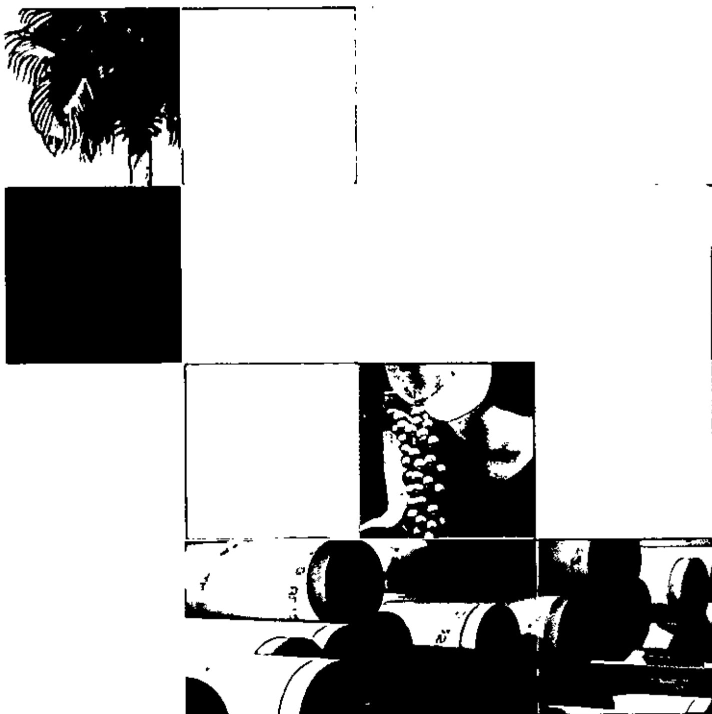
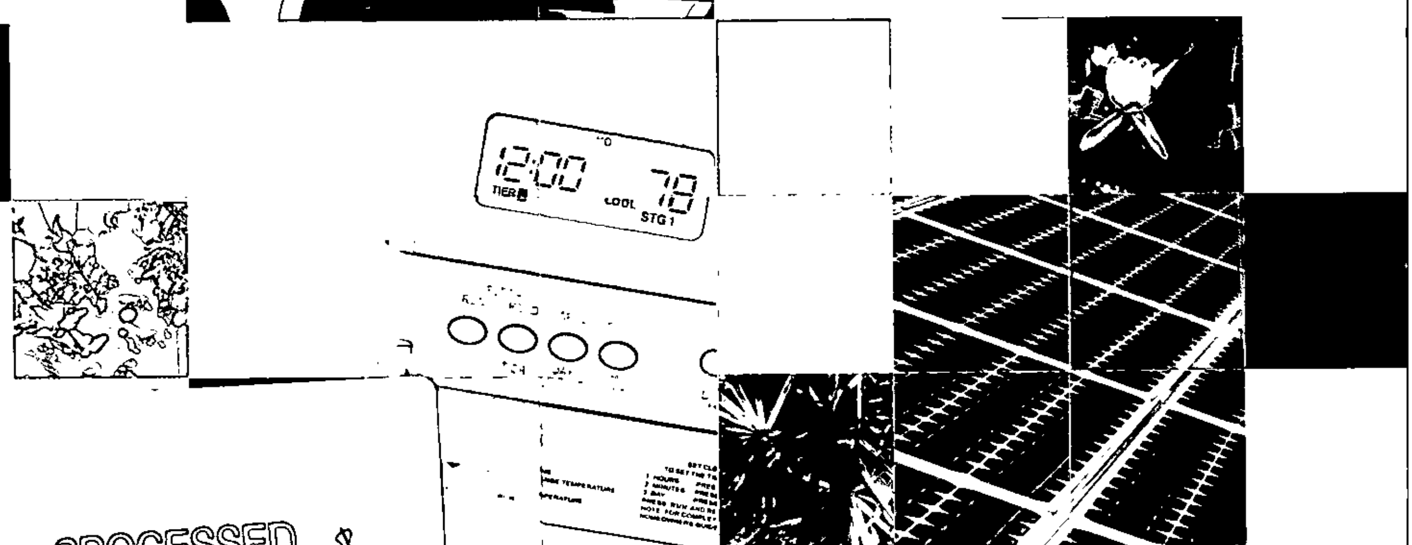
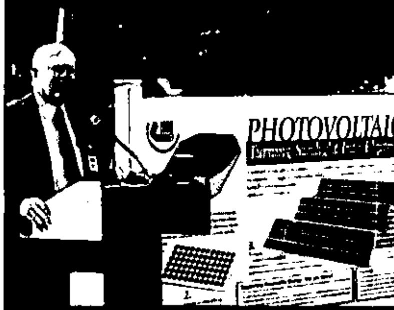
TECO ENERGY



TECO Energy, Inc. 2007 Annual Report





GREEN POWER: *Tampa Electric President Chuck Black dedicates a new photovoltaic array at a high school in Tampa. Not only does the array provide electricity to the state's grid, it also serves as a useful teaching tool for the school's faculty.*

TECO ENERGY

OUR PURPOSE

A commitment to inspiring trust, achieving excellence, providing environmental leadership and rising to any challenge we face, which will benefit our customers, team members and shareholders, and the communities we serve.

OUR VISION

A company where people want to work, an organization that is an asset to the community, and a business in which investors want to invest.

OUR VALUES

Safety

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

Integrity

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

Respect for Others

- *We value differences, development, teamwork, open communications and continuous learning.*
- *We treat all stakeholders, including customers, team members, business partners and investors, fairly.*
- *We communicate openly and in a timely way with all stakeholders.*

Achievement with a Sense of Urgency

- *We work, as a team, with speed, sound judgment and diligence toward common goals.*
- *We support the business strategy and accept ownership and personal responsibility for our actions.*

Customer Service

- *We realize customers are why our organization exists.*
- *We treat them fairly and provide high-quality services.*

TECO ENERGY, INC.

