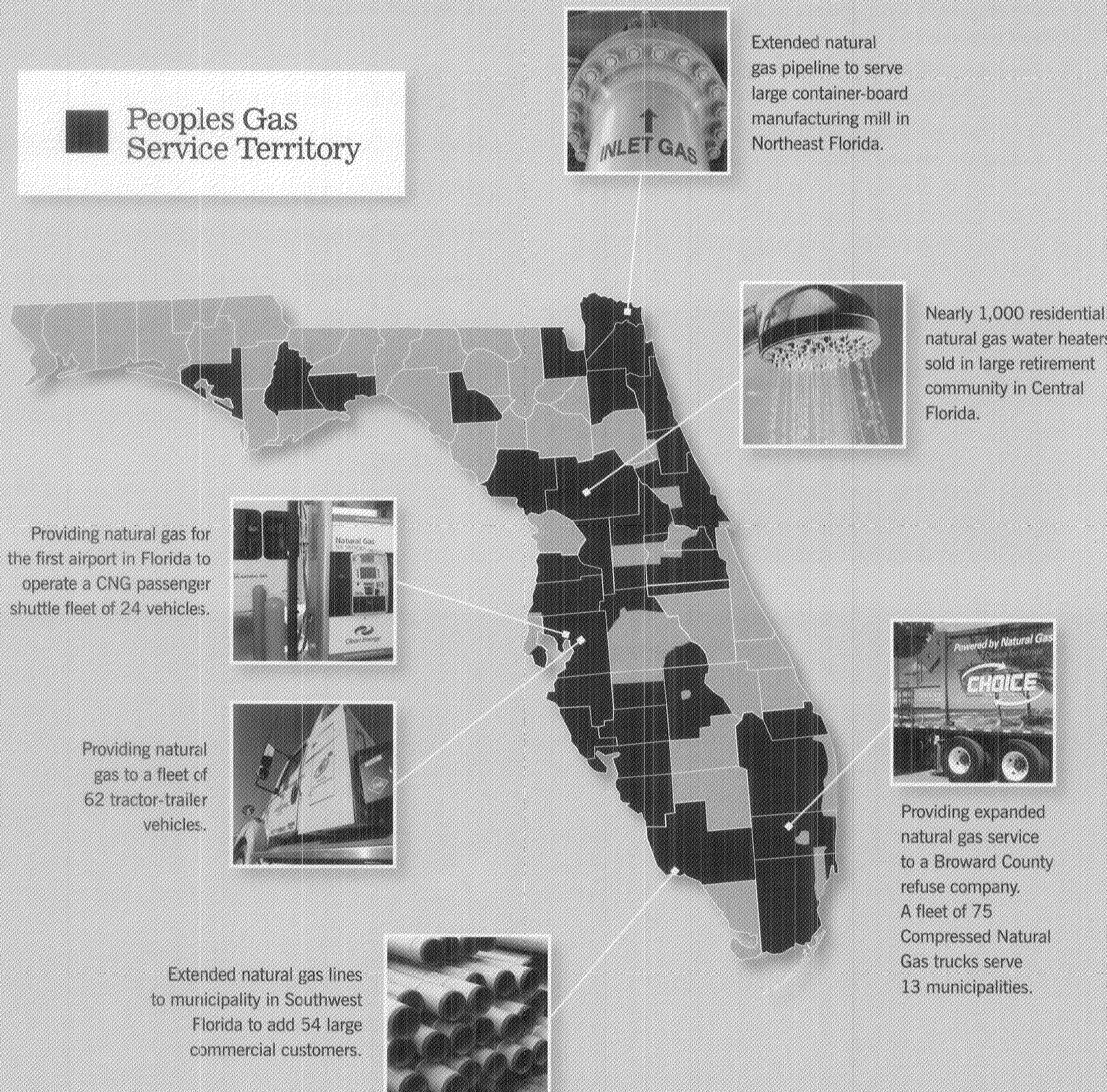
In 2012, TECO Energy announced the sale of its subsidiaries' equity interest in the Alborada and San José power stations and related facilities in Guatemala, for a total purchase price of $227.5 million.


San José Power Station

"These agreements position us to complete our exit from the Guatemalan power sector. Over the life of the investments, our Guatemalan power stations have provided good returns and cash that we've used to help strengthen TECO Energy's balance sheet and invest in our U.S. utilities."

– **John Ramil**, President and CEO, TECO Energy

Sharpening our focus on **gas operations** - expansion, saturation, retention

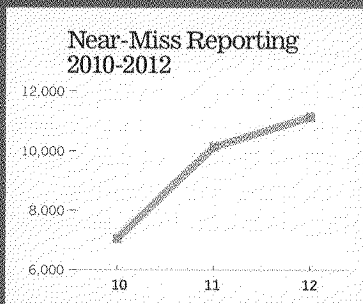


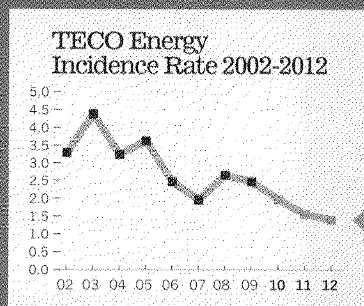
We're safe

TECO Energy uses a number of criteria to measure the success of our safety programs. No matter how we slice it, **TECO Energy companies broke records in safety in 2012**.

Peoples Gas and Tampa Electric set records for low incidence rates for the third straight year. Additionally, our electric operation ranked in the top quartile among members of the Southeastern Electric Exchange. Tampa Electric set an all-time record for safety performance related to injuries on the job in 2012.

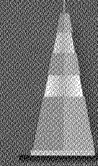
top of the competition. These competitions are designed to highlight performance and encourage ongoing training to prepare for responding to actual mine emergencies. **TECO Coal mine rescue teams finished in first place at the 2012 Kentucky State Mine Rescue Competition** held in Lexington, Kentucky. The TECO Coal Mine Rescue First Aid Team is the current National First Aid champion. While we hope they are never called to perform, every team member at TECO Coal appreciates their knowledge and expertise.





Statistics indicate that for every 100 near-miss incidents that go unreported, 10 recordable injuries and 1 serious injury or fatality occurs.

At TECO Energy, as reporting increased, starting in 2010, **accidents have steadily decreased.**



To focus on accident prevention instead of accident "reaction," emphasis has been placed on near-miss reporting and performance-based safety observations. **TECO Energy team members submitted more than 10,000 near-miss reports during the year**. Topping the list of our core values, safety continues to be an area where continuous improvement is not only encouraged, but expected.

At TECO Coal, our leadership team partnered with the federal Mine Safety and Health Administration (MSHA) to improve overall safety and minimize infractions. MSHA adopted new programs to prevent fatalities and increase regulatory compliance as a result of a number of high-profile mining disasters involving other companies throughout the country.

Another area where TECO Coal excelled was mine rescue training. **TECO Coal mine rescue personnel are regarded as some of the nation's best**, proven by their performance at annual and local, regional and national mine rescue competitions where they consistently have finished at the

We attribute our safety success to the continuous improvements that have been an integral part of our culture at TECO Energy.

Kentucky-based **TECO Coal** has received numerous safety awards for mining operations.

"We have proven that by working with regulators, we can be productive, profitable and safe. This provides an advantage over our competitors at a time when every penny counts."

– **Clark Taylor**, President, TECO Coal

Investing in advanced power line technology has allowed the company to use remote-control relays to reduce momentary outages, resulting in an all-time low in 2012.

99.9 PERCENT **RELIABILITY**

We're reliable

Tampa Electric and Peoples Gas continue to provide a high degree of reliability across Florida.

Tampa Electric had the fewest – and among the shortest – service interruptions among Florida investor-owned utilities for the past five consecutive years. Nationally, Tampa Electric has been in the top quartile for those same metrics.

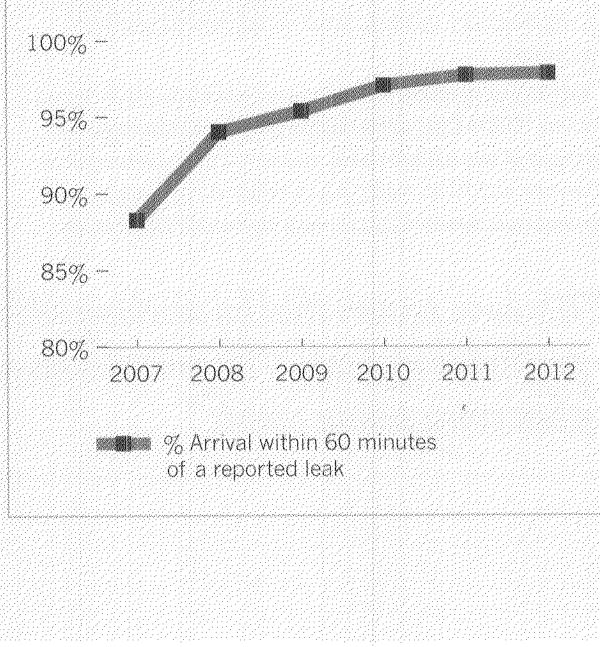
In 2012, **we provided 99.9 percent reliability to electric and natural gas customers.**

- Tampa Electric outages caused by trees or other vegetation contacting electric equipment decreased, while the company was recognized as a Tree Line USA Utility by the National Arbor Day Foundation for the fourth straight year.
- As a result of effective Call Before You Dig marketing by Peoples Gas, customer awareness of Call 811 continues to increase. In 2012, 89 percent of Peoples Gas customers surveyed said they were familiar with this service that helps maintain reliability by preventing third-party damage to natural gas lines.

We're responding quicker.

- Peoples Gas continued a five-year trend of responding faster to reported leaks in less than 60 minutes. The majority of significant leaks are caused by third-party damage. In 2012, we reached an all-time record of nearly 98 percent.
- For the second year in a row, Tampa Electric decreased the time it took to restore service. This is nearly 10 percent improvement over the past two years.

5 Years of Improved Performance



We're committed

Value to customers means:
price • reliability • solutions to customers' needs • corporate citizenship

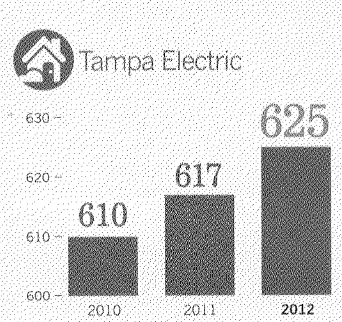
We continue to find ways to deliver value to our customers. We have identified key drivers of value, including the role of good communications and energy education in the mix of customers' expectations.

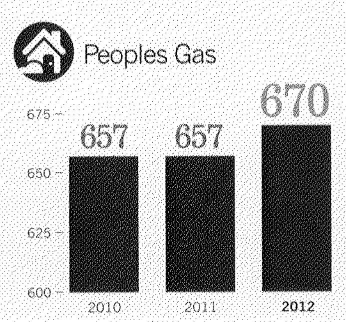
Since then, we have seen annual improvement in residential customer satisfaction, based on J.D. Power and Associates surveys.

We continue to expand communications options to meet our customers' needs.

- In November 2012, we launched **redesigned websites** for Tampa Electric, Peoples Gas and TECO Energy. The sites feature responsive design for better use on smartphones, tablets or other mobile devices.
- Employing a modern, streamlined design and customer feedback, the new sites simplify the **four million online transactions** and **11 million page views** the company gets each year.
- Online offerings include increased use of **social media** to communicate and educate.

Customer Satisfaction*





* *Results of J.D. Power and Associates residential surveys.*

tecoenergy.com
tampaelectric.com
peoplesgas.com

Customer Average Interruption

We're involved

Helping the **environment** and **our community**

We are proud to be part of the communities we serve. In 2012, TECO Energy continued our stewardship of the environment, anchoring our operations in a foundation of sustainable growth.

In September 2012, the Florida Aquarium, Florida Fish and Wildlife Conservation Commission and Tampa Electric created a landmark partnership with the announcement of the vision for a jointly-funded **Florida conservation and technology park**.

The park, which will be built near Tampa Electric's Manatee Viewing Center in Apollo Beach, Florida, will serve as a nexus for recreation, learning and conservation, and research and technology, and will include:

- **The Energy Technology Center** featuring state-of-the-art energy technologies.
- **The Center for Conservation**, where visitors can learn about Florida's waters, plants and fish.
- **Camps and an Educational Facility** providing unique learning experiences.
- **An Animal Rescue, Research and Holding Facility** for the Florida Aquarium.
- **A Saltwater Fish Hatchery** operated by the Florida Fish and Wildlife Conservation Commission (FWC).
- **Interpretive Trails**, including walking and canoe and kayak trails.
- **Catch and Release Fishing Programs** conducted by the Aquarium and FWC.

"This unique blend of environmental education and cutting-edge energy technology will complement the award-winning Manatee Viewing Center and will become a showcase the community can enjoy."

– **Tom Hernandez**, Vice President of Energy Supply, Tampa Electric

Tampa Electric, the Florida Aquarium and Florida Fish and Wildlife Conservation Commission break ground on the conservation and technology park with planting by students.

Community involvement is important to **TECO Energy**; it allows us to participate in and contribute back to the areas we serve and in which we live. Benefits we bring to the community benefit our business.

TECO Coal continues its award-winning program to restore previously mined lands for beneficial uses.

TECO Energy is one of the TOP 150 places to work in the U.S., based on employee surveys by Workplace Dynamics.

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, 2012

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 June 29, 2012 was approximately $3.85 billion 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. 15, 2013 was 217,255,694. As of Feb. 15, 2013, 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 2013 Annual Meeting of Shareholders of TECO Energy, Inc. are incorporated by reference into Part III.

DEFINITIONS

Acronyms and defined terms used in this and other filings with the U.S. Securities and Exchange Commission include the following:

Term	Meaning
ABS	asset-backed security
ADR	American depository receipt
AFUDC	allowance for funds used during construction
AFUDC - debt	debt component of allowance for funds used during construction
AFUDC - equity	equity component of allowance for funds used during construction
AMT	alternative minimum tax
AOCI	accumulated other comprehensive income
APBO	accumulated postretirement benefit obligation
ARO	asset retirement obligation
BACT	Best Available Control Technology
BTU	British Thermal Unit
capacity clause	capacity cost-recovery clause, as established by the FPSC
CCRs	coal combustion residuals
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980
CGESJ	Central Generadora Eléctrica San José, Limitada, owner of the San José Power Station in Guatemala
CMMA	Cardno MM&A
CMO	collateralized mortgage obligation
CNG	compressed natural gas
CPI-U	consumer price index - all urban consumers
CO_2	carbon dioxide
CT	combustion turbine
DECA II	Distribución Eléctrica Centro Americana, II, S.A.
DOE	U.S. Department of Energy
ECRC	environmental cost recovery clause
EEGSA	Empresa Eléctrica de Guatemala, S.A., the largest private distribution company in Central America
EEI	Edison Electric Institute
EGWP	Employee Group Waiver Plan
EPA	U.S. Environmental Protection Agency
EPS	earnings per share
ERISA	Employee Retirement Income Security Act
EROA	expected return on plan assets
ERP	enterprise resource planning
FASB	Financial Accounting Standards Board
FDEP	Florida Department of Environmental Protection
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company
FPSC	Florida Public Service Commission
fuel clause	fuel and purchased power cost-recovery clause, as established by the FPSC
GAAP	generally accepted accounting principles
GHG	greenhouse gas(es)
HCIDA	Hillsborough County Industrial Development Authority
HPP	Hardee Power Partners
IFRS	International Financial Reporting Standards
IGCC	integrated gasification combined-cycle
IOU	investor owned utility
IRS	Internal Revenue Service
ISDA	International Swaps and Derivatives Association
ISO	independent system operator
ITCs	investment tax credits
kW	Kilowatt(s)
kWh	kilowatt-hour(s)
LIBOR	London Interbank Offered Rate
MAP-21	Moving Ahead for Progress in the 21st Century Act
MARN	Ministry of Environment, Guatemala
MBS	mortgage-backed securities
MD&A	Management's Discussion and Analysis
met	mettalurgical

Term	Meaning
MMA	The Medicare Prescription Drug, Improvement and Modernization Act of 2003
MMBTU	one million British Thermal Units
MRV	market-related value
MSHA	Mine Safety and Health Administration
MW	megawatt(s)
MWh	megawatt-hour(s)
NAESB	North American Energy Standards Board
NAV	net asset value
NERC	North American Electric Reliability Corporation
NOL	net operating loss
Note __	Note__ to consolidated financial statements
NO_x	nitrogen oxide
NPNS	normal purchase normal sale
NYMEX	New York Mercantile Exchange
O&M expenses	operations and maintenance expenses
OATT	open access transmission tariff
OCI	other comprehensive income
OTC	over-the-counter
OTTI	other than temporary impairment
PBGC	Pension Benefit Guarantee Corporation
PBO	postretirement benefit obligation
PCI	pulverized coal injection
PCIDA	Polk County Industrial Development Authority
PGA	purchased gas adjustment
PGS	Peoples Gas System, the gas division of Tampa Electric Company
PPA	power purchase agreement
PPSA	Power Plant Siting Act
PRP	potentially responsible party
PUHCA 2005	Public Utility Holding Company Act of 2005
REIT	real estate investment trust
REMIC	real estate mortgage investment conduit
RFP	request for proposal
ROE	return on common equity
Regulatory ROE	return on common equity as determined for regulatory purposes
RPS	renewable portfolio standards
RTO	regional transmission organization
S&P	Standard and Poor's
SCR	selective catalytic reduction
SEC	U.S. Securities and Exchange Commission
SO_2	sulfur dioxide
SERP	Supplemental Executive Retirement Plan
SPA	stock purchase agreement
STIF	short-term investment fund
TCAE	Tampa Centro Americana de Electridad, Limitada, majority owner of the Alborada Power Station
Tampa Electric	Tampa Electric, the electric division of Tampa Electric Company
TEC	Tampa Electric Company, the principal subsidiary of TECO Energy, Inc.
TECO Diversified	TECO Diversified, Inc., a subsidiary of TECO Energy, Inc. and parent of TECO Coal Corporation
TECO Coal	TECO Coal Corporation, and its subsidiaries, a coal producing subsidiary of TECO Diversified
TECO Finance	TECO Finance, Inc., a financing subsidiary for the unregulated businesses of TECO Energy, Inc.
TECO Guatemala	TECO Guatemala, Inc., a subsidiary of TECO Energy, Inc., parent company of formerly owned generating and transmission assets in Guatemala.
TEMSA	Tecnología Marítima, S.A., a provider of dry bulk and coal unloading services located in Guatemala
TRC	TEC Receivables Company
USACE	U.S. Army Corps of Engineers
VIE	variable interest entity
WRERA3	The Worker, Retiree and Employer Recovery Act of 2008

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 3,900 employees as of Dec. 31, 2012.

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 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 TEC and, through its subsidiary TECO Diversified, owns TECO Coal.

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

TEC, a Florida corporation and TECO Energy's largest subsidiary, has two business segments. Its **Tampa Electric** division provides retail electric service to more than 687,000 customers in West Central Florida with a net winter system generating capacity of 4,668 MW. **PGS**, the gas division of TEC, is engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in Florida. With approximately 345,000 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 2012 was almost 1.9 billion therms.

TECO Coal, a Kentucky corporation, has 10 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, a Florida corporation, owned subsidiaries that participated in two contracted Guatemalan power plants, Alborada and San José. These subsidiaries were sold on Sept. 27, 2012 and Dec. 19, 2012, respectively.

Revenues from Continuing Operations

(millions)	*2012*	*2011*	*2010*
Tampa Electric	$1,981.3	$2,020.6	$2,163.2
PGS	398.9	453.5	529.9
Total regulated businesses	$2,380.2	$2,474.1	$2,693.1
TECO Coal	608.9	733.0	690.0
Other and Eliminations	7.5	2.8	(19.6)
Total revenues from continuing operations	$2,996.6	$3,209.9	$3,363.5

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

Discontinued Operations/Asset Dispositions

TECO Energy, Inc. completed the sale of its generating and transmission assets in Guatemala during 2012 as part of a business strategy to focus on the domestic electric and gas utilities.

On Sept. 27, 2012, TECO Guatemala entered into an agreement to sell all of the equity interests in the Alborada and San José power stations, related facilities and operations in Guatemala, for a total purchase price of $227.5 million in cash. The sale of the Alborada Power Station closed on the same date for a selling price of $12.5 million.

On Dec. 19, 2012, the closing occurred on the sale of the San José power station and related facilities in Guatemala for a purchase price of $215.0 million.

See **Notes 19, 20** and **21** to the **TECO Energy, Inc. Consolidated Financial Statements** for more information regarding these discontinued operations and asset dispositions.

TAMPA ELECTRIC – Electric Operations

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

Tampa Electric had 2,369 employees as of Dec. 31, 2012, of which 906 were represented by the International Brotherhood of Electrical Workers and 167 were represented by the Office and Professional Employees International Union.

In 2012, approximately 48% of Tampa Electric's total operating revenue was derived from residential sales, 31% from commercial sales, 9% from industrial sales and 12% from other sales, including bulk power sales for resale. Approximately 5% of revenues were attributable to governmental municipalities. The sources of operating revenue and MWH sales for the years indicated were as follows:

Operating Revenue

(millions)	*2012*	*2011*	*2010*
Residential	$ 958.9	$ 994.7	$1,100.0
Commercial	612.3	612.6	648.4
Industrial – Phosphate	75.7	62.0	84.2
Industrial – Other	101.2	99.3	103.7
Other retail sales of electricity	184.0	185.2	191.6
Total retail	1,932.1	1,953.8	2,127.9
Sales for resale	16.2	21.7	41.6
Other	33.0	45.1	(6.3)
Total operating revenues	$1,981.3	$2,020.6	$2,163.2

Megawatt-hour Sales

(thousands)	*2012*	*2011*	*2010*
Residential	8,395	8,718	9,185
Commercial	6,185	6,207	6,221
Industrial	2,002	1,804	2,010
Other retail sales of electricity	1,827	1,835	1,797
Total retail	18,409	18,564	19,213
Sales for resale	267	352	516
Total energy sold	18,676	18,916	19,729

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 FPSC, which has jurisdiction over retail rates, quality of service and reliability, issuances of securities, planning, siting and construction of facilities, accounting and depreciation practices and other matters.

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

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

Tampa Electric's rates and allowed ROE range of 10.25% to 12.25%, with a midpoint of 11.25%, which were established in 2009, are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, FPSC or other interested parties.

Tampa Electric's 2012 results reflect base rates established in March 2009, when the FPSC awarded $104 million higher revenue requirements effective in May 2009 that authorized an ROE mid-point of 11.25%, 54.0% equity in the capital structure, and 2009 13-month average rate base of $3.4 billion. In a series of subsequent decisions in 2009 and 2010, related to a calculation error and a step increase for combustion turbines and rail unloading facilities that entered service before the end of 2009, base rates increased an additional $33.5 million.

As a result of increasing pressure on O&M expense, higher depreciation expense from required infrastructure added to serve customers, and an economic recovery that has been slower than expected compared to the assumptions in Tampa Electric's last base rate proceeding in 2009, on Feb. 4, 2013, Tampa Electric notified the FPSC that it is planning to file a new base rate proceeding in April for new rates effective in early 2014. The actual revenue requirement calculation is not final, but is estimated to be approximately $135 million.

Tampa Electric is also subject to regulation by the FERC in various respects, including wholesale power sales, certain wholesale power purchases, transmission and ancillary services and accounting practices.

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

The transmission rate case updated Tampa Electric's charges under its FERC-approved 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 addressed 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 Sept. 14, 2010, subject to refund. The FERC also approved Tampa Electric's proposed wholesale requirements rates, as filed with the FERC, which became effective March 1, 2011, subject to refund. The proposed and ultimately accepted wholesale requirements and transmission rates did not have a material impact on Tampa Electric's results.

Settlements were reached with the applicable customers in both cases during 2011 and filed with the FERC during the first quarter of 2012. The FERC accepted these settlements as filed, and the settlements took effect during the latter part of 2012. Refunds with interest were provided to the customers last year for the differences between the settlement rates and the charges that were earlier approved by the FERC to be implemented conditionally.

Transactions between Tampa Electric and its affiliates are subject to regulation by the FPSC and FERC, and any charges deemed to be imprudently incurred may be disallowed for recovery from Tampa Electric's retail and wholesale customers.

On Nov. 6, 2012, Tampa Electric received notification from the FERC that its accounting practices and financial reporting processes would be audited, along with its compliance with the FERC's records retention requirements. This is considered a routine audit by the FERC staff, though it has been approximately 20 years since Tampa Electric last had a FERC accounting audit.

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

Competition

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

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

Tampa Electric is not a major participant in the wholesale market because it uses its lower cost generation to serve its retail customers rather than the wholesale market. Over the past three years, gross revenues from wholesale sales, which include fuel that is a pass-through cost, have averaged approximately 1% of Tampa Electric's total revenue.

FPSC rules promote cost-competitiveness in the building of new steam generating capacity by requiring IOUs, such as Tampa Electric, to issue RFPs prior to filing a petition for Determination of Need for construction of a power plant with a steam cycle greater than 75 MW. These rules, which allow independent power producers and others to bid to supply the new generating capacity, provide a mechanism for expedited dispute resolution, allow bidders to submit new bids whenever the IOU revises its cost estimates for its self-build option, require IOUs to disclose the methodology and criteria to be used to evaluate the bids and provide more stringent standards for the IOUs to recover cost overruns in the event that the self-build option is deemed the most cost-effective.

Fuel

Approximately 61% of Tampa Electric's generation of electricity for 2012 was coal-fired, with natural gas representing approximately 39% and oil representing less than 1%. Tampa Electric used its generating units to meet approximately 94% of the total system load requirements, with the remaining 6% coming from purchased power. Tampa Electric's average delivered fuel cost per MMBTU and average delivered cost per ton of coal burned have been as follows:

Average cost per MMBTU	*2012*	*2011*	*2010*	*2009*	*2008*
Coal	$ 3.57	$ 3.46	$ 3.08	$ 3.05	$ 2.91
Oil	25.88	21.21	16.43	16.01	20.48
Gas (Natural)	5.34	6.20	6.74	8.00	10.61
Composite	4.19	4.38	4.46	5.02	5.56
Average cost per ton of coal burned	84.59	83.17	74.80	72.98	69.14

Tampa Electric's generating stations burn fuels as follows: Bayside Station burns natural gas; Big Bend Station, which has SO_2 scrubber capabilities and NO_x reduction systems, burns a combination of high-sulfur coal and petroleum coke, No. 2 fuel oil and natural gas at CT4; Polk Power Station burns a blend of low-sulfur coal and petroleum coke (which is gasified and subject to sulfur and particulate matter removal prior to combustion), natural gas and oil; and Phillips Station, which burned residual fuel oil and was placed on long-term standby in September 2009.

Coal. Tampa Electric burned approximately 4.7 million tons of coal and petroleum coke during 2012 and estimates that its combined coal and petroleum coke consumption will be about 4.8 million tons in 2013. During 2012, Tampa Electric purchased approximately 80% of its coal under long-term contracts with four suppliers, and approximately 20% of its coal and petroleum coke in the spot market. Tampa Electric expects to obtain approximately 71% of its coal and petroleum coke requirements in 2013 under long-term contracts with four suppliers and the remaining 29% 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 2012, approximately 86% of Tampa Electric's coal supply was deep-mined, approximately 8% 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, 2012, approximately 65% of Tampa Electric's 1,250,000 MMBTU gas storage capacity was full. Tampa Electric has contracted for 70% of its expected gas needs for the April 2013 through October 2013 period. In early March 2013, to meet its generation requirements, Tampa Electric expects to issue RFPs to meet its remaining 2013 gas needs and begin contracting for its 2014 gas needs. 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 for its retail business in the localities it serves. The franchises specify the negotiated terms and conditions governing Tampa Electric's use of public rights-of-way and other public property within the municipalities it serves during the term of the franchise agreement. The franchises are irrevocable and not subject to amendment without the consent of Tampa Electric (except to the extent certain city ordinances relating to permitting and like matters are modified from time to time), although, in certain events, they are subject to forfeiture.

Florida municipalities are prohibited from granting any franchise for a term exceeding 30 years. The City of Temple Terrace reserved the right to purchase Tampa Electric's property used in the exercise of its franchise if the franchise is not renewed. In the absence of such right to purchase, based on judicial precedent, if the franchise agreement is not renewed, Tampa Electric would be able to continue to use public rights-of-way within the municipality, subject to reasonable rules and regulations imposed by the municipalities.

Tampa Electric has franchise agreements with 13 incorporated municipalities within its retail service area. These agreements have various expiration dates through September 2040.

Franchise fees payable by Tampa Electric, which totaled $44.3 million at Dec. 31, 2012, are calculated using a formula based primarily on electric revenues and are collected on customers' bills.

Utility operations in Hillsborough, Pasco, Pinellas and Polk Counties outside of incorporated municipalities are conducted in each case under one or more permits to use state or county rights-of-way granted by the Florida Department of Transportation or the County Commissioners of such counties. There is no law limiting the time for which such permits may be granted by counties. There are no fixed expiration dates for the Hillsborough County, Pinellas County and Polk County agreements. The agreement covering electric operations in Pasco County expires in 2023.

Environmental Matters

Tampa Electric operates stationary sources with air emissions regulated by the Clean Air Act, and material Clean Water Act implications and impacts by federal and state legislative initiatives. Tampa Electric Company, through its Tampa Electric and PGS divisions, is a PRP for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites.

Emission Reductions

Tampa Electric has undertaken major steps to dramatically reduce its air emissions through a series of voluntary actions, including technology selection (e.g., 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 BACT emissions controls; implementation of additional controls to accomplish early reductions of certain emissions; and enhanced controls and monitoring systems for certain pollutants.

Tampa Electric, through voluntary negotiations in 1999 with the EPA, the U.S. Department of Justice and the FDEP, signed a Consent Decree, as settlement of federal and state litigation to dramatically decrease emissions from its power plants. Tampa Electric has notified the parties that all obligations of the Consent Decree have been fulfilled and intends to file documents with the court to terminate the Consent Decree in 2013.

The emission reduction requirements of these agreements resulted in the repowering of the coal-fired Gannon Power Station to natural gas, which was renamed as the H. L. Culbreath Bayside Power Station (Bayside Power Station), enhanced availability of flue-gas desulfurization systems (scrubbers) at Big Bend Station to help reduce SO_2, and installation of SCR systems for NO_x reduction on Big Bend Units 1 through 4. Cost recovery for the SCRs began for each unit in the year that the unit entered service through the ECRC (see the **Regulation** section).

As a result of the actions taken under the consent decree, emissions of all pollutant types have been significantly reduced. Since 1998, Tampa Electric has reduced annual SO_2, NOx and PM emissions from its facilities by 164,000 tons (94%), 63,000 tons (91%) and 4,500 tons (87%), respectively.

Reductions in mercury emissions also have occurred due to the repowering of the Gannon Power Station to the Bayside Power Station. At the Bayside Power Station, where mercury levels have decreased 99% below 1998 levels, there are virtually zero mercury emissions. Additional mercury reductions have been achieved from the installation of the SCRs at Big Bend Power Station, which have led to a system wide reduction of mercury emissions of more than 90% from 1998 levels.

Carbon Reductions and GHG

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 scheduled to be in service in January 2017 (see the **Tampa Electric** and **Capital Expenditures** sections). Tampa Electric estimates that the repowering to natural gas and the shut-down of the Gannon Station coal-fired units resulted in an annual decrease in CO_2 emissions of approximately 4.8 million tons below 1998 levels. During this same time frame, the numbers of retail customers and retail energy sales have risen by approximately 25%.

Tampa Electric expects that the costs to comply with new environmental regulations would be eligible for recovery through the ECRC. If approved as prudent, the costs required to comply with CO_2 emissions reductions would be reflected in customers' bills. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the ECRC, Tampa Electric could seek to recover those costs through a base-rate proceeding, but cannot predict whether the FPSC would grant such recovery.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric division, is a PRP for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2012, TEC has estimated its ultimate financial liability to be approximately $37.5 million (primarily related to PGS), and this amount has been reflected in the company's financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices. The amounts represent only the estimated portion of the cleanup costs attributable to TEC. The estimates to perform the work are based on actual estimates obtained from contractors or TEC'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 TEC and other PRPs is based on each party's relative ownership interest in or usage of a site. Accordingly, TEC's share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered credit-worthy.

Factors that could impact these estimates include the ability of other PRPs to pay their pro-rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. Under current regulation, these additional costs would be eligible for recovery through customer rates.

Capital Expenditures

Tampa Electric's 2012 capital expenditures included approximately $23 million primarily for upgrades to scrubbers and modifications to coal combustion by-product storage areas at the Big Bend Power Station. See the **Liquidity, Capital Expenditures** section of **MD&A** for information on estimated future capital expenditures related to environmental compliance.

PEOPLES GAS SYSTEM – Gas Operations

PGS operates as the gas division of TEC. PGS is engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in the state of Florida.

Gas is delivered to the PGS system through three interstate pipelines. PGS does not engage in the exploration for or production of natural gas. PGS operates a natural gas distribution system that serves approximately 345,000 customers. The system includes approximately 11,200 miles of mains and 6,600 miles of service lines (see PGS's **Franchises and Other Rights** section below).

PGS had 535 employees as of Dec. 31, 2012. A total of 142 employees in six of PGS's 14 operating divisions are represented by various union organizations.

In 2012, the total throughput for PGS was almost 1.9 billion therms. Of this total throughput, 6% was gas purchased and resold to retail customers by PGS, 82% was third-party supplied gas that was delivered for retail transportation-only customers and 12% was gas sold off-system. Industrial and power generation customers consumed approximately 74% of PGS's annual therm volume, commercial customers consumed approximately 23%, off-system sales customers consumed 12% and the remaining balance was consumed by residential customers.

While the residential market represents only a small percentage of total therm volume, residential operations comprised about 32% of total revenues. Approximately 5% of revenues are attributed to governmental municipalities.

Natural gas has historically been used in many traditional industrial and commercial operations throughout Florida, including production of products such as steel, glass, ceramic tile and food products. Within the PGS operating territory, large cogeneration facilities utilize gas-fired technology in the production of electric power and steam. PGS has also seen increased interest and development in natural gas vehicles. There are 13 compressed natural gas stations connected to the PGS distribution system.

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

(millions)	*Revenues* 2012	2011	2010	*Therms* 2012	2011	2010
Residential	$125.4	$140.8	$159.5	70.8	77.7	90.5
Commercial	134.1	138.0	143.8	421.4	409.3	407.9
Industrial	84.0	114.8	171.2	461.3	436.0	507.2
Power generation	12.4	10.6	9.7	913.5	614.3	582.2
Other revenues	34.9	39.9	37.2			
Total	$390.8	$444.1	$521.4	1,867.0	1,537.3	1,587.8

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

Regulation

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

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

On May 5, 2009, the FPSC approved a base rate increase of $19.2 million which became effective on Jun. 18, 2009 and reflects an ROE of 10.75%, which is the middle of a range between 9.75% and 11.75%. The allowed equity in capital structure is 54.7% from all investor sources of capital, on an allowed rate base of $560.8 million.

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

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through the 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 2012, the FPSC approved rates under PGS's PGA clause for the period January 2013 through December 2013 for the recovery of the costs of natural gas purchased for its distribution customers.

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

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

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

Competition

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

In Florida, gas service is unbundled for all non-residential customers. PGS has a "NaturalChoice" program, offering unbundled transportation service to customers consuming in excess of 1,999 therms annually, allowing these customers to purchase commodity gas from a third party but continue to pay PGS for the transportation. As a result, PGS receives its base rate for distribution regardless of whether a customer decides to opt for transportation-only service or continue bundled service. PGS had approximately 19,500 transportation-only customers as of Dec. 31, 2012 out of approximately 35,000 eligible customers.

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

Gas Supplies

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

Gas is delivered by FGT through 65 interconnections (gate stations) serving PGS's operating divisions. In addition, PGS's Jacksonville division receives gas delivered by the Southern Natural Gas pipeline through two gate stations located northwest of Jacksonville. Gulfstream Natural Gas Pipeline provides delivery through seven gate stations. PGS also has one interconnection with its affiliate SeaCoast Gas Transmission, LLC in Clay County, Florida.

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

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

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

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

Franchises and Other Rights

PGS holds franchise and other rights with 109 municipalities throughout Florida. These franchises govern the placement of PGS's facilities on the public rights-of-way as it carries on its retail business in the localities it serves. The franchises specify the negotiated terms and conditions governing PGS's use of public rights-of-way and other public property within the municipalities it serves during the term of the franchise agreement. The franchises are irrevocable and are not subject to amendment without the consent of PGS, although in certain events they are subject to forfeiture.

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

PGS's franchise agreements with the incorporated municipalities within its service area have various expiration dates ranging from the present through 2041. PGS expects to negotiate 6 franchises in 2013, the majority of which will be renewals of existing agreements. Franchise fees payable by PGS, which totaled $7.9 million at Dec. 31, 2012, 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 commission of such counties. There is no law limiting the time for which such permits may be granted by counties. There are no fixed expiration dates, and these rights are, therefore, considered perpetual.