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

Table of Contents

TECO Energy Annual Report

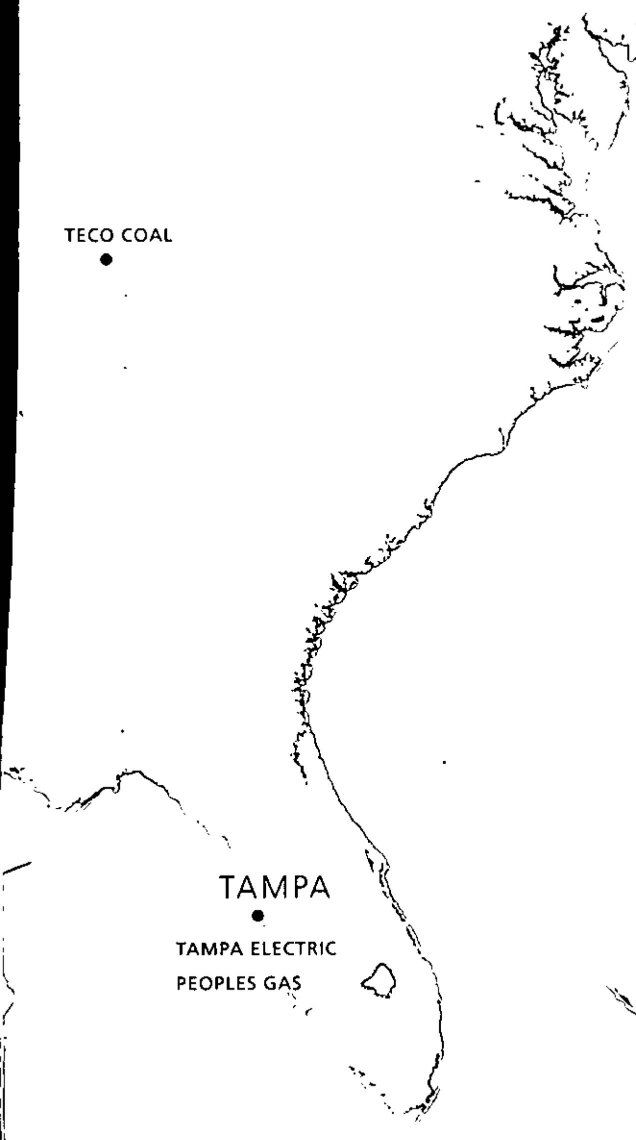
Our Businesses

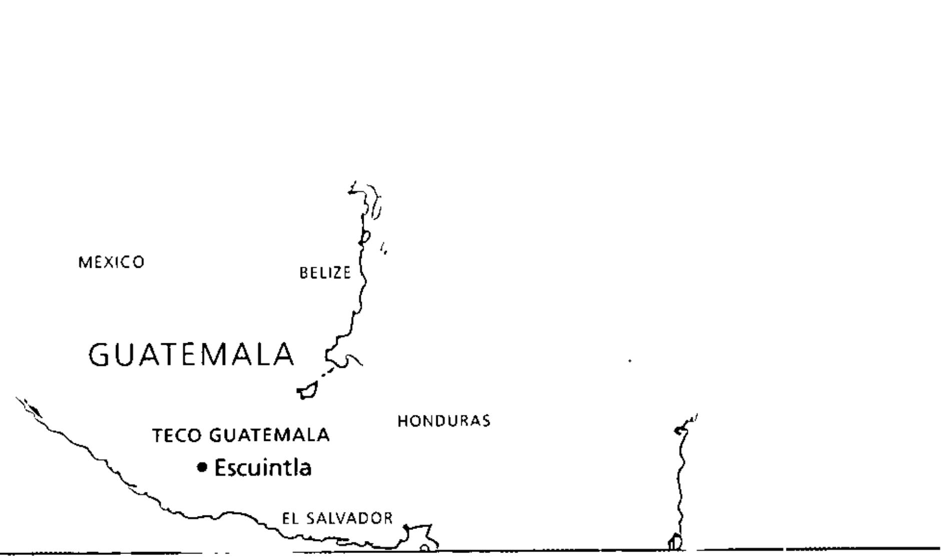
Tampa Electric is a regulated electric utility with almost 4,400 megawatts of generating capacity. The company's service area covers 2,000 square miles in West Central Florida, including nearly all of Hillsborough County and parts of Polk, Pasco and Pinellas counties. More than 666,000 residential, commercial and industrial customers depend on Tampa Electric for reliable power.

Peoples Gas is Florida's leading provider of regulated natural gas distribution services. With a presence in most of the state's major metropolitan areas, Peoples Gas brings reliable, environmentally friendly natural gas service to more than 334,000 residential, commercial and industrial customers.

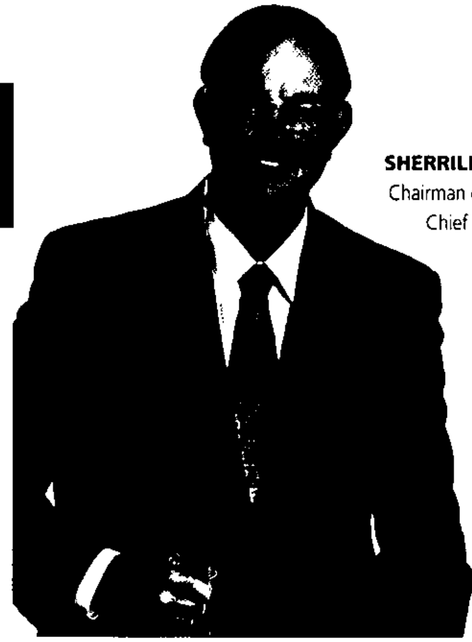
TECO Coal subsidiaries own and operate low-sulfur coal mines and coal preparation facilities in Kentucky and Virginia. These companies mine, process and ship more than nine million tons of conventional coal annually to the United States and European steel industries, as well as domestic utilities and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

TECO Guatemala subsidiaries own two power plants with long-term power purchase agreements in Guatemala: the 120-megawatt, coal-fired San José Power Station and the 78-megawatt, oil-fired Alborada Power Station. TECO Guatemala's operations also include a 24 percent interest in DECA II, which has an interest in EEGSA, Guatemala's largest electric distribution utility and other affiliated energy-related companies.





Dear Shareholders:



SHERRILL W. HUDSON
Chairman of the Board and
Chief Executive Officer

In 2007, our businesses delivered again on the commitments we've made to our investors. Working together, our team delivered results of $1.07 per share on a non-GAAP basis, at the top of our guidance range of $0.97 to $1.07.

We also were pleased to deliver an increase to our annual dividend. In May 2007, we announced that our quarterly dividend would increase by 2.6 percent to 19.5 cents per share.

Financial Accomplishments

TECO Energy's balance sheet strengthened significantly in 2007, thanks to our accelerated corporate debt retirement program and the sale of TECO Transport. In 2007, we retired a total of $764 million in parent and parent-guaranteed debt. This includes $357 million of 2007 maturities and $407 million of the $500 million of total 2007 and 2008 accelerated debt retirement that we committed to earlier in the year.

The credit rating agencies took notice of these accomplishments. Both Moody's and Standard and Poor's took positive action on TECO Energy's credit ratings in 2007, with both moving TECO Energy into the investment-grade category.

These credit rating improvements are another demonstration of meeting our commitment to return to investment-grade credit at the TECO Energy level.

Climate Change

From our experience in 2007 and as we look ahead to 2008, we are facing a time of unprecedented debate on environmental issues.

Climate change is the leading issue in the developed world. Clearly, it is the top issue affecting the energy industry – and we believe it will continue to be for some time.

Concerns about climate change have the potential to impact all of our businesses to some extent, but Tampa Electric will feel the most direct effects.

Tampa Electric has deferred the use of integrated gasification combined-cycle (IGCC) technology until all the rules and regulations for carbon reduction are in place. We felt to do otherwise would expose our shareholders and our customers to unnecessary risks.

Over the next several years, Tampa Electric expects to use natural gas, complemented by energy efficiency and renewables to meet its customers' growing needs.

Our Businesses

Tampa Electric continued to experience customer growth of 1.9 percent in 2007, but energy sales growth reflected the continued downward trend in per-customer usage patterns, primarily from smaller, more efficient multi-family residential construction, price elasticity and more efficient appliances.

The company continued to make great progress on its $1.2 billion environmental improvement program. The first of four nitrogen oxide (NOx) control units was installed on Big Bend Power Station Unit 4 mid-year.

While Peoples Gas, our natural gas utility business experienced customer growth of 1.6 percent for the year, it also experienced a similar slowdown in per-customer usage for similar reasons. Peoples Gas' customer growth slowed from its historic levels due to the slowdown in Florida's housing market.

TECO Coal's sales in 2007 were lower than in 2006 as the company responded to weaker coal markets. Market weakness resulted from mild weather, which drove high customer inventory levels.

Even with the weak coal markets, TECO Coal was able to maintain its margins due to hard work on the cost control front and measures taken in 2006 and early 2007 to move into more profitable mining areas.