Environmental Matters

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

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

Merco Group at Aventura Landings v. Peoples Gas System

In 2004, Merco Group at Aventura Landings I, II and III (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 now owned by Merco. Merco was seeking damages for costs associated with the removal of such coal tar and from out-of-pocket development expenses and lost profits due to the delay in its condominium development project allegedly caused by the presence of the coal tar. PGS denied liability on the grounds that the coal tar did not originate from its manufactured gas plant site and 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 PGS believes was the source of the coal tar on Merco's property. In addition, PGS filed a counterclaim against Merco which claimed that, because Merco purchased the property with actual knowledge of the presence of coal tar on the property, Merco should contribute toward any damages resulting from the presence of coal tar. The bench trial in this matter was concluded in February 2012 and, in June 2012, prior to receiving a ruling by the Judge, PGS and Merco settled the case, and PGS and Continental Holdings, Inc. agreed to a release for their claims against each other in the case. Both agreements have been approved by the court. The settlement is reflected as a regulatory asset at Dec. 31, 2012 and is expected to be recovered through the regulatory process. The settlement did not impact the results of operations for the year ended Dec. 31, 2012 and is not material to the financial position of TEC or TECO Energy as of Dec. 31, 2012.

Capital Expenditures

During the year-ended Dec. 31, 2012, PGS did not incur any material capital expenditures to meet environmental requirements, nor are any anticipated for the 2013 through 2017 period.

TECO COAL

Overview

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

TECO Coal owns no operating assets but holds all of the common stock of Gatliff Coal Company, Rich Mountain Coal Company, Clintwood Elkhorn Mining Company, Pike-Letcher Land Company, Premier Elkhorn Coal Company, Perry County Coal Corporation and Bear Branch Coal Company. TECO Coal owns, controls and operates, by lease or mineral rights, surface and underground mines and coal processing and loading facilities. TECO Coal produces, processes and sells bituminous, predominately low sulfur coal of metallurgical, PCI, steam and industrial grades.

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

Metallurgical, PCI and industrial stoker coals accounted for approximately 44% of TECO Coal's 2012 coal sales volume. Steam coal accounted for approximately 56% of 2012 coal sales volume.

As of Dec. 31, 2012, TECO Coal owned or leased mineral rights to approximately 310.9 million tons of proven and probable coal reserves. Of the total proven and probable reserves, approximately 78% are low sulfur reserves with high BTU content. Total proven and probable reserves are expected to support current production levels for more than 20 years.

The tons sold for 2012, 2011 and 2010 by market category is set forth in Table 1 below:

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

	Metallurgical, PCI & Stoker		Steam	
Year	**Tons**	**% Volume**	**Tons**	**% Volume**
2012	2.75	44%	3.53	56%
2011	3.71	46%	4.42	54%
2010	3.48	40%	5.21	60%

Sales of steam coal during 2012, 2011 and 2010 were made primarily to utilities and industrial customers throughout the eastern part of the United States. Sales of metallurgical and PCI coal during those years were made primarily to steel companies and coke plants in North America and Europe.

TECO Coal currently operates 16 underground mines, which employ the room and pillar mining method, and seven surface mines.

In 2012, TECO Coal sold 6.3 million tons of coal. All of this coal was sold to customers other than the TECO Coal affiliate, Tampa Electric.

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

History

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

In 1988, Gatliff Coal Company began selling coal to the ferro-silicon and silicon markets. Also in that year, properties were acquired in Pike County, Kentucky, and Clintwood Elkhorn Mining Company was formed. Premier Elkhorn Coal Company and Pike-Letcher Land Company were formed in 1991, when additional property was acquired in Pike and Letcher Counties, Kentucky.

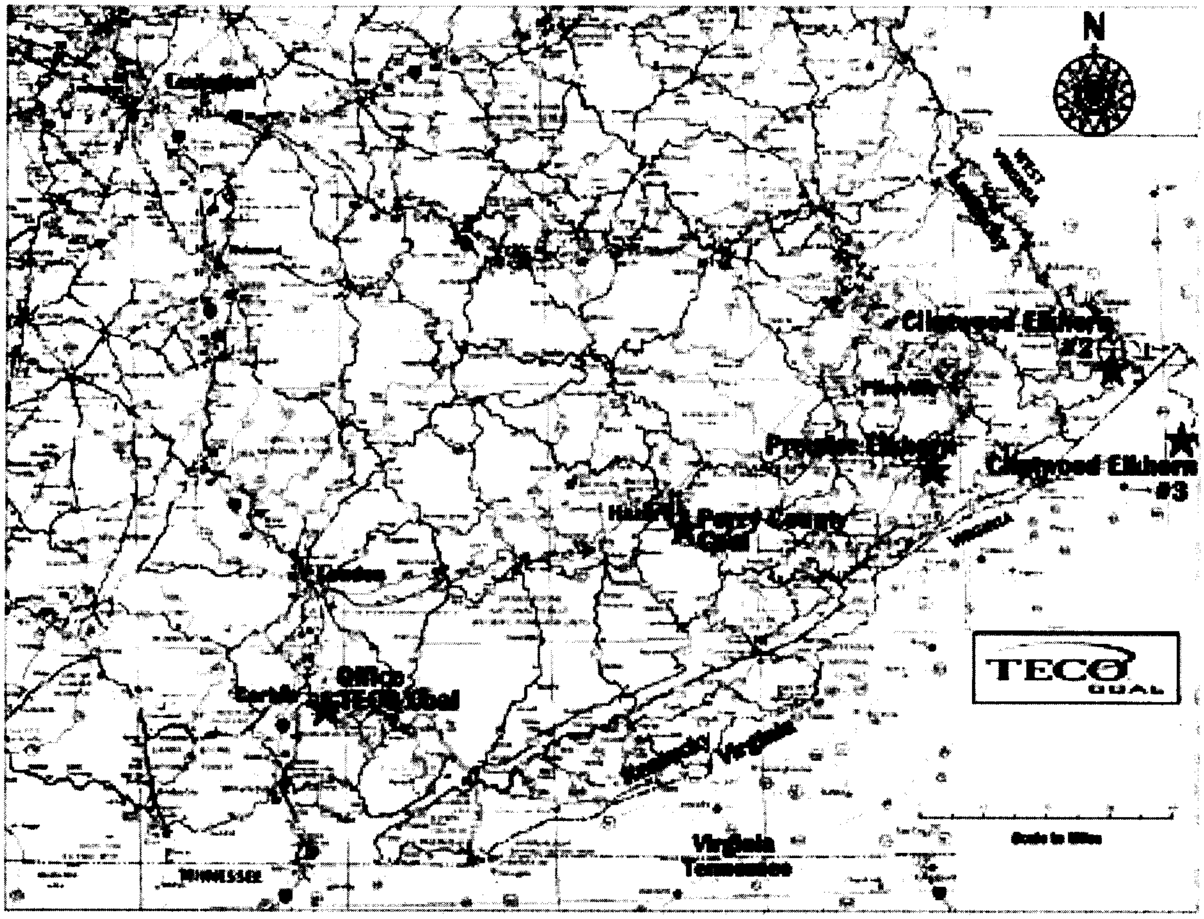
In 1997, Bear Branch Coal Company secured key leases for properties located in Perry County and Knott County, Kentucky.

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.

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. 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 eleven individual underground or surface mines. TECO Coal uses two distinct extraction techniques: continuous underground mining and dozer and front-end loader surface mining, sometimes accompanied by highwall mining.

The complexes have been developed at locations in close proximity to the TECO Coal preparation plants and rail shipping facilities. Coal is transported from TECO Coal's mining complexes to customers by means of railroad cars, trucks, barges or vessels, with rail shipments representing approximately 95% of 2012 coal shipments. The following map shows the locations of the four mining complexes and TECO Coal's offices in Corbin, Kentucky.



Facilities

Coal mined by the operating companies of TECO Coal is processed and shipped from facilities located at each of the operating companies, with Clintwood Elkhorn Mining Company having two facilities. The equipment at each facility is in good condition and regularly maintained by qualified personnel. Table 2 below is a summary of TECO Coal processing facilities:

Processing Facilities Summary
Table 2

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

Significant Projects

Significant projects for 2012 included the following:

Premier Elkhorn Coal

- Premier Elkhorn continued exploration operations in 2012 of the 65 million tons of the metallurgical coal discovered in 2011 in two below drainage seams underlying its current Burke Branch facilities and adjacent properties (See **New Frontier Project -- Burke Branch Development** below). Premier Elkhorn also performed evaluation of the newly discovered reserves and continued permitting for the construction phases of the project for slope and shaft construction. Much of the identified reserves are owned by TECO Coal.

Clintwood Elkhorn Mining

- Completed ventilation construction required to add second unit of production equipment at the Hubble #11 deep mine to increase production of High Volatile A metallurgical coal
- Completed surface construction to access metallurgical reserves that will report to the Clintwood #2 plant when activated
- Completed surface construction of Abners Fork deep mine face up in Virginia, which will produce High Volatile A metallurgical coal when activated
- Granted Surface Mining Control and Reclamation Act of 1977 (SMRCA) permit for extension of Laurel Branch surface mine in Virginia, which produces metallurgical and steam coal. The new permit extends the life of the project by approximately three years
- Core drilling in the Woodman area of northern Pike County, Kentucky resulted in additional metallurgical and steam reserves being proven
- Exploration in Virginia resulted in additional reserves to be mined by surface methods for the metallurgical and steam markets
- In Kentucky, a coarse refuse belt was extended at the Clintwood #2 plant, resulting in cost savings

Mining Complexes

Table 3 below shows annual production for each mining complex for each of the last three years and 2012 coal sales.

MINING COMPLEXES
Table 3

Location	Mine Type	Mining Equipment	Transportation	Tons Produced (in Millions) 2012	2011	2010	Tons Sold (1) (in Millions) 2012	Year Established Or Acquired
Gatliff Coal Co.								
Bell County, KY/ Knox County, KY/ Campbell County, TN	S	D/L	T	0.0	0.0	0.0	0.0	1974
Clintwood Elkhorn Mining								
Pike County, KY/ Buchanan County, VA	U, S	CM, D/L, HM, A	R, R/V	2.0	1.8	2.1	1.9	1988
Premier Elkhorn Coal Co.								
Pike County, KY/ Letcher County, KY/ Floyd County, KY	U, S	CM, D/L	R, T, R/B, T/B, R/V	2.0	2.2	2.6	2.1	1991
Perry County Coal Co.								
Perry County, KY/ Leslie County, KY/ Knott County, KY	U, S	CM, D/L, HM	R, T, R/B, T/B, R/V	2.3	3.1	3.1	2.3	2000
			Totals:	**6.3**	**7.1**	**7.8**	**6.3**	

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

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

Gatliff Coal

Gatliff Coal Company discontinued surface mine operations in Bell County, Kentucky in late autumn 2009. Poor market conditions and a depletion of the low sulfur content coal that was previously required on its sales contract led to this cessation of mining operations. Gatliff Coal had no production in 2010, 2011 or 2012, leaving a reserve base of 3.4 million recoverable tons of predominantly low sulfur underground mineable coal, which may later be recovered by Gatliff Coal or by neighboring competing coal companies for coal royalty considerations. Rich Mountain Coal Company formerly operated as a contractor for Gatliff Coal's Tennessee production but is currently in non-producing reclamation status.

Clintwood Elkhorn Mining

Clintwood Elkhorn Mining Company has two coal preparation facilities. One is located near Biggs, Kentucky in Pike County, and is supplied by eight underground mines and no surface mines. The second Clintwood Elkhorn Mining facility is located near Hurley, Virginia and is supplied by one underground mine and two surface mines. Some mines have supplied both locations during the course of the year. Principal products at both locations include High Volatile metallurgical coal and steam coal. Products from both locations are shipped domestically to customers in North America via Norfolk Southern Corporation and vessels via the Great Lakes. International customers receive their products via ocean vessels from Lamberts Point, Virginia. During 2012, a block of reserves containing 6.9 million tons previously classified as PCI coal, and now metallurgical, was assigned from Premier Elkhorn Coal Company to Clintwood Elkhorn Mining. CMMA completed an audit for new coal Clintwood Elkhorn now controls. CMMA has estimated by audit methodology that there are 8.5 million tons of recoverable tons of demonstrated coal reserves, as of December 31, 2012. Of the new demonstrated reserves, an estimated 7.3 million recoverable tons, or 86%, are of proven (measured) status and 1.2 million tons, or 14%, are of probable (indicated) status. All of the new reserves are leased. By market category, the new demonstrated reserves are: 6.2 million tons of metallurgical coal, 0 tons of PCI coal; and 2.3 million tons of steam coal. In total, Clintwood Elkhorn Mining produced 2.0 million tons of coal in 2012, and currently has a reserve base of 60.8 million recoverable tons.

Premier Elkhorn Coal Company

Located near Myra, in Pike County, Kentucky, Premier Elkhorn Coal Company is supplied by production from four underground mines and three surface mines. Principal products include metallurgical and PCI coal for the steel mills, high-quality steam coal for utilities and specialty stoker products for ferro-silicon and industrial customers. Facilities include a unit train load-out with a 200 car siding capable of loading at 6,000 tons per hour. Products from this location are shipped via CSXT Railroad and trucking contractors to destinations in North America and internationally. During 2012, a block of reserves containing 6.9 million tons previously classified as PCI coal was assigned from Premier Elkhorn Coal Company to Clintwood Elkhorn Mining. CMMA completed a comprehensive audit of the demonstrated coal reserves and non-coal deposits controlled by TECO Coal at the Premier Elkhorn Coal operating subsidiary. CMMA has estimated by audit methodology that TECO Coal controls an estimated 109.6 million recoverable tons of demonstrated coal reserves at Premier Elkhorn as of Dec. 31, 2012. Of the total demonstrated reserves, an estimated 67.7 million recoverable tons, or 62%, are of proven (measured) status and 41.9 million tons, or 38%, are of probable (indicated) status. Also, of the total demonstrated reserves, an estimated 85.6 million recoverable tons, or 78%, are owned and 24.0 million tons, or 22%, are leased. By market category, the Premier Elkhorn demonstrated reserves are 70.9 million tons of metallurgical coal, 18.8 million tons of PCI coal, and 19.9 million tons of steam coal. In total, Premier Elkhorn Coal produced 2.0 million tons of coal in 2012, and currently has a reserve base of 109.6 million recoverable tons.

New Frontier Project-Burke Branch Development

In 2011, CMMA completed an audit of the Glamorgan and Lower Banner coal deposits associated with the New Frontier Project-Burke Branch Development, which is controlled by TECO Coal's Premier Elkhorn Coal operating subsidiary. The subject property is located in Pike and Letcher Counties in eastern Kentucky, and a substantial portion of the mineral rights for the subject coal deposits is owned by TECO Coal's subsidiary, Pike-Letcher Land. The remainder of the mineral is leased from other entities under long-term lease agreements.

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

TECO Coal has received an amendment to an existing permit to allow surface excavation and development as well as slope access to a portion of these reserves and a revision to an existing permit to allow mining of a portion of the Lower Banner coal seam reserves. An additional amendment has been submitted to modify surface areas required for development of the slopes and shafts.

Perry County Coal Corporation

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

In 2009, Perry County Coal 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 proved an additional 6.9 million tons of reserves which were previously reported as resource coal. In 2010, Perry County Coal leased the First Creek reserve which is contiguous to its existing E4-1 underground mine. This lease will facilitate the mining of approximately 10.0 million tons of additional reserves. Perry County Coal produced 2.3 million tons of coal in 2012, leaving a total reserve base of 137.1 million recoverable tons.

Sales and Marketing

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

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

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

Distribution

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

Employees

As of Dec. 31, 2012, TECO Coal and its subsidiaries employed a total of 811 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 recent 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 July 1973. Historically, a small percentage of the miners currently seeking federal black lung benefits are awarded these benefits by the federal government. The trust fund is funded by an excise tax on coal production of up to $1.10 per ton for deep-mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price.

In December 2000, the Department of Labor issued new amendments to the regulations implementing the federal black lung laws that, among other things, establish a presumption in favor of a claimant's treating physician, limit a coal operator's ability to introduce medical evidence, and redefine Coal Workers Pneumoconiosis to include chronic obstructive pulmonary disease. These changes in the regulations, and regulations introduced by the 2010 Patient Protection and Affordability Care Act, will increase the percentage of claims approved and the overall cost of Black Lung to coal operators. TECO Coal, with the help of its consulting actuaries, intends to continue monitoring claims very closely.

Workers' Compensation

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

Environmental Laws

Surface Mining Control and Reclamation Act

Coal mining operations are subject to the Surface Mining Control and Reclamation Act of 1977 which places a charge of $0.135 and $0.315 on every net ton of underground and surface coal mined, respectively, to create a fund for reclaiming land and water adversely affected by past coal mining. Other provisions establish standards for the control of environmental effects and reclamation of surface coal mining and the surface effects of underground coal mining and requirements for federal and state inspections.

Clean Air Act/Clean Water Act

While conducting their mining operations, TECO Coal's subsidiaries are subject to various federal, state and local air and water pollution standards. In 2012, TECO Coal had expenditures of approximately $3.1 million for environmental protection and reclamation programs. TECO Coal expects to spend approximately $2.8 million on these programs in 2013.

CERCLA (Superfund)

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

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

Glossary of Selected Mining Terms

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

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

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

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

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

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

Compliance coal. Coal which, when burned, emits 1.2 pounds or less of sulfur dioxide per million BTUs, which is equivalent to 0.72% sulfur per pound of 12,000 BTU coal. Compliance coal requires no mixing with other coals or use of sulfur dioxide reduction technologies by generators of electricity to comply with the requirements of the federal Clean Air Act.

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

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

Deep mine. An underground coal mine.

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

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

Force Majeure. An event that may prevent the company from conducting its mining operations in whole or in part as a result of: 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; or any other like causes.

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

Highwall miner. An auger-like apparatus that drives parallel rectangular entries from the surface up to 1,000 feet deep.

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

Long-term contracts. Contracts with terms greater than 12 months.

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

Low Sulfur coal. Coal that when burned emits 1.6 pounds or less of sulfur dioxide per million BTUs.

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

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

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

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

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

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

Probable (Indicated) reserves. Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven 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 that could be economically and legally extracted or produced at the time of the reserve determination.

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

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

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

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

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

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

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

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

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

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

Unassigned reserves. Coal that has not been committed and that 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, a wholly-owned subsidiary of TECO Energy, had subsidiaries with interests in independent power projects in Guatemala, which were sold during 2012.

TECO Guatemala indirectly owned 100% of CGESJ, the owner of an electric generating station located in Guatemala, which consisted 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 PPA with EEGSA, the largest private distribution company in Central America, to provide 120 MW of capacity and energy for 15 years beginning in 2000. TEMSA, an indirect wholly-owned subsidiary, provided unloading services to third parties in addition to receiving the coal shipments for CGESJ.

TCAE, an entity 96.06% owned by TPS Guatemala One, Ltd., an indirect subsidiary of TECO Guatemala, and the owner of an oil-fired electric generating facility (the Alborada Power Station), had a U.S. dollar-denominated PPA with EEGSA to provide 78 MW of capacity ending in 2015. EEGSA was responsible for providing the fuel for the power station, with a subsidiary of TECO Guatemala providing assistance in fuel administration.

TECO Guatemala's plants in Guatemala operated 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.

On Sept. 27, 2012, TECO Guatemala entered into an agreement to sell all of the equity interests in the Alborada and San José power stations, related facilities and operations in Guatemala for a total purchase price of $227.5 million in cash. The sale of the Alborada Power Station closed on the same date for a selling price of $12.5 million.

On Dec. 19, 2012, the closing occurred on the (i) San José power station and related facilities in Guatemala for a purchase price of $213.5 million and (ii) the remaining TECO Guatemala operations company for a purchase price of $1.5 million.

See **Notes 19, 20** and **21** to the **TECO Energy, Inc. Consolidated Financial Statements** for more information regarding these discontinued operations and asset dispositions.

While TECO Energy and its subsidiaries will no longer have assets or operations in Guatemala, its subsidiary, TECO Guatemala Holdings, LLC, has retained its rights under its arbitration claim filed against the Republic of Guatemala in October 2010 under the Dominican Republic Central America – United States Free Trade Agreement (DR – CAFTA).

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
John B. Ramil	57	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	53	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.
Phil L. Barringer	59	Senior Vice President of Corporate Services and Chief Human Resources Officer, TECO Energy, Inc., January 30, 2013 to date; Vice President of Corporate Services and Chief Human Resources Officer, TECO Energy, Inc., January 1, 2013 to January 30, 2013; Vice President-Human Resources of TECO Energy, Inc. and Tampa Electric Company, July 2009 to November 2012; and prior thereto, Vice President-Controller, Operations of TECO Energy, Inc. and Chief Accounting Officer of Tampa Electric Company.
Deirdre A. Brown	52	Senior Vice President of Corporate Strategy and Technology and Chief Ethics and Compliance Officer, TECO Energy, Inc., January 30, 2013 to date, Vice President; of Corporate Strategy and Technology and Chief Ethics and Compliance Officer, TECO Energy, Inc., January 1, 2013 to January 30, 2013; Vice President-Business Strategy and Compliance and Chief Ethics and Compliance Officer, TECO Energy, Inc., July 2009 to January 1, 2013; Vice President-Regulatory Affairs of Tampa Electric Company and Vice President-Customer Service, Tampa Electric Division of Tampa Electric Company, April 2006 to July 2009.
Sandra W. Callahan	60	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-Treasurer and Assistant Secretary, Tampa Electric Company, April 2005 to July 2009.
Gordon L. Gillette	53	President, Tampa Electric Company, July 2009 to date; Executive Vice President and Chief Financial Officer, TECO Energy, Inc., July 2004 to July 2009; President, TECO Guatemala, October 2004 to July 2009.
Clark Taylor	63	President of TECO Coal Corporation, April 2011 to date; and prior thereto, Vice President-Controller of TECO Coal Corporation.

There is no family relationship between any of the persons named above or between executive officers and any director of the company. The term of office of each officer extends to the meeting of the Board of Directors following the next annual meeting of shareholders, scheduled to be held on May 1, 2013, 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 Florida is important to the realization of annual energy sales growth for Tampa Electric and PGS. Any weakening of economic conditions, including the Florida housing markets and general economy, could adversely affect Tampa Electric's or PGS's expected performance. Weak economic conditions could affect these companies' ability to collect payments from customers.

TECO Coal is also affected by general economic conditions effecting primarily the utility and steel industries, both nationally and internationally. TECO Coal sells metallurgical coal internationally, but primarily to European customers and demand in that continent has been reduced due to the European debt crisis and the resulting economic weakness. Continued economic weakness and the resulting lower demand for metallurgical coal in the European market could reduce TECO Coal's financial results.

Our electric and gas utilities are highly regulated; changes in regulation or the regulatory environment could reduce revenues or increase costs or competition.

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

Tampa Electric has announced plans to file a base rate proceeding in 2013 for new rates in 2014. Our financial position could be weaker after 2013 if the FPSC were to not grant the base rate relief requested.

Tampa Electric has notified the FPSC that its actual earned ROE could be as low as 7% in 2014, well below the bottom of the allowed ROE range of 10.25% to 12.25%, without base rate relief effective in 2014. If the FPSC does not grant adequate rate relief our financial position would be weakened in 2014, as Tampa Electric enters the period of peak capital spending on its next generation expansion project (see the **Liquidity and Capital Resources – Capital Expenditures** section of **Managements Discussion & Analysis** section).

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 residuals (CCR) could add to Tampa Electric's operating costs.

In response to a coal ash pond failure in December 2008, the EPA proposed new regulations for the management and disposal of CCRs. These proposed rules include two potential designations of CCRs. One designation would categorize CCRs destined for disposal as hazardous wastes. This designation is the most significant for Tampa Electric because hazardous waste landfills are currently prohibited in Florida by state law. CCRs designated as hazardous waste destined for disposal would have to be shipped out of state as hazardous waste at significantly increased costs. In addition, the hazardous designation could require improvements to Tampa Electric's current ash management practices and interim storage and handling facilities for CCRs inside its power stations, even though permanent onsite disposal would not be allowed. The other proposed rule would set minimum standards for the final disposal of CCRs under regulations similar to those in place for municipal non-hazardous solid waste. This proposal would not be as disruptive as the former, since it would allow for the continued operation of Tampa Electric's existing, lined ash ponds. However, this latter proposal would place additional management requirements on these existing disposal units, which would eventually reach the end of their useful life and need to be replaced.

Required changes would include disposing of any CCR as hazardous waste, which would be at a cost significantly higher than current costs, converting to dry handling of coal ash, and elimination of any wet storage impoundments in current use. If the EPA eliminates the use of ponds for by-product storage, Tampa Electric would have to invest in dry handling and storage, which could increase costs.

Federal or state regulation of GHG emissions, depending on how they are enacted, could increase our costs or the rates charged to our customers, which could curtail sales.

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

Current regulation in Florida allows utility companies to recover from customers prudently incurred costs for compliance with new environmental regulations. Tampa Electric would expect to recover from customers the costs of power plant modifications or other costs required to comply with new GHG emission regulation. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the 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.

Among other rules, the EPA has proposed a number of new rules, including the Clean Air Interstate Rule/Cross State Air Pollution Rule (CSAPR) and Hazardous Air Pollutants (HAPS) Maximum Achievable Control Technology (MACT) for emissions to the air, and a number of new rules focused on water use and discharges from power generation facilities.

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

The EPA's proposed water focused rules could limit the supply of water available to our power generating facilities, require the investment of significant capital for new equipment and increase operating costs.

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

In past sessions of the Florida Legislature, an RPS was debated but ultimately not enacted. There remains considerable interest in renewable energy sources by renewable energy suppliers, developers and the utilities in Florida. Previously the FPSC made a recommendation to the Florida Legislature that the RPS be 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. Tampa Electric's operating results could be adversely affected if Tampa Electric were not permitted to recover these costs from customers through the ECRC.

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.

In Florida and across the United States, utilities are increasingly relying on natural gas for new electric generating plants in response to GHG emissions concerns and attractive natural gas prices. Currently, there is an adequate supply and infrastructure to meet demand for natural gas in Florida and nationally. However, if 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 to customers without profit. Changes in regulations could reduce earnings if they required Tampa Electric or PGS to bear a portion of the increased cost. In addition, increased costs to customers could result in lower sales.

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

All of our businesses are affected by variations in general weather conditions and unusually severe weather. Tampa Electric's and PGS's energy sales are particularly sensitive to variations in weather conditions. Those companies forecast energy sales on the basis of normal weather, which represents a long-term historical average. If climate change or other factors cause significant variations from normal weather, this could have a material impact on energy sales.

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 negatively impact results at Tampa Electric and PGS.

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

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

As a company with electric service and natural gas operations in peninsular Florida, the company is exposed to extreme weather events, such as hurricanes. Extreme weather conditions can be destructive, causing outages and property damage that require the company to incur additional expenses. Extensive customer outages could reduce revenue collections. If warmer temperatures lead to changes in extreme weather events (increased frequency, duration and severity), these expenses could be greater.

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

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

All 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.

Competition among coal producers in Central Appalachia and other producing regions, and low natural gas prices may adversely affect TECO Coal's ability to sell it products. Low-cost natural gas has allowed utility steam coal users to switch from coal to natural gas to produce electricity, which has reduced the current market price and demand for TECO Coal's steam coal at domestic utilities. Continued low natural gas prices would keep demand and selling prices low, which would reduce TECO Coal's profitability, or reduce the value of its reserves.

TECO Coal sells approximately 50% of its production to domestic utilities for use in the generation of power. Since 2011, natural gas prices have dropped significantly, which caused utility coal users to switch to lower cost natural gas to generate electricity. Even with a modest increase in natural gas prices in 2013, it remains more cost effective for users of higher cost Central Appalachian coal, which TECO Coal produces, to burn a higher percentage of natural gas for power generation. Lower cost coals from other producing regions of the U.S. are being utilized by more utilities in lieu of Central Appalachian coals further reducing demand.

At the end of 2013, approximately 50% of TECO Coal's existing profitable steam coal contracts expire. Without an increase in the cost of natural gas and an increase in the use of coal for power generation, or a general improvement in coal market conditions, TECO Coal's profitability will be reduced. If these conditions were to persist, the value of TECO Coal's reserves could be reduced, which could result in a non-cash write off.

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

For the past several years, weather-normalized energy consumption per residential customer declined due to the combined effects of voluntary conservation efforts, economic conditions, improvements in lighting and appliance efficiency, trends toward smaller single family houses and increased multi-family housing, which we believe have contributed to lower per-customer usage.

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

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

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

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

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

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

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

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

The value of our existing deferred tax benefits are determined by existing tax laws, and could be negatively impacted by changes in these laws.

There are increasing calls in Congress for "comprehensive tax reform," which could significantly alter the existing tax code, including a reduction in corporate income tax rates. A reduction in the corporate income tax rate would reduce the value of our existing deferred tax assets and could result in write-offs and higher cash tax payments, which could reduce our ability to retire debt in 2016 and 2017.

The current administration in Washington D.C. has proposed the elimination of the percentage depletion tax deduction for coal mines and other hard minerals and fossil fuels.

If the percentage depletion tax deduction is eliminated for TECO Coal, the effective tax rate for that company would rise from the expected 20% to 25% to the general corporate tax rate of 37%, which would have an adverse effect on TECO Coal's financial results after 2013.

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

We evaluate our long-lived assets for impairment annually or more frequently if certain triggering events occur. Should the current carrying values of any of these assets not be recoverable, we would incur charges to write down the assets to fair market value.

Problems with operations could cause us to incur substantial costs.

Each of our subsidiaries is subject to various operational risks, including accidents, equipment failures and operations below expected levels of performance or efficiency. Our subsidiaries could incur problems such as the breakdown or failure of power generation equipment, transmission lines, pipelines, coal mining or processing equipment or other equipment or processes that would result in performance below assumed levels of output or efficiency. The occurrence of one or more of these problems could cause us to incur substantial costs, including potential claims for damages that may exceed the scope of our insurance coverage, which could have an adverse impact on our financial condition and results from operations.

Failure to obtain the permits necessary to open new surface mines could reduce earnings from TECO Coal.

Our coal mining operations are dependent on permits from the USACE to open new surface mines necessary to maintain or increase production. Since 2008, new permits issued by the USACE under Section 404 of the Clean Water Act for new surface coal mining operations have been challenged in court by various environmental groups, resulting in a backlog of permit applications and very few permits being issued. TECO Coal had three permits on the list of permits subject to enhanced review by the EPA under its memorandum of understanding with the USACE, which was issued in September 2009. In October 2011, the Federal District Court for the District of Columbia set aside the Enhanced Coordination Procedures (ECP) developed by the USACE and the EPA to expedite review of pending surface coal mining permit applications. USACE Districts and the EPA Regions in Appalachia have all ceased using the ECP as of the date of the District Court's decision. While the court invalidated the ECP, the decision does not affect any statutory or regulatory requirements established under the Clean Water Act, including the USACE's and the EPA's Section 404 permitting regulations. Failure to obtain the necessary permits to open new surface mines, which are required to maintain and expand production, could reduce production, cause higher mining costs or require purchasing coal at prices above our cost of production to fulfill contract requirements, which would reduce the earnings expected from TECO Coal.

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

On April 1, 2010, the EPA issued new guidance on environmental permitting requirements for Central Appalachian mountaintop removal and other surface mining projects. The guidance limits conductivity (level of mineral salts) in water discharges into streams from permitted areas, and was effective immediately on an interim basis. At that time, the EPA stated that it would decide whether to modify the guidance after consideration of public comments and the results of the Science Advisory Board (SAB) technical review of the EPA scientific reports. In July 2011, the EPA made this guidance final without modification. Because the EPA's standards appear to be unachievable under most circumstances, surface mining activity could be substantially curtailed since most new and pending permits would likely be rejected. This guidance could also be extended to discharges from deep mines and preparation plants, which could result in a substantial curtailing of those activities as well. In July 2012, the United States District Court for the District of Columbia ruled that the EPA had exceeded its statutory authority in establishing the water quality guidance discussed above in the manner in which it was done. Following the outcome of these court decisions, pending appeals by the EPA, few, if any, new permits have been issued by USACE. Over time, if new permits are not issued, TECO Coal could incur higher production costs or reduced production from surface mining operations.

TECO Coal's sales to international customers are subject to risks that could result in losses or increased costs.

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

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

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

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

From time to time, we are a party to legal proceedings that may result in a material adverse effect on our financial condition.

From time to time, we are a party to, or otherwise involved in, lawsuits, claims, proceedings, investigations and other legal matters that have arisen in the ordinary course of conducting our business. While the outcome of these lawsuits, claims, proceedings, investigations and other legal matters which we are a party to, or otherwise involved in, cannot be predicted with certainty, an adverse outcome could 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 TEC must meet certain financial tests as defined in the applicable agreements to use their respective credit facilities. Also, TECO Energy, TECO Finance, TEC and other operating companies have certain restrictive covenants in specific agreements and debt instruments. 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, 2012, we were in compliance with required financial covenants, but we cannot be assured that we will be in compliance with these financial covenants in the future. Our failure to comply with any of these covenants or to meet our payment obligations could result in an event of default which, if not cured or waived, could result in the acceleration of other outstanding debt obligations, We may not have sufficient working capital or liquidity to satisfy our debt obligations in the event of an acceleration of all or a portion of our outstanding obligations.

We also incur obligations in connection with the operations of our subsidiaries and affiliates that do not appear on our balance sheet. These obligations take the form of guarantees, letters of credit and contractual commitments, as described under **Liquidity, Capital Resources** sections of the **Management's Discussion & Analysis**.

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

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

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

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

Declines in the financial markets or in interest rates used to determine benefit obligations could increase our pension expense or the required cash contributions to maintain required levels of funding for our plan.

The value of our pension fund assets were negatively impacted by unfavorable market conditions in 2008. As of Jan. 1, 2012, our plan was approximately 84% funded under calculation requirements of the Pension Protection Act. As calculated under the MAP-21 legislation, signed into law in 2012, our funded percentage is expected to be approximately 94% as of the next Pension Protection Act measurement date of Jan. 1, 2013. TECO Energy estimates its required minimum contributions to range from $15 million to $50 million annually over the next five years. Any future declines in the financial markets or further declines in interest rates could increase the amount of contributions required to fund our plan in the future.

We estimate that pension expense in 2013 will be slightly higher than levels experienced in 2012, primarily due to the lower interest rate environment. Any future declines in the financial markets or a continuation of the low interest rate environment could cause pension expense to increase in future years.

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

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

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

Our financial condition and ability to access capital may be materially adversely affected by multiple ratings downgrades to below investment grade, 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 Baa2 with a stable outlook, and by Fitch Ratings (Fitch) at BBB with a stable outlook. The senior unsecured debt of TEC is rated by S&P at BBB+ with a stable outlook, by Moody's at A3 with a stable outlook and by Fitch at A—with a stable outlook. A downgrade to below investment grade 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 TEC decline to below investment grade, Tampa Electric and PGS could be required to post collateral to support their purchases of electricity and gas.

We are a holding company with no business operations of our own and depend on cash flow from our subsidiaries to meet our obligations.

We are a holding company with no business operations of our own or material assets other than the stock of our subsidiaries. Accordingly, all of our operations are conducted by our subsidiaries. As a holding company, we require dividends and other payments from our subsidiaries to meet our cash requirements. If our subsidiaries are unable to pay us dividends or make other cash payments to us when needed, we may be unable to pay dividends or satisfy our obligations.

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 three electric generating plants in service, with a December 2012 net winter generating capability of 4,668 MW. Tampa Electric assets include the Big Bend Power Station (1,572 MW capacity from four coal units and 61 MW from a CT), the Bayside Power Station (1,839 MW capacity from two natural gas combined cycle units and 244 MW from four CTs) and the Polk Power Station (220 MW capacity from the IGCC unit and 732 MW from four CTs).

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. Bayside Unit 1 was completed in April 2003, Unit 2 was completed in January 2004 and Units 3 through 6 were completed in 2009. In 2009, Tampa Electric placed the Phillips Power Station on long-term reserve standby. In July of 2012, Tampa Electric placed the City of Tampa Partnership Station in long-term reserve standby.

Tampa Electric owns 180 substations having an aggregate transformer capacity of 22,279 Mega Volts Amps. The transmission system consists of approximately 1,347 pole miles (including underground and double-circuit) of high-voltage transmission lines, and the distribution system consists of 6,301 pole miles of overhead lines and 4,762 trench miles of underground lines. As of Dec. 31, 2012, there were 687,185 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.

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

PEOPLES GAS SYSTEM

PGS's distribution system extends throughout the areas it serves in Florida and consists of approximately 17,800 miles of pipe, including approximately 11,200 miles of mains and 6,600 miles of service lines. Mains and service lines are maintained under rights-of-way, franchises or permits.

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

TECO COAL

Property Control

Operations of TECO Coal and its subsidiaries are conducted on both owned and leased properties totaling approximately 295,000 acres in Kentucky, Tennessee and Virginia. TECO Coal's current practice is to obtain a title review from a licensed attorney prior to purchasing or leasing property. As is typical in the coal mining industry, TECO Coal generally has not obtained title insurance in connection with its acquisitions of coal reserves and/or related surface properties. In many cases, the seller or lessor will grant the purchasing or leasing entity a warranty of property title. When leasing coal reserves and/or related surface properties where mining has previously occurred, TECO Coal may opt not to perform a separate title confirmation due to the previous mining activities on such a property. In cases involving less significant properties and consistent with industry practices, title and boundaries to less significant properties are now verified during lease or purchase negotiations.

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

Coal Reserves

As of Dec. 31, 2012, the TECO Coal operating companies had a combined estimated 310.9 million tons of proven and probable recoverable reserves. All of the reserves consist of high quality bituminous coal. Reserves are the portion of the proven and probable tonnage that meet TECO Coal's economic criteria regarding mining height, preparation plant recovery, depth of overburden and stripping ratio. Generally, these reserves would be commercially mineable at year-end price and cost levels. Additionally, other controlled areas presently identified as resource total 94.5 million tons of coal.

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

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

Probable (Indicated) Reserves - Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven 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.

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

The following table (Table 4) shows recoverable reserves by quantity and the method of property control as well as the Assigned and Unassigned reserves per mining complex.

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

							Assigned (2)		Unassigned (2)	
Mining Complex	**Location**	**Total**	**Proven**	**Probable**	**Owned**	**Leased**	**2013**	**2012**	**2013**	**2012**
Gatliff Coal	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	60.8	51.6	9.2	3.2	57.6	60.8	44.5	0.0	0.1
Premier Elkhorn Coal	Pike County, KY/ Letcher County, KY/ Floyd County, KY	109.6	67.7	41.9	85.6	24.0	58.6	60.9	51.0	75.1
Perry County Coal	Perry County, KY/ Leslie County, KY/ Knott County, KY	137.1	82.4	54.7	1.5	135.6	131.9	139.0	5.2	2.2
TOTALS		310.9	204.7	106.2	91.5	219.4	251.8	244.9	59.1	80.3

Notes:

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

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

RECOVERABLE RESERVES BY QUALITY (1)
Table 5

Mining Complex	Recoverable Reserves (Millions of tons)	Sulfur Content < 1% (2)	Sulfur Content >1% (2)	Compliance Tons (3)	Average BTU As received	Coal Type (4)
Gatliff Coal	3.4	3.2	0.2	0.0	12,000 - 13,100	LSU
Clintwood Elkhorn Mining	60.8	39.1	21.7	20.3	12,500 - 13,500	HVM, LSU, PCI
Premier Elkhorn Coal	109.6	93.6	16.0	57.9	12,700 -13,100	HVM, IS, LSU, PCI,
Perry County Coal	137.1	106.7	30.4	83.2	12,500 -13,100	LSU, PCI, V
Total	310.9	242.6	68.3	161.4		

Notes:

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

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

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

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

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

Market Allocation of Reserves

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

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

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

The following table (Table 6) shows the recoverable reserves by market category per mining complex and in total. The total reserve mix is approximately 41% metallurgical, 40% PCI and 19% steam.

RESERVES BY MARKET CATEGORY

Table 6

	Met Reserves			PCI Reserves			Steam Reserves			Grand Totals
	Proven	Probable	Total	Proven	Probable	Total	Proven	Probable	Total	
Gatliff Coal	0.0	0.0	0.0	0.0	0.0	0.0	2.8	0.6	3.4	3.4
Clintwood Elkhorn Mining	46.6	8.5	55.1	0.0	0.0	0.0	5.0	0.7	5.7	60.8
Premier Elkhorn Coal	34.5	36.4	70.9	15.8	3.0	18.8	17.4	2.5	19.9	109.6
Perry County Coal	0.0	0.0	0.0	62.8	43.9	106.7	19.5	10.9	30.4	137.1
Totals:	81.1	44.9	126.0	78.6	46.9	125.5	44.7	14.7	59.4	310.9

Reserve Estimation Procedure

TECO Coal's reserves are based on over 3,800 data points, including drill holes, prospect measurements and mine measurements. Reserve estimates also include information obtained from on-going exploration drilling and in-mine channel sampling programs. Reserve classification is determined by 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 geologists and engineers at TECO Coal, and is computer modeled from which preliminary reserve estimations are generated. The information derived from the geological database is then combined with data on ownership or control of the mineral and surface interests to determine the extent of the reserves in a given area. Determinations of reserves are made after in-house geologists have reviewed the computer generated models and enhanced the grid models to better reflect regional trends.

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

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 **10, Commitments and Contingencies**, of the **TECO Energy** and **Tampa Electric Company Consolidated Financial Statements**, respectively.

Item 4. MINE SAFETY DISCLOSURES.

TECO Coal is subject to regulation by the 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 adopted Item 104 of Regulation S-K (17 CFR 229.104) is included in **Exhibit 95** to this annual report.

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*
2012				
High	$19.41	$18.33	$18.64	$18.14
Low	17.35	16.90	17.26	16.12
Close	17.55	18.06	17.74	16.76
Dividend	$0.220	$0.220	$0.220	$0.220
2011				
High	$18.82	$19.66	$19.38	$19.30
Low	17.47	18.20	15.82	16.15
Close	18.76	18.89	17.13	19.14
Dividend	$0.205	$0.215	$0.215	$0.215

The approximate number of shareholders of record of common stock of TECO Energy as of Feb. 18, 2013 was 12,243.

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.

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 TEC's common stock is owned by TECO Energy and, therefore, there is no market for the stock. TEC pays dividends on its common stock substantially equal to its net income. Such dividends totaled $228.3 million in 2012, $240.7 million in 2011 and $239.3 million in 2010. 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.

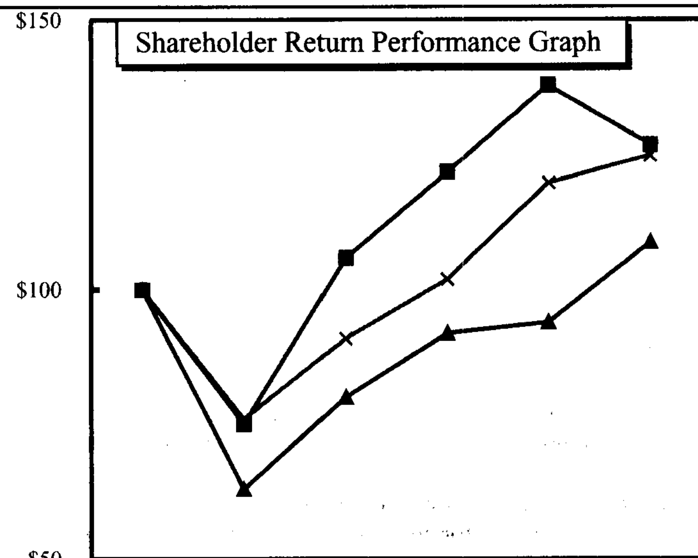
Set forth below is a table showing shares of TECO Energy common stock deemed repurchased by the issuer.

	(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, 2012 – Oct. 31, 2012	432	$17.83	0.0	0.0
Nov. 1, 2012 – Nov. 30, 2012	8,758	$16.55	0.0	0.0
Dec. 1, 2012 – Dec. 31, 2012	9,988	$16.57	0.0	0.0
Total 4th Quarter 2012	19,178	$16.59	0.0	0.0

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

Shareholder Return Performance Graph

The following graph shows the cumulative total shareholder return on our common stock on a yearly basis over the five-year period ended Dec. 31, 2012 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, 2007 and that all dividends were reinvested.



	2007	2008	2009	2010	2011	2012
TECO Energy, Inc.	$100	$75	$106	$122	$138	$127
S&P 500 Index	$100	$63	$80	$92	$94	$109
S&P Multi Utility Index	$100	$76	$91	$102	$120	$125

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

(millions, except per share amounts) *Years ended Dec. 31,*	*2012*	*2011*	*2010*	*2009*	*2008*
Revenues [1]	$2,996.6	$3,209.9	$3,363.5	$3,302.2	$3,366.9
Net income from continuing operations[1]	246.0	250.8	211.6	182.4	138.1
Net income from discontinued operations attributable to TECO Energy [1]	(33.3)	21.8	27.4	31.5	24.3
Net income attributable to TECO Energy	212.7	272.6	239.0	213.9	162.4
Total assets	7,356.5	7,322.2	7,278.3	7,219.5	7,147.4
Long-term debt, including current portion	2,972.7	3,073.4	3,226.4	3,309.5	3,213.5
EPS - Basic					
From continuing operations [1]	$ 1.14	$ 1.17	$ 0.99	$ 0.85	$ 0.65
From discontinued operations attributable to TECO Energy [1]	(0.15)	0.10	0.13	0.15	0.12
Attributable to TECO Energy	$ 0.99	$ 1.27	$ 1.12	$ 1.00	$ 0.77
EPS - Diluted					
From continuing operations [1]	$ 1.14	$ 1.17	$ 0.98	$ 0.85	$ 0.65
From discontinued operations attributable to TECO Energy [1]	(0.15)	0.10	0.13	0.15	0.12
Attributable to TECO Energy	$ 0.99	$ 1.27	$ 1.11	$ 1.00	$ 0.77
Dividends paid per common share outstanding	$ 0.880	$ 0.850	$ 0.815	$ 0.800	$ 0.795

(1) Amounts shown include reclassifications to reflect discontinued operations as discussed in **Note 19** to the **TECO Energy Consolidated Financial Statements**.

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 as of the date we filed this report, 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 PGS, respectively, and TECO Coal, which owns and operates coal production facilities in the Central Appalachian coal production region.

Our regulated utility companies, Tampa Electric and PGS, operate in the Florida market. Tampa Electric serves more than 687,000 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 4,668 MW. PGS, Florida's largest gas distribution utility, serves approximately 345,000 residential, commercial, industrial and electric power generating customers in all major metropolitan areas of the state, with a total natural gas throughput of almost 1.9 billion therms in 2012.

Our unregulated business, TECO Coal, which through its subsidiaries, operates surface and underground mines and related coal processing facilities in eastern Kentucky, southwestern Virginia and Tennessee, producing metallurgical-grade and high-quality steam coals. Sales in 2012 were 6.3 million tons. In 2012 we sold our ownership interest in TECO Guatemala, which through its subsidiaries, owned a coal-fired generating facility and a 96% ownership interest in an oil-fired peaking power generating plant, both in Guatemala.

2012 PERFORMANCE

All amounts included in this MD&A are after tax, unless otherwise noted.

In 2012, our net income and earnings per share attributable to TECO Energy were $212.7 million, or $0.99 per share, compared to $272.6 million, or $1.27 per share, in 2011. Net income and earnings per share from continuing operations were $246.0 million and $1.14 in 2012, compared with $250.8 million and $1.17 in 2011. The 2012 losses in discontinued operations of $33.3 million reflect the results from operations of $18.2 million for the generating plants in Guatemala through the closing of the sales, a $28.6 million loss on assets sold including transaction costs, and a $22.9 million charge associated with foreign tax credit write-off.

In 2012, we focused on managing our utility businesses to earn their allowed ROE despite unfavorable weather patterns and lower per customer usage. Mild winter weather and an unusually rainy summer weather pattern offset by higher than normal degree days in the shoulder month periods, which do not generate significantly higher energy sales, reduced energy sales volumes for both Tampa Electric and PGS in 2012, following 2011 when weather patterns were similarly unfavorable. We benefited from the retirement of parent debt, and lower interest rates on TECO Finance and TEC debt in 2012. Results at TECO Coal reflected improved margins from better selling prices for its specialty coal products, partially offset by higher operating costs and lower volumes driven by the coal market conditions. In September we announced the sale of our ownership interests in the two power plants in Guatemala, and results for that segment were reclassified to discontinued operations.

In 2011, our net income and earnings per share attributable to TECO Energy were $272.6 million, or $1.27 per share, compared to $239.0 million, or $1.12 per share, in 2010.

There were no charges or gains to cause non-GAAP results to differ from net income in 2012 or in 2011.

OUTLOOK

Our outlook for 2013 results reflects our expectations that state and local economies will continue to strengthen and that PGS will earn at or above the middle of its allowed ROE range. Tampa Electric expects to earn below the bottom of its allowed ROE range, and as a result has notified the FPSC that it is planning to file a new base rate proceeding in April for new rates effective in early 2014. Tampa Electric's actual revenue requirement calculation is not final, but is expected to be approximately $135 million (see the **Tampa Electric** and **Regulation** sections). TECO Coal expects to generate positive net income from fewer tons and at lower margins, which reflects the current weak coal markets. The drivers impacting 2013 are summarized below and discussed in further detail in the individual operating company sections.

Tampa Electric expects customer growth in 2013 to continue at a pace similar to 2012, when the average number of customers increased 1.2%. Total retail energy sales growth is expected to average about 0.5% lower than customer growth due to lower average customer usage. Sales to the lower margin industrial-phosphate customers are expected to be lower in 2013 due to increased self-generation following outages of customers' generating equipment that increased sales to these customers in 2012. PGS expects customer growth consistent with trends in 2012 when the average number of customers increased 1.2%. PGS expects energy sales volumes to be higher than in 2012, assuming normal weather conditions, as mild winter temperatures reduced natural gas volumes sold in 2012. It also expects to benefit from customers converting from petroleum and other fuel sources to natural gas due to the attractive economics.

Due to the current very weak domestic and international coal market conditions, we expect TECO Coal's net income to be about $12 million at the middle of the cost and sales guidance ranges in 2013. TECO Coal expects to sell between 5.2 and 5.7 million tons in 2013 with 90% of its sales contracted. The average selling price across all products is expected to be more than $86 per ton, which is $10 per ton lower than 2012, while the fully-loaded, all-in cost of production is expected to be in a range between $81 and $85 per ton.

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

Our priorities for the use of cash remain investment in the utility companies and, over time, reduction of parent debt. In 2013, we expect to make additional equity contributions to Tampa Electric and PGS to support their capital structures and financial integrity. Our opportunities to invest capital in Tampa Electric are expected to grow significantly over the next several years as it invests in its next increment of new generating capacity. We anticipate capital spending in 2013 to increase to $520 million, including the investments in generating capacity additions at Tampa Electric and opportunities to grow the PGS system described below (see the **Liquidity, Capital Resources** section).

Over the next several years, after maintaining Tampa Electric's and PGS's capital structure, we expect to repurchase shares to offset dilution from shares issued as compensation, and use additional cash to repurchase shares as market opportunities allow, which in total could be as much as $50 million.

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

- We believe that there are opportunities to grow the use of CNG for fleet vehicles. To date, we have had success working with fleet owners to install 13 CNG filling stations with conversions or planned conversions over the next two years of about 700 vehicles of various sizes to CNG. The number of vehicles already converted or committed to conversion is the equivalent volume usage of 24,000 residential customers on an annual basis. Such conversions offer compelling economics to customers, and expand PGS therm sales without significant capital investment by PGS.
- We are looking closely at Smart Grid applications that have proven technology and offer operating and financial benefits to our overall operations. These include, among other opportunities, transitioning automatic meter reading technology to advanced metering infrastructure, which would include a significant investment in our communications infrastructure but would also result in O&M expense savings.
- We also recognize that there is a growing demand for natural gas generation in Florida over the next decade. We project that Florida may need between 0.8 and 1.25 billion cubic feet per day (Bcf/day) by as early as 2016. Given our expertise in this area, we continue to evaluate opportunities to partner with transmission and end-use natural gas customers.

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

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

RESULTS SUMMARY

The table below compares our GAAP net income to our non-GAAP results. A reconciliation between GAAP net income and non-GAAP results is contained in the **Reconciliation of GAAP net income from continuing operations to non-GAAP results** tables for 2010. 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)	**2012**	*2011*	*2010*
Net income attributable to TECO Energy	**$212.7**	$272.6	$239.0
Net income from continuing operations	**$246.0**	$250.8	$211.6
Non-GAAP results from continuing operations	**$246.0**	$250.8	$244.2

The table below provides a summary of revenues, earnings per share, net income and shares outstanding for the 2012-2010 period.

Earnings Summary

(millions) Except per-share amounts	**2012**	*2011*	*2010*
Consolidated revenues	**$2,996.6**	$3,209.9	$3,363.5
Earnings per share – basic			
Earnings per share from continuing operations	**$ 1.14**	$ 1.17	$ 0.99
Earnings (loss) per share from discontinued operations	**(0.15)**	0.10	0.13
Earnings per share attributable to TECO Energy	**$ 0.99**	$ 1.27	$ 1.12
Earnings per share – diluted			
Earnings per share from continuing operations	**$ 1.14**	$ 1.17	$ 0.98
Earnings (loss) per share from discontinued operations	**(0.15)**	0.10	0.13
Earnings per share attributable to TECO Energy	**$ 0.99**	$ 1.27	$ 1.11
Net income from continuing operations	**$ 246.0**	$ 250.8	$ 211.6
Net income (loss) from discontinued operations	**(33.3)**	21.8	27.4
Net income attributable to TECO Energy	**212.7**	272.6	239.0
Charges and (gains)(1)	**—**	—	36.5
Non-GAAP results	**$ 212.7**	$ 272.6	$ 275.5
Average common shares outstanding (millions)			
Basic	**214.3**	213.6	212.6
Diluted	**215.0**	215.1	214.8

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

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

There were no charges or gains in 2012 or 2011 to cause non-GAAP results to differ from net income.

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

Net income impact (millions)	*Tampa Electric*	*PGS*	*TECO Coal*	*Parent/ other(1)*	*Total continuing Operations*	*Discontinued Operations(1)*	*Total*
GAAP Net income attributable to TECO Energy	$208.8	$34.1	$53.0	$(84.3)	$211.6	$27.4	$239.0
Restructuring charges	—	—	—	0.9	0.9	—	0.9
Loss on the sale of DECA II net of taxes	—	—	—	—	—	3.9	3.9
Charges related to early debt retirement	—	—	—	33.5	33.5	—	33.5
Recovery of fees related to McAdams Power Station sale	—	—	—	(1.8)	(1.8)	—	(1.8)
Total charges and (gains)	—	—	—	32.6	32.6	3.9	36.5
Non-GAAP results	$208.8	$34.1	$53.0	$(51.7)	$244.2	$31.3	$275.5

(1) Certain costs previously included in Parent/other have been recast to Discontinued Operations.

NON-GAAP INFORMATION

From time to time, in this MD&A, we provide non-GAAP results, which present financial results after elimination of the effects of certain identified charges and gains. In 2012 and 2011, there were no charges or gains to cause non-GAAP results to differ from net income. We believe that the presentation of this non-GAAP financial performance provides investors a measure that reflects the company's operations under our business strategy. We also believe that it is helpful to present a non-GAAP measure of performance that clearly reflects the ongoing operations of our business and allows investors to better understand and evaluate the business as it is expected to operate in future periods. Management and the board of directors use this non-GAAP presentation as a yardstick for measuring our performance, making decisions that are dependent upon the profitability of our various operating units and in determining levels of incentive compensation.

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

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

OPERATING RESULTS

This MD&A 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		*2012*	*2011*	*2010*
Segment revenues (1)				
Regulated companies	Tampa Electric	**$1,981.3**	$2,020.6	$2,163.2
	Peoples Gas	**398.9**	453.5	529.9
Total regulated		**$2,380.2**	$2,474.1	$2,693.1
	TECO Coal	**$ 608.9**	$ 733.0	$ 690.0
Net income (2)				
Regulated companies	Tampa Electric	**$ 193.1**	$ 202.7	$ 208.8
	Peoples Gas	**34.1**	32.6	34.1
Total regulated		**227.2**	235.3	242.9
	TECO Coal	**50.2**	51.5	53.0
	Parent/other(4)	**(31.4)**	(36.0)	(84.3)
Net income from continuing operations		**246.0**	250.8	211.6
Net income (loss) from discontinued operations		**(33.3)**	21.8	27.4
Net income attributable to TECO Energy		**$ 212.7**	$ 272.6	$ 239.0
Earnings per share - basic (2)(3)				
Regulated companies	Tampa Electric	**$ 0.90**	$ 0.95	$ 0.98
	Peoples Gas	**0.16**	0.15	0.16
Total regulated		**1.06**	1.10	1.14
	TECO Coal	**0.23**	0.24	0.25
	Parent/other(4)	**(0.15)**	(0.17)	(0.40)
Earnings per share from continuing operations		**1.14**	1.17	0.99
Earnings (loss) per share from discontinued operations		**(0.15)**	0.10	0.13
Earnings per share attributable to TECO Energy		**$ 0.99**	$ 1.27	$ 1.12
Average shares outstanding – basic		**214.3**	213.6	**212.6**

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

(2) Segment net income and earnings per share are reported on a basis that includes internally allocated interest costs to the unregulated companies. Internally allocated interest costs were at a pretax interest rate of 6.00% for 2012, 6.25% for 2011, 6.50% for July through December 2010, and 7.15% for January through June 2010.

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

(4) From continuing operations

TAMPA ELECTRIC

Electric Operations Results

Net income in 2012 was $193.1 million, compared to $202.7 million in 2011.

Results in 2012 reflected a mild winter weather period and an extremely rainy summer period, and lower per-customer average usage, partially offset by 1.2% growth in the average number of customers, higher O&M expense and lower interest expenses. Net income in 2012 included $2.6 million of AFUDC–equity, which represents allowed equity cost capitalized to construction costs, compared with $1.0 million in the 2011 period.

Results in 2011 reflected the significant impact on energy sales of extremely mild weather, partially offset by a 0.7% higher average number of customers, and lower non-fuel O&M expense. Net income in 2011 included $1.0 million of AFUDC equity, compared with $1.9 million in the 2010 period.

In 2012, total degree days in Tampa Electric's service area were normal, but almost 3% below the prior year, reflecting mild winter weather and an unusually rainy summer weather pattern (the second wettest summer period on record) offset by higher than normal degree days in the normally mild spring and fall periods, which do not generate significantly higher energy sales. Pretax base revenue was almost $6.0 million lower than in 2011, primarily reflecting lower sales to residential customers from the milder weather, voluntary conservation that typically occurs during periods without extreme weather, and changes in customer usage patterns.

In 2012, total net energy for load was 0.3% higher than in 2011. Milder weather reduced sales to higher-margin residential and smaller commercial customers. Industrial-other sales were higher, reflecting improvements in the Florida economy, and higher energy sales to industrial-phosphate customers due to the transfer of certain load from self-generation to Tampa Electric's system. The energy sales shown in the summary table below reflect the energy sales based on the timing of billing cycles, which can vary from period to period.

In 2012, O&M expense, excluding all FPSC-approved cost-recovery clauses, increased $11.8 million reflecting higher generating system maintenance expenses, higher costs to operate and maintain the distribution system and higher pension and other employee benefit expenses, partially offset by lower bad-debt expense. Compared to the 2011 full-year period, depreciation and amortization expense increased $9.6 million, reflecting additions to facilities to serve customers. Interest expense decreased $7.4 million due to lower long-term debt interest rates and balances and a lower interest rate on customer deposits.

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

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

Base Rates

Tampa Electric's 2012 results reflect base rates established in March 2009, when the FPSC awarded $104.0 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. In a series of subsequent decisions in 2009 and 2010, related to a calculation error and a step increase for combustion turbines and rail unloading facilities that entered service before the end of 2009, base rates increased an additional $33.5 million.

As a result of increasing pressure on O&M expense, and an economic recovery that has been slower than expected compared to the assumptions in Tampa Electric's last base rate proceeding initially filed in 2008, on Feb. 4, 2013, Tampa Electric notified the FPSC that it is planning to file a new base rate proceeding in April for new rates effective in early 2014. The actual revenue requirement calculation is not final, but is estimated to be approximately $135 million.

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

Summary of Operating Results

(millions)	*2012*	*% Change*	*2011*	*% Change*	*2010*
Revenues	**$1,981.3**	(1.9)	$2,020.6	(6.6)	$2,163.2
O & M expenses	**375.7**	7.6	349.2	(13.9)	405.6
Depreciation and amortization	**237.6**	7.0	222.1	2.9	215.9
Taxes, other than income	**151.3**	5.4	143.6	(1.2)	145.3
Non-fuel operating expenses	**764.6**	7.0	714.9	(6.8)	766.8
Fuel	**694.7**	(5.3)	733.5	(4.4)	767.6
Purchased power	**105.3**	(16.4)	125.9	(29.9)	179.6
Total fuel & purchased power expense	**800.0**	(6.9)	859.4	(9.3)	947.2
Total operating expenses	**1,564.6**	(0.7)	1,574.3	(8.2)	1,714.0
Operating income	**416.7**	(6.6)	446.3	(0.6)	449.2
AFUDC equity	**2.6**	160.0	1.0	(47.4)	1.9
Net income	**$ 193.1**	(4.7)	$ 202.7	(2.9)	$ 208.8
Megawatt-Hour Sales (thousands)					
Residential	**8,395**	(3.7)	8,718	(5.1)	9,185
Commercial	**6,185**	(0.4)	6,207	(0.2)	6,221
Industrial	**2,001**	10.9	1,804	(10.2)	2,010
Other	**1,828**	(0.3)	1,835	2.1	1,797
Total retail	**18,409**	(0.8)	18,564	(3.4)	19,213
Sales for resale	**267**	(24.2)	352	(31.8)	516
Total energy sold	**18,676**	(1.3)	18,916	(4.1)	19,729
Retail customers (thousands)-average	**684.2**	1.2	675.8	0.7	671.0
Retail net energy for load	**19,255**	0.3	19,205	(5.7)	20,362

Operating Revenues

In 2012, retail MWh sales, as measured on a billing cycle basis shown in the table above, decreased 0.8% despite 1.2% higher average number of customers, an improving local economy and higher sales to the lower margin phosphate-industrial customers. In 2012, total degree days in Tampa Electric's service area were normal, but almost 3% below 2011, reflecting mild winter weather and an unusually rainy summer weather pattern offset by higher than normal degree days in the normally mild spring and fall periods, which do not generate significantly higher energy sales. Pretax base revenue was almost $6.0 million lower than in 2011, primarily reflecting lower sales to residential customers from the milder weather, changes in customer usage patterns and voluntary conservation that typically occurs during periods without extreme weather. In 2012, total net energy for load, which is a calendar measurement of retail energy sales rather than a billing cycle measurement, was 0.3% higher than in 2011.

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

For the past several years, energy consumption per residential customer declined due to the combined effects of economic conditions, high unemployment, increased multi-family homes and smaller single family homes, improvements in lighting and appliance efficiency, and voluntary conservation efforts.

Sales for resale, which are a decreasing portion of Tampa Electric's energy sales, declined 24.2% in 2012 after a 31.8% decline in 2011, primarily due to changes in Tampa Electric's wholesale rates and reduced demand due to the mild weather.

Based on billing cycle measurements, electricity sales to the phosphate industry increased 25% in 2012 due to the transfer of certain load from self-generation to Tampa Electric's system and an outage on a phosphate customer's self-generating equipment. Sales to these customers decreased 23.2% in 2011, driven by the return to service of a phosphate customer's self-generating capacity following an outage in 2010. Base revenues from sales to phosphate customers represented 3.3% of base revenue in 2012, and almost 3% of base revenues in 2011 and 2010. Sales to commercial customers decreased 0.3% in 2012 and 0.2% in 2011, primarily reflecting the mild weather.

Customer and Energy Sales Growth Forecast

The Florida economy continues to slowly recover from the economic downturn, as evidenced by lower levels of unemployment, and slow improvements in the new housing construction market, which was a major driver of growth in the Florida economy for many years (see the **Risk Factors** section). In general, economists are forecasting a continued improvement in the unemployment rate in 2013, and an acceleration of improvement in the economy in 2014 and beyond. The 2013 forecast used by Tampa Electric reflects a continuation of the customer growth trend that was experienced in 2012. Energy sales are expected to reflect continued lower per customer usage in response to increased energy efficiency, voluntary conservation, and economic conditions. The average number of customers increased 1.2% in 2012 and 0.7% in 2011.

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 of about 1.3% and weather-normalized average retail energy sales growth about 0.5% lower than customer growth. This energy sales growth projection is lower than in periods prior to the economic downturn, reflecting increased lighting and appliance efficiency, smaller new single family homes, increased percentage of multi-family homes, changes in usage patterns and changes in population trends. These growth projections assume continued modest local area economic growth, normal weather, a recovery in the housing market over time, and a continuation of the current energy market structure.

The economy in Tampa Electric's service area continued to grow in 2012 after modest growth in 2011 and 2010. The Tampa metropolitan area had the largest gain in jobs of 22 metropolitan areas in Florida, with 21,000 new jobs led primarily by the business services, healthcare and tourism-related businesses. The total nonfarm employment in the Tampa metropolitan area increased 1.8% in 2012 and 1.2% in 2011 after decreasing 1.5% in 2010. The increase in nonfarm employment compared favorably with the state of Florida's increase of 0.9%. The local Tampa area unemployment rate decreased to 7.6% at year-end 2012 compared to 9.5% at year-end 2011, and 12.0% at year-end 2010. The Tampa area year-end 2012 unemployment rate was below the state of Florida's 8.0% rate, and the national rate of 7.8%.

Operating Expenses

Total pretax operating expenses decreased 0.6% in 2012 driven primarily by lower fuel and purchased power expenses. Excluding all FPSC approved cost-recovery clause related expenses, which are net income neutral, O&M expense increased 6.6%, or $11.8 million, driven by higher generating system maintenance expenses, higher costs to operate and maintain the distribution system and higher pension and other employee benefit expenses, partially offset by lower bad-debt expense. O&M expense is expected to increase in 2013 due to increased expenses to operate the system and reliably serve customers and higher employee-related expenses, including pension expense, driven by discount rate assumptions in the current low interest rate environment.

Total pretax operating expenses decreased 8.2% in 2011, driven primarily by lower purchased-power expense and lower other operating expense. Excluding all FPSC-approved cost-recovery clause-related expenses, O&M expense decreased $23.6 million, driven primarily by lower accruals for performance-based incentive compensation for all employees and other benefit costs, lower power plant maintenance costs, and lower costs to operate and maintain the transmission and distribution system.

Compared to 2011, depreciation and amortization expense increased $9.5 million in 2012, reflecting additions to required infrastructure to serve customers. Depreciation expense is expected to increase at similar levels in 2013. Compared to 2010, depreciation and amortization expense increased $3.8 million in 2011, reflecting the additions to facilities to serve customers.

Fuel Prices and Fuel Cost Recovery

In November 2012, the FPSC approved cost-recovery rates for fuel and purchased power, capacity, environmental and conservation costs for 2013. The rates include the expected cost for natural gas and coal in 2013, and the net over-recovery of fuel, purchased power and capacity clause expenses which were collected in 2012 and 2011.

Total fuel cost decreased in both 2012 and 2011, due to increased natural gas-fired generation as lower costs for natural gas was partially offset by higher costs for coal. Purchased-power expense decreased in 2012 as the cost-per-MWh decreased, due to lower natural gas prices, which is the primary fuel used by other generators in Florida. Purchased power expense decreased in 2011 due to lower volumes purchased at lower prices due to lower natural gas prices, and higher Tampa Electric coal-fired generation. Delivered natural gas prices decreased 14.0% in 2012 as a result of historically low natural gas prices in the first half of 2012 due to mild winter weather and abundant supplies from on-shore domestic natural gas produced from shale formations, and storage inventories above historic averages. Higher natural gas inventories resulted from lower demand for natural gas caused by mild weather and lower natural gas demand from industrial users due to economic conditions. Delivered coal costs increased 3.2% in 2012. The average coal and natural gas costs were $3.57/MMBTU and $5.34/MMBTU, respectively, in 2012.

Natural gas futures as traded on the NYMEX and various forecasts for natural gas prices indicate that natural gas prices are expected to increase in 2013, compared to the unusually low 2012 levels as fewer new natural gas wells are drilled in on-shore shale gas formations due to the low prices received by the producers, and the expectation for more normal weather and lower levels of gas in storage. Beyond 2013, forecasts are for stable to slightly rising natural gas prices for several years due to increased availability of domestic supplies of natural gas. Delivered coal prices increased 3.2% in 2012 due to normal escalation in fuel and transportation contracts. Tampa Electric's primary coal supplies are from the Illinois Basin, which have been more stable than the Central Appalachian coal-producing region over the past several years. Excluding normal escalation and transportation costs, Tampa Electric's coal prices are expected to remain stable in 2013 due to long-term supply contracts.

Energy Supply

Tampa Electric's generation decreased in 2012 due to the mild weather and lower cost natural gas-fired generation available within Florida, which increased MWh purchased but at a lower cost. Tampa Electric's generation decreased in 2011 in line with lower energy sales due to mild weather, which also reduced purchased power volumes. Lower natural gas prices also contributed to the decrease in purchased-power expense on a per-MW basis.

Prior to the conversion of the coal-fired Gannon Station to the natural gas-fired Bayside Power Station in 2003, nearly all of Tampa Electric's generation was from coal. Upon completion of that conversion, the mix shifted with the increased use of natural gas. Coal is expected to continue to represent more than half of Tampa Electric's fuel mix due to the baseload units at the Big Bend Power Station and the coal gasification unit, Polk Unit One. Longer term, natural gas prices, which declined to exceptionally low levels in early 2012 as a result of increased supply and lower demand due to mild winter temperatures, are expected to remain stable for several years at about the same levels as early 2013, and we expect to maintain the generation mix at about 2012 levels.

Polk Power Station Units 2 – 5 Combined Cycle Conversion

Following the completion of its last increment of new generating capacity additions in 2009, Tampa Electric was in a period of essentially maintenance capital spending for infrastructure to reliably serve its customer base, hurricane storm hardening, investments in its transmission and distribution system to improve reliability and reduce customer outages, for generating unit reliability and information technology systems improvements in 2012 and 2011.

Tampa Electric had previously deferred its next increment of new baseload generating capacity, originally scheduled to be in service in 2013, due to the recession experienced in the Florida and national economies and the Florida housing market slowdown. In 2011, Tampa Electric made the decision to take advantage of generating capacity available in Florida at attractive rates and to purchase power to meet its 2013 through 2016 energy demand and sales growth. In 2011, Tampa Electric announced that, subject to FPSC approval, it planned to convert four CTs in peaking service at the Polk Power Station to combined cycle with an early 2017 in-service date. In 2012, as required under Florida regulations, Tampa Electric issued a request for proposal to determine its lowest cost option to provide generating capacity beginning in early 2017. The bid process showed that the lowest cost option to serve customers, over the long-term, was Tampa Electric's planned conversion of CTs to combined cycle operation.

In September 2012, Tampa Electric submitted a petition to the FPSC for a Determination of Need for the conversion of these peaking CTs to combined-cycle service. In December 2012, the FPSC conducted a hearing for the need, and at the conclusion the FPSC made a bench decision to approve the Polk Power Station Units 2 – 5 conversion. The capital expenditures for the conversion and the related transmission system improvements to support the additional generating capacity are included in the capital expenditure forecast located in the **Capital Expenditures** section. Capital spending in 2013 will support environmental permitting activities and engineering and design (see the **Capital Expenditures** and **Regulation** sections).

PGS

Operating Results

In 2012, PGS reported net income of $34.1 million, compared with $32.6 million in 2011. Results in 2012 reflected a 1.2% higher average number of customers, but lower sales to residential customers due to mild winter weather more than offset by higher sales to commercial and industrial customers and power generation customers due to improving economic conditions. Volumes for the low-margin transportation service for electric power generators increased due to low natural gas prices, which made it more economical to use natural gas for power generation. Non-fuel O&M expense decreased $2.1 million, compared with 2011, due in part to an insurance recovery of legal expenses associated with environmental-contamination claims. In 2011, O&M expense included $2.5 million related to legal expenses associated with environmental-contamination claims. Interest expense decreased $1.0 million due to lower long-term debt interest rates and balances and a lower interest rate on customer deposits. Depreciation expense increased $1.4 million reflecting additions to facilities to serve customers.

In 2012, the total throughput for PGS was almost 1.9 billion therms. Industrial and power generation customers consumed approximately 49% of PGS's annual therm volume, commercial customers used approximately 22%, approximately 12% was sold off system, and the balance was consumed by residential customers.

In 2011, PGS reported net income of $32.6 million compared to $34.1 million in 2010. Results in 2011 reflected a 0.8% higher average number of customers. Increased volumes to commercial and industrial customers reflected improvements in the

Florida and national economies and generally higher usage by those customers, while lower volumes sold to residential customers reflected the milder weather in contrast to the cold 2010 winter. Gas transported for power generation customers increased in 2011 due to lower natural gas prices, which made it more economical for some customers to switch to natural gas for power generation. Excluding the impact of the 2010 provision related to potential earnings above the top of the allowed ROE range in 2010 described below, non-fuel O&M expense was higher in 2011, including $2.5 million of expenses related to the defense of environmental contamination claims. Results in 2011 also reflect increased depreciation expense due to routine plant additions.