TECO Guatemala had another strong year, with excellent operation at its two generating facilities and good returns from its ownership interest in Guatemala's largest distribution utility, EEGSA, and the unregulated affiliate companies.

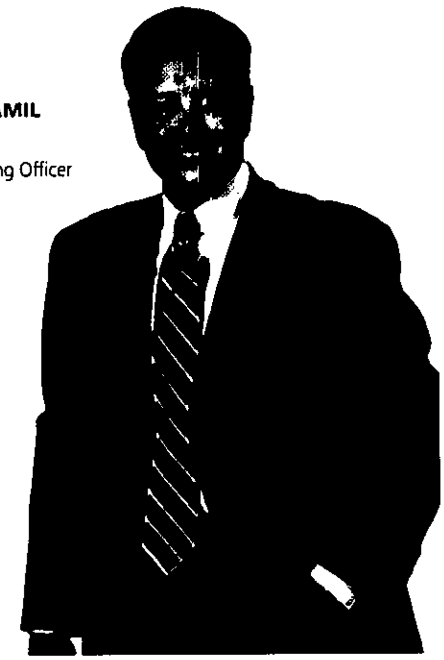
TECO Transport was part of the TECO Energy family of companies for many years, and provided efficient, reliable and cost-effective transportation services to Tampa Electric and third parties over that time.

In early 2007, we announced our intent to explore the market for a purchaser for TECO Transport. The resulting sale closed late in the year, allowing TECO Energy to increase its emphasis on our utility businesses.

2008 Strategic Focus

As we look forward to 2008 and beyond, we continue to focus on our utilities and their growth needs as our top priority, followed by growth in our other businesses.

Tampa Electric will require significant capital investment for the foreseeable future for investments in its delivery system to address storm hardening requirements and new transmission requirements, in addition to normal investments to support growth and system reliability.



JOHN B. RAMIL
President and
Chief Operating Officer

Tampa Electric also will need to make significant investments in new generating facilities beginning in 2008 to meet its customers' peak load needs in the 2009-2012 period, plus its 2013 baseload generation need.

With appropriate regulatory support, this increase in investment in the company's facilities should allow continued reliable service, along with the opportunity for Tampa Electric to grow its contribution to earnings over time.

Peoples Gas also will need capital to grow its system to bring environmentally friendly natural gas to more consumers and businesses in the state.

To make the continued capital investments to meet growing demand and maintain the reliable service to which our utility customers are accustomed and to address continued cost increases for labor and materials, both utilities expect to need base rate relief in the 2009 period.

At TECO Coal, coal prices for both domestic and international customers have improved, driven primarily by international factors, such as demand from China and the weaker U.S. dollar and a gradual reduction in user inventories.

With TECO Coal's proven strategy of selling its production under longer-term contracts, the increasing coal prices will be marginally seen in 2008 and more fully reflected in 2009 results.

TECO Guatemala expects good operations and utility customer growth again in 2008. As occurs every five years, the retail rates charged by EEGSA will be set this year for the next five-year period. The process will not be completed until the summer, and the company is actively participating in the process with its partners, Iberdrola and the Portuguese energy company, EDP.

TECO Guatemala also expects to participate in the new request for proposals for 200 megawatts of base-load coal-fired capacity in Guatemala, with a requested in-service date in 2012.

2008 Guidance

We have projected earnings for 2008 in a range of $0.95 to $1.10 per share. Earnings at this level reflect the continued strength of our operating companies, but also the loss of earnings from TECO Transport.

As we work to provide those results for you, our shareholders, we hold ourselves and our decisions up against our five core values: safety, integrity, respect for others, achievement with urgency and customer service. Doing so, we know that we're doing our best to earn your continued support.

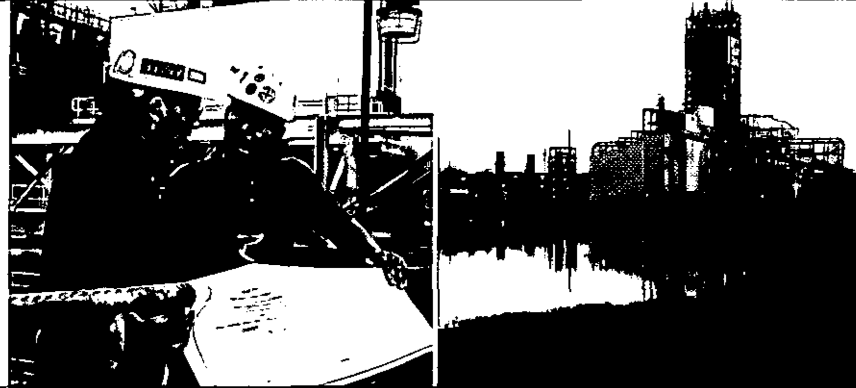
We thank you for your investment, and for your confidence in our company.

Sincerely,

Sherrill W. Hudson JLB.Ral

Sherrill W. Hudson
Chairman and
Chief Executive Officer

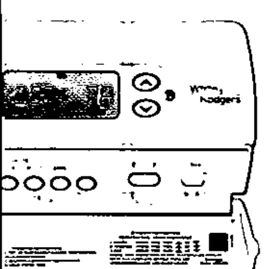
John B. Ramil
President and
Chief Operating Officer



WORLD LEADERSHIP:
Powered by clean coal technology, Tampa Electric's Polk Power Station Unit 1 is the world leader in the production of electricity from synthesis gas, which offers dramatically lower emissions than conventional coal-fired generation.

Tampa Electric

ENERGY EFFICIENCY:
In 2007, Tampa Electric received regulatory approval for 13 new energy efficiency programs and improvements to nine existing programs. Energy Planner, one of the new offerings, gives customers near real-time price signals on their energy consumption, letting them modify their usage to save energy and money.



Continued Growth, Energy Efficiency

Despite negative news surrounding the U.S. housing market, Florida and the West Central Florida region served by Tampa Electric continue to experience good population growth, although at a slower pace than the previous several years of robust growth.

The Census Bureau found in its most recent report that Florida added 194,000 new residents in 2007, and the Tampa Bay area experienced an increase in the civilian work force of nearly 20,000.

Tampa Electric has seen a slowing of customer growth from the very strong growth enjoyed earlier this decade, primarily due to the slowdown in the housing market. Despite this, the company still enjoyed 1.9 percent customer growth in 2007, which is above the national average.

At the same time, our residential customers are using slightly less energy than they have in the past. Factors affecting usage patterns include more efficient appliances and lighting, a move toward more energy-efficient multi-family residences and voluntary conservation by customers.

As customers look for ways to save energy for economic and environmental reasons, Tampa Electric is working to provide new and innovative means for them to do so. In 2007, the company received approval from the Florida Public Service Commission for 13 new additions to the company's roster of energy-efficiency programs, as well as updates to nine longtime programs.

New programs include Energy Planner, which gives customers near real-time price signals on their energy use and allows them to make informed decisions on conserving energy based on that data. In the company's highly successful Energy Planner pilot study, customers saved an average of a month's worth of electricity costs over a one-year period. Tampa Electric is one of only a few utilities in the Southeast that offers a similar program.

Other new energy efficiency programs include a low-income program that provides energy-saving equipment like compact fluorescent light bulbs to qualifying residents.

Almost 400,000 customers have participated in Tampa Electric's energy efficiency programs since their inception in 1979.

Environmental Accolades

In January 2008, the Chicago Climate Exchange (CCX) applauded Tampa Electric for meeting the program's Phase I greenhouse gas commitment of a 4 percent carbon dioxide (CO_2) reduction. With an actual reduction of more than 20 percent, the company far surpassed CCX's target.