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

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

Residential operations were about 32% of total revenues in each of the past three years. New residential construction that includes natural gas and conversions of existing residences to gas has slowed significantly, compared to the pre-2007 period, due to the slower Florida housing market. Like most other natural gas distribution utilities, PGS is adjusting to lower per-customer usage due to improving appliance efficiency. As customers replace existing gas appliances with newer, more efficient models, per-customer usage tends to decline.

Natural gas has historically been used in many traditional industrial and commercial operations throughout Florida, including production of products such as steel, glass, ceramic tile and food products. Within the PGS operating territory, large cogeneration facilities utilize gas-fired technology in the production of electric power and steam. PGS has also experienced increased interest in the usage of CNG as an alternative fuel for vehicles. Currently, there are 13 CNG fueling stations connected to the PGS system, and additional stations are expected to be added in 2013. Such initiatives add therm sales, at lower margin transportation rates, to the gas system without requiring significant capital investment.

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

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

Summary of Operating Results

(millions)	*2012*	*% Change*	*2011*	*% Change*	*2010*
Revenues	**$ 398.9**	(12.0)	$ 453.5	(14.4)	$ 529.9
Cost of gas sold	**157.6**	(25.4)	211.3	(25.8)	284.8
Operating expenses	**170.0**	(1.3)	172.2	0.2	171.8
Operating income	**71.3**	1.9	70.0	(4.5)	73.3
Net income	**34.1**	4.6	32.6	(4.4)	34.1
Therms sold – by customer segment					
Residential	**70.8**	(8.9)	77.7	(14.1)	90.5
Commercial	**421.4**	3.0	409.2	0.3	407.9
Industrial	**461.3**	5.8	436.1	(14.0)	507.2
Power generation	**913.5**	48.7	614.3	5.5	582.2
Total	**1,867.0**	21.4	1,537.3	(3.2)	1,587.8
Therms sold – by sales type					
System supply	**334.3**	(5.4)	353.3	(21.7)	451.0
Transportation	**1,532.7**	29.5	1,184.0	4.2	1,136.8
Total	**1,867.0**	21.4	1,537.3	(3.2)	1,587.8
Customer (thousands) – average	**342.9**	1.2	338.8	0.8	336.0

In Florida, natural gas service is unbundled for non-residential customers and residential customers that use more than 1,999 therms annually that elect this option, affording these customers the opportunity to purchase gas from any provider. The net result of unbundling is a shift from bundled transportation and commodity sales to transportation-only sales. Because the commodity portion of bundled sales is included in operating revenues at the cost of the gas on a pass-through basis, there is no net earnings impact to the company when a customer shifts to transportation-only sales. PGS markets its unbundled gas delivery services to customers through its "NaturalChoice" program. At year-end 2012, approximately 19,500 out of 35,000 of PGS's eligible non-residential customers had elected to take service under this program.

PGS Outlook

In 2013, PGS expects continued customer growth at rates in line with those experienced in 2012, reflecting its expectations that the housing markets in some areas of the state that it serves are recovering but others will be slower to recover. Assuming normal weather, therm sales to weather-sensitive customers, especially residential customers, are expected to increase in 2013 compared to 2012 when mild winter weather reduced sales. Excluding all FPSC-approved cost-recovery clause-related expenses, operation and maintenance expense is expected to increase in 2013 primarily due to higher employee-related expenses, which includes pension expense driven by lower discount rates in the current low interest rate environment. Depreciation expense is expected to increase from continued capital investments in facilities to reliably serve customers.

Since its acquisition by TECO Energy in 1997, PGS has expanded its gas distribution system into areas of Florida not previously served by natural gas, such as the lower southwest coast in the Fort Myers and Naples areas and the northeast coast in the Jacksonville area. In 2013, PGS expects capital spending to support moderate residential and commercial customer growth and system expansion to serve large commercial and industrial customers.

Due to the current slow rate of new residential development in Florida, the PGS business model for system expansion has evolved to focus on extending the system to serve large commercial or industrial customers that are currently using petroleum and propane as fuel under multi-year contracts. The current low natural gas prices and the projections that natural gas prices are going to remain low into the future makes it attractive for these customers to convert from fuels that are currently three to four times more expensive on a cost-per-MMBTU basis. In 2012, PGS acquired a block propane system serving hotels and other commercial customers on Marco Island, a tourist area near Naples, Florida, and extended the distribution system to that block system and converted those hotels and commercial customers to natural gas service. Also in 2012, PGS completed a pipeline expansion project to Amelia Island, north of Jacksonville, Florida, to convert a large paperboard manufacturing facility from petroleum to natural gas service under a long-term contract.

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 FGT through 65 interconnections (gate stations) serving PGS's operating divisions. In addition, PGS's Jacksonville Division receives gas delivered by the Southern Natural Gas Company pipeline through two gate stations located northwest of Jacksonville. PGS also receives gas delivered by Gulfstream Natural Gas Pipeline through seven gate stations, and by its affiliate, SeaCoast Gas Transmission, LLC, through a single gate station in northeast Florida.

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

TECO COAL

In 2012, TECO Coal recorded net income of $50.2 million on sales of 6.3 million tons, compared with $51.5 million on sales of 8.1 million tons in 2011. Lower sales volumes in 2012 reflect much weaker coal market conditions than in 2011. Because the 2012 sales were contracted at a time when the markets were much stronger, the 2012 average net per-ton selling price was more than $95 per ton, compared with almost $88 per ton in 2011. The all-in total per-ton cost of sales was more than $85 per ton compared with almost $80 per ton in 2011. The 2012 cost of sales reflects spreading fixed costs over fewer tons, and costs associated with personnel reductions and with idling certain mining operations. TECO Coal's effective income tax rate was 24% in 2012, compared with 23% in the 2011 full-year period.

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

TECO Coal Outlook

We expect TECO Coal's net income to decrease significantly in 2013 compared with 2012 from lower contract selling prices and lower sales volumes. TECO Coal has 90% of its expected 2013 sales of between 5.2 and 5.7 million tons contracted. The average expected selling price across all products is expected to be more than $86 per ton in 2013, which reflects all of the planned 2013 steam coal sales committed and priced. In 2013, specialty coal volumes are expected to be about at 2012 levels and expected to represent about 50% of total sales.

The all-in total cost of production is expected to be below 2012 levels in a range between $81 and $85 per ton due to actions taken in 2012 to reduce mining costs, and lower royalty payments and severance taxes, which are a function of selling price. TECO Coal's effective income tax rate in 2013 is expected to be 25%.

Various federal tax overhaul proposals include provisions to eliminate depletion accounting for mineral extraction companies, which would increase TECO Coal's effective income tax rate and reduce net income if those proposals are implemented (see the **Risk Factors** section).

The lower volume projected for 2013 reflects TECO Coal's response to market conditions by exercising production discipline through a combination of idling sections of mines, reducing shifts, reducing overtime and reducing volumes produced by contract miners. Mild winter weather in 2012, low natural gas prices and world-wide economic conditions caused the selling price for certain types of coal to decline in 2012, and prices for coal in general remain significantly below levels experienced in 2010 and 2011.

In November 2011, TECO Coal announced that it had made a new discovery of an additional 65 million tons of proven and probable metallurgical coal reserves on properties it controls, and an additional estimated 9 million tons of metallurgical coal classified as resource (non-reserve coal deposits) due to seam thickness. There is an additional 14 million tons of coal classified as resource pending further geologic studies (see **Item 2 Properties** in the **TECO Coal** section). These metallurgical coal reserves are located below existing reserves and substantially all of these reserves are owned by TECO Coal, which eliminates royalty payments. The coal from these reserves can be transported by conveyor belt to an existing preparation plant, which has adequate capacity, and thus eliminate trucking costs. TECO Coal has received the permit amendments from the state of Kentucky related to surface development activities to access these reserves. TECO Coal performed preliminary surface and infrastructure development in 2012, but does not expect to begin the work required to bring these reserves into production until there are clear indications that the current weak metallurgical coal market conditions are improving (see the **Capital Investments** section of **Liquidity, Capital Resources**). An additional permit amendment was submitted to modify surface areas required for development of the slopes and shafts to access the reserves.

TECO Coal allocates its reserves by market category. As a result of this allocation, 40.7% of the reserves are classified as metallurgical coal, 40.2% as PCI coal and 19.1% as steam coal. See **Item 2 Properties** in the **TECO Coal** section for a discussion of this allocation.

Since 2008, the issuance of permits by the USACE under Section 404 of the Clean Water Act required for surface mining activities in the Central and Northern Appalachian mining regions has been challenged in the courts by various entities. These challenges have been appealed by various mining companies affected on a number of occasions, but very few permits have been issued over the past several years. TECO Coal had six permits on the list of permits subject to enhanced review by the EPA under its memorandum of understanding with the USACE, which was issued in September 2009, however, three have subsequently been withdrawn. At this time, TECO Coal has all of the permits required to meet its 2013 sales projections. See the **Environmental** section, the **Section 404 of the Clean Water Act and Coal Surface Mine Permits** section for a more detailed discussion of surface mining permit activities.

Coal Markets

Prices for metallurgical coal rose in 2010, driven by increased demand from expanding economies in China and India, and recovering demand in the U.S. and Europe. The U.S. steel industry operated at about a 70% utilization rate in 2010, compared to a 40% utilization rate for most of 2009. During 2010, spot prices for various grades of metallurgical coal produced by TECO Coal and others reportedly ranged from $110 to $180 per short ton. TECO Coal produces high quality metallurgical coals but they are not the equivalent quality of hard coking coal produced in Australia, which has become the benchmark for metallurgical coal prices worldwide. In 2010 prices for this benchmark Australian coal ranged from $200 to $285 per metric ton.

In the first half of 2011, prices for certain grades of Australian metallurgical coal peaked at $335 per metric ton as monsoon rains in Australia caused disruptions in supplies from that important provider of metallurgical coal to Asian markets. Subsequent to that peak, coal prices declined as supplies from Australia returned to the market and concerns related to worldwide demand for steel in the weak international economy became more pronounced. In January 2012, prices for the same grade of Australian metallurgical coal were $235 per metric ton, and in January 2013 the price for those same coals was $165 per metric ton. In the U.S., the steel industry continued to operate above a 70% utilization rate in 2012 and demand for metallurgical coal remained stable. However, weaker demand in the international market and increased supply of metallurgical coal for the domestic markets caused prices for most grades of metallurgical coal to decline significantly in 2012.

In 2012 and 2011, demand for coal used by utilities to generate electricity declined due to mild winter weather, the slow economic recovery in the U.S., and low natural gas prices, which made it more economical to generate electricity with natural gas than with coal, and uncertainty regarding the impact of certain proposed EPA regulations' on utilities' ability to burn coal in the future. Various industry reports, and estimates by the EPA, indicated that a number of smaller, older coal-fired utility boilers without current environmental controls would be retired in response to the proposed rules. In December 2011, the United States District Court for the District of Columbia stayed the implementation of the EPA's proposed CSAPR (see the **Environmental** section). In January 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied the EPA's request for reconsideration of its ruling against CSAPR, significantly reducing the possibility that the rule will be enforced in its current form. Despite the stay of CSAPR in 2011, demand for coal by utilities remains weak.

The significant factors that could influence TECO Coal's results in 2013 include the cost of production, the pricing on uncontracted tons, and customers taking contracted volumes. Longer-term factors that could influence results include inventories at steam coal users, weather, the ability for utilities to continue to burn coal under new rules proposed by the EPA, the ability to obtain environmental permits for mining operations, general economic conditions, the level of 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).

PARENT/OTHER

In 2012, the cost for Parent /other in continuing operations was $31.4 million in 2012, compared with $36.0 million in 2011. Results for 2012 reflect tax items and lower interest expense as a result of the mid-year 2011 debt retirement, and a charge of $0.8 million associated with the early retirement of the remaining $8.8 million of TECO Energy parent debt. The total cost for Parent & other for 2012 was $35.4 million, compared with $36.6 million in the same period in 2011. Total cost for 2012 includes transaction costs and tax items recorded at Parent related to the TECO Guatemala discontinued operations.

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

The total 2010 non-GAAP cost for Parent/other was $51.7 million, which excluded a $33.5 million charge related to early retirement of TECO Energy debt, 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 (see the **2010 Reconciliation of GAAP net income from continuing operations to non-GAAP results** table).

The GAAP cost in 2010 included 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 in 2010 also included a $3.5 million unfavorable tax adjustment that offset the favorable domestic production deduction at Tampa Electric due to TECO Energy's consolidated NOL position. Results in 2010 also reflected $3.4 million lower interest expense as a result of debt restructuring and retirement.

DISCONTINUED OPERATIONS (TECO GUATEMALA)

On Sept. 28, 2012, TECO Energy announced that its international power subsidiary, TECO Guatemala, entered into agreements to sell all of its equity interests in the Alborada and San José power stations, and related solid fuel handling and port facilities in Guatemala, for a total purchase price of $227.5 million in cash. The sale of the Alborada Power Station closed on the same date for a price of $12.5 million. On Dec. 19, 2012, the sale closed on the San José Power Station and related facilities and operations for a price of $215.0 million (see **Note 19** to the **TECO Energy Consolidated Financial Statements**).

The 2012 losses in discontinued operations of $33.3 million reflect the results from operations of $18.2 million for the generating plants in Guatemala through the closing of the sales, a $28.6 million loss on assets sold including transaction costs, and a $22.9 million charge associated with foreign tax credit write offs.

TECO Guatemala reported full-year net income of $22.4 million in 2011, compared to $41.6 million in 2010. In 2010, non-GAAP results were $39.5 million, which excluded the gain on the sale of DECA II described below, and a related tax charge. Results in 2011 reflected the absence of DECA II earnings, which were $13.2 million in 2010, and $5.2 million of lower capacity payments related to the Alborada Power Station contract extension, which became effective September 2010.

In October 2010, a TECO Guatemala subsidiary sold its 30% interest in DECA II to EPM, a multi-utility company based in Medellín Colombia, for a sales price of $181.5 million. DECA II was a holding company in which, prior to the sale, TECO Guatemala Holdings, LLC (TGH), a wholly-owned subsidiary of TECO Guatemala, held a 30% interest. DECA II held an 80.9% ownership interest in EEGSA and affiliated companies. 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 (see the **2010 Reconciliation of GAAP net income from continuing operations to non-GAAP results** table). 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.

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. While TECO Energy and its subsidiaries no longer have assets or operations in Guatemala, TGH has retained its rights under this 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. Hearings on the matter before an international tribunal began in January 2013, but were not completed. The timing of a final decision is unknown at this time.

OTHER ITEMS IMPACTING NET INCOME

Other Income (Expense)

Other income (expense) of $10.8 million in 2012 and of $7.7 million in 2011 included miscellaneous services at the utilities such as lightning surge protection equipment, royalties for coal mined on properties leased by TECO Coal and from the sale of assets no longer in service.

AFUDC equity at Tampa Electric, which is included in Other income (expense), was $2.6 million, $1.0 million, and $1.9 million in 2012, 2011 and 2010, respectively. AFUDC is expected to increase in 2013 due to the construction of a reclaimed water pipeline to ground water usage at the Polk Power Station and spending related to the Polk Unit 2 – 5 conversion project (see the **Liquidity, Capital Resources** section).

Interest Expense

In 2012 interest expense was $183.5 million compared to $197.4 million in 2011. In 2012 interest expense decreased due to lower debt balances and lower interest rates on debt at TEC as a result of refinancing activities in 2012 (see **Financing Activity** section). Interest expense also declined due to an FPSC-approved lower interest rate paid on customer deposits at the utilities.

In 2011, total interest expense was $197.4 million compared to $215.5 million in 2010. In 2011, interest expense decreased due to lower debt balances as a result of the early retirement of TECO Energy and TECO Finance debt in December 2010 and the retirement of $63.7 million of TECO Energy and TECO Finance debt at maturity in May 2011.

Interest expense is expected to be lower in 2013, due to refinancing activity completed by TEC in 2012, and lower debt balances.

Income Taxes

The provision for income taxes decreased in 2012, primarily due to lower operating income. The provision for taxes was higher in 2011, primarily due to higher operating income and state income taxes. Income tax expense as a percentage of income from continuing operations before taxes was 35.9% in 2012, 36.3% in 2011 and 34.1% in 2010. We expect our 2013 annual effective tax rate to range between 37.0% and 38.0%.

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

The cash payments for federal income taxes, as required by the federal AMT rules, state income taxes, foreign income taxes and payments (refunds) related to prior years' audits totaled $7.2 million, $9.4 million and $5.5 million in 2012, 2011 and 2010, respectively.

Due to the NOL carryforward position resulting from the disposition of the generating assets formerly held by TWG Merchant, our merchant power subsidiary, cash tax payments for income taxes are limited to approximately 10% of the AMT rate. We expect future cash tax payments to be limited to a similar level and various state taxes. Due to additional bonus depreciation allowed in the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 and in the American Taxpayer Relief Act of 2012, we currently project to utilize these NOL carryforwards primarily in the 2015 through 2017 period. Beginning with 2017, we also expect to start using more than $211 million of AMT carry-forward to limit future cash tax payments for federal income taxes to the level of AMT. We currently project minimal cash tax payments over the next five years.

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

LIQUIDITY, CAPITAL RESOURCES

The table below sets forth the Dec. 31, 2012 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 TEC credit facilities.

	Balances as of Dec. 31, 2012			
(millions)	*Consolidated*	*Tampa Electric Company*	*Unregulated Companies*	*Parent*
Credit facilities	$675.0	$475.0	$—	$200.0
Drawn amounts/LCs	1.5	1.5	—	—
Available credit facilities	673.5	473.5	—	200.0
Cash and short-term investments	200.5	45.2	3.8	151.5
Total liquidity	$874.0	$518.7	$ 3.8	$351.5

In 2012, we met our cash needs primarily from internal sources. Cash from operations was $757 million. We paid dividends of $190 million in 2012, and capital expenditures were $505 million. Other sources of cash included $194 million of net proceeds, primarily from the sale of our ownership interest in TECO Guatemala, (see **Discontinued Operations**). We reduced long-term debt by $101 million, which included the retirement of $34 million of San José project debt with its sale, $9 million of TECO Energy parent debt and the net effect of Tampa Electric's refinancing activities. There was no short-term debt outstanding at year-end 2012 or 2011.

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

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

Cash from Operations

In 2012, consolidated cash flow from operations was $757 million. Although the timing of recoveries, particularly fuel and purchased power, under FPSC-approved cost-recovery clauses can have a significant impact on cash from operations in any one year, in 2012 the net impact was only $9 million. We had anticipated a more significant impact as the 2012 FPSC-approved clause rates provided for refunds of previous over-recoveries; however, lower than expected actual fuel prices resulted in a net over-recovered balance at the end of 2012. The 2012 cash from operations reflects pension contributions of $36 million.

We made minimal cash payments for state and federal income taxes in 2012 (see the **Income Taxes** section). Bonus depreciation, enacted under economic stimulus legislation annually since 2008, has significantly reduced federal taxable income at

Tampa Electric and PGS. We file a consolidated tax return, and under our tax sharing agreements, each subsidiary's tax payment is determined on a standalone basis. Significant NOL carryforwards are available at TECO Energy parent that can be used to offset taxable income in the consolidated return such that cash payments for federal income taxes are limited to approximately 10% of the AMT rate. During the period of bonus depreciation, taxable income has been reduced significantly by the bonus deductions and as a result we have utilized our NOL carryforwards less than expected in recent years. TECO Energy parent cash flows have therefore been less than expected through this period and our projections for the full utilization of the NOL carryforwards has been extended to 2017. Tampa Electric and PGS have realized higher cash flows in recent years as a result of reduced taxes from bonus depreciation, which has supported their capital spending programs. We expect that this trend will substantially continue in 2013 and 2014 as a result of the extension of bonus depreciation in January 2013 and expected technical guidance from the IRS on repair deductions for generation activities, and that TECO Energy parent will realize the cash benefit of the NOL carryforwards primarily in the 2015 through 2017 period.

We expect cash from operations in 2013 to be lower than the 2012 level. We expect lower net income in 2013 and lower net recoveries under various regulatory clauses to reduce cash from operations. In November 2012, the FPSC approved fuel-adjustment and other recovery clause rates that provide for refunds to customers of estimated 2012 net over-recoveries of fuel and purchased power over 12 months beginning Jan. 1, 2013 (see the **Regulation** section).

Cash from Investing Activities

Our investing activities in 2012 resulted in a net use of cash of $299 million, which reflects capital expenditures totaling $505 million and the net proceeds from the sale of business/assets of $194 million, primarily from the sale of the TECO Guatemala assets.

We expect capital spending for the next several years to be above 2012 levels, primarily due to generating capacity additions at Tampa Electric (see the Capital Expenditures section).

Cash from Financing Activities

Our financing activities in 2012 resulted in a net use of cash of $301 million. Major items included TEC's refinancing of $608 million of maturing, called or repurchased debt with $550 million of new long-term debt, the retirement of $34 million of San José project debt with its sale and the repayment of $9 million of TECO Energy parent long-term debt (see the **Financing Activity** section). We paid $190 million in common stock dividends, and we received $4 million from exercises of stock options.

Cash and Liquidity Outlook

In general, we target consolidated liquidity (unrestricted cash on hand plus undrawn credit facilities) of at least $500 million. At Dec. 31, 2012, our consolidated liquidity was $874 million, consisting of $519 million at TEC, $351 million at TECO Energy parent and $4 million at the other operating companies.

We expect our sources of cash in 2013 to include cash from operations at levels below 2012, due in large part to lower net income from the operating companies and lower net recoveries under various regulatory clauses in 2013 as described above. We plan to use cash generated in 2013 to fund capital spending estimated at $520 million and for dividends to shareholders. In 2013, Tampa Electric has $52 million of tax-exempt notes due for remarketing. There are no long-term debt maturities in 2013.

We expect to continue to make equity contributions to TEC in order to support the capital structure and financial integrity of the utilities. TEC expects to fund its capital needs with a combination of internally generated cash and equity contributions from us, and we anticipate that these contributions will total $50 million to $70 million in 2013 and $180 million to $200 million in 2014. Because of the delayed recognition of TECO Energy parent cash benefits from the utilization of NOL carryforwards (see the **Cash from Operations** section) we expect to use cash on hand from the sale of our TECO Guatemala assets (see the **Discontinued Operations** section) to support investment in the utilities in 2013 and 2014.

Over the next several years, after maintaining Tampa Electric's and PGS's capital structure, we expect to repurchase shares to offset dilution from shares issued as compensation, and use additional cash to repurchase shares as market opportunities allow, which in total could be as much as $50 million.

Our goal is to reduce leverage at TECO Finance over time as we are able to utilize our NOL carryforwards and as the equity needs of Tampa Electric normalize after the peak capital spending expected over the next several years during the Polk combined cycle conversion project (see the **Capital Expenditures** section). Our long-term debt maturities for TECO Finance total $191 million in 2015, $250 million in 2016, $300 million in 2017 and $300 million in 2020.

TEC expects to utilize cash from operations and equity contributions from TECO Energy to support its capital spending program, supplemented with incremental long-term debt and utilization of its credit facilities in proportions to maintain a strong capital structure. 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 2013 and remain within the covenant restrictions.

Our expected cash flow could be affected by variables discussed in the individual operating company sections, such as customer growth, weather and usage changes at our regulated businesses, and coal margins. In addition, actual fuel and other regulatory clause net recoveries will typically vary from those forecasted; however, the differences are generally recovered within the next calendar year. It is possible however, that unforeseen cash requirements and/or shortfalls, or higher capital spending requirements could cause us to fall short of our liquidity target (see the **Risk Factors** section).

As a result of our significant reduction of parent debt, and reduced business risk, we have improved our debt credit ratings (see **Credit Ratings** section). In the unlikely event TEC'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, 2012, we could have been required to post additional collateral or settle existing positions with counterparties totaling $14.9 million, which are TEC 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 $65.5 million. None of our credit facilities or financing agreements have ratings downgrade covenants that would require immediate repayment or collateralization; however, in the event of a downgrade, our interest expense could be higher.

SHORT-TERM BORROWING

Credit Facilities

At Dec. 31, 2012, and 2011, the following credit facilities and related borrowings existed:

(millions)	Dec. 31, 2012			Dec. 31, 2011		
	Credit Facilities	Borrowings Outstanding	Letters of Credit Outstanding	Credit Facilities	Borrowings Outstanding	Letters of Credit Outstanding
Tampa Electric Company:						
5-year facility[1]	$325.0	$—	$ 1.5	$325.0	$—	$ 0.7
1-year accounts receivable facility	150.0	—	—	150.0	—	—
TECO Energy/TECO Finance :						
5-year facility[1][2]	200.0	—	—	200.0	—	—
Total	$675.0	$—	$ 1.5	$675.0	$—	$ 0.7

(1) This 5-year facility matures Oct. 25, 2016.
(2) TECO Finance is the borrower and TECO Energy is the guarantor of this facility.

These credit facilities, including the one-year accounts receivable facility that was renewed in February 2013, require commitment fees ranging from 12.5 to 25.0 basis points. There were no borrowings outstanding under the credit facilities at Dec. 31, 2012 or Dec. 31, 2011.

At Dec. 31, 2012, TECO Finance had a $200 million bank credit facility in place guaranteed by TECO Energy with a maturity date in October 2016. TEC had a bank credit facility totaling $325 million, also maturing in October 2016. In addition, TEC had a $150 million accounts receivable securitized borrowing facility that was renewed in February 2013 with a maturity date of February 14, 2014. The TECO Finance and TEC bank credit facilities both include sub-limits for letters of credit of $200 million. At Dec. 31, 2012, the TECO Finance credit facility was undrawn and no letters of credit were outstanding. At Dec. 31, 2012, the TEC credit facilities were undrawn and $1.5 million of letters of credit were outstanding.

The table below sets forth TECO Finance and TEC maximum, minimum, and average credit facility utilization in 2012.

(millions)	2012 Credit Facility Utilization			
	Maximum drawn amount	Minimum drawn amount	Average drawn amount	Average interest rate
TECO Finance	$35.0	$ —	$13.9	1.58%
Tampa Electric Company	$91.0	$ —	$17.8	0.65%

Significant Financial Covenants

In order to utilize their respective bank credit facilities, TECO Energy, TECO Finance and TEC must meet certain financial tests as defined in the applicable agreements. In addition, TECO Energy, TECO Finance, TEC, and the other operating companies have certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2012, TECO Energy, TECO Finance, TEC and the other operating companies were in compliance with all applicable financial covenants. The table that follows lists the covenants and the performance relative to them at Dec. 31, 2012. Reference is made to the specific agreements and instruments for more details.

(millions, unless otherwise indicated)

Instrument	*Financial Covenant*(1)	*Requirement/Restriction*	*Calculation at Dec. 31, 2012*
Tampa Electric Company			
Credit facility(2)	Debt/capital	Cannot exceed 65%	46.0%
Accounts receivable credit facility(2)	Debt/capital	Cannot exceed 65%	46.0%
6.25% senior notes	Debt/capital	Cannot exceed 60%	46.0%
	Limit on liens(3)	Cannot exceed $700	$0 liens outstanding
Insurance agreement relating to certain pollution bonds	Limit on liens(3)	Cannot exceed $469 (7.5% of net assets)	$0 liens outstanding
TECO Energy/TECO Finance			
Credit facility(2)	Debt/capital	Cannot exceed 65%	56.1%
TECO Finance 6.75% notes	Restrictions on secured debt(4)	(5)	(5)

(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) These restrictions would not apply to first mortgage bonds of Tampa Electric if any were outstanding.
(5) The indentures for these notes contain restrictions which limit secured debt of TECO Energy if secured by Principal Property or Capital Stock or indebtedness of directly held subsidiaries (with exceptions as defined in the indentures) without equally and ratably securing these notes. At Dec. 31, 2012, neither TECO Energy nor TECO Finance had secured debt outstanding.

Credit Ratings of Senior Unsecured Debt at Dec. 31, 2012

	Standard & Poor's (S&P)	*Moody's*	*Fitch*
Tampa Electric Company	BBB+	A3	A-
TECO Energy/TECO Finance	BBB	Baa2	BBB

On May 4, 2012, Moody's upgraded the credit ratings of TEC, TECO Energy and TECO Finance to A3, Baa2 and Baa2, respectively, all with stable outlooks.

S&P, Moody's and Fitch describe credit ratings in the BBB or Baa category as representing adequate capacity for payment of financial obligations. The lowest investment grade credit ratings for S&P is BBB-, for Moody's is Baa3 and for Fitch is BBB-; thus all three credit rating agencies assign TECO Energy, TECO Finance and TEC'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 TEC's derivative instruments contain provisions that require TEC's debt to maintain investment grade credit ratings (see **Note 12** to the **TECO Energy Consolidated Financial Statements**). The credit ratings listed above are included in this report in order to provide information that may be relevant to these matters and because downgrades, if any, in credit ratings may affect our ability to borrow and may increase financing costs, which may decrease earnings (see the **Risk Factors** section). These credit ratings are not necessarily applicable to any particular security that we may offer and therefore should not be relied upon for making a decision to buy, sell or hold any of our securities.

Summary of Contractual Obligations

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

Contractual Cash Obligations at Dec. 31, 2012

	Payments Due by Period					
(millions)	**Total**	**2013**	**2014**	**2015**	**2016-2017**	**After 2017**
Long-term debt (1)						
Recourse	$2,975.5	$ —	$ 83.3	$274.5	$ 633.4	$1,984.3
Operating leases/rentals (2)	111.1	19.6	19.1	18.2	28.9	25.3
Net purchase obligations/commitments (3)	190.9	94.6	30.0	26.4	34.1	5.8
Interest payment obligations	1,773.2	160.3	157.7	146.0	251.0	1058.2
Pension plans (4)	175.8	15.1	30.2	39.2	91.3	—
Total contractual obligations	$5,226.5	$289.6	$320.3	$504.3	$1,038.7	$3,073.6

(1) Includes debt at TECO Finance and TEC (see **Note 7** to the **TECO Energy Consolidated Financial Statements** for a list of long-term debt and the respective due dates).

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

(3) Reflects those contractual obligations and commitments considered material to the respective operating companies, individually. At the end of 2012, these commitments include Tampa Electric's outstanding commitments for major projects and long-term capitalized maintenance agreements for its combustion turbines.

(4) 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, 2012

		Commitment Expiration					
(millions)		**Total(2)**	**2013**	**2014**	**2015**	**2016 - 2017**	**After 2017(1)**
Letters of credit		$ 1.5	$ 0.8	$—	$—	$—	$ 0.7
Guarantees	Fuel purchase/energy management (2)	105.3	—	10.0	—	—	95.3
	Other	10.2	—	4.8	—	—	5.4
Total contingent obligations		$117.0	$ 0.8	$14.8	$—	$—	$101.4

(1) These guarantees renew annually and are shown on the basis that they will continue to renew beyond 2017.

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

CAPITAL INVESTMENTS

Capital Investments

(millions)	Actual 2012	Forecast 2013	2014	2015-2017	2013-2017 Total
Tampa Electric[1]					
Transmission	$ 31	$ 30	$ 35	$ 70	$ 135
Distribution	103	105	115	325	545
Generation	153	165	170	395	730
New generation and transmission	5	50	210	345	605
Other	28	30	35	95	160
Other environmental	23	40	75	25	140
Tampa Electric total	343	420	640	1,255	2,315
Net cash effect of AFUDC, accruals and retentions[1]	19	—	—	—	—
Tampa Electric net	362	420	640	1,255	2,315
Peoples Gas	98	80	100	310	490
Unregulated companies	45	20	35	120	175
Total	$505	$520	$775	$1,685	$2,980

(1) Individual line items exclude AFUDC-debt and equity; however total AFUDC is a reconciling item in 2012.

TECO Energy's 2012 capital expenditures of $505 million included $362 million at Tampa Electric, including AFUDC debt and equity. Capital expenditures at PGS were $98 million in 2012. Tampa Electric's capital expenditures in 2012 included $17 million for a reclaimed water pipeline to serve the Polk Power Station, approximately $40 million to improve the Big Bend Station solid fuel handling and flue gas desulphurization systems reliability, for equipment and facilities to meet modest customer growth, generating equipment maintenance, and environmental compliance. Capital expenditures for PGS were approximately $70 million for system expansion, including $25 million for a 30-mile pipeline extension to convert a paperboard manufacturer from petroleum to natural gas; approximately $3 million to acquire a block propane system and extend the natural gas pipeline system to serve major commercial customers in a resort area of Southwest Florida; and approximately $27 million for maintenance of the existing system. TECO Coal's capital expenditures included $30 million primarily for normal mining equipment replacement, and $5 million for permitting and surface site preparation for new metallurgical coal reserves announced in November 2011.

TECO Energy estimates capital spending for ongoing operations to be $520 million for 2013 and approximately $2.5 billion during the 2014 – 2017 period. As described below, this forecast includes $610 million for Tampa Electric's next increment of generation expansion, including transmission system improvements to support the increased plant output.

For 2013, Tampa Electric expects to spend $420 million. For the transmission and distribution systems, Tampa Electric expects to spend $135 million in 2013, including approximately $95 million for normal transmission and distribution system expansion and reliability, and approximately $40 million for transmission and distribution system storm hardening. Capital expenditures for the existing generating facilities of $165 million include approximately $20 million for repair and refurbishments of CTs under long-term agreements with equipment manufacturers, approximately $70 million for generating unit outages in 2013 and advance purchases for 2014 unit outages, $35 million for a reclaimed water pipeline to eliminate ground water usage at the Polk Power Station, approximately $15 million to improve the Big Bend Station solid fuel handling system reliability and $25 million for other improvements and refurbishments to generating units. In addition, Tampa Electric expects to spend $40 million for environmental compliance programs and improvements to environmental control equipment in 2013.

In the 2014 – 2017 period, Tampa Electric expects to spend approximately $320 million annually to support normal system growth and reliability, environmental compliance and improvements to computer systems to serve customers better. 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 CTs under long-term agreements with equipment manufacturers, average annual expenditures of more than $130 million to support generating unit availability and reliability, combustion by-product handling and storage, and coal-handling equipment replacement and refurbishment; average annual expenditures of more than $30 million for general infrastructure and facilities; average annual expenditures of approximately $30 million for transmission and distribution system storm hardening; approximately $115 million annually for transmission and distribution system capacity improvements to meet expected customer growth and reliability.

Tampa Electric's capital spending forecast includes amounts related to the conversion of the Polk Units 2 – 5 from peaking service to combined cycle with a January 2017 in-service date. The determination of need was approved by the FPSC in December 2012, and the final site certification approval by the FDEP is expected in the fourth quarter of 2013. The capital expenditures for the conversion and the related transmission system improvements to support the additional generating capacity are included in the

"New generation and transmission" line in the **Capital Investments** table above. The peak capital spending is forecast at $490 million for both the transmission system and plant conversions in the 2014 and 2015 periods. Following the expiration of the PPA with the Hardee Power Station in Central Florida, Tampa Electric will take advantage of generating capacity available in Florida at attractive rates and purchase power to meet its 2013 through 2016 energy demand and sales growth.

Capital expenditures for PGS are expected to be about $80 million in 2013 and $410 million during the 2014 – 2017 period. Included in these amounts is an average of approximately $50 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing renewal, replacement and system safety, including approximately $12 million annually for the replacement of cast iron and bare steel pipe, which is recovered through a rider clause approved by the FPSC in 2012 (see the **Regulation** section).

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

The unregulated companies expect to invest $20 million in 2013, primarily for or normal mining equipment replacement at TECO Coal. The unregulated companies expect to spend $155 million during the 2014 – 2017 period, primarily 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.

The capital expenditure forecast beyond 2013 does not include additional investment to develop the metallurgical coal reserves that TECO Coal announced in November 2011. Based on current market conditions, TECO Coal does not expect to make additional investments to develop these reserves until metallurgical coal prices improve to a level to support that investment. These reserves constitute an additional estimated 65 million tons of metallurgical coal on properties it controls that are classified as proven and probable reserves, and an additional estimated 9 million tons of metallurgical coal classified as resource (non-reserve coal deposits) due to seam thickness. There is an additional 14 million tons of coal also classified as resource pending further geologic studies (see **Item 2 Properties** in the **TECO Coal** section). In 2012, TECO Coal obtained the necessary permit amendments from the State of Kentucky related to surface development activities to access these reserves, and further evaluated detailed mining plans and potential markets for this high-volatile metallurgical coal. TECO Coal completed utility relocation and preliminary surface work to bring these reserves into production. Based on current estimates, subject to development of final plans, the cost to develop these reserves is estimated to be approximately $160 million.

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

The forecast of capital expenditures shown above is based on our current estimates and assumptions for normal maintenance capital at the operating companies; capital expenditures to support normal system reliability and growth at Tampa Electric and PGS; the replacement of cast iron and bare steel pipe at PGS; the programs for transmission and distribution system storm hardening and transmission system reliability requirements; generating capacity expansion at Tampa Electric and incremental investments above normal maintenance capital to expand the PGS system and production capacity at TECO Coal. Actual capital expenditures could vary materially from these estimates due to changes in costs for materials or labor or changes in plans (see the **Risk Factors** section).

Financing Activity

Our year-end 2012 consolidated capital structure was 56.5% debt and 43.5% common equity. The debt-to-total-capital ratio has improved significantly over the past six years, primarily due to the repayment of more than $1.0 billion of parent and parent guaranteed debt, consisting of $779 million in 2007, a net $189 million in 2010, $64 million in 2011, and $9 million in 2012, as well as the increase in retained earnings. At Dec. 31, 2012, TEC's year-end capital structure was 46.0% debt and 54.0% common equity.

In 2012, we raised $3.9 million of equity primarily through the exercise of stock options.

On Dec. 5, 2012, TECO Energy redeemed $8.8 million of 6.75% Notes due May 15, 2015. The redemption price was equal to $1,141.86 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, $0.8 million of premiums 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, 2012.

On Oct. 1, 2012, Tampa Electric redeemed $147.1 million of Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Project), Series 2002 due Oct. 1, 2013 and Oct. 1, 2023 (2002 Bonds) at a redemption price equal to 100% of the principal amount of the 2002 Bonds to be redeemed, plus accrued and unpaid interest to Oct. 1, 2012. Before the optional redemption, the $60.7 million of 2002 Bonds due Oct. 1, 2013 bore interest at 5.10% and the $86.4 million of 2002 Bonds due Oct. 1, 2023 bore interest at 5.50%.

On Sept. 28, 2012, TEC completed an offering of $250 million aggregate principal amount of 2.60% Notes due 2022. The 2.60% Notes were sold at 99.878% of par. The offering resulted in net proceeds to TEC (after deducting underwriting discounts and commissions and estimated offering expenses) of approximately $247.7 million. Net proceeds were used to repay the 2002 Bonds. The remaining net proceeds were used to repay short-term debt and for general corporate purposes. At any time prior to June 15, 2022, TEC may redeem all or any part of the 2.60% Notes at its option at a redemption price equal to the greater of (i) 100% of the principal amount of 2.60% Notes to be redeemed or (ii) the sum of the present values of the remaining payments of principal and interest on the 2.60% Notes to be redeemed, discounted to the redemption date on a semiannual basis at an applicable treasury rate, plus 15 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. At any time on or after June 15, 2022, TEC may at its option redeem the 2.60% Notes, in whole or in part, at 100% of the principal amount of the 2.60% Notes being redeemed plus accrued and unpaid interest thereon to but excluding the date of redemption.

On June 5, 2012, TEC completed an offering of $300 million aggregate principal amount of 4.10% Notes due 2042. The 4.10% Notes were sold at 99.724% of par. The offering resulted in net proceeds to TEC (after deducting underwriting discounts, commissions, and estimated offering expenses and before settlement of interest rate swaps) of approximately $296.2 million. Net proceeds were used to repay maturing long-term debt, to repay short-term debt and for general corporate purposes. At any time prior to Dec. 15, 2041, TEC may redeem all or any part of the 4.10% Notes at its option and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of 4.10% Notes to be redeemed or (ii) the sum of the present value of the remaining payments of principal and interest on the 4.10% Notes to be redeemed, discounted at an applicable treasury rate, plus 25 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. At any time on or after Dec. 15, 2041, TEC may at its option redeem the 4.10% Notes, in whole or in part, at 100% of the principal amount of the 4.10% Notes being redeemed plus accrued and unpaid interest thereon to but excluding the date of redemption.

On March 15, 2012, Tampa Electric purchased in lieu of redemption $86 million Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2006 (the $86 million Bonds). On March 19, 2008, the HCIDA remarketed the $86 million Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. The $86 million Bonds bore interest at a term rate of 5.00% per annum from March 19, 2008 to March 15, 2012. Tampa Electric is responsible for payment of the interest and principal associated with the $86 million Bonds. Regularly scheduled principal and interest payments, when due, are insured by Ambac Assurance Corporation.

On March 1, 2011, Tampa Electric purchased in lieu of redemption $75 million Polk County Industrial Development Authority Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2010 (the PCIDA Bonds). On Nov. 23, 2010, the PCIDA issued the PCIDA Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. Proceeds of the PCIDA Bonds were used to redeem $75 million PCIDA Solid Waste Disposal Facility Revenue Refunding Bonds, Series 2007, which previously were in auction rate mode and were held since March 26, 2008. The PCIDA Bonds bore interest at the initial term rate of 1.50% per annum from Nov. 23, 2010 to March 1, 2011.

On March 26, 2008, Tampa Electric purchased in lieu of redemption $20 million Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007C. The $181 million in bonds purchased in lieu of redemption were held by the trustee at the direction of TEC as of Dec. 31, 2012 (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.

On Sept. 27, 2012, TECO Energy announced that its international power subsidiary, TECO Guatemala, entered into agreements to sell all of the equity interests in the Alborada and San José power stations and related facilities and operations in Guatemala. The sale of the Alborada power station closed on Sept. 27, 2012 for a selling price of $12.5 million. The sale of the San José power station and related facilities and operations in Guatemala closed on Dec. 19, 2012 for a price of $215.0 million. TECO Energy utilized $25.3 million of the proceeds to repay the San José Power Station project debt at closing (see **Discontinued Operations** section and **Note 19** to the **TECO Energy Consolidated Financial Statements**).

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Deferred Income Taxes

We use the asset and liability method in the measurement of deferred income taxes. Under the asset and liability method, we estimate our current tax exposure and assess the temporary differences resulting from differing treatment of items, such as depreciation for financial statement and tax purposes. These differences are reported as deferred taxes measured at current rates in the consolidated financial statements. Management reviews all reasonably available current and historical information, including forward-looking information, to determine if it is more likely than not that some or the entire 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, 2012, we had a net deferred income tax liability of $214.6 million, attributable primarily to property-related items, AMT credit carry forwards and operating loss carry forwards. Based primarily on historical income levels and the company's expectations for steady future earnings growth, management has determined that the deferred tax assets associated with operating losses and AMT credit carryforwards recorded at Dec. 31, 2012, 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.

The FASB has guidance that prescribes a recognition threshold and measurement attribute for financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return, and also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. See further discussion of uncertainty in income taxes and other tax items in **Note 4** to the **TECO Energy Consolidated Financial Statements**.

Employee Postretirement Benefits

TECO Energy sponsors a defined benefit pension plan (pension plan) that covers substantially all employees. In addition, the company has 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 the company within certain guidelines and with the help of external consultants. The company considers market conditions, including changes in investment returns and interest rates, in making these assumptions.

The company believes 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, AOCI and results of operations; and 2) changes in assumptions could change the annual pension funding requirements, having a significant impact on the company's 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 the company's portfolio, with provision for active management and expenses paid from the trust. The discount rate assumption used to determine the 2012 benefit expense and Dec. 31, 2012, benefit obligation was based on a cash flow matching technique developed by the company's outside actuaries and a review of current economic conditions. This technique constructs hypothetical bond portfolios using high-quality (AA or better by S&P) corporate bonds available from the Barclays Capital database at the measurement dates to meet the plan's year-by-year projected cash flows. The technique calculates all possible bond portfolios that produce adequate cash flows to pay the yearly benefits and then selects the portfolio with the highest yield and uses that yield as the recommended discount rate. The compensation increase assumption was based on the same underlying expectation of long-term inflation together with assumptions regarding real growth in wages and company-specific merit and promotion increases. Holding all other assumptions constant, a 1% decrease in the assumed rate of return on plan assets would have increased 2012 pretax pension cost by approximately $5.0 million. Likewise, a 1% decrease in the discount rate assumption would have increased 2012 pretax pension cost approximately $3.2 million. For 2013, a 1% decrease in the discount rate assumption would result in an approximately $3.1 million pretax increase in the expected pension cost. A 1% decrease in the assumed rate of return on plan assets would result in an approximately $5.2 million pretax increase in expected pension cost.

Unrecognized actuarial gains and losses for the pension plan are being recognized over a period of approximately 12 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. The company's policy is to fund the plan based on the required contribution determined by its actuaries within the guidelines set by the ERISA, as amended.

In July 2012, the president signed into law the MAP-21. MAP-21 provides funding relief for pension plan sponsors by stabilizing discount rates used in calculating the required minimum pension contributions and increasing PBGC premium rates to be paid by plan sponsors. The company expects the required minimum pension contributions to be lower than the levels previously projected; however, the company plans on funding at levels above the required minimum pension contributions under MAP-21.

In addition, the company currently provides 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 and recorded a corresponding charge and a regulatory tax asset in the first quarter of 2010 and recorded a true-up of the deferred tax asset in the fourth quarter of 2012. The company decided to implement an EGWP for its post-65 retiree prescription drug plan effective Jan. 1, 2013. The EGWP is a private Medicare Part D plan designed to provide benefits that are at least equivalent to Medicare Part D. The EGWP reduces net periodic benefit cost by taking advantage of rebate and discount enhancements provided under the Health Care Reform Acts. As a result, the company will no longer receive Medicare Part D subsidy payments beginning with the 2013 plan year.

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 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. Since 2009 the company has determined 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, the company considers its actual health care cost experience, future benefit structures, industry trends, and advice from its outside actuaries. The company assumes that the relative increase in health care cost will trend downward over the next several years, reflecting assumed increases in efficiency in the health care system and industry wide cost-containment initiatives.

The assumed health care cost trend rate for medical costs was 7.75% in 2012 and decreases to 4.50% in 2025 and thereafter. A 1% increase in the health care trend rates would have produced a $0.5 million pretax increase in the aggregate service and interest cost for 2012, and an $8.0 million increase in the accumulated postretirement benefit obligation as of Dec. 31, 2012.

The actuarial assumptions used in determining the company's 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 the company believes that the assumptions used are appropriate, differences in actual experience or changes in assumptions may materially affect the company's 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.

See Note 20 to the TECO Energy Consolidated Financial Statements for discussion of the company's treatment of impairment of long-lived assets for the year ended Dec. 31, 2012.

Regulatory Accounting

Tampa Electric's and PGS's retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by the FERC. As a result, the regulated utilities qualify for the application of accounting guidance for certain types of regulation. This guidance recognizes that the actions of a regulator can provide reasonable assurance of the existence of an asset or liability. Regulatory assets and liabilities arise as a result of a difference between GAAP and the accounting principles imposed by the regulatory authorities. Regulatory assets generally represent incurred costs that have been deferred, as their future recovery in customer rates is probable. Regulatory liabilities generally represent obligations to make refunds to customers from previous collections for costs that are not likely to be incurred.

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

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

RECENTLY ISSUED ACCOUNTING STANDARDS

Comprehensive Income

In February 2013, the FASB issued guidance requiring improved disclosures of significant reclassifications out of AOCI and their corresponding effect on net income. The guidance is effective for interim and annual reporting periods beginning on or after Dec. 15, 2012. The company will adopt this guidance as required. It will have no effect on the company's results of operations, financial position or cash flows.

Offsetting Assets and Liabilities

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

INFLATION

The effects of general inflation on our results have not been significant for the past several years. The annual average rate of inflation, as measured by the CPI-U, as reported by the U.S. Department of Labor, was 1.7%, 3.0%, and 1.5% in 2012, 2011 and 2010, respectively. The current economic outlook and the pace of economic recovery have caused the outlook for inflation in 2013 to be higher than in 2012, but lower than in 2011, when oil and commodity prices rose sharply. Reports published by the Federal Reserve Bank of Chicago and others indicate that CPI-U is expected to be about 2.0% in 2013.

ENVIRONMENTAL COMPLIANCE

Environmental Matters

All of our companies have significant environmental considerations. Tampa Electric operates stationary sources with air emissions regulated by the Clean Air Act, and material Clean Water Act implications and impacts by federal and state legislative initiatives. Tampa Electric Company, through its Tampa Electric and PGS divisions, is a PRP for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites. Additionally, TECO Coal has considerations concerning wastewater management and environmental permitting.

Air Quality Control

Emission Reductions

Tampa Electric has undertaken major steps to dramatically reduce its air emissions through a series of voluntary actions, including technology selection (e.g., 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 BACT emissions controls; implementation of additional controls to accomplish early reductions of certain emissions; and enhanced controls and monitoring systems for certain pollutants.

Tampa Electric, through voluntary negotiations in 1999 with the EPA, the U.S. Department of Justice and the FDEP, signed a Consent Decree, as settlement of federal and state litigation to dramatically decrease emissions from its power plants. Tampa Electric has notified the parties that all obligations of the Consent Decree have been fulfilled and intends to file documents with the court to terminate the Consent Decree in 2013.

The emission reduction requirements of these agreements resulted in the repowering of the coal-fired Gannon Power Station to natural gas, which was renamed as the H. L. Culbreath Bayside Power Station (Bayside Power Station), enhanced availability of flue-gas desulfurization systems (scrubbers) at Big Bend Station to help reduce SO_2 and installation of SCR systems for NO_x reduction on Big Bend Units 1 through 4. Cost recovery for the SCRs began for each unit in the year that the unit entered service through the ECRC (see the **Regulation** section).

As a result of the actions taken under the consent decree, emissions of all pollutant types have been significantly reduced. Since 1998, Tampa Electric has reduced annual SO_2, NO_x and PM emissions from its facilities by 164,000 tons (94%), 63,000 tons (91%) and 4,500 tons (87%), respectively.

Reductions in mercury emissions also have occurred due to the repowering of the Gannon Power Station to the Bayside Power Station. At the Bayside Power Station, where mercury levels have decreased 99% below 1998 levels, there are virtually zero mercury emissions. Additional mercury reductions have been achieved from the installation of the SCRs at Big Bend Power Station, which have led to a system wide reduction of mercury emissions of more than 90% from 1998 levels.

Clean Air Interstate Rule/Cross State Air Pollution Rule

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

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

On Dec. 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit granted the motion to stay the implementation of CSAPR in all aspects, which had been scheduled to take effect Jan. 1, 2012, and ordered the reinstatement of CAIR pending the outcome of the litigation. On Aug. 21, 2012, the court vacated the rule entirely and remanded it back to the EPA while leaving the CAIR in place. In January 2013, the Court of Appeals rejected the request for a rehearing. The EPA can appeal this decision to the U.S. Supreme Court.

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

The EPA published proposed rules under National Emission Standards for HAPS on May 3, 2011, pursuant to a court order. These rules are expected to reduce mercury, acid gases, organics, and certain non-mercury metals emissions and require MACT.

The final Utility MACT rules, now called Mercury Air Toxics Standards (MATS), were published in December 2011 with implementation called for in early 2015 with extensions to early 2016 or 2017 under certain specific criteria. A potential outcome of the Utility MACT rule is the retirement of smaller, older coal-fired power plants that do not already have emissions controls installed.

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

The retirement of coal-fired generating units as a result of the implementation of this rule could reduce demand for sales at TECO Coal.

Carbon Reductions and GHG

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 systemwide 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 scheduled to be in service in January 2017 (see the **Tampa Electric** and **Capital Expenditures** sections). Tampa Electric estimates that the repowering to natural gas and the shut-down of the Gannon Station coal-fired units resulted in an annual decrease in CO_2 emissions of approximately 4.8 million tons below 1998 levels. During this same time frame, the numbers of retail customers and retail energy sales have risen by approximately 25%.

Tampa Electric's power plants currently emit approximately 16 million tons of CO_2 per year. Assuming a projected long-term average annual load growth of more than 1.0%, Tampa Electric could emit approximately 17 million tons of CO_2 (an increase of approximately 6%) by 2020 if natural gas-fired peaking and combined-cycle generation additions are used to meet customer demand.

In 2010, the EPA issued its Final Rule on the mandatory reporting of GHGs, requiring facilities that emit 25,000 metric tons or more of CO_2, or its equivalent, per year to begin collecting GHG data under a new reporting system on Jan. 1, 2010, with the first annual report due Sept. 28, 2011. Tampa Electric complied with the mandatory reporting requirement, in large part through the methods and procedures already utilized. The rule also requires natural gas distribution, underground coal mining facilities, and electric transmission and distribution companies, including PGS, TECO Coal and Tampa Electric, that emit 25,000 metric tons or more of CO_2, or its equivalent, per year to begin collecting GHG data under a new reporting system on Jan. 1, 2011, with the first annual report due Sept. 28, 2012. Tampa Electric complied with the reporting requirement.

In December 2009, the EPA published the final Endangerment Finding in the Federal Register. Although the finding was technically made in the context of GHG emissions from new motor vehicles and did not, in itself, impose any requirements on industry or other entities, the finding triggered GHG regulation of a variety of sources under the Clean Air Act (CAA). Related to utility sources, the EPA's "tailoring rule," which addresses the GHG emission threshold triggers that would require permitting review of new and/or major modifications to existing stationary sources of GHG emissions, became effective Jan. 2, 2011. While this rule does not have an immediate impact on Tampa Electric's ongoing operations, GHG permitting is in progress for Tampa Electric's next baseload unit, the Polk Unit 2 – 5 conversion to combined cycle.

Tampa Electric expects that the costs to comply with new environmental regulations would be eligible for recovery through the ECRC. If approved as prudent, the costs required to comply with CO_2 emissions reductions would be reflected in customers' bills. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the ECRC, Tampa Electric could seek to recover those costs through a base-rate proceeding, but cannot predict whether the FPSC would grant such recovery. Although Tampa Electric's current coal-based generation has declined to about 60% of its output in 2012 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 Coal, there are not yet federal limits on GHG emissions, and it is unclear if future requirements for GHG emissions reductions would directly impact it as a carbon-based fuel provider or the end users of its products. In either case, these requirements could make the use of coal more expensive or less desirable, which could impact TECO Coal's margins and profitability.

Renewable Energy

Renewables are a component of Tampa Electric's environmental portfolio. Tampa Electric's renewable energy program offers to sell renewable energy as an option to customers and utilizes energy generated in the state from renewable sources (e.g. biomass and solar). To date, more than 55 million kWh of renewable energy have been produced by Tampa Electric and other renewable energy generating sources within Florida to support participating customer requirements.

Tampa Electric has installed over 100 kW of solar panels to generate electricity from the sun at six community sites including two schools, Tampa Electric's Manatee Viewing Center, the Museum of Science and Industry, Tampa's Lowry Park Zoo and the Florida Aquarium. Tampa Electric's largest solar panel array, rated at 43.8 kW, is located at Tampa Electric's Manatee Viewing Center in Apollo Beach, Florida. The electricity the photovoltaic array generates, which flows to Tampa Electric's grid, could offset the carbon dioxide emissions produced by seven typical-size cars in a year. The company continues to evaluate opportunities for additional solar panel installations.

Florida does not currently have an RPS or similar programs that require Florida's IOU's to have renewable generation as part of their generation portfolio. Florida's IOUs are currently limited in their ability to pursue renewable energy projects by laws that prohibit them from buying power from qualifying facility (QFs) and renewable power at prices above avoided cost – federal and state – absent a renewable mandate. If a mandatory RPS were implemented at the state or federal level, it could add to Tampa Electric's costs and adversely affect its operating results.

Water Supply and Quality

The EPA's final Clean Water Act Section 316(b) rule took effect in 2004. The rule established aquatic protection requirements for existing facilities that withdraw 50 million gallons or more of water per day from rivers, streams, lakes, reservoirs, estuaries, oceans, or other U.S. waters for cooling purposes. Tampa Electric uses water from Tampa Bay at its Bayside and Big Bend facilities as cooling water. Both plants use mesh screens to reduce the adverse impacts to aquatic organisms, and Big Bend units 3 and 4 use proprietary fine-mesh screens, BACT, to further reduce impacts to aquatic organisms. Subsequent to promulgation of the rule, a number of states, environmental groups and others sought judicial review of the rule. In 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule to the EPA for revisions. Among other things, the court rejected the EPA's use of "cost-benefit" analysis and suggested some ways to incorporate cost considerations. The Supreme Court agreed to review the Second Circuit's decision and heard arguments in December 2008. The EPA decided to rewrite the rule, and expects to propose a new rule in the summer of 2013. The full impact of the new regulations will depend on subsequent legal proceedings, the results of studies and analyses performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies.

On Dec. 6, 2010, the EPA published its final rule, setting numeric nutrient criteria for Florida's lakes and flowing waters. The rule, as published, is being challenged in the courts by numerous parties, including the state of Florida. The rule sets numeric limits for nitrogen and phosphorous in lakes and streams and for nitrate plus nitrite in springs. The EPA promulgated the rule pursuant to the terms of a consent decree approved by the court in Florida Wildlife Federation v. Jackson, 08-0324 (N.D. Fla.), in which environmentalists sued the EPA for allegedly violating a duty under the Federal Water Pollution Control Act (Clean Water Act or Act) to set the numeric criteria. In response to comments raising numerous implementation concerns, the EPA decided to delay the effective date of the criteria until 15 months after publication. The EPA announced that, in the interim, it would undertake a series of implementation steps in Florida, including an "education and outreach rollout," training meetings, and the development of guidance materials to coincide with the expected comment period on proposed site-specific alternative criteria. On Nov. 30, 2012, the EPA approved the FDEP rule in its entirety. The EPA proposed additional criteria in December 2012, including a re-proposal of streams criteria that were previously invalidated by the court. If the streams criteria is implemented as published, it would directly affect Polk Power Station's cooling reservoir discharge to surface water, requiring the station to reduce the amount of nutrients in the cooling reservoir water before discharge. However, the full effect of the EPA's numeric nutrient criteria will depend on the outcome of the various legal proceedings. The deadline for public comments to the re-proposed streams criteria was Feb. 1, 2013. Finalization of the streams criteria is scheduled for Aug. 31, 2013, with an effective date anticipated in November 2013. This schedule for implementation is also uncertain due to expected legal challenges.

After the completion of a study into wastewater discharges by the electric utility industry in 2009, the EPA announced its intent to revise the existing steam electric effluent limit guidelines (ELGs) that place technology-based limits on wastewater discharges. The rulemaking will focus on wastewater discharges from scrubbers, fly ash and bottom ash sluicing processes, leachate from ponds and landfills containing CCRs, IGCC processes, and flue gas mercury controls. The EPA is evaluating a suite of technology options which include treatment processes for wastewater discharges as well as the conversion to dry handling of fly ash and bottom ash to allow for zero discharge of transport water. Final impacts will vary depending on the mandated technology, the volume of wastewater to be treated and the pollutant limits. Tightened limits are anticipated for mercury, selenium, trace metals, and chlorides. New guidelines will likely add stricter limits to future NPDES permits in 2014-2019 (based on the 5-year permit cycle).

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 and the EPA have engaged in discussions regarding settlement of the matter. While an agreement has not been finalized and therefore the ultimate outcome of such matter remains uncertain, at this time, TECO Coal anticipates that the costs associated with resolving this matter will not be material.

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

Since 2008, the issuance of permits by the USACE under Section 404 of the Clean Water Act required for surface mining activities in the Central and Northern Appalachian mining regions has been challenged in the courts by various environmental groups. The challenges to permits by these groups have been appealed by the mining companies affected on a number of occasions, but very few permits have been issued over the past five years. In September 2009, the EPA established an enhanced review by the EPA under its memorandum of understanding with the USACE. TECO Coal had six permits on the list of permits subject to the enhanced review process at the time it was established, three of which have subsequently been withdrawn.

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

This guidance was challenged in the courts by a number of coal mining industry-related organizations, states and municipalities relating to the stringency of the standards as well as the focus on the coal industry and the Appalachian region in particular. In 2011, the United States District Court for the District of Columbia ruled that the EPA had exceeded the statutory authority conferred upon it by the Clean Water Act in implementing the coordinated review process with the USACE. In July 2012, the United States District Court for the District of Columbia ruled that the EPA had exceeded its statutory authority in establishing the water quality guidance discussed above in the manner in which it was done. Following the outcome of these court decisions, pending appeals by the EPA, few, if any, new permits have been issued by USACE.

Conservation

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

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

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric division, is a PRP for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2012, TEC has estimated its ultimate financial liability to be approximately $37.5 million (primarily related to PGS), and this amount has been reflected in the company's financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices. The amounts represent only the estimated portion of the cleanup costs attributable to TEC. The estimates to perform the work are based on actual estimates obtained from contractors or TEC'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 TEC and other PRPs is based on each party's relative ownership interest in or usage of a site. Accordingly, TEC's share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered credit-worthy.

Factors that could impact these estimates include the ability of other PRPs to pay their pro-rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. Under current regulation, these additional costs would be eligible for recovery through customer rates.

Coal Combustion Residuals Recycling and Disposal

The combustion of coal at two of Tampa Electric's power-generating facilities, the Big Bend and Polk Power stations, produces ash and other by-products, collectively known as CCRs. The CCRs produced at Big Bend include fly ash, FGD gypsum, boiler slag, bottom ash and economizer ash. The CCRs produced at the Polk Power Station include gasifier slag and sulfuric acid. Overall, over 97% of all CCRs produced at these facilities were marketed to customers for beneficial use in commercial and industrial products in 2012. The remaining 3% were either disposed onsite or shipped offsite to nearby industrial waste landfills in Central Florida.

In response to a coal ash pond failure in December 2008, the EPA proposed new regulations for the management and disposal of CCRs. These proposed rules include two potential designations of CCRs. One designation would categorize CCRs destined for disposal as hazardous wastes. This is the most significant for Tampa Electric, because hazardous waste landfills are currently prohibited in Florida by state law, so CCRs destined for disposal would have to be shipped out of state as hazardous waste at significantly increased costs. In addition, the hazardous designation could require improvements to Tampa Electric's current ash management practices and interim storage and handling facilities for CCRs inside its power stations, even though permanent onsite disposal would not be allowed. The other proposed rule would set minimum standards for the final disposal of CCRs under regulations similar to those in place for municipal non-hazardous solid waste. This proposal would not be as disruptive as the former, since it would allow for the continued operation of Tampa Electric's existing, lined ash ponds. However, this latter proposal would place additional management requirements on these existing disposal units, which would eventually reach the end of their useful life and need to be replaced. The EPA's current schedule would result in a final proposed rule in 2014, although expected litigation would likely delay the rule's effective date.

REGULATION

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

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

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

Tampa Electric is also subject to regulation by the FERC in various respects, including wholesale power sales, certain wholesale power purchases, transmission and ancillary services, and accounting practices.

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

Tampa Electric - Base Rates

Tampa Electric's rates and allowed ROE range of 10.25% to 12.25%, with a midpoint of 11.25%, were established in 2009, and are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, the FPSC or other interested parties.

Tampa Electric's base rates were established in March 2009, when the FPSC awarded $104 million higher revenue requirements effective in May 2009 that authorized an ROE mid-point of 11.25%, 54.0% equity in the capital structure, and 2009 13-month average rate base of $3.4 billion. In a series of subsequent decisions in 2009 and 2010 related to a calculation error and a step increase for five peaking combustion turbines and solid-fuel rail unloading facilities at the Big Bend Power Station that entered service before the end of 2009, base rates increased an additional $33.5 million.

As a result of increasing pressure on O&M expense, higher depreciation expense from required infrastructure added to serve customers, and an economic recovery that has been slower than expected compared to the assumptions in Tampa Electric's last base rate proceeding in 2009, on Feb. 4, 2013, Tampa Electric notified the FPSC that it is planning to file a new base rate proceeding in April for new rates effective in early 2014. The actual revenue requirement calculation is not final, but is estimated to be approximately $135 million.

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 2012, 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 2013. In November 2012, the FPSC approved Tampa Electric's requested rates. The rates include the projected cost for natural gas, oil and coal, including transportation, for 2012 and the net over-recovery of fuel, purchased power and capacity clause expenses, which were collected in 2012 and 2011. Rates approved for 2013 also reflected a two-tiered residential fuel factor structure with a lower factor for the first 1,000 kWh used each month. Due to increased reliance on natural gas to fuel its generating fleet and continued low natural gas prices, Tampa Electric's residential customer rate per 1,000 kWh decreased 4% from $106.90 in 2012 to $102.58 in 2013.

Transmission and Wholesale Rate Cases

In July 2010, Tampa Electric filed transmission rate and wholesale requirements cases with the FERC. The transmission rate case updates Tampa Electric's charges under its FERC-approved 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 addressed the rates and terms and conditions of Tampa Electric's existing wholesale customers.

The FERC approved Tampa Electric's proposed transmission rates as filed with the FERC, which became effective Sep. 14, 2010, subject to refund. The FERC also approved Tampa Electric's proposed wholesale requirements rates, as filed with the FERC, which became effective March 1, 2011, subject to refund.

Settlements were reached with the applicable customers in both cases in 2011, and these settlements were filed with the FERC in 2012. In July 2012, the FERC approved the uncontested settlement that Tampa Electric filed with its customers in its wholesale requirements rate case earlier in 2012. The approved settlement took effect in August 2012 and Tampa Electric made refunds to its wholesale requirements' customers the appropriate amounts given the terms of the settlement. The FERC also approved for the uncontested transmission rate case settlement. The wholesale requirements and transmission rate case settlements' rates did not have a material impact on Tampa Electric's results.

Utility Competition – Electric

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

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

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

FPSC rules promote cost-competitiveness in the building of new steam generating capacity by requiring IOUs, such as Tampa Electric, to issue RFPs prior to filing a petition for Determination of Need for construction of a power plant with a steam cycle greater than 75 MW. The rules, which allow independent power producers and others to bid to supply the new generating capacity, provide a mechanism for expedited dispute resolution, allow bidders to submit new bids whenever the IOU revises its cost estimates for its self-build option, require IOUs to disclose the methodology and criteria to be used to evaluate the bids, and provide more stringent standards for the IOUs to recover cost overruns in the event the self-build option is deemed the most cost-effective.

PGS Rates

PGS's rates and allowed ROE range of 9.75% to 11.75%, with a midpoint of 10.75%, and an equity ratio of 54.7%, 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 or other interested parties.

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 pretax total provision related to the 2010 earnings above the top of the range. In December 2010, PGS and the Office of Public Counsel entered into a stipulation and settlement agreement requesting FPSC approval that $3.0 million pretax 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 2012, the FPSC approved rates under PGS's PGA for 2013 for the recovery of the costs of natural gas purchased for its distribution customers.

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

In 2012, the FPSC approved a Cast Iron/Bare Steel Pipe Replacement Rider to recover the cost of accelerating the replacement of cast iron and bare steel distribution lines in the PGS system. Utilities nationwide have been encouraged by the U.S. Department of Transportation to replace this older infrastructure as a safety measure. The FPSC approved PGS' request to accelerate the replacement program of approximately 5%, or 500 miles, of the PGS system at a cost of approximately $80 million over a 10-year period.

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 19,500 transportation-only customers as of Dec. 31, 2012, out of approximately 35,000 eligible customers.

Competition is most prevalent in the large commercial and industrial markets. In recent years, these classes of customers have been targeted by companies seeking to sell gas directly by transporting gas through other facilities and thereby by-passing PGS facilities, or by other utilities seeking to expand existing distribution systems to new customers previously unserved by another utility. In response to this competition, PGS has developed various programs, including the provision of transportation services at discounted rates.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Risk Management Infrastructure

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

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

The RAC also 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 that arise from the ownership of physical assets and contractual obligations, such as debt instruments and firm customer sales contracts. The primary objectives of the risk management organization, the Middle Office, are to quantify, measure, and monitor the market risk exposures arising from the activities of the Front Office and the ownership of physical assets. In addition, the Middle Office is responsible for enforcing the limits and procedures established under the approved risk management policies. Based on the policies approved by the company's board of directors and the procedures established by the RAC, from time to time, our companies enter into futures, forwards, swaps and option contracts to limit the exposure to items such as:

- Price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric and PGS;
- Interest rate fluctuations on debt at TECO Energy and its affiliates; and
- Price fluctuations for physical purchases of fuel at TECO Coal.

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

Derivatives and Hedge Accounting

Accounting standards for derivative instruments and hedging activities require us to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as components of OCI or net income, depending on the designation of those instruments.

Designation of a hedging relationship requires management to make assumptions about the future probability of the timing and amount of the hedged transaction and the future effectiveness of the derivative instrument in offsetting the change in fair value or cash flows of the hedged item or transaction. The determination of fair value is dependent upon certain assumptions and judgments, as described more fully below (see **Note 16** to the **TECO Energy Consolidated Financial Statements**).

Fair Value Measurements

The company has adopted the accounting standards for fair value measurement. These standards define fair value, establish a framework for measuring fair value under GAAP, and expand disclosures about financial assets and liabilities carried at fair value. The majority of the company's financial assets and liabilities are in the form of natural gas, heating oil or interest rate derivatives classified as cash flow hedges. This adoption did not have a material impact on our results of operations, liquidity or capital.

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

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

The valuation methods we used to determine fair value are described in **Note 17** 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 TEC is the counterparty, TEC's debt, to maintain an investment-grade credit rating from any or all of the major credit rating agencies. If our debt ratings, including TEC'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, 2012, was $14.9 million, of which $14.1 million were TEC positions and $0.8 million were TECO Energy positions. If the credit-risk-related contingent features underlying these agreements were triggered as of Dec. 31, 2012, we could have been required to post collateral or settle existing positions with counterparties totaling $14.9 million. In the unlikely event that this situation would occur, we believe that we maintain adequate lines of credit to meet these obligations.

Interest Rate Risk

We are exposed to changes in interest rates primarily as a result of our borrowing activities. We may enter into futures, swaps and option contracts, in accordance with the approved risk management policies and procedures, to moderate this exposure to interest rate changes and achieve a desired level of fixed and variable rate debt. As of Dec. 31, 2012 and 2011, 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, 2012, and 2.4% at Dec. 31, 2011 (see the **Financing Activity** section and **Notes 6 and 7** to the **TECO Energy Consolidated Financial Statements**). The above sensitivities assume no changes to our financial structure and could be affected by changes in our credit ratings, changes in general economic conditions or other external factors (see the **Risk Factors** section).

Commodity Risk

We and our affiliates face varying degrees of exposure to commodity risks including coal, natural gas, fuel oil and other energy commodity prices. Any changes in prices could affect the prices these businesses charge, their operating costs and the competitive position of their products and services. Management uses different risk measurement and monitoring tools based on the degree of exposure of each operating company to commodity risks.

Regulated Utilities

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

Currently, Tampa Electric's and PGS's commodity price risks are largely mitigated by the fact that increases in the price of fuel and purchased power are recovered through FPSC-approved cost-recovery clauses, with no anticipated effect on earnings. However, increasing fuel cost-recovery has the potential to affect total energy usage and the relative attractiveness of electricity and natural gas to consumers. To moderate the impacts of fuel price changes on customers, both Tampa Electric and PGS manage commodity price risk by entering into long-term fuel supply agreements, prudently operating plant facilities to optimize cost, and entering into derivative transactions designated as cash flow hedges of anticipated purchases of wholesale natural gas. At Dec. 31, 2012 and 2011, 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).

TECO Coal

TECO Coal is subject to significant commodity risk. TECO Coal does 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, 2012, TECO Coal had derivative instruments in place to reduce the price variability for its anticipated 2013 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.

Changes in Fair Value of Derivatives (millions)

The following tables summarize the changes in and the fair value balances of derivative assets (liabilities) for the 12-month period ended Dec. 31, 2012:

Net fair value of derivatives as of Dec. 31, 2011	$(66.1)
Additions and net changes in unrealized fair value of derivatives	(24.6)
Changes in valuation techniques and assumptions	0.0
Realized net settlement of derivatives	75.7
Net fair value of derivatives as of Dec. 31, 2012	$(15.0)

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

Total derivative net liabilities as of Dec. 31, 2011	$(66.1)
Change in fair value of net derivative assets:	
Recorded as regulatory assets and liabilities or other comprehensive income	(24.6)
Recorded in earnings	0.0
Realized at settlement of derivatives	75.7
Net option premium payments	0.0
Net purchase (sale) of existing contracts	0.0
Net fair value of derivatives as of Dec. 31, 2012	$(15.0)

Maturity and Source of Energy Derivative Contracts Net Assets (Liabilities) at Dec. 31, 2012

(millions)	*Current*	*Non-current*	*Total Fair Value*
Source of fair value			
Actively quoted prices	$ 0.0	$ 0.0	$ 0.0
Other external price sources [(1)]	(14.7)	(0.3)	(15.0)
Model prices [(2)]	0.0	0.0	0.0
Total	$(14.7)	$(0.3)	$(15.0)

(1) Reflects over-the-counter natural gas or diesel fuel swaps for which the primary pricing inputs in determining fair value are NYMEX quoted closing prices of exchange-traded instruments.
(2) Model prices are used for determining the fair value of energy derivatives where price quotes are infrequent or the market is illiquid. Significant inputs to the models are derived from market-observable data and actual historical experience.

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

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

TECO ENERGY, INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

Report of Independent Registered Certified Public Accounting Firm

To the Board of Directors and Shareholders of 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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 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, 2012, 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.

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 26, 2013

TECO ENERGY, INC.