Launched in 2003, CCX is the world's first and North America's only active voluntary but legally-binding integrated trading system to reduce emissions of all six major greenhouse gases.

In addition to its CO_2 reduction, by year-end 2007, the company had reduced sulfur dioxide (SO_2) by 93 percent, nitrogen oxide (NOx) by 60 percent, particulate matter by 70 percent and mercury (Hg) by 70 percent, all compared to 1998 levels.

No other utility in the state and few in the nation have made similar reductions.

With regard to furthering its reduction of NOx, Tampa Electric continues to make progress on the final

ENVIRONMENTAL COMMITMENT: *The repowered natural gas-fueled H.L. Culbreath Bayside Power Station is a central component to Tampa Electric's 10-year, $1.2 billion environmental improvement program, now in its final stages.*

component of its landmark 10-year, $1.2 billion environmental improvement program. The company is in the final stages of the $330 million installation of state-of-the-art selective catalytic reduction (SCR) equipment at Big Bend Power Station.

One SCR unit has already been installed and is operating; a second is nearing completion and expected to be in service by May 2008. The remaining two units will be operating by May 2010.

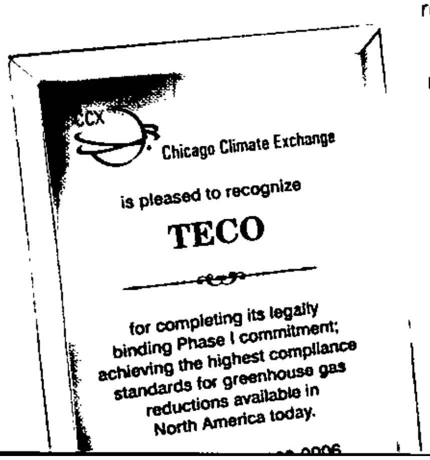
Investment to Meet Demand

With the uncertainty inherent in future regulations related to greenhouse gas emissions, in late 2007, the company moved away from its original plan to construct a baseload coal-fired 630-megawatt integrated gasification combined-cycle (IGCC) facility at its Polk Power Station.

While the ultimate decision on how to meet Tampa Electric's 2013 baseload need will be made in 2008, the company presently expects it will construct a natural gas-fueled combined-cycle facility at the same location and also utilize energy efficiency and renewables.

In early 2008, the company announced its intent to build five 60-megawatt natural gas-fired peaking units to meet peak demand for the next several years. These units would be located at H.L. Culbreath Bayside Power Station and Big Bend Power Station. In addition to meeting growing customer demand, these units will provide the "black start" capability now required to meet federal reliability standards.

To complement the need for conventional generation, Tampa Electric issued a request for proposals in late 2007, with the goal of securing 150 megawatts of power from renewable sources. The company is in the final stages of evaluating those proposals in early 2008.



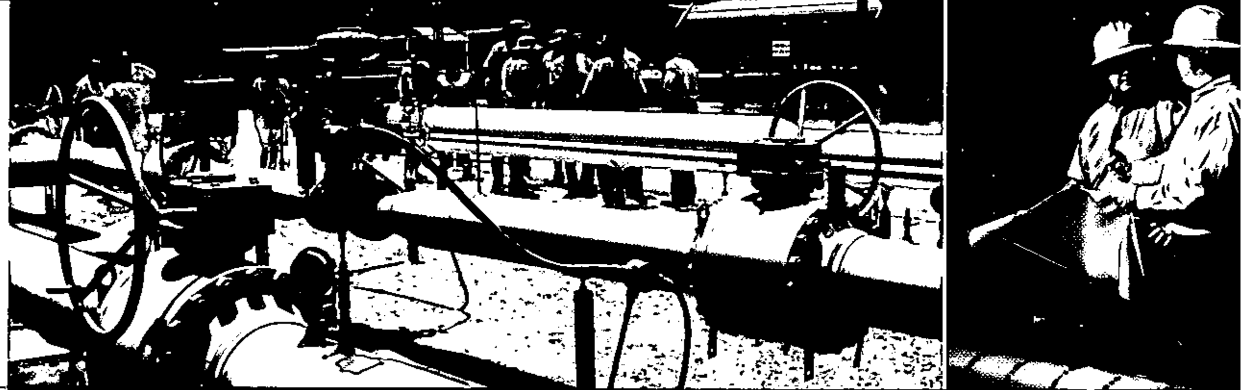
CARBON REDUCTION: *In early 2008, Tampa Electric was recognized for its carbon reductions by the Chicago Climate Exchange, the world's first and North America's only voluntary, legally-binding integrated trading system to reduce greenhouse gas emissions.*

On the energy delivery side of the business, Tampa Electric is investing significantly to expand its portion of the state's 230,000-volt transmission network to maintain the reliable flow of electricity in accordance with federal standards. Several major infrastructure projects are in planning and implementation, totaling around 100 miles of new high-voltage equipment by 2011.

These projects are in addition to efforts being required as a result of storm-hardening requirements at the state level and new transmission requirements at the federal level.

Tampa Electric has not sought a base rate increase since 1992. Since that time, the company has added more than 200,000 customers and made significant investments in facilities and infrastructure, including baseload and peaking generating capacity additions to reliably serve its growing customer base. The company expects a continued high level of capital investment and higher levels of non-fuel operations and maintenance expenditures.

Based on our current forecast for energy sales growth, expected higher operations and maintenance expenses and ongoing higher levels of capital investment, Tampa Electric's forecasted return on equity is expected to fall below the bottom of its range for the full year 2008. The company expects this will cause it to need base rate relief in 2009.



Peoples Gas

REDUCING CARBON: *By adding highly efficient natural gas appliances to the typical all-electric home, residential customers can significantly reduce their carbon footprint.*

Peoples Gas had customer growth of 1.6 percent in 2007, after exceptional growth in the 2004 to 2006 period. This lower growth was a function of the weaker housing market statewide.

Peoples Gas serves some areas of Florida that experienced the most robust growth during the housing boom; these areas now have the highest inventories of homes in the state. Studies show that normal growth should return as excess inventory is absorbed, possibly in the 2009 period.

The current housing market is also contributing to lower sales to industrial customers in the wallboard, asphalt and concrete industries.

Like all natural gas distribution utilities, Peoples Gas is adjusting to lower per-customer usage due to improving appliance efficiency. As customers replace gas appliances with newer, more efficient models, usage tends to decline.

The national and statewide move toward a carbon-constrained future poses opportunities for natural gas as a premium fuel. In addition to helping supply natural gas to new generating units in Florida, there are many benefits to using natural gas directly in residential applications. By adding four highly efficient natural gas appliances – tankless water heater, range, dryer and furnace – to the typical all-electric home, residential customers in Florida can reduce their carbon footprint by as much as 4,000 pounds per year.

ADDING CUSTOMERS: *In 2007, Peoples Gas signed several new construction projects in Florida and began work on two extensions of its gas main in and around the Orlando area.*

Likewise, Peoples Gas is partnering with the solar industry on ways to promote non-traditional uses of natural gas, such as tankless gas water heaters as the backup fuel supply for solar water heaters in residential settings.