Consolidated Balance Sheets

Assets

(millions)	*Dec. 31, 2012*	*Dec. 31, 2011*
Current assets		
Cash and cash equivalents	$ 200.5	$ 44.0
Restricted cash	0.0	8.7
Receivables, less allowance for uncollectibles of $4.2 and $2.6 at Dec. 31, 2012 and 2011, respectively	282.7	327.7
Inventories, at average cost		
Fuel	123.6	136.8
Materials and supplies	82.1	87.3
Derivative assets	0.0	0.9
Regulatory assets	70.3	87.3
Deferred income taxes	63.3	72.7
Prepayments and other current assets	33.9	31.9
Income tax receivables	0.4	0.6
Total current assets	856.8	797.9
Property, plant and equipment		
Utility plant in service		
Electric	6,655.8	6,731.7
Gas	1,228.3	1,169.9
Construction work in progress	336.1	247.4
Other property	443.8	432.3
Property, plant and equipment, at original costs	8,664.0	8,581.3
Accumulated depreciation	(2,673.9)	(2,613.5)
Total property, plant and equipment, net	5,990.1	5,967.8
Other assets		
Regulatory assets	382.6	364.5
Derivative assets	0.2	0.0
Goodwill	0.0	55.4
Deferred charges and other assets	126.8	136.6
Total other assets	509.6	556.5
Total assets	$ 7,356.5	$ 7,322.2

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

TECO ENERGY, INC.

Consolidated Balance Sheets—continued

Liabilities and Capital

(millions)	*Dec. 31, 2012*	*Dec. 31, 2011*
Current liabilities		
Long-term debt due within one year		
Recourse	$0.0	$374.9
Non-recourse	0.0	11.2
Accounts payable	232.8	252.3
Customer deposits	162.9	159.5
Regulatory liabilities	106.7	86.2
Derivative liabilities	14.6	58.4
Interest accrued	33.2	39.3
Taxes accrued	32.1	20.7
Other	19.9	17.2
Total current liabilities	602.2	1,019.7
Other liabilities		
Deferred income taxes	277.9	150.8
Investment tax credits	9.7	10.0
Regulatory liabilities	651.9	619.4
Derivative liabilities	0.6	8.6
Deferred credits and other liabilities	549.7	559.2
Long-term debt, less amount due within one year		
Recourse	2,972.7	2,665.0
Non-recourse	0.0	22.3
Total other liabilities	4,462.5	4,035.3
Commitments and Contingencies (see **Note 12**)		
Capital		
Common equity (400.0 million shares authorized; par value $1; 216.6 million and 215.8 million shares outstanding at Dec. 31, 2012 and 2011, respectively)	216.6	215.8
Additional paid in capital	1,564.5	1,553.4
Retained earnings	541.7	519.4
Accumulated other comprehensive loss	(31.0)	(22.0)
TECO Energy capital	2,291.8	2,266.6
Noncontrolling interest	0.0	0.6
Total capital	2,291.8	2,267.2
Total liabilities and capital	$7,356.5	$7,322.2

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

TECO ENERGY, INC.

Consolidated Statements of Income

(millions, except per share amounts) *For the years ended Dec. 31,*	*2012*	*2011*	*2010*
Revenues			
Regulated electric and gas (includes franchise fees and gross receipts taxes of $111.5 in 2012, $109.3 in 2011 and $116.1 in 2010)	$2,377.4	$2,469.8	$2,672.6
Unregulated	619.2	740.1	690.9
Total revenues	2,996.6	3,209.9	3,363.5
Expenses			
Regulated operations & maintenance			
Fuel	694.7	731.4	748.9
Purchased power	105.3	125.9	179.6
Cost of natural gas sold	155.7	210.4	284.5
Other	462.5	436.9	492.9
Operation & maintenance other expense			
Mining related costs	461.1	574.1	541.4
Other	7.9	7.1	5.1
Depreciation and amortization	330.6	317.2	305.6
Taxes, other than income	222.3	223.7	224.5
Total expenses	2,440.1	2,626.7	2,782.5
Income from operations	556.5	583.2	581.0
Other income (expense)			
Allowance for other funds used during construction	2.6	1.0	1.9
Other income	9.4	6.7	11.2
Loss on debt extinguishment	(1.2)	0.0	(54.6)
Income from equity investments	0.0	0.0	(2.8)
Total other income	10.8	7.7	(44.3)
Interest charges			
Interest expense	185.0	198.0	216.6
Allowance for borrowed funds used during construction	(1.5)	(0.6)	(1.1)
Total interest charges	183.5	197.4	215.5
Income from continuing operations before provision for income taxes	383.8	393.5	321.2
Provision for income taxes	137.8	142.7	109.6
Net income from continuing operations	246.0	250.8	211.6
Discontinued operations			
Income (loss) from discontinued operations	(10.6)	33.3	88.4
Provision for income taxes	22.4	11.2	60.4
Income (loss) from discontinued operations, net	(33.0)	22.1	28.0
Less: Income from discontinued operations attributable to noncontrolling interest	0.3	0.3	0.6
Income (loss) from discontinued operations attributable to TECO Energy, net	(33.3)	21.8	27.4
Net income attributable to TECO Energy	$212.7	$272.6	$239.0
Average common shares outstanding — Basic	214.3	213.6	212.6
— Diluted	215.0	215.1	214.8
Earnings per share from continuing operations—Basic	$ 1.14	$ 1.17	$ 0.99
—Diluted	$ 1.14	$ 1.17	$ 0.98
Earnings per share from discontinued operations attributable to TECO Energy — Basic	$ (0.15)	$ 0.10	$ 0.13
— Diluted	$ (0.15)	$ 0.10	$ 0.13
Earnings per share attributable to TECO Energy — Basic	$ 0.99	$ 1.27	$ 1.12
— Diluted	$ 0.99	$ 1.27	$ 1.11
Dividends paid per common share outstanding	$ 0.880	$ 0.850	$ 0.815

Amounts shown include reclassifications to reflect discontinued operations as discussed in **Note 19**.

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

TECO ENERGY, INC.

Consolidated Statements of Comprehensive Income

(millions) *For the years ended Dec. 31,*	*2012*	*2011*	*2010*
Net income attributable to TECO Energy	$212.7	$272.6	$239.0
Other comprehensive income (loss), net of tax			
Net unrealized (losses) gains on cash flow hedges	(4.2)	(0.8)	3.1
Amortization of unrecognized benefit costs and other	(4.8)	(4.6)	3.7
Recognized benefit costs due to settlement	0.0	0.6	1.0
Other comprehensive (loss) income, net of tax	(9.0)	(4.8)	7.8
Comprehensive income attributable to TECO Energy	$203.7	$267.8	$246.8

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,*	*2012*	*2011*	*2010*
Cash flows from operating activities			
Net income attributable to TECO Energy	$ 212.7	$ 272.6	$ 239.0
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	337.7	324.6	312.9
Deferred income taxes	136.9	146.0	162.9
Investment tax credits	(0.3)	(0.4)	(0.4)
Allowance for other funds used during construction	(2.6)	(1.0)	(1.9)
Non-cash stock compensation	12.0	9.1	7.4
Loss (gain) on sales of business/assets, pretax	35.7	(0.5)	(39.6)
Non-cash debt extinguishment/exchange, pretax	0.0	0.0	2.2
Equity in earnings of unconsolidated affiliates, net of cash distributions on earnings	0.0	0.0	6.9
Deferred recovery clauses	(8.9)	(9.0)	55.0
Receivables, less allowance for uncollectibles	37.7	5.7	(43.9)
Inventories	(2.4)	23.5	(41.4)
Prepayments and other current assets	(2.0)	(2.8)	(1.3)
Taxes accrued	12.1	(5.7)	4.9
Interest accrued	(5.9)	0.3	(6.0)
Accounts payable	(1.3)	(42.6)	51.0
Other	(4.7)	34.3	(43.3)
Cash flows from operating activities	756.7	754.1	664.4
Cash flows from investing activities			
Capital expenditures	(505.1)	(454.1)	(489.7)
Allowance for other funds used during construction	2.6	1.0	1.9
Net proceeds from sales of business/assets	194.4	3.5	183.1
Net cash increase from consolidation	0.0	0.0	24.1
Restricted cash	8.9	0.0	0.0
Contributions to unconsolidated affiliates	0.0	0.0	(1.7)
Other investing activities	0.0	14.4	(14.0)
Cash flows used in investing activities	(299.2)	(435.2)	(296.3)
Cash flows from financing activities			
Dividends	(190.4)	(183.2)	(174.7)
Proceeds from the sale of common stock	3.9	7.0	7.8
Proceeds from long-term debt issuance	538.1	0.0	661.2
Repayment of long-term debt/Purchase in lieu of redemption	(650.4)	(153.6)	(797.2)
Dividend to noncontrolling interest	(0.3)	(0.6)	(0.7)
Restricted cash	(1.9)	0.0	0.0
Net decrease in short-term debt	0.0	(12.0)	(43.0)
Cash flows used in financing activities	(301.0)	(342.4)	(346.6)
Net increase (decrease) in cash and cash equivalents	156.5	(23.5)	21.5
Cash and cash equivalents at beginning of the year	44.0	67.5	46.0
Cash and cash equivalents at end of the year	$ 200.5	$ 44.0	$ 67.5
Supplemental disclosure of cash flow information			
Cash paid during the year for:			
Interest	$ 188.4	$ 191.6	$ 219.0
Income taxes paid	$ 7.2	$ 9.4	$ 5.5

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, 2009	213.9	$213.9	$1,530.8	$365.7	($25.0)	$0.0	$2,085.4
Net income				239.0		0.6	239.6
Other comprehensive income, after tax					7.8		7.8
Common stock issued	1.0	1.0	2.6				3.6
Cash dividends declared				(174.7)			(174.7)
Stock compensation expense			7.4				7.4
Noncontrolling - dividends						(0.7)	(0.7)
Noncontrolling - effect of TCAE consolidation						1.0	1.0
Tax benefits - stock options			1.2				1.2
Balance, Dec. 31, 2010	214.9	$214.9	$1,542.0	$430.0	($17.2)	$0.9	$2,170.6
Net income				272.6		0.3	272.9
Other comprehensive loss, after tax					(4.8)		(4.8)
Common stock issued	0.9	0.9	0.1				1.0
Cash dividends declared				(183.2)			(183.2)
Stock compensation expense			9.1				9.1
Noncontrolling - dividends						(0.6)	(0.6)
Tax benefits - stock options			2.2				2.2
Balance, Dec. 31, 2011	215.8	$215.8	$1,553.4	$519.4	($22.0)	$0.6	$2,267.2
Net income				212.7		0.3	213.0
Other comprehensive loss, after tax					(9.0)		(9.0)
Common stock issued	0.8	0.8	(3.7)				(2.9)
Cash dividends declared				(190.4)			(190.4)
Stock compensation expense			12.0				12.0
Noncontrolling - dividends						(0.3)	(0.3)
Tax benefits - stock options			2.8				2.8
Noncontrolling - sale of business						(0.6)	(0.6)
Balance, Dec. 31, 2012	216.6	$216.6	$1,564.5	$541.7	($31.0)	$0.0	$2,291.8

(1) TECO Energy had a maximum of 400.0 million shares of $1 par value common stock authorized as of Dec. 31, 2012, 2011, 2010 and 2009.

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 and Basis of Presentation

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

For entities that are determined to meet the definition of a 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 18**).

Use of Estimates

The use of estimates is inherent in the preparation of financial statements in accordance with GAAP. Actual results could differ from these estimates.

Cash Equivalents

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

Restricted Cash

Restricted cash at Dec. 31, 2011 of $8.7 million related to cash held in escrow for the 2003 sale of HPP. The cash was released from escrow in 2012 upon maturity of debt financing that was held by the purchaser of HPP. There was no restricted cash at Dec. 31, 2012.

Planned Major Maintenance

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

Tampa Electric and PGS expense major maintenance costs as incurred. For Tampa Electric and PGS, concurrent with a planned major maintenance outage, the cost of adding or replacing retirement units-of-property is capitalized in conformity with FPSC and FERC regulations.

Depreciation

Tampa Electric and PGS compute depreciation and amortization for electric generation, electric transmission and distribution, gas distribution and general plant facilities using the following methods:

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

The provision for total regulated utility plant in service, expressed as a percentage of the original cost of depreciable property, was 3.8% for 2012 and 3.6% for 2011 and 2010.

Other TECO Energy subsidiaries compute depreciation primarily by the straight-line method at annual rates that amortize the original cost, less net salvage value, of depreciable property over the following estimated useful lives:

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

Total depreciation expense for the years ended Dec. 31, 2012, 2011 and 2010 was $309.3 million, $306.6 million and 297.1 million, respectively.

Allowance for Funds Used During Construction

AFUDC is a non-cash credit to income with a corresponding charge to utility plant which represents the cost of borrowed funds and a reasonable return on other funds used for construction. The FPSC approved 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 2012. Total AFUDC for the years ended Dec. 31, 2012, 2011 and 2010 was $4.1 million, $1.6 million and $3.0 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, 2012*	*Dec. 31, 2011*
Tampa Electric Company	$89.1	$97.9
TECO Coal	34.5	26.5
TECO Guatemala	0.0	12.4
Total	$123.6	$136.8

Regulatory Assets and Liabilities

Tampa Electric and PGS are subject to accounting guidance for the effects of certain types of regulation (see **Note 3** for additional details).

Deferred Income Taxes

TECO Energy uses the asset and liability method to determine deferred income taxes. Under the asset and liability method, the company estimates its current tax exposure and assesses the temporary differences resulting from differences in the treatment of items, such as depreciation, for financial statement and tax purposes. These differences are reported as deferred taxes, measured at current rates, in the consolidated financial statements. Management reviews all reasonably available current and historical information, including forward-looking information, to determine if it is more likely than not that some or all of the deferred tax assets will not be realized. If management determines that it is likely that some or all of deferred tax assets will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized (see **Note 4** for additional details).

Investment Tax Credits

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

Revenue Recognition

TECO Energy recognizes revenues consistent with accounting standards for revenue recognition. Except as discussed below, TECO Energy and its subsidiaries recognize revenues on a gross basis when earned for the physical delivery of products or services and the risks and rewards of ownership have transferred to the buyer.

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

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

Revenues for energy marketing operations at TECO Energy Source 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, 2012, 2011 and 2010 were $13.8 million, $2.5 million and $8.7 million, respectively.

Shipping and Handling

TECO Coal includes the costs to ship product to customers in "Operation & maintenance other expense - Mining related costs" on the Consolidated Statements of Income which for the years ended Dec. 31, 2012, 2011 and 2010 were $9.0 million, $16.6 million and $27.3 million, respectively.

Cash Flows Related to Derivatives and Hedging Activities

The company classifies cash inflows and outflows related to derivative and hedging instruments in the appropriate cash flow sections associated with the item being hedged. In the case of diesel fuel swaps, which are used to mitigate the fluctuations in the price of diesel fuel, the cash inflows and outflows are included in the operating section. For natural gas and ongoing interest rate swaps, the cash inflows and outflows are included in the operating section. For interest rate swaps that settle coincident with the debt issuance, the cash inflows and outflows are treated as premiums or discounts and included in the financing section of the Consolidated 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, 2012 and 2011, unbilled revenues of $49.0 million and $50.2 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 $105.3 million, $125.9 million and $179.6 million, for the years ended Dec. 31, 2012, 2011 and 2010, respectively. The prudently incurred purchased power costs at Tampa Electric have historically been recovered through an FPSC-approved cost recovery clause.

Accounting for Excise Taxes, Franchise Fees and Gross Receipts

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

The regulated utilities are allowed to recover certain costs on a dollar-per-dollar basis incurred from customers through prices approved by the FPSC. The amounts included in customers' bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Statements of Income. Franchise fees and gross receipt taxes payable by the regulated utilities are included as an expense on the Consolidated Statements of Income in "Taxes, other than income". These amounts totaled $111.5 million, $109.3 million and $116.1 million for the years ended Dec. 31, 2012, 2011 and 2010, 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.

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.

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 Dec. 31, 2012 and 2011 ranged from 2.60% to 4.00% and 3.75% to 4.75%, respectively.

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.

Receivables and Allowance for Uncollectible Accounts

Receivables consist of services billed to residential, commercial, industrial and other customers. An allowance for uncollectible accounts is established based on Tampa Electric's and PGS's collection experience. Circumstances that could affect Tampa Electric's and PGS's estimates of uncollectible receivables include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible. TECO Coal's receivables consist of coal sales billed to industrial and utility customers. An allowance for uncollectible accounts is established based on TECO Coal's collection experience. Circumstances that could affect TECO Coal's estimates of uncollectable receivables include customer credit issues and general economic conditions. Accounts are written off once they are determined to be uncollectible.

Reclassifications

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

2. New Accounting Pronouncements

Comprehensive Income

In February 2013, the FASB issued guidance requiring improved disclosures of significant reclassifications out of AOCI and their corresponding effect on net income. The guidance is effective for interim and annual reporting periods beginning on or after Dec. 15, 2012. The company will adopt this guidance as required. It will have no effect on the company's results of operations, financial position or cash flows.

Offsetting Assets and Liabilities

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

3. Regulatory

Tampa Electric's and PGS's businesses are regulated by the FPSC. Tampa Electric also is subject to regulation by the FERC under the PUHCA 2005. However, pursuant to a waiver granted in accordance with the FERC's regulations, TECO Energy is not subject to certain accounting, record-keeping and reporting requirements prescribed by the FERC's regulations under the PUHCA 2005. The operations of PGS are regulated by the FPSC separately from the operations 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.

Base Rates

Tampa Electric's 2012 results reflect base rates established in March 2009, when the FPSC awarded $104 million higher revenue requirements effective in May 2009 that authorized an ROE mid-point of 11.25%, 54.0% equity in the capital structure, and 2009 13-month average rate base of $3.4 billion. In a series of subsequent decisions in 2009 and 2010, related to a calculation error and a step increase for combustion turbines and rail unloading facilities that entered service before the end of 2009, base rates increased an additional $33.5 million.

As a result of increasing pressure on operations and maintenance expense, higher depreciation expense from required infrastructure added to serve customers, and an economic recovery that has been slower than expected compared to the assumptions in Tampa Electric's last base rate proceeding in 2009, on Feb. 4, 2013, Tampa Electric notified the FPSC that it is planning to file a new base rate proceeding in April for new rates effective in early 2014. The actual revenue requirement calculation is not final, but is estimated to be approximately $135 million.

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

In July 2012, the FERC approved the uncontested settlement that Tampa Electric filed with its customers in its wholesale requirements rate case earlier this year. The approved settlement took effect in August and Tampa Electric refunded its wholesale requirements' customers the appropriate amounts under the terms of the settlement. On Oct. 5, 2012, Tampa Electric received FERC approval for its uncontested transmission rate case settlement, which was filed with FERC earlier that year. The wholesale requirements and transmission rate case settlements' rates will not have a material impact on Tampa Electric's results.

Storm Damage Cost Recovery

Tampa Electric accrues $8.0 million annually to a FERC-authorized and FPSC-approved self-insured storm damage reserve. This reserve was created after Florida's IOUs were unable to obtain transmission and distribution insurance coverage due to destructive acts of nature. Tampa Electric's storm reserve was $50.4 million and $43.6 million as of Dec. 31, 2012 and 2011, respectively.

Stipulation with the Office of Public Counsel - PGS

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

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

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

Regulatory Assets and Liabilities

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

Tampa Electric and PGS apply the accounting standards for regulated operations. Areas of applicability include: 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, 2012 and 2011 are presented in the following table:

Regulatory Assets and Liabilities

(millions)	*Dec. 31, 2012*	*Dec. 31, 2011*
Regulatory assets:		
Regulatory tax asset (1)	$ 67.2	$ 63.6
Other:		
Cost-recovery clauses	42.9	73.3
Postretirement benefit asset	276.1	252.4
Deferred bond refinancing costs (2)	9.2	11.1
Environmental remediation	46.9	30.5
Competitive rate adjustment	4.1	3.5
Other	6.5	17.4
Total other regulatory assets	385.7	388.2
Total regulatory assets	452.9	451.8
Less: Current portion	70.3	87.3
Long-term regulatory assets	$382.6	$364.5
Regulatory liabilities:		
Regulatory tax liability (1)	$ 14.6	$ 16.0
Other:		
Cost-recovery clauses	73.9	61.4
Transmission and delivery storm reserve	50.4	43.6
Deferred gain on property sales (3)	3.4	5.0
Provision for stipulation and other	1.0	0.8
Accumulated reserve - cost of removal	615.3	578.8
Total other regulatory liabilities	744.0	689.6
Total regulatory liabilities	758.6	705.6
Less: Current portion	106.7	86.2
Long-term regulatory liabilities	$651.9	$619.4

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

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

Regulatory assets

(millions)	*Dec. 31, 2012*	*Dec. 31, 2011*
Clause recoverable (1)	$ 47.0	$ 76.8
Components of rate base (2)	279.1	264.9
Regulatory tax assets (3)	67.2	63.6
Capital structure and other (3)	59.6	46.5
Total	$452.9	$451.8

(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 Taxes

In 2012, 2011 and 2010, TECO Energy recorded net tax provisions of $160.2 million, $153.9 million and $170.0 million, respectively. A majority of this provision is non-cash. TECO Energy has net operating losses that are being utilized to reduce its taxable income. As such, cash taxes paid for income taxes as required for the alternative minimum tax, state income taxes, foreign income taxes and prior year audits in 2012, 2011 and 2010 were $7.2 million, $9.4 million and $5.5 million, respectively.

Income tax expense consists of the following:

Income Tax Expense (Benefit)

(millions) *For the year ended Dec. 31,*	*2012*	*2011*	*2010*
Continuing Operations			
Current income taxes			
Federal	$ 15.7	$ 0.0	$ 5.7
State	1.1	0.9	(5.2)
Deferred income taxes			
Federal	102.9	124.0	93.9
State	18.4	18.2	15.6
Amortization of investment tax credits	(0.3)	(0.4)	(0.4)
Income tax expense from continuing operations	$137.8	$142.7	$109.6
Discontinued Operations			
Current income taxes			
Federal	$ 0.0	$ 0.0	$ 0.0
Foreign	6.8	7.4	7.0
State	0.0	0.0	0.0
Deferred income taxes			
Federal	14.9	4.4	53.5
Foreign	0.0	(0.3)	0.0
State	0.7	(0.3)	(0.1)
Income tax expense from discontinued operations	22.4	11.2	60.4
Total income tax expense	$160.2	$153.9	$170.0

Total current income tax expense for the years ended Dec. 31, 2012, 2011 and 2010 was reduced by $13.6 million, $32.1 million and $78.4 million, respectively, to reflect the benefits of operating loss carryforwards.

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

Effective Income Tax Rate

(millions) *For the year ended Dec. 31,*	*2012*	*2011*	*2010*
Income tax expense at the federal statutory rate of 35%	$134.3	$137.7	$112.4
Increase (decrease) due to			
State income tax, net of federal income tax	12.7	12.4	6.8
Equity portion of AFUDC	(0.9)	(0.4)	(0.7)
Valuation allowance	1.1	0.0	1.9
Depletion	(8.5)	(9.1)	(9.1)
Other	(0.9)	2.1	(1.7)
Total income tax expense from continuing operations	$137.8	$142.7	$109.6
Income tax expense as a percent of income from continuing operations, before income taxes	35.9%	36.3%	34.1%

For the three years presented, the overall effective tax rate on continuing operations was higher than the 35% U.S. federal statutory rate primarily due to state income taxes offset by depletion.

As discussed in **Note 1**, TECO Energy uses the asset and liability method to determine deferred income taxes. Based primarily on the reversal of deferred income tax liabilities and future earnings of the company's utility operations, management has determined that the net deferred tax assets recorded at Dec. 31, 2012 will be realized in future periods.

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

Deferred Income Taxes

(millions) *As of Dec. 31,*	*2012*	*2011*
Deferred tax liabilities [1]		
Property related	$1,023.3	$ 884.2
Deferred fuel	11.3	3.9
Pension	43.0	38.4
Total deferred tax liabilities	1,077.6	926.5
Deferred tax assets [1]		
Alternative minimum tax credit carryforward	211.8	196.1
Loss and credit carryforwards	473.2	503.4
Other postretirement benefits	68.0	69.5
Other	113.0	89.1
Total deferred tax assets	866.0	858.1
Valuation allowance	(3.0)	(9.7)
Total deferred tax assets, net of valuation allowance	863.0	848.4
Total deferred tax liability, net	214.6	78.1
Less: Current portion of deferred tax asset	(63.3)	(72.7)
Long-term portion of deferred tax liability, net	$ 277.9	$ 150.8

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

At Dec. 31, 2012, the company had cumulative unused federal and state (Florida) NOLs of $1,298.8 million and $326.8 million, respectively, expiring at various times between 2025 and 2028. In addition, the company has unused general business credits of $3.9 million expiring between 2026 and 2031. Due to the sale of the company's remaining Guatemalan operations, unused foreign tax credits of $38.5 million have been reclassed to net operating loss. During 2012, the company's available alternative minimum tax credit carryforward for tax purposes increased from $196.1 million to $211.8 million, reflecting the future AMT payable for the amendment of prior years' federal income tax returns to claim a deduction for foreign tax paid. The alternative minimum tax credit 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. At Dec. 31, 2011, valuation allowances had been established for state capital loss carryforwards net of federal tax, and foreign tax credits. During 2012, the valuation allowance decreased by $6.7 million. As a result of the company's intent to amend prior year federal income tax returns, the company reclassified $7.8 million of the foreign tax credit valuation allowance to net operating loss. The company increased the state capital loss valuation allowance by $1.1 million. The company has state capital loss carryforward deferred tax assets of $3.0 million for which a full valuation allowance has been established due to the uncertainty of recognizing the benefit from these losses before they expire in 2013.

The company accounts for uncertain tax positions in accordance with FASB guidance. This guidance addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under the guidance, the company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. The guidance also provides standards on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures.

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

Unrecognized Tax Benefits

(millions)	*2012*	*2011*
Balance at Jan. 1,	$ 4.1	$4.1
Decreases due to tax positions related to prior years	0.0	0.0
Decreases due to settlements with taxing authorities	0.0	0.0
Decreases due to expiration of statute of limitations	0.0	0.0
Dispositions	(1.2)	0.0
Balance at Dec. 31,	$ 2.9	$4.1

The company recognizes interest and penalties associated with uncertain tax positions in "Operation other expense – Other" in the Consolidated Statements of Income. In 2012, 2011 and 2010, the company recognized $0.3 million, $0.2 million and $(1.1) million, respectively, of pretax charges (benefits) for interest only. Additionally, the company had $0.9 million of interest accrued at Dec. 31, 2012. No amounts have been recorded for penalties. As a result of the sale of TCAE, interest and penalties recorded on TCAE's books for an uncertain tax position have been removed from the company's unrecognized tax benefits, (see **Note 19).**

The company believes that it is reasonably possible that the remaining unrecognized tax benefits may be recognized by the end of 2013 as a result of a lapse of the statute of limitations, which would affect the annual effective tax rate.

The company's U.S. subsidiaries join in the filing of a U.S. federal consolidated income tax return. The IRS concluded its examination of the company's 2011 consolidated federal income tax return during 2012. The U.S. federal statute of limitations remains open for the year 2009 and forward. The federal income tax return for calendar year 2012 is part of the IRS's Compliance Assurance Program. As a result, the IRS audit of such return is expected to be completed in 2013. U.S. state jurisdictions have statutes of limitations generally ranging from three to four 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 jurisdictions include 2009 and forward. The company does not expect the settlement of audit examinations to significantly change the total amount of unrecognized tax benefits within the next 12 months.

5. Employee Postretirement Benefits

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 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 PBGC if they sponsor defined benefit plans, amend plan documents and provide additional plan disclosures in regulatory filings and to plan participants.

WRERA was signed into law on Dec. 23, 2008. WRERA grants plan sponsors relief from certain funding requirements and benefits restrictions, and also provides some technical corrections to the Pension Protection Act. There are two primary provisions that impact funding results for TECO Energy. First, for plans funded less than 100%, required shortfall contributions will be based on a percentage of the funding target until 2012, rather than the funding target of 100%. Second, one of the technical corrections, referred to as asset smoothing, allows the use of asset averaging subject to certain limitations in the determination of funding requirements. TECO Energy utilizes asset smoothing in determining funding requirements.

In July 2012, the President signed into law the MAP-21. MAP-21 provides funding relief for pension plan sponsors by stabilizing discount rates used in calculating the required minimum pension contributions and increasing PBGC premium rates to be paid by plan sponsors. The company expects the required minimum pension contributions to be lower than the levels previously projected; however, the company plans on funding at levels above the required minimum pension contributions under MAP-21.

The qualified pension plan's actuarial value of assets, including credit balance, was 83.7% of the Pension Protection Act funded target as of Jan. 1, 2012 and is estimated at 94.4% of the Pension Protection Act funded target as of Jan. 1, 2013 due to the funding relief provided under MAP-21.

Amounts disclosed for pension benefits also include the unfunded obligations for the 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.

MMA added prescription drug coverage to Medicare, with a 28% tax-free subsidy to encourage employers to retain their prescription drug programs for retirees, along with other key provisions. TECO Energy's current retiree medical program for those eligible for Medicare (generally over age 65) includes coverage for prescription drugs. The company has determined that prescription drug benefits available to certain Medicare-eligible participants under its defined-dollar-benefit postretirement health care plan are at least "actuarially equivalent" to the standard drug benefits that are offered under Medicare Part D.

The FASB issued accounting guidance and disclosure requirements related to the MMA. The guidance requires (a) that the effects of the federal subsidy be considered an actuarial gain and recognized in the same manner as other actuarial gains and losses and (b) certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits.

In March 2010, the Patient Protection and Affordability Care Act and a companion bill, the Health Care and Education Reconciliation Act, collectively referred to as the Health Care Reform Acts, were signed into law. Among other things, both acts reduce the tax benefits available to an employer that receives the Medicare Part D subsidy, resulting in a write-off of any associated deferred tax asset. As a result, TECO Energy reduced its deferred tax asset in 2010 and recorded a true up in 2012. TEC is amortizing the regulatory asset over the remaining average service life of 12 years. 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 PBO. TECO Energy will continue to monitor and assess the impact of the Health Care Reform Acts, including any clarifying regulations issued to address how the provisions are to be implemented, on its future results of operations, cash flows or financial position.

During 2012, the company received subsidy payments under Medicare Part D for its post-65 retiree prescription drug plan. In the second half of 2012, the company decided to implement an EGWP for its post-65 retiree prescription drug plan beginning Jan. 1, 2013. The EGWP is a private Medicare Part D plan designed to provide benefits that are at least equivalent to Medicare Part D. The EGWP reduces net periodic benefit cost by taking advantage of rebate and discount enhancements provided under the Health Care Reform Acts.

Obligations and Funded Status

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 PBO in the case of its defined benefit plan, or the 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 AOCI in the case of the unregulated companies, or the benefit liabilities and regulatory assets in the case of TEC. The results of operations are not impacted. Below is the detail of the change in benefit obligations, change in plan assets, unfunded liability and amounts recognized in the Consolidated Balance Sheets for 2012 and 2011.

Obligations and Funded Status *(millions)*	**Pension Benefits**		**Other Benefits**	
	2012	*2011*	*2012*	*2011*
Change in benefit obligation				
Net benefit obligation at prior measurement date (1)	$646.4	$610.3	$216.5	$222.0
Service cost	17.0	16.0	2.4	2.1
Interest cost	30.1	30.9	10.1	11.0
Plan participants' contributions	0.0	0.0	3.7	3.9
Plan amendments (4)	0.0	0.0	(5.2)	0.0
Actuarial loss (gain)	54.7	26.8	16.3	(7.4)
Gross benefits paid	(33.2)	(35.2)	(14.5)	(16.2)
Settlements	0.0	(2.4)	0.0	0.0
Federal subsidy on benefits paid	n/a	n/a	1.0	1.1
Net benefit obligation at measurement date (1)	$715.0	$646.4	$230.3	$216.5
Change in plan assets				
Fair value of plan assets at prior measurement date (1)	$467.6	$479.7	$0.0	$0.0
Actual return on plan assets (2)	57.9	21.8	0.0	0.0
Employer contributions	36.8	3.7	9.8	11.2
Plan participants' contributions	0.0	0.0	3.7	3.9
Settlements	0.0	(2.4)	0.0	0.0
Net benefits paid	(33.2)	(35.2)	(13.5)	(15.1)
Fair value of plan assets at measurement date (1)	$529.1	$467.6	$0.0	$0.0
Funded status				
Fair value of plan assets (3)	$529.1	$467.6	$0.0	$0.0
Less: Benefit obligation (PBO/APBO)	715.0	646.4	230.3	216.5
Funded status at measurement date (1)	(185.9)	(178.8)	(230.3)	(216.5)
Unrecognized net actuarial loss	270.3	251.7	42.7	25.5
Unrecognized prior service (benefit) cost	(0.7)	(1.2)	(1.0)	4.9
Unrecognized net transition obligation	0.0	0.0	0.0	1.9
Net amount required to be recognized at end of year	$83.7	$71.7	($188.6)	($184.2)
Amounts recognized in balance sheet				
Regulatory assets	$216.5	$199.7	$59.6	$52.7
Accrued benefit costs and other current liabilities	(5.3)	(2.9)	(13.1)	(13.2)
Deferred credits and other liabilities	(180.6)	(175.9)	(217.2)	(203.3)
Accumulated other comprehensive loss (income) (pretax)	53.1	50.8	(17.9)	(20.4)
Net amount recognized at end of year	$83.7	$71.7	($188.6)	($184.2)

(1) The measurement dates were Dec. 31, 2012 and Dec. 31, 2011.
(2) The actual return on plan assets differed from expectations due to general market conditions.
(3) The MRV of plan assets is used as the basis for calculating the 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.
(4) TECO Energy implemented an EGWP for its post-65 retiree prescription drug plan beginning Jan. 1, 2013.

Amounts recognized in accumulated other comprehensive income

	Pension Benefits		Other Benefits	
(millions)	*2012*	*2011*	*2012*	*2011*
Net actuarial loss (gain)	$52.7	$50.3	$(17.2)	$(20.0)
Prior service cost (credit)	0.4	0.5	(0.7)	(0.8)
Transition obligation	0.0	0.0	0.0	0.4
Amount recognized	$53.1	$50.8	$(17.9)	$(20.4)

The accumulated benefit obligation for all defined benefit pension plans was $664.7 million at Dec. 31, 2012 and $596.2 million at Dec. 31, 2011.

Assumptions used to determine benefit obligations at Dec. 31:

	Pension Benefits		Other Benefits	
	2012	*2011*	*2012*	*2011*
Discount rate	4.196%	4.797%	4.180%	4.744%
Rate of compensation increase - weighted	3.76%	3.83%	3.74%	3.82%
Healthcare cost trend rate				
Immediate rate	n/a	n/a	7.50%	7.75%
Ultimate rate	n/a	n/a	4.50%	4.50%
Year rate reaches ultimate	n/a	n/a	2025	2025

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

(millions)	1% Increase	1% Decrease
Effect on postretirement benefit obligation	$8.0	$(7.0)

The discount rate assumption used to determine the Dec. 31, 2012 benefit obligation was based on a cash flow matching technique developed by outside actuaries and a review of current economic conditions. This technique constructs hypothetical bond portfolios using high-quality (AA or better by S&P) corporate bonds available from the Barclays Capital database at the measurement date to meet the plan's year-by-year projected cash flows. The technique calculates all possible bond portfolios that produce adequate cash flows to pay the yearly benefits and then selects the portfolio with the highest yield and uses that yield as the recommended discount rate.

	Pension Benefits			Other Benefits		
Net periodic benefit cost (1) *(millions)*	*2012*	*2011*	*2010*	*2012*	*2011*	*2010*
Service cost	$ 17.0	$ 16.0	$ 16.2	$ 2.4	$ 2.1	$ 3.2
Interest cost	30.1	30.9	33.2	10.1	11.1	10.9
Expected return on plan assets	(37.1)	(38.4)	(36.3)	0.0	0.0	0.0
Amortization of:						
Actuarial loss	15.3	11.3	12.4	0.1	0.1	0.0
Prior service (benefit) cost	(0.4)	(0.4)	(0.4)	0.8	0.8	0.8
Transition obligation	0.0	0.0	0.0	1.8	2.3	2.3
Settlement loss	0.0	0.9	1.6	0.0	0.0	0.0
Net periodic benefit cost	$ 24.9	$ 20.3	$ 26.7	$15.2	$16.4	$17.2

(1) Benefit cost was measured for the years ended Dec. 31, 2012, 2011 and 2010.

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year are $4.4 million and $0.1 million, respectively. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year are $0.2 million and $0.3 million, respectively.

In addition, the estimated net loss and prior service credit for the defined benefit pension plans that will be amortized from regulatory assets into net periodic benefit cost over the next fiscal year are $15.7 million and $0.5 million, respectively. The estimated net loss 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 $0.9 million.

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

	Pension Benefits			Other Benefits		
	2012	*2011*	*2010*	*2012*	*2011*	*2010*
Discount rate	4.797%	5.300%	5.750%	4.744%	5.250%	5.600%
Expected long-term return on plan assets	7.50%	7.75%	8.25%	n/a	n/a	n/a
Rate of compensation increase	3.83%	3.88%	4.25%	3.82%	3.87%	4.25%
Healthcare cost trend rate						
Initial rate	n/a	n/a	n/a	7.75%	8.00%	8.00%
Ultimate rate	n/a	n/a	n/a	4.50%	4.50%	5.00%
Year rate reaches ultimate	n/a	n/a	n/a	2025	2023	2017

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

The expected return on assets assumption was based on historical returns, fixed income spreads and equity premiums consistent with the portfolio and asset allocation at the measurement date. 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, 2012, TECO Energy's pension plan experienced actual asset returns of approximately 12.6%.

The compensation increase assumption was based on the same underlying expectation of long-term inflation together with assumptions regarding real growth in wages and company-specific merit and promotion increases.

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

(millions)	1% Increase	1% Decrease
Effect on periodic cost	$0.5	$(0.4)

Pension Plan Assets

Pension plan assets (plan assets) are primarily invested in a mix of equity and fixed income securities. The company's investment objective is to obtain above-average returns while minimizing volatility of expected returns and funding requirements over the long term. The company's strategy is to hire proven managers and allocate assets to reflect a mix of investment styles, emphasize preservation of principal to minimize the impact of declining markets, and stay fully invested except for cash to meet benefit payment obligations and plan expenses.

		Actual Allocation, End of Year	
Asset Category	**Target Allocation**	*2012*	*2011*
Equity securities	55%	55%	50%
Fixed income securities	45%	45%	50%
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.

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. The following table sets forth by level within the fair value hierarchy the plan's investments as of Dec. 31, 2012 and Dec. 31, 2011.

Pension Plan Investments

(millions)	At Fair Value as of Dec. 31, 2012			
	Level 1	**Level 2**	**Level 3**	**Total**
Cash	$ 0.0	$ 0.0	$0.0	$ 0.0
Accounts receivable	64.8	0.0	0.0	64.8
Accounts payable	(72.8)	0.0	0.0	(72.8)
Cash equivalents				
Short term investment funds (STIFs)	9.0	0.0	0.0	9.0
Treasury bills (T bills)	0.0	0.6	0.0	0.6
Repurchase agreements	0.0	23.1	0.0	23.1
Certificates of deposit (CDs)	0.0	1.1	0.0	1.1
Commercial paper	0.0	0.9	0.0	0.9
Money markets	0.0	0.6	0.0	0.6
Total cash equivalents	9.0	26.3	0.0	35.3
Equity securities				
Common stocks	125.3	0.0	0.0	125.3
American depository receipts (ADRs)	6.2	0.0	0.0	6.2
Real estate investment trusts (REITs)	2.0	0.0	0.0	2.0
Mutual funds	153.4	0.0	0.0	153.4
Preferred stocks	0.0	0.8	0.0	0.8
Total equity securities	286.9	0.8	0.0	287.7
Fixed income securities				
Municipal bonds	0.0	8.0	0.0	8.0
Government bonds	0.0	53.0	0.0	53.0
Corporate bonds	0.0	19.8	0.0	19.8
Asset backed securities (ABS)	0.0	0.5	0.0	0.5
Mortgage backed securities (MBS)	0.0	17.6	0.0	17.6
Commercial mortgage backed securities (CMBS)	0.0	0.3	0.0	0.3
Collateralized mortgage obligations (CMOs)	0.0	2.5	0.0	2.5
Mutual fund	0.0	63.7	0.0	63.7
Commingled fund	0.0	49.4	0.0	49.4
Total fixed income securities	0.0	214.8	0.0	214.8
Derivatives				
Swaps	0.0	(0.5)	0.0	(0.5)
Purchased options (swaptions)	0.0	0.1	0.0	0.1
Written options (swaptions)	0.0	(0.4)	0.0	(0.4)
Total derivatives	0.0	(0.8)	0.0	(0.8)
Miscellaneous	0.0	0.1	0.0	0.1
Total	$287.9	$241.2	$0.0	$529.1

Pension Plan Investments

(millions)	At Fair Value as of Dec. 31, 2011			
	Level 1	Level 2	Level 3	Total
Cash	$ 4.4	$ 0.0	$0.0	$ 4.4
Accounts receivable	39.6	0.0	0.0	39.6
Accounts payable	(20.4)	0.0	0.0	(20.4)
Cash equivalents				
STIF	13.2	0.0	0.0	13.2
T bills	0.0	4.3	0.0	4.3
Money markets	0.0	0.3	0.0	0.3
Total cash equivalents	13.2	4.6	0.0	17.8
Equity securities				
Common stocks	114.2	0.0	0.0	114.2
ADRs	6.5	0.6	0.0	7.1
REITs	2.0	0.0	0.0	2.0
Mutual fund	88.3	0.0	0.0	88.3
Preferred stocks	0.0	1.0	0.0	1.0
Commingled fund	0.0	19.8	0.0	19.8
Total equity securities	211.0	21.4	0.0	232.4
Fixed income securities				
Municipal bonds	0.0	8.7	0.0	8.7
Government bonds	0.0	31.7	0.0	31.7
Corporate bonds	0.0	29.5	0.0	29.5
ABS	0.0	0.5	0.0	0.5
MBS	0.0	20.0	0.0	20.0
CMO	0.0	2.5	0.0	2.5
Mutual funds	0.0	101.1	0.0	101.1
Total fixed income securities	0.0	194.0	0.0	194.0
Derivatives				
Swaps	0.0	(0.3)	0.0	(0.3)
Written options	0.0	0.1	0.0	0.1
Total derivatives	0.0	(0.2)	0.0	(0.2)
Total	$247.8	$219.8	$0.0	$467.6

- The primary pricing inputs in determining the fair value of the Level 1 assets, excluding the mutual funds and STIF, are closing quoted prices in active markets.
- The STIFs are valued at NAV as determined by JP Morgan. 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 Level 1 mutual funds are the mutual funds' NAVs. The funds are registered open-ended mutual funds and the NAVs are validated with purchases and sales at NAV, making these Level 1 assets.
- The T bills, CDS, commercial paper, money markets, and repurchase agreements are valued at cost due to their short term nature. Additionally, repurchase agreements are backed by collateral.
- The primary pricing inputs in determining the fair value of the preferred stock is the price of comparable issues and dealer quotes.
- The primary pricing inputs in determining the fair value Level 2 municipal bonds are benchmark yields, historical spreads, sector curves, rating updates, and prepayment schedules. The primary pricing inputs in determining the fair value of government bonds are the U.S. Treasury curve, CPI, and broker quotes, if available. The primary pricing inputs in determining the fair value of corporate bonds are the U.S. Treasury curve, base spreads, YTM, and benchmark quotes. ABS and CMO are priced using TBA prices, Treasury curves, swap curves, cash flow information, and bids and offers as inputs. MBS are priced using TBA prices, Treasury curves, average lives, spreads, and cash flow information. Commercial MBS are priced using payment information and yields.

- The primary pricing input in determining the fair value of the Level 2 mutual fund is its NAV. However, since this mutual fund is an unregistered open-ended mutual fund, it is a Level 2 asset.
- The commingled fund at Dec. 31, 2012 is a private fund valued at NAV. The fund invests in long duration U.S. investment-grade fixed income assets and seeks to increase return through active management of interest rate and credit risks. The NAV is calculated based on bid prices of the underlying securities. The fund honors subscription activity on the first business day of the month and the first business day following the 15th calendar day of the month. Redemptions are honored on the 15th or last business day of the month, providing written notice is given at least ten business days prior to withdrawal date. The commingled fund at Dec. 31, 2011 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.
- Swaps are valued using benchmark yields, swap curves, and cash flow analyses.
- Options are valued using the bid-ask spread and the last price.

Other Postretirement Benefit Plan Assets

There are no assets associated with the company's other postretirement benefits plan.

Contributions

The company's policy is to fund the qualified pension plan at or above amounts determined by its actuaries to meet ERISA guidelines for minimum annual contributions and minimize PBGC premiums paid by the plan. The company made $35.5 million of contributions to this plan in 2012 and no cash contributions in 2011, which met the minimum funding requirements for both 2012 and 2011. These amounts are reflected in the "Other" line on the Consolidated Statements of Cash Flows. The company estimates its required minimum contribution in 2013 to be $15.1 million and required minimum annual contributions from 2014 to 2017 to range from $30.0 to $50.0 million per year based on current assumptions.

The SERP is funded annually to meet the benefit obligations. The company made contributions of $1.3 million and $3.7 million to this plan in 2012 and 2011, respectively. In 2013, the company expects to make a contribution of about $5.3 million to this plan.

The other postretirement benefits are funded annually to meet benefit obligations. The company's contribution toward health care coverage for most employees who retired after the age of 55 between Jan. 1, 1990 and Jun. 30, 2001 is limited to a defined dollar benefit based on service. The company's contribution toward pre-65 and post-65 health care coverage for most employees retiring on or after Jul. 1, 2001 is limited to a defined dollar benefit based on an age and service schedule. In 2013, the company expects to make a contribution of about $13.1 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
(including projected service and net of employee contributions)

(millions)	Pension Benefits	Other Postretirement Benefits
2013	$ 50.2	$13.1
2014	48.2	13.8
2015	50.4	14.3
2016	54.4	14.9
2017	54.7	15.3
2018-2022	296.3	80.5

Defined Contribution Plan

The company has a defined contribution savings plan covering substantially all employees of TECO Energy and its subsidiaries that enables participants to save a portion of their compensation up to the limits allowed by IRS guidelines. The company and its subsidiaries match up to 6% of the participant's payroll savings deductions. Effective April 2010, employer matching contributions were 60% of eligible participant contributions with additional incentive match of up to 40% of eligible participant contributions based on the achievement of certain operating company financial goals. Prior to this, the employer matching contributions were 50% of eligible participant contributions, with an additional incentive match of up to 50%. For the years ended Dec. 31, 2012, 2011 and 2010, the company and its subsidiaries recognized expense totaling $7.0 million, $9.0 million and $12.6 million, respectively, related to the matching contributions made to this plan.

6. Short-Term Debt

At Dec. 31, 2012 and Dec. 31, 2011, the following credit facilities and related borrowings existed:

Credit Facilities

	Dec. 31, 2012			*Dec. 31, 2011*		
(millions)	*Credit Facilities*	*Borrowings Outstanding (1)*	*Letters of Credit Outstanding*	*Credit Facilities*	*Borrowings Outstanding (1)*	*Letters of Credit Outstanding*
Tampa Electric Company:						
5-year facility (2)	$325.0	$0.0	$1.5	$325.0	$0.0	$0.7
1-year accounts receivable facility	150.0	0.0	0.0	150.0	0.0	0.0
TECO Energy/TECO Finance:						
5-year facility (2)(3)	200.0	0.0	0.0	200.0	0.0	0.0
Total	$675.0	$0.0	$1.5	$675.0	$0.0	$0.7

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

At Dec. 31, 2012, these credit facilities require commitment fees ranging from 12.5 to 30.0 basis points. There were no outstanding borrowings at Dec. 31, 2012 or 2011.

Tampa Electric Company Accounts Receivable Facility

On Feb. 15, 2013, TEC and TRC amended their $150 million accounts receivable collateralized borrowing facility, entering into Amendment No. 11 to the Loan and Servicing Agreement with certain lenders named therein and Citibank, N.A., Inc. as Program Agent. The amendment extends the maturity date to Feb. 14, 2014 and makes certain other technical changes. Please refer to **Note 23** for additional information.

TECO Energy/TECO Finance bank credit facility amendment

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

Tampa Electric Company bank credit facility amendment

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

7. Long-Term Debt

At Dec. 31, 2012, total long-term debt had a carrying amount of $2,972.7 million and an estimated fair market value of $3,439.4 million. At Dec. 31, 2011, total long-term debt had a carrying amount of $3,073.4 million and an estimated fair market value of $3,432.9 million. The company uses the market approach in determining fair value. The majority of the outstanding debt is valued using real-time financial market data obtained from Bloomberg Professional Service. The remaining securities are valued using prices obtained from the Municipal Securities Rulemaking Board and by applying estimated credit spreads obtained from a third party to the par value of the security. All debt securities are level 2 instruments.

TECO Finance is a wholly-owned subsidiary of TECO Energy. 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, and no other subsidiaries of TECO Energy, Inc. guarantee TECO Finance's securities.

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

TECO Energy's maturities and annual sinking fund requirements of long-term debt for 2013 through 2017 and thereafter are as follows:

Long-Term Debt Maturities

As of Dec. 31, 2012 (millions)	*2013*	*2014*	*2015*	*2016*	*2017*	*Thereafter*	*Total Long-Term Debt*
TECO Finance	$0.0	$0.0	$191.2	$250.0	$300.0	$300.0	$1,041.2
Tampa Electric	0.0	83.3	83.3	83.4	0.0	1,452.5	1,702.5
PGS	0.0	0.0	0.0	0.0	0.0	231.7	231.7
Total long-term debt maturities	$0.0	$83.3	$274.5	$333.4	$300.0	$1,984.2	$2,975.4

Debt Securities

Redemption of TECO Energy, Inc. 6.75% Notes due 2015

On Dec. 5, 2012, TECO Energy redeemed $8.8 million of 6.75% Notes due May 15, 2015. The redemption price was equal to $1,141.86 per $1,000.00 principal amount of notes redeemed, plus accrued and unpaid interest on the redeemed notes up to the redemption date. In connection with this transaction, $1.2 million of premiums 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, 2012.

Redemption of Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2002

On Oct. 1, 2012, TEC redeemed $147.1 million of Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2002 due Oct. 1, 2013 and Oct. 1, 2023 (2002 Bonds) at a redemption price equal to 100% of the principal amount of the 2002 Bonds to be redeemed, plus accrued and unpaid interest to Oct. 1, 2012. Before the optional redemption, $60.7 million of the 2002 Bonds due Oct. 1, 2013 bore interest at 5.1% and $86.4 million of the 2002 Bonds due Oct. 1, 2023 bore interest at 5.5%.

Issuance of Tampa Electric Company 2.60% Notes due 2022

On Sept. 28, 2012, TEC completed an offering of $250 million aggregate principal amount of 2.60% Notes due 2022 (the 2022 Notes). The 2022 Notes were sold at 99.878% of par. The offering resulted in net proceeds to TEC (after deducting underwriting discounts and commissions and estimated offering expenses) of approximately $247.7 million. Net proceeds were used to repay the 2002 Bonds. The remaining net proceeds were used to repay short-term debt and for general corporate purposes. At any time prior to June 15, 2022, TEC may redeem all or any part of the 2022 Notes at its option at a redemption price equal to the greater of (i) 100% of the principal amount of 2022 Notes to be redeemed or (ii) the sum of the present values of the remaining payments of principal and interest on the 2022 Notes to be redeemed, discounted to the redemption date on a semiannual basis at an applicable treasury rate, plus 15 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. At any time on or after June 15, 2022, TEC may at its option redeem the 2022 Notes, in whole or in part, at 100% of the principal amount of the 2022 Notes being redeemed plus accrued and unpaid interest thereon to but excluding the date of redemption.

Issuance of Tampa Electric Company 4.10% Notes due 2042

On June 5, 2012, TEC completed an offering of $300 million aggregate principal amount of 4.10% Notes due 2042 (the 2042 Notes). The 2042 Notes were sold at 99.724% of par. The offering resulted in net proceeds to TEC (after deducting underwriting discounts, commissions, and estimated offering expenses and before settlement of interest rate swaps) of approximately $296.2 million. Net proceeds were used to repay maturing long-term debt, to repay short-term debt and for general corporate purposes. At any time prior to Dec. 15, 2041, TEC may redeem all or any part of the 2042 Notes at its option and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of the 2042 Notes to be redeemed or (ii) the sum of the present value of the remaining payments of principal and interest on the 2042 Notes to be redeemed, discounted at an applicable treasury rate, plus 25 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. At any time on or after Dec. 15, 2041, TEC may at its option redeem the 2042 Notes, in whole or in part, at 100% of the principal amount of the 2042 Notes being redeemed plus accrued and unpaid interest thereon to but excluding the date of redemption.

Purchase in Lieu of Redemption of Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds, Series 2006 and Polk County Industrial Development Authority Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2010

On March 15, 2012, TEC purchased in lieu of redemption $86 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2006 (the HCIDA Bonds). On March 19, 2008, the HCIDA remarketed the HCIDA Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. The HCIDA Bonds bore interest at a term rate of 5.00% per annum from March 19, 2008 to March 15, 2012. TEC is responsible for payment of the interest and principal associated with the HCIDA Bonds. Regularly scheduled principal and interest when due are insured by Ambac Assurance Corporation.

On March 1, 2011, TEC purchased in lieu of redemption $75 million PCIDA Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2010 (the PCIDA Bonds). On Nov. 23, 2010, the PCIDA issued the PCIDA Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. Proceeds of the PCIDA Bonds were used to redeem $75 million PCIDA Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007, which previously were in auction rate mode and were held by TEC since March 26, 2008. The PCIDA Bonds bore interest at the initial term rate of 1.50% per annum from Nov. 23, 2010 to March 1, 2011.

On March 26, 2008, TEC purchased in lieu of redemption $20 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007C. $181 million in bonds purchased in lieu of redemption were held by the trustee at the direction of TEC as of Dec. 31, 2012 (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 Guatemala San José Project Notes

On Dec. 19, 2012, in conjunction with the closing on the sale of its equity interests in the San José Power Station, TECO Energy utilized $25.3 million of the sale proceeds to repay the San José project notes.

At Dec. 31, 2012 and 2011, TECO Energy had the following long-term debt outstanding:

Long-Term Debt (millions) Dec. 31,		*Due*	*2012*	*2011*
TECO Energy	Notes [1][2]: 6.75% (effective rate of 6.9% for 2011)	2015	$0.0	$8.8
TECO Finance	Notes [1][2][3]: 6.75% (effective rate of 6.9%)	2015	191.2	191.2
	4.0% (effective rate of 4.2%)	2016	250.0	250.0
	6.572% (effective rate of 7.3%)	2017	300.0	300.0
	5.15% (effective rate of 5.3%)	2020	300.0	300.0
Total long-term debt of TECO Finance			1,041.2	1,041.2
Tampa Electric	Installment contracts payable [4]:			
	5.1% Refunding bonds (effective rate of 5.6% for 2011)	2013	0.0	60.7
	5.65% Refunding bonds (effective rate of 5.9%)	2018	54.2	54.2
	Variable rate bonds repurchased in 2008 [5]	2020	0.0	0.0
	5.5% Refunding bonds (effective rate of 6.2% for 2011)	2023	0.0	86.4
	5.15% Refunding bonds (effective rate of 5.4%) [6]	2025	51.6	51.6
	1.5% Term rate bonds repurchased in 2011 [7]	2030	0.0	0.0
	5.0% Refunding bonds repurchased in 2012 (effective rate of 5.8% for 2011) [8]	2034	0.0	86.0
	Notes [1]: 6.875% (effective rate of 7.1% for 2011)	2012	0.0	99.6
	6.375% (effective rate of 7.9% for 2011)	2012	0.0	208.7
	6.25% (effective rate of 6.3%) [2]	2014-2016	250.0	250.0
	6.1% (effective rate of 6.4%)	2018	200.0	200.0
	5.4% (effective rate of 5.9%)	2021	231.7	231.7
	2.6% (effective rate of 2.7%)	2022	225.0	0.0
	6.55% (effective rate of 6.6%)	2036	250.0	250.0
	6.15% (effective rate of 6.2%)	2037	190.0	190.0
	4.1% (effective rate of 4.2%)	2042	250.0	0.0
Total long-term debt of Tampa Electric			1,702.5	1,768.9
PGS	Senior Notes [1][2]: 8.00% for 2011	2012	0.0	3.4
	Notes [1]: 6.875% (effective rate of 7.1% for 2011)	2012	0.0	19.0
	6.375% (effective rate of 7.9% for 2011)	2012	0.0	44.3
	6.1% (effective rate of 7.0%)	2018	50.0	50.0
	5.4% (effective rate of 5.8%)	2021	46.7	46.7
	2.6% (effective rate of 2.7%)	2022	25.0	0.0
	6.15% (effective rate of 6.2%)	2037	60.0	60.0
	4.1% (effective rate of 4.2%)	2042	50.0	0.0
Total long-term debt of PGS			231.7	223.4
TECO Guatemala	San José Project Notes [1][2]: 3.00% Fixed rate for 2011		0.0	33.5
Total long-term debt of TECO Energy			2,975.4	3,075.8
Unamortized debt discount, net			(2.7)	(2.4)
Total carrying amount of long-term debt			2,972.7	3,073.4
Less amount due within one year			0.0	386.1
Total long-term debt			$2,972.7	$2,687.3

(1) These securities are subject to redemption in whole or in part, at any time, at the option of the company.
(2) These long-term debt agreements contain various restrictive financial covenants.
(3) Guaranteed by TECO Energy.
(4) Tax-exempt securites.
(5) In March 2008 these bonds, which were in auction rate mode, were purchased in lieu of redemption by TEC. These held variable rate bonds have a par amount of $20.0 million due in 2020.
(6) These bonds were converted in March 2008 from an auction rate mode to a fixed rate mode for the term ending Sep. 1, 2013.
(7) In March 2011 these bonds, which were in term rate mode, were purchased in lieu of redemption by TEC. These held term rate bonds have a par amount of $75.0 million due in 2030.
(8) In March 2012 these bonds, which were in term rate mode, were purchased in lieu of redemption by TEC. These held term rate bonds have a par amount of $86.0 million due in 2034.

8. Preferred Stock

Preferred stock of TECO Energy – $1 par
10 million shares authorized, none outstanding.
Preference stock (subordinated preferred stock) of Tampa Electric – no par
2.5 million shares authorized, none outstanding.
Preferred stock of Tampa Electric – no par
2.5 million shares authorized, none outstanding.
Preferred stock of Tampa Electric – $100 par
1.5 million shares authorized, none outstanding.

9. Common Stock

Stock-Based Compensation

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

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

The types of awards that can be granted under the 2010 Plan include stock options, stock grants and stock equivalents. Stock options were last awarded in 2006 under the Old Plans. Stock grants and time-vested restricted stock are valued at the fair market value on the date of grant, with expense recognized over the vesting period, which is normally three years. Time-vested restricted stock granted to directors prior to 2011 vest one-third each year. Beginning in 2011, time-vested restricted stock granted to directors vest in one year. Performance-based restricted stock has been granted to officers and employees, with shares potentially vesting after three years. The total awards for performance-based restricted stock vest based on the total return of TECO Energy common stock compared to a peer group of utility stocks. The performance-based grants can vest between 0% and 150% of the original grant. Dividends are paid on all time-vested stock grants during the vesting period. Dividends are paid during the vesting period on all performance stock granted prior to 2010. Beginning in 2010, dividends are accrued during the vesting period on all performance stock granted under the 2010 Plan and paid at vesting date on the shares that vest. The value of time-vested restricted stock and stock grants are based on the fair market value of TECO Energy common stock at the time of grant.

The fair market value of stock options is determined using the Black-Scholes valuation model, and the company uses the following methods to determine its underlying assumptions: expected volatilities are based on the historical volatilities; the expected term of options granted is based on accounting guidance for the simplified method of averaging the vesting term and the original contractual term; the risk-free interest rate is based on the U.S. Treasury implied yield on zero-coupon issues (with a remaining term equal to the expected term of the option); and the expected dividend yield is based on the current annual dividend amount divided by the stock price on the date of grant.

The fair market value of performance-based restricted stock awards is determined using the Monte-Carlo valuation model, and the company uses the following methods to determine its underlying assumptions: expected volatilities are based on the historical volatilities; the expected term of the awards is based on the performance measurement period (which is generally three years); the risk-free interest rate is based on the U.S. Treasury implied yield on zero-coupon issues (with a remaining term equal to the expected term of the award); and the expected dividend yield is based on the current annual dividend amount divided by the stock price on the date of grant, with continuous compounding.

Assumptions	*2012*	*2011*	*2010*
Assumptions applicable to performance-based restricted stock			
Risk-free interest rate	0.38%	0.96%	1.37%
Expected lives (in years)	3	3	3
Expected stock volatility	20.99%	34.61%	35.83%
Dividend yield	4.78%	4.48%	4.90%

Under the 2010 Plan and the Old Plans 1.0 million, 0.8 million and 0.8 million shares of restricted stock were granted in 2012, 2011 and 2010, respectively, with weighted-average fair values per share of $15.96, $18.44 and $17.22, respectively. The total fair market value of awards vesting during 2012, 2011 and 2010 was $14.3 million, $13.4 million and $10.2 million, respectively, which includes stock grants, time-vested restricted stock and performance-based restricted stock. As of Dec. 31, 2012, there was $17.4 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)	*2012*	*2011*	*2010*
Compensation costs (1)	$ 12.0	$ 9.1	$ 7.4
Income tax benefits (1)	4.6	3.5	2.9
Excess tax benefits (2)	2.6	1.7	0.8

(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 $0.3 million, $1.5 million and $0.7 million for the periods ended Dec. 31, 2012, 2011 and 2010, respectively. Cash received from option exercises under all share-based payment arrangements was $1.1 million, $5.0 million and $2.9 million for the periods ended Dec. 31, 2012, 2011 and 2010, respectively. The income tax benefit realized from stock option exercises was $0.1 million, $0.6 million and $0.3 million for the periods ended Dec. 31, 2012, 2011 and 2010, 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, 2011	579	$15.68	1,357	$15.29
Granted	270	17.98	722	15.21
Vested	(250)	12.50	(572)	10.33
Forfeited	(7)	18.16	(17)	17.11
Nonvested balance at Dec. 31, 2012	592	$18.04	1,490	$17.13

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

Stock option transactions during 2012 under the 2010 Plan are summarized as follows:

	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, 2011	3,529	$20.01		
Granted	0	0.00		
Exercised	(78)	13.52		
Cancelled	(1,364)	27.97		
Outstanding balance at Dec. 31, 2012 (1)	2,087	$15.05	2	$3.6
Exercisable at Dec. 31, 2012 (1)	2,087	$15.05	2	$3.6
Available for future grant at Dec. 31, 2012	2,978			

(1) Option prices range from $11.09 to $19.01 per share.

As of Dec. 31, 2012, the options outstanding and exercisable under the 2010 Plan are summarized below:

Range of Option Prices (per share)	*Option Shares (thousands)*	*Weighted-Avg. Option Price (per share)*	*Weighted-Avg. Remaining Contractual Life*
$11.09 - $13.64	750	$12.80	1 Years
$16.21 - $19.01	1,337	$16.32	3 Years
Total	2,087	$15.05	2 Years

Dividend Reinvestment Plan

In 1992, TECO Energy implemented a Dividend Reinvestment and Common Stock Purchase Plan. TECO Energy raised $3.7 million of common equity from this plan in 2010. TECO Energy purchased shares on the open market for this plan in 2011 and 2012, resulting in no increase in equity.

10. Other Comprehensive Income

TECO Energy reported the following OCI (loss) for the years ended Dec. 31, 2012, 2011 and 2010, 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*
2012			
Unrealized gain (loss) on cash flow hedges	$ (7.4)	$ 2.8	$ (4.6)
Reclassification from AOCI to net income	0.6	(0.2)	0.4
Gain (Loss) on cash flow hedges	(6.8)	2.6	(4.2)
Amortization of unrecognized benefit costs and other [1]	(4.8)	0.0	(4.8)
Total other comprehensive (loss) income	$(11.6)	$ 2.6	$ (9.0)
2011			
Unrealized gain (loss) on cash flow hedges	$ 1.8	$(0.6)	$ 1.2
Reclassification from AOCI to net income	(3.1)	1.1	(2.0)
Gain (Loss) on cash flow hedges	(1.3)	0.5	(0.8)
Amortization of unrecognized benefit costs and other	(7.9)	3.3	(4.6)
Recognized benefit costs due to settlement	0.9	(0.3)	0.6
Total other comprehensive (loss) income	$ (8.3)	$ 3.5	$ (4.8)
2010			
Unrealized gain (loss) on cash flow hedges	$ 1.0	$(0.4)	$ 0.6
Reclassification from AOCI to net income	3.9	(1.4)	2.5
Gain (Loss) on cash flow hedges	4.9	(1.8)	3.1
Amortization of unrecognized benefit costs and other	3.7	0.0	3.7
Recognized benefit costs due to settlement	1.7	(0.7)	1.0
Total other comprehensive income (loss)	$ 10.3	$(2.5)	$ 7.8

Accumulated Other Comprehensive Loss (millions) As of Dec. 31,	*2012*	*2011*
Unrecognized pension losses and prior service credits [2]	$(32.9)	$(31.2)
Unrecognized other benefit gains, prior service costs and transition obligations [3]	11.1	14.2
Net unrealized losses from cash flow hedges [4]	(9.2)	(5.0)
Total accumulated other comprehensive loss	$(31.0)	$(22.0)

(1) Tax amounts include adjustments made related to Medicare Part D and changes to retirement plan. See **Note 5** for further discussion.
(2) Net of tax benefit of $20.1 million and $19.6 million as of Dec. 31, 2012 and Dec. 31, 2011, respectively.
(3) Net of tax expense of $6.7 million and $6.2 million as of Dec. 31, 2012 and Dec. 31, 2011, respectively.
(4) Net of tax benefit of $5.8 million and $3.2 million as of Dec. 31, 2012 and Dec. 31, 2011, respectively.

11. Earnings Per Share

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

(millions, except per share amounts)	*2012*	*2011*(1)	*2010*(1)
Basic earnings per share			
Net income from continuing operations	$ 246.0	$250.8	$211.6
Amount allocated to nonvested participating shareholders	(0.8)	(1.3)	(1.5)
Income before discontinued operations available to common shareholders - Basic	$ 245.2	$249.5	$210.1
Income (loss) from discontinued operations attributable to TECO Energy, net	($ 33.3)	$ 21.8	$ 27.4
Amount allocated to nonvested participating shareholders	0.1	(0.1)	(0.2)
Income (loss) from discontinued operations attributable to TECO Energy available to common shareholders - Basic	($ 33.2)	$ 21.7	$ 27.2
Net income attributable to TECO Energy	$ 212.7	$272.6	$239.0
Amount allocated to nonvested participating shareholders	(0.7)	(1.4)	(1.7)
Net income attributable to TECO Energy available to common shareholders - Basic	$ 212.0	$271.2	$237.3
Average common shares outstanding - Basic	214.3	213.6	212.6
Earnings per share from continuing operations available to common shareholders - Basic	$ 1.14	$ 1.17	$ 0.99
Earnings per share from discontinued operations attributable to TECO Energy available to common shareholders - Basic	($ 0.15)	$ 0.10	$ 0.13
Earnings per share attributable to TECO Energy available to common shareholders - Basic	**$ 0.99**	**$ 1.27**	**$ 1.12**
Diluted earnings per share			
Net income from continuing operations	$ 246.0	$250.8	$211.6
Amount allocated to nonvested participating shareholders	(0.8)	(1.3)	(1.5)
Income before discontinued operations available to common shareholders - Diluted	$ 245.2	$249.5	$210.1
Income (loss) from discontinued operations attributable to TECO Energy, net	($ 33.3)	$ 21.8	$ 27.4
Amount allocated to nonvested participating shareholders	0.1	(0.1)	(0.2)
Income (loss) from discontinued operations attributable to TECO Energy available to common shareholders - Diluted	($ 33.2)	$ 21.7	$ 27.2
Net income attributable to TECO Energy	$ 212.7	$272.6	$239.0
Amount allocated to nonvested participating shareholders	(0.7)	(1.4)	(1.7)
Net income attributable to TECO Energy available to common shareholders - Diluted	$ 212.0	$271.2	$237.3
Unadjusted average common shares outstanding - Diluted	214.3	213.6	212.6
Assumed conversion of stock options, unvested restricted stock and contingent performance shares, net	0.7	1.5	2.2
Average common shares outstanding - Diluted	215.0	215.1	214.8
Earnings per share from continuing operations available to common shareholders - Diluted	$ 1.14	$ 1.17	$ 0.98
Earnings per share from discontinued operations attributable to TECO Energy available to common shareholders - Diluted	($ 0.15)	$ 0.10	$ 0.13
Earnings per share attributable to TECO Energy available to common shareholders - Diluted	**$ 0.99**	**$ 1.27**	**$ 1.11**
Anti-dilutive shares	0.4	1.7	2.7

(1) All prior periods presented reflect the classification of TECO Guatemala as discontinued operations (see **Note 19**).

12. Commitments and Contingencies

Legal Contingencies

From time to time, TECO Energy and its subsidiaries are involved in various legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies in the ordinary course of its business. Where appropriate, accruals are made in accordance with accounting standards for contingencies to provide for matters that are probable of resulting in an estimable loss. While the outcome of such proceedings is uncertain, management does not believe that their ultimate resolution will have a material adverse effect on the company's results of operations, financial condition or cash flows.

Merco Group at Aventura Landings v. Peoples Gas System

In 2004, Merco Group at Aventura Landings I, II and III (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 now owned by Merco. Merco was seeking damages for costs associated with the removal of such coal tar and from out-of-pocket development expenses and lost profits due to the delay in its condominium development project allegedly caused by the presence of the coal tar. PGS denied liability on the grounds that the coal tar did not originate from its manufactured gas plant site and 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 PGS believes was the source of the coal tar on Merco's property. In addition, PGS filed a counterclaim against Merco, which claimed that, because Merco purchased the property with actual knowledge of the presence of coal tar on the property, Merco should contribute toward any damages resulting from the presence of coal tar. The bench trial in this matter was concluded in February 2012 and, in June 2012, prior to receiving a ruling by the Judge, PGS and Merco settled the case, and PGS and Continental Holdings, Inc. agreed to a release for their claims against each other in the case. Both agreements have been approved by the court. The settlement is reflected as a regulatory asset at Dec. 31, 2012 and is expected to be recovered through the regulatory process. The settlement did not impact the results of operations for the year ended Dec. 31, 2012 and is not material to the financial position of TEC or TECO Energy as of Dec. 31, 2012.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and Peoples Gas divisions, is a PRP for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2012, TEC has estimated its ultimate financial liability to be $37.5 million, primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under "Other" on the Consolidated Balance Sheets. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

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

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

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

Potentially Responsible Party Notification

In October 2010, the EPA notified TEC that it is a PRP under the CERCLA for the proposed conduct of a contaminated soil removal action, if necessary, at a property owned by TEC in Tampa, Florida. The property owned by TEC is undeveloped except for the location of transmission lines and poles, and is adjacent to an industrial site, not owned by TEC. The EPA has asserted this potential liability due to TEC's ownership of the property described above but, to the knowledge of TEC, this assertion is not based upon any release of hazardous substances by TEC. TEC has been in contact with the EPA to resolve this matter, and in July 2012, TEC signed an Administrative Settlement Agreement and Order on Consent (AOC) with the EPA, which outlines the remediation actions the EPA is requiring at the site. The estimated costs to conduct the remediation required under the AOC are not expected to be material to the financial results or financial position of TEC or TECO Energy. TEC expects the remediation required under the AOC to be substantially completed in 2013.

Environmental Protection Agency Administrative Order

In December 2010, Clintwood Elkhorn Mining Company, a subsidiary of TECO Coal, received an Administrative Order from the EPA relating to the discharge of wastewater associated with inactive mining operations in Pike County, Kentucky. TECO Coal responded to the EPA in February 2011, and has been in contact with the EPA to resolve this matter. Based on discussions with the EPA, the estimated costs to settle this matter are not expected to be material to the financial results or financial position of TECO Energy.

Long-Term Commitments

TECO Energy has commitments under long-term leases, primarily for building space, capacity payments, office equipment and heavy equipment. Total rental expense for these leases, included in "Regulated operations and maintenance- Other", "Operation & maintenance other expense – Mining related costs" and "Operation & maintenance other expense - Other" on the Consolidated Statements of Income for the years ended Dec. 31, 2012, 2011 and 2010, totaled $8.1 million, $10.2 million and $11.5 million, respectively. The following is a schedule of future minimum lease payments with non-cancelable lease terms in excess of one year and capacity payments under PPAs at Dec. 31, 2012:

Future Minimum Lease and Capacity Payments

(millions)	*Capacity Payments*	*Operating Leases*	*Total*
Year ended Dec. 31:			
2013	$14.6	$ 5.0	$ 19.6
2014	14.7	4.4	19.1
2015	14.9	3.3	18.2
2016	14.6	2.4	17.0
2017	9.9	2.0	11.9
Thereafter	10.1	15.2	25.3
Total future minimum payments	$78.8	$32.3	$111.1

Guarantees and Letters of Credit

TECO Energy accounts for guarantees in accordance with the applicable accounting standards. Upon issuance or modification of a guarantee the company determines if the obligation is subject to either or both of the following:

- Initial recognition and initial measurement of a liability, and/or
- Disclosure of specific details of the guarantee.

Generally, guarantees of the performance of a third party or guarantees that are based on an underlying (where such a guarantee is not a derivative) are likely to be subject to the recognition and measurement, as well as the disclosure provisions. Such guarantees must initially be recorded at fair value, as determined in accordance with the interpretation.

Alternatively, guarantees between and on behalf of entities under common control or that are similar to product warranties are subject only to the disclosure provisions of the interpretation. The company must disclose information as to the term of the guarantee and the maximum potential amount of future gross payments (undiscounted) under the guarantee, even if the likelihood of a claim is remote.