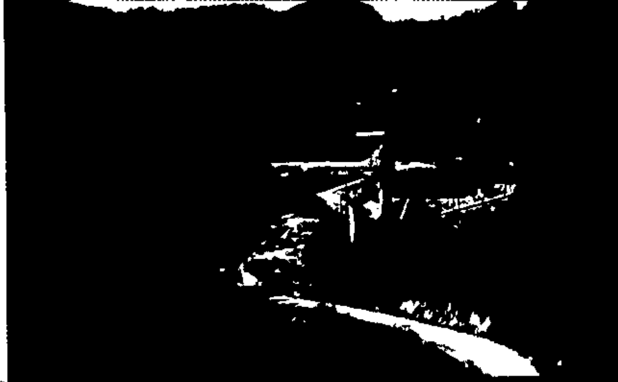
And, the company continued to build on its more than 20-year history of efforts to promote energy efficiency and conservation. More than 200,000 homes have participated in Peoples Gas conservation programs to date.

In 2007, Peoples Gas signed on to serve several new construction projects totaling about 9,000 new homes in Florida. The company also worked with Hillsborough County to incorporate natural gas into a new processing plant, which has an expected annual load of 1.4 million therms.

Investments in the Peoples Gas system included a new delivery station at Port Manatee to serve industrial customers. Work began on two extensions to the company's gas main in and around Orlando; one will serve a new amusement park now in development.

Peoples Gas also opened a technical training center in Central Florida in 2007. The facility will provide team members with hands-on training in standardized procedures to ensure safe and reliable natural gas service.

Due to higher operating costs, continued investment in Peoples Gas' distribution system and higher costs associated with new safety requirements, such as pipeline integrity, the company's return on equity levels are below the bottom of its allowed range. As a result, Peoples Gas expects to need rate relief in 2009.



TECO Coal

NATIONAL RECOGNITION: *TECO Coal received a "Sentinels of Safety" award in 2007, honoring the company's ironclad commitment to the safety of its team members, as reflected at its Premier Elkhorn operations.*

With market conditions that began improving during the second half of 2007, TECO Coal projects higher sales in 2008, and virtually all of the production planned for the year is under contract and priced at slightly higher average prices than in 2007.

The coal markets are currently experiencing very strong pricing from increased international demand in the high-growth nations of China and India and supply problems in certain key exporting countries.

Domestic consumers of coal are responding to the rising prices by contracting for future needs now, which should lead to improved realized prices in 2009.

The company benefited in 2007 from actions taken in 2006 and early 2007 to move into less costly mining production areas and optimize its mining plans.

However, the cost of production is expected to rise in 2008 due to the escalating costs for diesel fuel, tires, chemicals and other petroleum-related products affecting many industries. In the mining industry in particular, new safety requirements will also contribute to higher costs.

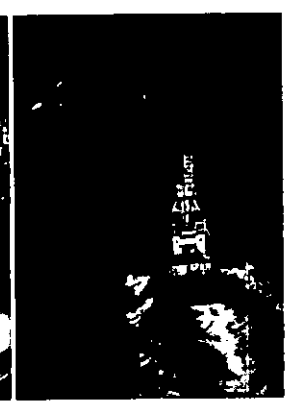
Despite these cost challenges, certain aspects of TECO Coal's business are non-negotiable: safety and environmental protection.

In 2007, reflecting the company's relentless focus on safety excellence, TECO Coal received a prestigious national safety award. The "Sentinels of Safety" award, which was presented to TECO Coal's Premier Elkhorn Coal Company, is the highest nationally-recognized safety award in the United States mining industry. It is co-sponsored by the National Mining Association and the Mining Safety and Health Administration. This follows a number of other honors TECO Coal and its affiliates have received for their excellence in safety.

TECO Coal team members also work continuously to reclaim and improve mined areas and enhance wildlife habitat. Over the past decade, TECO Coal and its affiliates have been honored 12 times by various reforestation organizations and by the states of Kentucky and Tennessee, recognizing their exceptional environmental reclamation accomplishments.

TECO Transport

In late 2007, TECO Energy completed the sale of TECO Transport. The sale was a very positive event for TECO Energy, allowing the company to make further progress on its accelerated debt retirement plans and further focus on its utility businesses.



TECO Guatemala

STRONG PERFORMANCE: *TECO Guatemala's two power plants had excellent availability in 2007, particularly San José Power Station, which would rank in the top 1 percent of similar-sized coal units in the United States.*

The TECO Guatemala business segments include the San José Power Station; the Alborada Power Station; and an ownership interest in DECA II, which has an interest in Guatemala's largest distribution utility, Emprésa Eléctrica de Guatemala (EEGSA). Other DECA II businesses include energy-related companies that provide, among other things, electricity transmission services, wholesale power sales to unregulated electric customers, engineering services and telecommunication services. Each of these segments had strong growth in 2007.

San José Power Station had exceptional performance, with availability that would put it in the top 1 percent of coal units in the United States in the same size range. Alborada Power Station also had good performance in 2007.

In addition to its existing operations, TECO Guatemala is pursuing a future growth opportunity within Guatemala. Two local distribution utilities that serve rural Guatemala have issued a request for proposals for a 200-megawatt baseload coal-fired power station, with a requested in-service date in 2012.

COMMUNITY SUPPORT: *In early 2008, the company, including TECO Guatemala President Gordon Gillette (top right), celebrated the dedication of a new primary school funded by the company. The new school, near the Alborada Power Plant, will educate around 560 students and is one of four schools TECO Guatemala supports near its facilities.*

TECO Guatemala expects to submit a bid to serve this capacity when bids are due in April. A long-term power sales agreement would then be awarded to the successful bidder later in 2008. TECO Guatemala's response to this bid is envisioned as an expansion to the San José plant.

The normal five-year review of retail power distribution rates for EEGSA will take place in 2008. The final decision in this review is anticipated in mid-summer, and while the company can't predict the outcome of the process, it is actively participating in it with its partners, Iberdrola and EDP.

In early 2008, TECO Guatemala and TECO Energy team members celebrated the dedication of Escuela Los Lirios, a new public school funded by the company and located near its Alborada Power Station. This primary school, which will educate an estimated 560 students, is the latest in a series of significant investments the company has made as part of its commitment to education in the communities near its operations.

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, 2007

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

SEC Mail Processing Section
MAR 19 2008
Washington, DC 101

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

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

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

Indicate by check mark if TECO Energy, Inc. is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☒ NO ☐

Indicate by check mark if the registrant is 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 registrant (1) has 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) has been subject to such filing requirements for the past 90 days. 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 registrant's 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. (Check one):

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 nonaffiliates of the registrant as of June 29, 2007 was $3,617,304,251 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. 25, 2008 was 210,915,193.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement relating to the 2008 Annual Meeting of Shareholders of TECO Energy, Inc. are incorporated by reference into Part III.

PART I

Item 1. BUSINESS.

TECO ENERGY

TECO Energy, Inc. (TECO Energy) was incorporated in Florida in 1981 as part of a restructuring in which it became the parent corporation of Tampa Electric Company. TECO Energy and its subsidiaries had 4,300 employees as of Dec. 31, 2007.

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

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

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

Tampa Electric Company, a Florida corporation and TECO Energy's largest subsidiary, has two business segments. Its **Tampa Electric** division **(Tampa Electric)** provides retail electric service to more than 668,000 customers in West Central Florida with a net winter system generating capability of 4,602 megawatts (MW). **Peoples Gas System (PGS)**, the gas division of Tampa Electric Company, is engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in Florida. With more than 334,000 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 2007 was 1.4 billion therms.

TECO Coal Corporation (TECO Coal), a Kentucky corporation, has 13 subsidiaries, located in Eastern Kentucky, Tennessee and Virginia. These entities own interests in coal processing and loading facilities, mineral rights, own or operate surface and underground mines, and owned synthetic fuel production facilities, prior to the program's expiration on Dec. 31, 2007.