A summary of the face amount or maximum theoretical obligation under TECO Energy's letters of credit and guarantees as of Dec. 31, 2012 are as follows:

Guarantees-TECO Energy

(millions) *Guarantees for the Benefit of:*	*2013*	*2014-2017*	*After (1) 2017*	*Total*	*Liabilities Recognized at Dec. 31, 2012*
TECO Coal					
Fuel purchase related (2)	$0.0	$0.0	$5.4	$5.4	$1.5
Other subsidiaries					
Guaranty under sale agreement (3)	0.0	4.8	0.0	4.8	4.8
Fuel purchase/energy management (2)	0.0	10.0	95.3	105.3	0.9
Total	$0.0	$14.8	$100.7	$115.5	$7.2

Letters of Credit-Tampa Electric Company

(millions) *Letters of Credit for the Benefit of:*	*2013*	*2014-2017*	*After [1] 2017*	*Total*	*Liabilities Recognized at Dec. 31, 2012*
Tampa Electric [2]	$0.8	$0.0	$0.7	$1.5	$0.3

(1) These letters of credit and guarantees renew annually and are shown on the basis that they will continue to renew beyond 2017.

(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, 2012. The obligations under these letters of credit and guarantees include net accounts payable and net derivative liabilities.

(3) The liability recognized relates to an indemnification provision for an uncertain tax position at TCAE that was provided for in the purchase agreement. See **Note 19** for additional information.

Financial Covenants

In order to utilize their respective bank facilities, TECO Energy and its subsidiaries must meet certain financial tests, including a debt to capital ratio, as defined in the applicable agreements. In addition, TECO Energy, TECO Finance, TEC and the other operating companies have certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2012, TECO Energy, TECO Finance, TEC and the other operating companies were in compliance with all applicable financial covenants.

13. Related Parties

The company and its subsidiaries had certain transactions, in the ordinary course of business, with entities in which directors of the company had interests. The company paid legal fees of $1.3 million, $1.3 million and $1.2 million for the years ended Dec. 31, 2012, 2011 and 2010, 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, 2012, 2011 and 2010. No material balances were payable as of Dec. 31, 2012 or 2011.

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 Guatemala*	*Other & Eliminations*	*TECO Energy*
2012						
Revenues - external	$1,980.7	$396.6	$608.9	$0.0	$10.4	$2,996.6
Sales to affiliates	0.6	2.3	0.0	0.0	(2.9)	0.0
Total revenues	1,981.3	398.9	608.9	0.0	7.5	2,996.6
Depreciation and amortization	237.6	50.6	41.0	0.0	1.4	330.6
Total interest charges (1)	109.8	16.0	7.1	0.0	50.6	183.5
Internally allocated interest (1)	0.0	0.0	6.8	0.0	(6.8)	0.0
Provision for income taxes	120.2	21.5	15.7	0.0	(19.6)	137.8
Net income from continuing operations	193.1	34.1	50.2	0.0	(31.4)	246.0
Discontinued operations attributable to TECO, net of tax (2)	0.0	0.0	0.0	(29.3)	(4.0)	(33.3)
Net income attributable to TECO Energy	193.1	34.1	50.2	(29.3)	(35.4)	212.7
Goodwill	0.0	0.0	0.0	0.0	0.0	0.0
Total assets	6,063.9	1,009.9	356.6 (3)	164.9	(238.8)	7,356.5
Capital expenditures	361.7	97.3	36.3	8.6	1.2	505.1
2011						
Revenues - external	$2,019.3	$450.5	$733.0	$0.0	$7.1	$3,209.9
Sales to affiliates	1.3	3.0	0.0	0.0	(4.3)	0.0
Total revenues	2,020.6	453.5	733.0	0.0	2.8	3,209.9
Depreciation and amortization	222.1	48.4	45.3	0.0	1.4	317.2
Total interest charges (1)	121.8	17.7	6.9	0.0	51.0	197.4
Internally allocated interest (1)	0.0	0.0	6.7	0.0	(6.7)	0.0
Provision for income taxes	124.8	20.6	15.4	0.0	(18.1)	142.7
Net income from continuing operations	202.7	32.6	51.5	0.0	(36.0)	250.8
Discontinued operations attributable to TECO, net of tax (2)	0.0	0.0	0.0	22.4	(0.6)	21.8
Net income attributable to TECO Energy	202.7	32.6	51.5	22.4	(36.6)	272.6
Goodwill	0.0	0.0	0.0	55.4	0.0	55.4
Total assets	5,940.9	932.0	385.2 (3)	304.1	(240.0)	7,322.2
Capital expenditures	314.9	71.9	56.6	7.2	3.5	454.1
2010						
Revenues - external	$2,161.9	$510.7	$690.0	$0.0	$0.9	$3,363.5
Sales to affiliates	1.3	19.2	0.0	0.0	($20.5)	0.0
Total revenues	2,163.2	529.9	690.0	0.0	($19.6)	3,363.5
Earnings from unconsol. affiliates	0.0	0.0	0.0	0.0	$0.0	0.0
Depreciation and amortization	215.9	46.0	43.5	0.0	$0.2	305.6
Restructuring charges	0.0	0.0	0.0	0.0	$1.5	1.5
Total interest charges (1)	122.7	18.3	6.8	0.0	$67.7	215.5
Internally allocated interest ( )	0.0	0.0	6.6	0.0	($6.6)	0.0
Provision for income taxes	122.4	21.3	11.8	0.0	($45.9)	109.6
Net income from continuing operations	208.8	34.1	53.0	0.0	($84.3)	211.6
Discontinued operations attributable to TECO, net of tax (2)	0.0	0.0	0.0	41.6	($14.2)	27.4
Net income attributable to TECO Energy	208.8	34.1	53.0	41.6	($98.5)	239.0
Goodwill	0.0	0.0	0.0	55.4	0.0	55.4
Total assets	5,833.3	918.4	332.2(3)	292.7	(98.3)	7,278.3
Capital expenditures	331.2	62.4	47.4	0.8	47.9	489.7

(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 2012 were at a pretax rate of 6.00%, for 2011 were at a pretax rate of 6.25%, for July through December 2010 were at a pretax rate of 6.50% and for January through June 2010 were at a pretax rate of 7.15% based on an average of each subsidiary's equity and indebtedness to TECO Energy assuming a 50/50 debt/equity capital structure.

(2) All periods have been adjusted to reflect the reclassification of results from operations to discontinued operations for TECO Guatemala and certain charges at Parent that directly relate to TECO Guatemala. See **Note 19**.

(3) The carrying value of mineral rights as of Dec. 31, 2012, 2011 and 2010 was $13.4 million, $15.0 million and $15.8 million, respectively.

Tampa Electric provides retail electric utility services to more than 687,000 customers in West Central Florida. PGS is engaged in the purchase and distribution of natural gas for approximately 345,000 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.

15. Asset Retirement Obligations

TECO Energy accounts for AROs under the applicable accounting standards. An ARO for a long-lived asset is recognized at fair value at inception of the obligation if there is a legal obligation under an existing or enacted law or statute, a written or oral contract or by legal construction under the doctrine of promissory estoppel. Retirement obligations are recognized only if the legal obligation exists in connection with or as a result of the permanent retirement, abandonment or sale of a long-lived asset.

When the liability is initially recorded, the carrying amount of the related long-lived asset is correspondingly increased. Over time, the liability is accreted to its estimated future value. The corresponding amount capitalized at inception is depreciated over the remaining useful life of the asset. The liability must be revalued each period based on current market prices.

TECO Energy has recognized AROs for reclamation and site restoration obligations principally associated with coal mining, storage and transfer facilities at TECO Coal. The majority of obligations arise from environmental remediation and restoration activities for coal-related operations.

For the years ended Dec. 31, 2012, 2011 and 2010, TECO Energy recognized $1.4 million annually of accretion expense associated with AROs in "Depreciation and amortization" on the Consolidated Statements of Income. For the year ended Dec. 31, 2012, $29.1 million of liabilities settled resulted primarily from asbestos abatement and other dismantling at the generating stations at Tampa Electric.

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

(millions)	*Dec. 31, 2012*	*2011*
Beginning balance	$ 53.8	$55.7
Additional liabilities	0.7	0.8
Liabilities settled	(29.1)	(3.6)
Accretion expense	1.4	1.4
Revisions to estimated cash flows	0.0	(2.2)
Other (1)	1.8	1.7
Ending balance	$ 28.6	$53.8

(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. 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. TEC'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 17**). The changes in fair value that are recorded in OCI are not immediately recognized in current net income. As the underlying hedged transaction matures or the physical commodity is delivered, the deferred gain or loss on the related hedging instrument must be reclassified from OCI to earnings based on its value at the time of the instrument's settlement. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the market change of the amount paid or received on the underlying physical transaction.

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

The company's physical contracts qualify for the 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, 2012, 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, 2012 and Dec. 31, 2011:

Total Derivatives

(millions)	*Dec. 31, 2012*	*Dec. 31, 2011*
Current assets	$ 0.0	$ 0.9
Long-term assets	0.2	0.0
Total assets	$ 0.2	$ 0.9
Current liabilities	$14.6	$58.4
Long-term liabilities	0.6	8.6
Total liabilities	$15.2	$67.0

The following table presents the derivative cash flow hedges of diesel fuel contracts at Dec. 31, 2012 and 2011 to limit the exposure to changes in the market price for diesel fuel:

Diesel Fuel Derivatives

(millions)	*Dec. 31, 2012*	*Dec. 31, 2011*
Current assets	$0.0	$0.9
Long-term assets	0.0	0.0
Total assets	$0.0	$0.9
Current liabilities	$0.5	$0.0
Long-term liabilities	0.4	1.2
Total liabilities	$0.9	$1.2

The following table presents the derivative hedges of natural gas contracts at Dec. 31, 2012 and 2011 to limit the exposure to changes in market price for natural gas used to produce energy and natural gas purchased for resale to customers:

Natural Gas Derivatives (1)

(millions)	*Dec. 31, 2012*	*Dec. 31, 2011*
Current assets	$ 0.0	$ 0.0
Long-term assets	0.2	0.0
Total assets	$ 0.2	$ 0.0
Current liabilities	$14.1	$58.4
Long-term liabilities	0.2	7.4
Total liabilities	$14.3	$65.8

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

The ending balance in AOCI related to the cash flow hedges and previously settled interest rate swaps at Dec. 31, 2012 is a net loss of $9.2 million after tax and accumulated amortization. This compares to a net loss of $5.0 million in AOCI after tax and accumulated amortization at Dec. 31, 2011.

The following table presents the fair values and locations of derivative instruments recorded on the balance sheet at Dec. 31, 2012 and 2011:

Derivatives Designated As Hedging Instruments

	Asset Derivatives		Liability Derivatives	
(millions) *at Dec. 31, 2012*	*Balance Sheet Location*	*Fair Value*	*Balance Sheet Location*	*Fair Value*
Commodity Contracts:				
Diesel fuel derivatives:				
Current	Derivative assets	$0.0	Derivative liabilities	$ 0.5
Long-term	Derivative assets	0.0	Derivative liabilities	0.4
Natural gas derivatives:				
Current	Derivative assets	0.0	Derivative liabilities	14.1
Long-term	Derivative assets	0.2	Derivative liabilities	0.2
Total derivatives designated as hedging instruments		$0.2		$15.2

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

The following table presents the effect of energy related derivatives on the fuel recovery clause mechanism on the Consolidated Balance Sheets as of Dec. 31, 2012 and 2011:

Energy Related Derivatives

(millions) *at Dec. 31, 2012*	Asset Derivatives *Balance Sheet Location* [1]	*Fair Value*	Liability Derivatives *Balance Sheet Location* [1]	*Fair Value*
Commodity Contracts:				
Natural gas derivatives:				
Current	Regulatory liabilities	$0.0	Regulatory assets	$14.1
Long-term	Regulatory liabilities	0.2	Regulatory assets	0.2
Total		$0.2		$14.3

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

(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, 2012, net pretax losses of $14.1 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]	
2012			
Interest rate contracts:	($4.9)	Interest expense	($0.8)
Commodity contracts:			
Diesel fuel derivatives	0.3	Mining related costs	0.4
Total	($4.6)		($0.4)
2011			
Interest rate contracts:	$0.0	Interest expense	($0.7)
Commodity contracts:			
Diesel fuel derivatives	1.2	Mining related costs	2.7
Total	$1.2		$2.0
2010			
Interest rate contracts:	$0.0	Interest expense	($1.7)
Commodity contracts:			
Diesel fuel derivatives	0.6	Mining related costs	(0.8)
Total	$0.6		($2.5)

(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, 2012, 2011 and 2010, all hedges were effective.

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

(millions)	*Fair Value Asset/(Liability)*	*Amount of Gain/(Loss) Recognized in OCI* (1)	*Amount of Gain/(Loss) Reclassified From AOCI Into Income* (1)
2012			
Interest rate swaps	$0.0	($4.9)	($0.8)
Diesel fuel derivatives	(0.9)	0.3	0.4
Total	($0.9)	($4.6)	($0.4)
2011			
Interest rate swaps	$0.0	$0.0	($0.7)
Diesel fuel derivatives	(0.3)	1.2	2.7
Total	($0.3)	$1.2	$2.0
2010			
Interest rate swaps	$0.0	$0.0	($1.7)
Diesel fuel derivatives	1.8	0.6	(0.8)
Total	$1.8	$0.6	($2.5)

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

The maximum length of time over which the company is hedging its exposure to the variability in future cash flows extends to Dec. 31, 2014 for both financial natural gas and financial diesel fuel contracts. The following table presents by commodity type the company's derivative volumes that, as of Dec. 31, 2012, are expected to settle during the 2013 and 2014 fiscal years:

(millions)	**Diesel Fuel Contracts (Gallons)**		**Natural Gas Contracts (MMBTUs)**	
Year	*Physical*	*Financial*	*Physical*	*Financial*
2013	0.0	3.0	0.0	34.2
2014	0.0	1.5	0.0	6.4
Total	0.0	4.5	0.0	40.6

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, 2012, 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) EEI agreements - standardized power sales contracts in the electric industry; (2) ISDA agreements - standardized financial gas and electric contracts; and (3) NAESB agreements - 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 its 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, 2012, 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 TEC is the counterparty, TEC's debt, to maintain an investment grade credit rating from any or all of the major credit rating agencies. If debt ratings, including TEC'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, 2012:

Contingent Features

(millions)	*Fair Value Asset/ (Liability)*	*Derivative Exposure Asset/ (Liability)*	*Posted Collateral*
Credit Rating	($14.9)	($14.9)	$0.0

17. Fair Value Measurements

Items Measured at Fair Value on a Recurring Basis

The following tables set forth by level within the fair value hierarchy the company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of Dec. 31, 2012 and 2011. As required by accounting standards for fair value measurements, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. For natural gas and diesel fuel swaps, the market approach was used in determining fair value.

Recurring Fair Value Measures

	At fair value as of Dec. 31, 2012			
(millions)	*Level 1*	*Level 2*	*Level 3*	*Total*
Assets				
Natural gas swaps	$0.0	$ 0.2	$0.0	$ 0.2
Diesel fuel swaps	0.0	0.0	0.0	0.0
Total	$0.0	$ 0.2	$0.0	$ 0.2
Liabilities				
Natural gas swaps	$0.0	$14.3	$0.0	$14.3
Diesel fuel swaps	0.0	0.9	0.0	0.9
Total	$0.0	$15.2	$0.0	$15.2

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

Natural gas and diesel fuel swaps are OTC swap instruments. The primary pricing inputs in determining the fair value of these swaps are the NYMEX quoted closing prices of exchange-traded instruments. These prices are applied to the notional amounts of active positions to determine the reported fair value (see **Note 16**).

The company considered the impact of nonperformance risk in determining the fair value of derivatives. The company considered the net position with each counterparty, past performance of both parties, the intent of the parties, indications of credit deterioration and whether the markets in which the company transacts have experienced dislocation. At Dec. 31, 2012, the fair value of derivatives was not materially affected by nonperformance risk. The company's net positions with substantially all counterparties were liability positions. There were no Level 3 assets or liabilities during the 2012 or 2011 fiscal years.

18. Variable Interest Entities

The determination of a VIE's 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.

TEC has entered into multiple PPAs with wholesale energy providers in Florida to ensure the ability to meet customer energy demand and to provide lower cost options in the meeting of this demand. These agreements range in size from 117 MW to 370 MW of available capacity, are with similar entities and contain similar provisions. Because some of these provisions provide for the transfer or sharing of a number of risks inherent in the generation of energy, these agreements meet the definition of being VIEs. These risks include: operating and maintenance, regulatory, credit, commodity/fuel and energy market risk. TEC 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, TEC is not required to consolidate any of these entities. TEC purchased $75.8 million, $81.2 million and $108.8 million, under these PPAs for the three years ended Dec. 31, 2012, 2011 and 2010, respectively.

In one instance, TEC's agreement with an entity for 370 MW of capacity was entered into prior to Dec. 31, 2003, the effective date of these standards. Under these standards, TEC 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, TEC is unable to determine if this entity is a VIE and, if so, which variable interest holder, if any, is the primary beneficiary. TEC has no obligation to this entity beyond the purchase of capacity; therefore, the maximum exposure for TEC is the obligation to pay for such capacity under terms of the PPA at rates that could be unfavorable to the wholesale market. TEC purchased $46.6 million, $34.4 million and $52.8 million, for the three years ended Dec. 31, 2012, 2011 and 2010, 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. In the normal course of business, the company's involvement with these VIEs does not affect its Consolidated Condensed Balance Sheets, Statements of Income or Cash Flows.

19. Discontinued Operations

On Aug. 7, 2012, TECO Energy received an offer from Renewable Energy Investments Guatemala Limited (REIN), a wholly-owned subsidiary of Sur Eléctrica Holding Limited (SUR), to purchase the independent power projects in Guatemala and certain affiliated Guatemala companies. SUR and REIN are international business companies organized under the laws of the Commonwealth of the Bahamas. On Sept. 27, 2012, an indirect wholly-owned subsidiary of TECO Energy, Inc., TECO Guatemala Holdings II, LLC (TGH), entered into an equity purchase agreement with SUR, and two equity purchase agreements with REIN (the three equity purchase agreements are collectively referred to herein as the "PAs"). Pursuant to the PA with SUR, TGH agreed to sell all of its ownership interests in TPS Guatemala One, Ltd. (TPS GO) for $12.5 million, and pursuant to the PAs with REIN, it agreed to sell all of its ownership interests in (i) TPS San José International, Inc. (TPS SJI) for $213.5 million and (ii) TECO Guatemala Services, Ltd. (TGS) for $1.5 million (TPS GO, TPS SJI and TGS are collectively referred to herein as the Disposal Group). The companies in the Disposal Group are the ultimate parent companies of TCAE, CGESJ, TEMSA, and TPS Operaciones de Guatemala, Limitada (TPSO), the owner of certain local real estate assets and the employer of the local employees. The total purchase price for the Disposal Group under the PAs was $227.5 million.

The sale of TPS GO, which owns 96.06% of TCAE, closed on Sept. 27, 2012. An affiliate of the party that controlled the remaining interest in TCAE (the "noncontrolling interest holder") held certain contractual rights with respect to TEMSA and CGESJ, including a right of first offer. The noncontrolling interest holder was also granted the opportunity to purchase TGS since the operations of TPSO are integral to the operations of TEMSA and CGESJ. The noncontrolling interest holder exercised the right of first offer for TPS SJI and elected to purchase TGS by executing PAs similar to the PAs with REIN on Oct. 17, 2012 and Oct. 26, 2012, respectively. The sales of TPS SJI and TGS to the noncontrolling interest holder closed on Dec. 19, 2012.

As a result of the PAs, the TECO Guatemala segment is accounted for as a discontinued operation at Dec. 31, 2012. The following table provides selected components of discontinued operations:

Components of income from discontinued operations attributable to TECO Energy

(millions)	*Twelve months ended Dec. 31,* 2012	2011	2010
Revenues	$114.2	$133.5	$124.4
Income from operations	27.7	33.7	88.4
Loss on assets sold, including transaction costs	(38.3)	(0.4)	0.0
Income (loss) from discontinued operations	(10.6)	33.3	88.4
Provision for income taxes	22.4	11.2	60.4
Income (loss) from discontinued operations, net	(33.0)	22.1	28.0
Less: Income from discontinued operations attributable to noncontrolling interest	0.3	0.3	0.6
Income (loss) from discontinued operations attributable to TECO Energy, net	$(33.3)	$ 21.8	$ 27.4

The provision for income taxes line item includes an after-tax charge of $22.9 million in 2012 associated with foreign tax credits and a $24.9 million after-tax charge in 2010 associated with the unwinding of the deferral tax structure. The 2012 charge is a result of the sales of the Disposal Group which eliminate future foreign source income that would be required to utilize these credits. The 2010 charge relates to the sale of DECA II on Oct. 20, 2010 (see **Note 21**).

The PAs contain customary representations, warranties and covenants. The PAs also contain indemnification provisions subject to specified limitations as to time and amount, including an indemnification provision related to an uncertain tax position related to TCAE.

TEC will perform and be paid for certain transitional services related to the sales, including certain engineering and information technology support. These cash flows will continue only while SUR and the noncontrolling interest holder (as applicable) are integrating the entities into their operations and information systems. Once the transitions to ultimate purchasers are complete, the cash flows from the continuation of activities will cease. Additionally, cash flows will not be material to the previously forecasted cash flows at TGI.

20. Goodwill and Asset Impairments

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 at 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. The goodwill formerly on the company's balance sheet related to the TECO Guatemala segment and arose from the purchase of multiple entities as a result of the company's investments in the Alborada (held by TPS GO) and San José (held by TPS SJI) power plants. Since these reporting units were one level below the operating segment level, discrete cash flow information was available, and management regularly reviewed their operating results separately, these were the reporting unit level at which potential impairment was tested.

Prior to the sales (see **Note 19**), goodwill balances for the TPS GO and TPS SJI reporting units were written down to their implied fair value calculated using the offers from SUR and REIN. Although these were binding quoted prices, the fair value measurements were considered Level 2 measurements since the market was not active as defined by accounting standards (i.e. transactions for these assets were too infrequent to provide pricing information on an ongoing basis). Prior to receiving the offers from REIN and SUR, the fair values of TPS GO's and TPS SJI's goodwill amounts were calculated using the discounted cash flows appropriate for the business model of each reporting unit. Discounted cash flows were formerly the best estimates of fair value of the reporting units, since neither a sale nor a similar transaction was readily observed in the marketplace for many years due to an inactive market.

The changes in the carrying amount of goodwill for the year ended Dec. 31, 2012 are represented in the following table:

(millions)	*TPS GO*	*TPS SJI*	*Total*
Balance as of Jan. 1, 2012	$ 3.1	$ 52.3	$ 55.4
Impairment losses, pretax	(3.1)	(12.1)	(15.2)
Goodwill written off upon sale, pretax	0.0	(40.2)	(40.2)
Balance as of Dec. 31, 2012	$ 0.0	$ 0.0	$ 0.0

The Impairment losses, pretax and Goodwill written off upon sale, pretax amounts from the table above are recorded in the Income (loss) from discontinued operations line item in the **Consolidated Statements of Income** and the Loss (gain) on sales of business/assets, pretax line item in the **Consolidated Statements of Cash Flows** for the year ended Dec. 31, 2012.

The company accounts for long-lived asset impairments in accordance with the accounting guidance for long-lived assets, which requires that long-lived assets held and used be tested for recoverability whenever events or changes in circumstances indicate that its carrying value may not be recoverable, and assets held for sale be recorded at the lower of its carrying amount or fair value less cost to sell. 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.

Prior to the sale of TGS, the company recorded a long-lived asset pretax impairment charge of $2.0 million. This amount is recorded in the Income (loss) from discontinued operations line item in the **Consolidated Statements of Income** and the Loss (gain) on sales of business/assets, pretax line item in the **Consolidated Statements of Cash Flows** for the year ended Dec. 31, 2012. The fair value was calculated using the offer from REIN. Although it was a binding quoted price, the fair value measurement was considered a Level 2 measurement since the market was not active as defined by accounting standards (i.e. transactions for these assets are too infrequent to provide pricing information on an ongoing basis).

Additionally, in November and December of 2012, TECO Coal temporarily closed some of its mines due to the softened coal market. As a result, the company performed an impairment analysis on the mining complexes with closed mines and the coal reserves. All assets were determined to have carrying values that are recoverable; therefore, no impairment charge was deemed necessary. No indicators of potential impairment of assets existed as of Dec. 31, 2011 or 2010.

21. Dispositions

Sale of San José and Alborada

On Sept. 27, 2012, TECO Guatemala entered into an agreement to sell all of the equity interests in the Alborada and San José power stations and their related facilities and operations in Guatemala for a total purchase price of $227.5 million in cash. The TECO Guatemala segment was accounted for as discontinued operations beginning in the third quarter of 2012. For more information regarding the sale, see **Note 19**.

While TECO Energy and its subsidiaries will no longer have assets or operations in Guatemala, its subsidiary, TECO Guatemala Holdings, LLC, has retained its rights under its arbitration claim filed against the Republic of Guatemala in October 2010 under the Dominican Republic Central America – United States Free Trade Agreement (DR – CAFTA).

Net proceeds from the sale of all Guatemalan operations, after estimated transaction-related costs and the $25.3 million repayment of the San José power station project debt, were approximately $197.0 million. The sale resulted in an after-tax book loss and an after-tax charge associated with foreign tax credits of $28.6 million and $22.9 million, respectively.

Sale of DECA II

On Oct. 21, 2010, TECO Guatemala Holdings, LLC, a TECO Energy subsidiary, sold its 30% interest in DECA II to EPM, a multi-utility company based in Medellín, Colombia, under a SPA.

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

22. Quarterly Data (unaudited)

Financial data by quarter is as follows:

(millions, except per share amounts) *Quarter ended*	*Dec. 31*	*Sept. 30*	*June 30*	*March 31*
2012				
Revenues [(1)]	$688.4	$858.6	$752.5	$697.1
Income from operations[(1)]	109.5	183.1	149.1	114.8
Net income from continuing operations[(1)]	45.6	90.2	65.6	44.6
Net income attributable to TECO Energy	45.1	44.0	73.1	50.5
EPS — Basic				
From continuing operations [(1)]	$ 0.21	$ 0.42	$ 0.30	$ 0.21
Attributable to TECO Energy	0.21	0.20	0.34	0.24
EPS — Diluted				
From continuing operations [(1)]	$ 0.21	$ 0.42	$ 0.30	$ 0.20
Attributable to TECO Energy	0.21	0.20	0.34	0.23
Dividends paid per common share outstanding	$0.220	$0.220	$0.220	$0.220

Quarter ended	*Dec. 31*	*Sept. 30*	*June 30*	*March 31*
2011				
Revenues [(1)]	$720.0	$877.8	$849.5	$762.5
Income from operations[(1)]	120.8	181.3	160.3	120.7
Net income from continuing operations[(1)]	47.3	86.1	72.0	45.4
Net income attributable to TECO Energy	53.2	90.2	77.5	51.7
EPS — Basic				
From continuing operations [(1)]	$ 0.22	$ 0.40	$ 0.34	$ 0.21
Attributable to TECO Energy	0.25	0.42	0.36	0.24
EPS — Diluted				
From continuing operations [(1)]	$ 0.22	$ 0.40	$ 0.34	$ 0.21
Attributable to TECO Energy	0.25	0.42	0.36	0.24
Dividends paid per common share outstanding	$0.215	$0.215	$0.215	$0.205

(1) Amounts shown include reclassifications to reflect discontinued operations as discussed in **Note 19**.

23. Subsequent Events

Tampa Electric Rate Case Proceeding

On Feb. 4, 2013, the Tampa Electric Division of TEC delivered a letter to the FPSC notifying it of its intent to file a request for an increase in its retail base rates and service charges, to be effective at the conclusion of the rate case. See **Note 3** for more information.

Tampa Electric Company Accounts Receivable Facility

On Feb. 15, 2013, TEC and TEC Receivables Corporation (TRC), a wholly-owned subsidiary of TEC, amended their $150 million accounts receivable collateralized borrowing facility, entering into Amendment No. 11 to the Loan and Servicing Agreement with certain lenders named therein and Citibank, N.A. as Program Agent. The amendment (i) extends the maturity date to Feb. 14, 2014, (ii) provides that TRC will pay program and liquidity fees, which will total 52.5 basis points, (iii) continues to provide that the interest rates on the borrowings will be based on prevailing asset-backed commercial paper rates, unless such rates are not available from conduit lenders, in which case the rates will be at an interest rate equal to, at TEC's option, either Citibank's prime rate (or the federal funds rate plus 50 basis points, if higher) or a rate based on the London interbank offered rate (if available) plus a margin and (iv) makes other technical changes.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

Item 9A. CONTROLS AND PROCEDURES.

TECO Energy, Inc.

Conclusions Regarding Effectiveness of Disclosure Controls and Procedures.

TECO Energy's management, with the participation of its principal executive officer and principal financial officer, has evaluated the effectiveness of TECO Energy's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act)) as of the end of the period covered by this annual report, Dec. 31, 2012 (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, 2012 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, 2012.

TECO Energy's internal control over financial reporting as of Dec. 31, 2012 has been audited by PricewaterhouseCoopers LLP, an independent registered certified public accounting firm, as stated in their report which is on page 79 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.

TECO Energy has implemented an ERP system, developed by SAP, to replace certain of its legacy computer systems. This system became operational in July 2012 and materially affected TECO Energy's internal control over financial reporting. In response, the company has made appropriate changes to internal controls and procedures, as is expected with a major system implementation. None of these changes resulting from the implementation impair or significantly alter the effectiveness of the internal controls over financial reporting. There were no other changes in TECO Energy's internal controls 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 control over financial reporting that occurred during TECO Energy's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, such controls.

Tampa Electric Company

Conclusions Regarding Effectiveness of Disclosure Controls and Procedures.

TEC's management, with the participation of its principal executive officer and principal financial officer, has evaluated the effectiveness of TEC'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, 2012 (the "Evaluation Date"). Based on such evaluation, TEC's principal executive officer and principal financial officer have concluded that, as of the Evaluation Date, TEC's disclosure controls and procedures are effective.

Management's Report on Internal Control over Financial Reporting.

TEC's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) of the Securities Exchange Act of 1934, as amended. We conducted an evaluation of the effectiveness of TEC's internal control over financial reporting as of Dec. 31, 2012 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 TEC's internal control over financial reporting was effective as of Dec. 31, 2012.

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.

TEC has implemented an ERP system, developed by SAP, to replace certain of its legacy computer systems. This system became operational in July 2012 and materially affected TEC's internal control over financial reporting. In response, TEC has made appropriate changes to internal controls and procedures, as is expected with a major system implementation. None of these changes resulting from the implementation impair or significantly alter the effectiveness of the internal controls over financial reporting. There were no other changes in TEC's internal controls 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 TEC's internal control over financial reporting that occurred during TEC'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 1, 2013 (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 22 of this report.

(c) The information required by Item 10 concerning Section 16(a) Beneficial Ownership Reporting Compliance is included under that caption in the Proxy Statement and is incorporated herein by reference.

(d) Information regarding TECO Energy's Audit Committee, including the committee's financial experts, is included under the caption "Committees of the Board" in the Proxy Statement, and is incorporated herein by reference.

(e) TECO Energy has adopted a code of ethics applicable to all of its employees, officers and directors. The text of the *Code of Ethics and Business Conduct* is available in the Corporate Governance section of the Investors page of the company's website at www.tecoenergy.com. Any amendments to or waivers of the *Code of Ethics and Business Conduct* for the benefit of any executive officer or director will also be posted on the website.

Item 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is included in the Proxy Statement beginning with the caption "Compensation Committee Report" and ending with "Executive Chairman Employment Agreement" just above the caption "Ratification of Appointment of Independent Auditor" and is incorporated herein by reference.

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

The information required by Item 201(d) of Regulation S-K is included below. The remainder of 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 per share 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	2,087	$15.05	2,978
Equity compensation plans/arrangements not approved by the stockholders			
None	0	0.00	0
Total	2,087	$15.05	2,978

(1) The reported amount for the 2010 Equity Incentive Plan excludes performance shares which have been issued or may potentially be issued due to performance, subject to a performance-based vesting schedule. Because of the nature of these awards, these shares have also not been taken into account in calculating the weighted-average exercise price under column (b) of this table.

(2) The reported amount for the 2010 Equity Incentive Plan includes shares which may be issued as restricted stock, performance shares, performance-accelerated restricted stock, bonus stock, phantom stock, performanc units, dividend equivalents and other forms of award available for grant under the plan.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by Item 13 is included under the captions "Certain Relationships and Related Person Transactions" and "Director Independence" in the Proxy Statement, and is incorporated herein by reference.

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 for TECO Energy is included under the caption "Item 2 – Ratification of Appointment of Independent Auditor" in the Proxy Statement and is incorporated herein by reference.

TEC incurred $0.8 million, $0.7 million and $0.7 million in audit-related fees rendered by PricewaterhouseCoopers for each of the years 2012, 2011 and 2010, respectively, including $0.3 million related to Sarbanes-Oxley in each of those three years. No other fees for services rendered by PricewaterhouseCoopers were incurred by TEC in those years.

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) **Certain Documents Filed as Part of this Form 10-K**

1. Financial Statements

   TECO Energy, Inc. Financial Statements – See index on page 78

2. Financial Statement Schedules

   TECO Energy, Inc. Schedule II – page 122

3. Exhibits

(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 schedule filed as part of this Form 10-K is listed in paragraph (a)(2) above, and follows immediately.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

TECO ENERGY, INC.
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
For the Years Ended Dec. 31, 2012, 2011 and 2010

(millions)

	Balance at Beginning of Period	Additions		Payments & Deductions [1]	Balance at End of Period
		Charged to Income	Other Charges		
Allowance for Uncollectible Accounts:					
2012	$2.6	$ 4.8	$0.0	$3.2	$4.2
2011	$4.5	$ 3.8	$0.0	$5.7	$2.6
2010	$3.0	$10.7	$0.0	$9.2	$4.5

(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 26, 2013

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 26, 2013:

Signature	Title
/s/ JOHN B. RAMIL **JOHN B. RAMIL**	President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ SANDRA W. CALLAHAN **SANDRA W. CALLAHAN**	Senior Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer) (Principal Financial and Principal Accounting Officer)

Signature	Title	Signature	Title
/s/ C. DUBOSE AUSLEY **C. DUBOSE AUSLEY**	Director	/s/ LORETTA A. PENN **LORETTA A. PENN**	Director
/s/ JAMES L. FERMAN, JR. **JAMES L. FERMAN, JR.**	Director	/s/ TOM L. RANKIN **TOM L. RANKIN**	Director
/s/ EVELYN V. FOLLIT **EVELYN V. FOLLIT**	Director	/s/ WILLIAM D. ROCKFORD **WILLIAM D. ROCKFORD**	Director
/s/ SHERRILL W. HUDSON **SHERRILL W. HUDSON**	Chairman of the Board and Director	/s/ PAUL L. WHITING **PAUL L. WHITING**	Director
/s/ JOSEPH P. LACHER **JOSEPH P. LACHER**	Director		

[THIS PAGE INTENTIONALLY LEFT BLANK]

[THIS PAGE INTENTIONALLY LEFT BLANK]

[THIS PAGE INTENTIONALLY LEFT BLANK]

TECO Energy **Corporate Officers**

TECO ENERGY EXECUTIVE OFFICERS

John B. Ramil
President and Chief Executive Officer

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

Deirdre A. Brown
Senior Vice President -
Corporate Strategy and Technology and Chief Ethics and Compliance Officer

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

Clark Taylor
President, TECO Coal Corporation

Phil L. Barringer
Senior Vice President -
Corporate Services and Chief Human Resources Officer

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

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

TECO ENERGY AND OPERATING COMPANY OFFICERS

Kim M. Caruso
Treasurer, TECO Energy Inc.

Charles O. Hinson III
Vice President -
State and Community Relations, Tampa Electric Company

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

Bruce Narzissenfeld
Vice President -
Marketing, Customer Service, Business Development and Fuels Operations, Tampa Electric Company

William A. Stark
Vice President -
Controller, TECO Coal Corporation

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

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

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

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

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

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

**Mr. Childress retired January 1, 2013.*

TECO ENERGY

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 1, 2013, 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 651-450-4064 (outside the U.S.)
By Web: shareowneronline.com

TRANSFER AGENT & REGISTRAR
Wells Fargo Shareowner Services
P.O. Box 64856, St. Paul, MN 55164-0856

DIVIDEND REINVESTMENT
The company offers a Dividend Reinvestment and Common Stock Purchase Plan that allows common shareholders of record to purchase additional shares of common stock. All correspondence concerning this plan should be directed to the Plan Agent:
Wells Fargo Shareowner Services
P.O. Box 64856, St. Paul, MN 55164-0856

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

For fast access to TECO Energy's website, **tecoenergy.com**, scan the QR code (left) with a barcode reader app on your smart phone.