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

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

TWG Merchant, Inc. (TWG Merchant), a Florida corporation, had subsidiaries that formerly held interests in merchant power projects. TWG Merchant continuing operations included the results of operations for the uncompleted Dell power plant, which was sold in 2005 and the uncompleted McAdams power plant, the turbines from which were sold to Tampa Electric in 2006 and the balance of the plant sold to an unrelated party in 2006. Effective with 2006 results, all assets were divested and any residual results of operations were included in the "Other and eliminations" segment.

Revenues from Continuing Operations

(millions)	*2007*	*2006*	*2005*
Tampa Electric	$2,188.4	$2,084.9	$1,746.8
PGS	599.7	577.6	549.5
Total regulated businesses	2,788.1	2,662.5	2,296.3
TECO Coal	544.5	574.9	505.1
TECO Guatemala [1]	8.0	7.6	7.7
TECO Transport	290.3	308.5	278.2
TWG Merchant	—	—	0.4
	3,630.9	3,553.5	3,087.7
Other and eliminations	(94.8)	(105.4)	(77.6)
	$3,536.1	$3,448.1	$3,010.1

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

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

Discontinued Operations/Asset Dispositions

TECO Energy completed a number of asset dispositions in 2007, 2006, and 2005 as part of a business strategy to focus on the electric and gas utilities and to eliminate exposure to the merchant power sector.

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

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

In 2005, TWG Merchant sold its membership interest in Commonwealth Chesapeake Power Station (CCC) in Virginia and substantially all the assets of the Dell Power Station in Arkansas. BCH Mechanical, Inc. (BCH Mechanical) was also sold in 2005. In 2005, TECO Energy completed the sale and transfer of the Union and Gila River project companies (TPGC) (see **Notes 16** and **20** to the TECO Energy **Consolidated Financial**

Statements). TPGC's results are accounted for as discontinued operations for 2005. Revenues from the discontinued operations of TPGC in 2005 were $109.1 million. Net income from the discontinued operations of TPGC were $65.1 million in 2005.

Results for CCC, BCH Mechanical and TECO Thermal have been accounted for as discontinued operations for all periods reported. Revenues from these discontinued operations were $0.8 million and $10.6 million in 2006 and 2005, respectively (see **Notes 16** and **20** to the TECO Energy **Consolidated Financial Statements**).

TAMPA ELECTRIC—Electric Operations

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

Tampa Electric had 2,531 employees as of Dec. 31, 2007, of which 902 were represented by the International Brotherhood of Electrical Workers and 242 were represented by the Office and Professional Employees International Union.

In 2007, approximately 46% of Tampa Electric's total operating revenue was derived from residential sales, 30% from commercial sales, 9% from industrial sales and 15% from other sales, including bulk power sales for resale. The sources of operating revenue and megawatt-hour sales for the years indicated were as follows:

Operating Revenue

(millions)	*2007*	*2006*	*2005*
Residential	$1,017.9	$ 956.7	$ 838.1
Commercial	653.6	602.4	516.4
Industrial—Phosphate	73.0	61.5	63.3
Industrial—Other	118.2	113.0	96.3
Other retail sales of electricity	178.4	162.1	140.3
Total retail	2,041.1	1,895.7	1,654.4
Sales for resale	69.0	71.1	50.6
Other	78.3	118.1	41.8
	$2,188.4	$2,084.9	$1,746.8

Megawatt-hour Sales

(millions)	*2007*	*2006*	*2005*
Residential	8,871	8,721	8,558
Commercial	6,542	6,357	6,234
Industrial	2,366	2,279	2,478
Other retail sales of electricity	1,754	1,668	1,642
Total retail	19,533	19,025	18,912
Sales for resale	905	862	773
Total energy sold	20,438	19,887	19,685

No significant part of Tampa Electric's business is dependent upon a single customer or a few customers, the loss of any one or more of whom would have a significant adverse effect on Tampa Electric. The Mosaic Company, a large phosphate producer, is Tampa Electric's largest customer and represented less than 2% of Tampa Electric's 2007 base revenues.

Tampa Electric's business is not highly seasonal, but winter peak loads are experienced due to electric space heating, fewer daylight hours and colder temperatures, and summer peak loads are experienced due to the use of air conditioning and other cooling equipment.

Regulation

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

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

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

Tampa Electric's rates and allowed return on equity (ROE) range of 10.75% to 12.75% with a midpoint of 11.75% are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, the FPSC or other interested parties. Tampa Electric has not sought a base rate increase since 1992. Since that last rate proceeding, Tampa Electric has earned within its allowed return on equity (ROE) range while adding more than 200,000 customers and making significant investments in facilities and infrastructure, including baseload and peaking generating capacity additions to reliably serve the growing customer base, and it expects a continued high level of capital investment and higher levels of non-fuel operations and maintenance expenditures. After dropping to the bottom of its allowed ROE range in the middle of 2007, by the end of 2007 Tampa Electric's 13-month moving average regulatory ROE was 11.4% resulting from the positive impact of favorable weather in the second half of 2007, as well as lower depreciation expense and lower property taxes in the second half of the year. However, based on its current lower forecast for energy sales growth, expected higher operations and maintenance expenses and ongoing higher levels of capital investment, Tampa Electric's forecasted ROE is expected to go below the bottom of its allowed range for the full year 2008. This is expected to cause a need for base rate relief for Tampa Electric in 2009.

Fuel, purchased power, conservation and certain environmental costs are recovered through levelized monthly charges established pursuant to the FPSC's cost recovery clauses. These charges, which are reset annually in an FPSC proceeding, are based on estimated costs of fuel, environmental compliance, conservation programs and purchased power and estimated customer usage for a specific recovery period, with a true-up adjustment to reflect the variance of actual costs from the projected costs. The FPSC may disallow recovery of any costs that it considers imprudently incurred. In September 2007, Tampa Electric filed with the FPSC for approval of fuel and purchased power, capacity, environmental and conservation cost recovery rates for the period January 2008 through December 2008. In November 2007, the FPSC approved Tampa Electric's requested changes. The rates include the impacts of natural gas and coal prices expected in 2008, the refund of the overestimated 2007 fuel and purchased power expenses, the collection of previously unrecovered 2006 fuel and purchased power expenses, the proceeds from the actual and projected sale of excess sulfur dioxide (SO_2) emissions allowances in 2007 and 2008 and the operating cost for and a return on the capital invested on the selective catalytic reduction (SCR) projects to enter service on Big Bend Units 3 and 4 as well as the operating and maintenance (O&M) costs associated with the Big Bend Units 1 and 2 pre- SCR projects, which are required by the Environmental Protection Agency (EPA) Consent Decree and Florida Department of Environmental Protection (FDEP) Consent Final Judgment. In addition, the rates reflect the FPSC's September 2004 decision to reduce the annual cost recovery amount for water transportation services for coal and petroleum coke provided under Tampa Electric's contract with TECO Transport described below. See **Regulation-Cost Recovery Clauses-Tampa Electric** sections of **Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A)**.

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

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

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

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

Competition

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

In 1999, the FERC approved a three-year market-based sales tariff for Tampa Electric, which allows Tampa Electric to sell excess wholesale power at market prices within Florida. The FERC had already approved market-based prices for interstate sales for Tampa Electric and the other investor-owned utilities (IOUs) operating in the state; however, Tampa Electric is the only IOU in the state with intrastate market-based sales authority, except in its own balancing-authority area. In 2006 FERC reinstated Tampa Electric's authority to transact with Reedy Creek in its service territory at market-determined prices, which provides benefits for both entities.

There is presently competition in Florida's wholesale power markets, largely as a result of the Energy Policy Act of 1992 and related federal initiatives. However, the state's Power Plant Siting Act, which sets the state's electric energy and environmental policy and governs the building of new generation involving steam capacity of 75 megawatts or more, requires that applicants demonstrate that a plant is needed prior to receiving construction and operating permits. In 2003, the FPSC implemented rules that modified rules from 1994 that required IOUs to issue requests for proposals (RFPs) prior to filing a petition for Determination of Need for construction of a power plant with a steam cycle greater than 75 megawatts. The new rules became effective for requests for proposal for applicable capacity additions, prospectively. See **Regulation—Utility Competition—Electric** section of **MD&A**.

FERC requires transmission system owners to operate an Open Access Non-discriminatory Transmission Same-time Information System (OASIS) providing, via the Internet, access to transmission service information (including price and availability) and to rely exclusively on their own OASIS system for such information for effecting their own wholesale power transactions that make use of capacity on their own transmission system. This rule works to open access for wholesale power flows on transmission systems and requires utilities such as Tampa Electric, which own transmission facilities, to provide services to wholesale transmission customers comparable to those they provide to themselves on comparable terms and conditions, including price. Among other things, the rules require transmission services to be unbundled from power sales and owners of transmission systems to take transmission service under their own transmission tariffs. To facilitate compliance, owners must maintain Standards of Conduct to ensure that personnel involved in marketing wholesale power are functionally separated from personnel involved in transmission services and reliability functions. Tampa Electric, together with other utilities, has an OASIS system and believes it is in compliance with the Standards of Conduct.

Fuel

Approximately 59% of Tampa Electric's generation of electricity for 2007 was coal-fired, with natural gas representing approximately 40% and oil representing approximately 1%. Tampa Electric used its generating units to meet approximately 85% of the total system load requirements, with the remaining 15% coming from purchased power. Tampa Electric's average delivered fuel cost per million British thermal unit (Btu) and average delivered cost per ton of coal burned, have been as follows:

Average cost per million Btu:	*2007*	*2006*	*2005*	*2004*	*2003*
Coal	$ 2.57	$ 2.49	$ 2.25	$ 2.14	$ 2.02
Oil	$13.87	$13.39	$10.16	$ 6.81	$ 6.42
Gas (Natural)	$ 9.52	$ 9.61	$ 9.37	$ 7.14	$ 6.45
Composite	$ 5.05	$ 4.75	$ 4.79	$ 3.64	$ 2.83
Average cost per ton of coal burned	$60.72	$58.75	$53.00	$50.06	$48.32

Tampa Electric's generating stations burn fuels as follows: Bayside 1, which entered commercial operation in April of 2003, and Bayside 2, which entered commercial operation in January of 2004, burn natural gas; Big Bend Station, which has sulfur dioxide scrubber capabilities, burns a combination of high-sulfur coal, petroleum coke and No. 2 fuel oil; Polk Power Station burns a blend of high-sulfur coal, petroleum coke, which is gasified and subject to sulfur and particulate matter removal prior to combustion, natural gas and oil; and Phillips Station burns residual fuel oil.

Coal. Tampa Electric burned approximately 4.7 million tons of coal and petroleum coke during 2007 and estimates that its combined coal and petroleum coke consumption will be about 4.8 million tons for 2008. During

2007, Tampa Electric purchased approximately 82% of its coal under long-term contracts with seven suppliers, and approximately 18% of its coal and petroleum coke in the spot market. Tampa Electric attempts to maintain a portfolio of 60% long-term versus 40% spot contracts, but market conditions, actual deliveries and unit performance can change this portfolio on a year-by-year basis. Renegotiated contracts and reduced burn contributed to Tampa Electric not purchasing more spot tons in 2007. Tampa Electric expects to obtain approximately 66% of its coal and petroleum coke requirements in 2008 under long-term contracts with six suppliers and the remaining 34% 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 2007, approximately 66% of Tampa Electric's coal supply was deep-mined, approximately 26% was surface-mined and the remaining was a processed oil by-product known as petroleum coke. Federal surface-mining laws and regulations have not had any material adverse impact on Tampa Electric's coal supply or results of its operations. Tampa Electric, however, cannot predict the effect of any future mining laws and regulations.

Natural Gas. As of Dec. 31, 2007, Tampa Electric had contracted for 100% of the expected gas needs for the January 2008—September 2008 period and 83% for October 2008. It had already contracted for 55% of its November 2008 through March 2009 and 30% of its April 2009 through October 2009 expected gas supply needs. Additional volume requirements in excess of expected gas needs are purchased on the short-term spot market.

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

Franchises and Other Rights

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

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

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

Franchise fees payable by Tampa Electric, which totaled $37.3 million in 2007, are calculated using a formula based primarily on electric revenues and are collected on customers' bills.

Utility operations in Hillsborough, Pasco, Pinellas and Polk Counties outside of incorporated municipalities are conducted in each case under one or more permits to use state or county rights-of-way granted by the Florida Department of Transportation or the county commissioners of such counties. There is no law limiting the time for which such permits may be granted by counties. There are no fixed expiration dates for the Hillsborough County, Pinellas County and Polk County agreements. The agreement covering electric operations in Pasco County expires in 2023. A franchise agreement with the City of Tampa expired in September 2006, and negotiations for renewal were ongoing throughout 2007. A new, 25-year agreement has been negotiated and is pending before the Tampa City Council for review and approval. Tampa Electric cannot predict when the City Council will act on the pending agreement.

Environmental Matters

Consent Decree

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

The emission reduction requirements included specific detail with respect to the availability of the flue gas desulfurization systems (scrubbers) to help reduce SO_2, projects for NOx reduction efforts on Big Bend Units 1 through 4, and the repowering of the coal-fired Gannon Station to natural gas. The commercial operation dates for the two repowered Gannon units (now known as Bayside) were Apr. 24, 2003 and Jan. 15, 2004. The completed station has total station capacity of about 1,800 megawatts (nominal) of natural gas-fueled electric generation.

Tampa Electric completed installation of the SCR system for NOx control on Big Bend Unit 4 and put it in-service on Jun. 1, 2007. Tampa Electric is also installing SCRs on Big Bend Units 1, 2 and 3 with expected in-service dates for Unit 3 by May 1, 2008, Unit 2 by May 1, 2009 and Unit 1 by May 1, 2010. The engineering, design and construction of the SCRs are currently in progress. Tampa Electric's capital investment forecast includes amounts through 2012 for compliance with the NOx, SO_2 and particulate matter reduction requirements (see **Environmental Matters**—*Capital Expenditures* section below).

Emission Reductions

Projects to which Tampa Electric has committed under the Consent Decree and Consent Final Judgment will result in significant reductions in emissions. Since 1998, Tampa Electric has reduced annual SO_2, NOx, and particulate matter (PM) emissions from its facilities by 162,000 tons, 42,000 tons, and 4,000 tons, respectively. Reductions in SO_2 emissions were accomplished through the installation of scrubber systems on Big Bend Units 1 and 2 in 1999. Big Bend Unit 4 was originally constructed with a scrubber. The Big Bend Unit 4 scrubber system was modified in 1994 to allow it to scrub emissions from Big Bend Unit 3, as well. Currently, the scrubbers at Big Bend Station remove more than 95% of the SO_2 emissions from the flue gas streams.

The repowering of Gannon Station to Bayside Power Station in April 2003 (Bayside Unit 1) and January 2004 (Bayside Unit 2) resulted in the significant reduction in emissions of all pollutant types. Tampa Electric's decision to install additional NOx emissions controls on all Big Bend Units will result in the further reduction of emissions. By 2010, these projects are expected to result in the total phased reduction of NOx by 62,000 tons per year, which is a 90% reduction from 1998 levels.

To date, these projects have resulted in the reduction of SO_2, NOx and PM emissions by 93%, 60%, and 77%, respectively, below 1998 levels. In total, by 2010 Tampa Electric's system-wide emission reduction initiatives will result in the reduction of SO_2, NOx and PM emissions by 90%, 90%, and 72%, respectively, below 1998 levels. With these improvements in place, Tampa Electric's facilities will meet the same standards required of newer power generating facilities and help to significantly enhance the quality of the air in the community.

Due to pollution control co-benefits from the Consent Decree and Consent Final Judgment, reductions in mercury emissions have occurred due to the re-powering of Gannon Station to Bayside Station. At Bayside, where mercury levels have decreased 99% below 1998 levels, there are virtually zero mercury emissions. Additional mercury reductions are also anticipated from the installation of NOx controls at Big Bend Station, which would lead to a mercury removal efficiency of over 70%.

Carbon Reductions

Tampa Electric has historically supported voluntary efforts to reduce carbon emissions and has taken significant steps to reduce overall emissions at Tampa Electric's facilities. Since 1998, Tampa Electric has reduced its system-wide emissions of CO_2 by approximately 20%, bringing emissions to near 1990 levels. Tampa Electric expects emissions of CO_2 to remain near 1990 levels until the addition of the next baseload unit, which is expected after 2012. Tampa Electric estimates that the repowering to natural gas and the shut-down of the Gannon Station coal-fired units have resulted in a decrease in CO_2 emissions of approximately 4.8 million tons below 1998 levels. During this same timeframe, the numbers of retail customers and retail energy sales have risen by approximately 25%.

Tampa Electric's voluntary activities to reduce carbon emissions, also include membership in the U.S. Department of Energy's Climate Challenge (now Power Partners) program since 1994, voluntary annual reporting of GHG emissions through the EIA-1605(b) Report since 1995 and participation in the Chicago Climate Exchange (CCX), a voluntary but legally binding cap and trade program dedicated to reducing greenhouse gas emissions since 2003. Because of Tampa Electric's membership in the CCX, its reported CO_2 emissions are audited annually by the Financial Industry Regulatory Authority (formerly National Association of Securities Dealers), which has certified the results thus far. In January 2008, the CCX recognized Tampa Electric for achieving its Phase I GHG reduction commitment of 4% below the average of the years 1998 through 2001. Tampa Electric has committed to an additional 2 percent reduction in greenhouse gas emissions by 2010 for CCX Phase II.

There are pending initiatives on the federal and state levels to adopt climate legislation that would require reductions in greenhouse gas (GHG) emissions. Tampa Electric has made significant investments in emissions reductions that have demonstrated that coal can be utilized as an environmentally sound, economic and reliable electric generation fuel source. It is Tampa Electric's position that there are several key elements that should be included in any legislative plan addressing greenhouse gases. Tampa Electric supports an economy wide cap and trade system that directly provides allocations to regulated entities that actually reduce CO_2 emissions. Because Tampa Electric has already achieved substantial greenhouse gas reductions, it believes any climate policy must fully recognize these early reductions. Tampa Electric would support legislation that provides aggressive funding for the development of new technology that reduces, captures and sequesters greenhouse gases and ensure that compliance timelines are coordinated with the availability of such technology. Tampa Electric would support legislation that keeps energy prices affordable and not harm economic competitiveness. It believes that such economic certainty is also needed to promote major investment in new technology and that comprehensive strategies to reduce GHG on a global basis must include meaningful commitments from other developed and developing nations to reduce GHG emissions. For information concerning potential new state and/or federal legislation limiting CO_2 emissions, see the **Environmental Compliance—Carbon Reductions** section of **MD&A**.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party (PRP) for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2007, Tampa Electric Company has estimated its ultimate financial liability to be approximately $11.5 million, with the majority attributable to the Peoples Gas division, and this amount has been reflected in the consolidated financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

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

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

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

Capital Expenditures

In total, Tampa Electric spent an estimated $105.8 million in 2007 on environmental projects. Environmental expenditures are estimated at $94.9 million for 2008 and an additional $99.0 million in total for 2009 through 2012. These totals include the expenditures required to comply with the EPA Consent Decree and to undertake comprehensive environmental operations improvements at Big Bend Station, the largest project of which is to install SCRs on each of the coal-fired units.

In 2007, Tampa Electric spent approximately $78.9 million for compliance with the EPA Consent Decree requirements at Big Bend Station for early NOx and PM emissions reductions. Estimated expenditures for the on-going early NOx emission reductions in 2008 are estimated at $71.7 million and an additional $66.0 million in 2009-2012. In a letter dated Aug. 19, 2004, Tampa Electric notified the EPA that based on the results of a comprehensive study performed on Big Bend Station, Big Bend Units 1, 2, 3 and 4 would continue to be fired on coal and as such will comply with the applicable provisions of the Consent Decree associated with this decision, including installation of SCRs for the reduction of NOx.

In addition, Tampa Electric is undertaking a number of large environmental projects at Big Bend Station that were identified voluntarily to enhance environmental operations at the site, including the recycle/settling ponds, new slag de-watering bins that will replace the existing industrial waste water permitted slag pond system, a new gypsum storage area, and upgrades to the storm water system. Also, the company will remove the vast majority of coal-combustion product source material from the existing systems in conjunction with construction of the new/replacement systems. In 2007, Tampa Electric spent approximately $13.8 million on these environmental operations projects. Estimated expenditures for the continued implementation of these projects in 2008 are estimated at $10.4 million, with an additional $8.0 million in 2009-2012.

PEOPLES GAS SYSTEM—Gas Operations

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

Gas is delivered to the PGS system through three interstate pipelines. PGS does not engage in the exploration for or production of natural gas. PGS operates a natural gas distribution system that serves more than 334,000 customers. The system includes approximately 11,000 miles of mains and 6,000 miles of service lines. (See PGS' **Franchises** section below.)

In 2007, the total throughput for PGS was 1.4 billion therms. Of this total throughput, 9% was gas purchased and resold to retail customers by PGS, 69% was third-party supplied gas that was delivered for retail transportation-only customers, and 22% was gas sold off-system. Industrial and power generation customers consumed approximately 68% of PGS' annual therm volume, commercial customers used approximately 26%, and the balance was consumed by residential customers.

While the residential market represents only a small percentage of total therm volume, residential operations generally comprise almost 25% of total revenues.

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

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

(millions)	Revenues 2007	Revenues 2006	Revenues 2005	Therms 2007	Therms 2006	Therms 2005
Residential	$140.2	$146.0	$138.9	70.1	73.0	70.7
Commercial	158.4	164.4	173.8	370.9	375.7	380.3
Industrial	242.4	204.2	187.6	490.2	456.6	394.6
Power generation	14.6	14.0	13.7	471.7	395.7	291.7
Other revenues	37.4	43.3	35.5	—	—	—
Total	$593.0	$571.9	$549.5	1,402.9	1,301.0	1,137.3

PGS had 583 employees as of Dec. 31, 2007. A total of 90 employees in six of PGS' 15 operating divisions are represented by various union organizations.

Regulation

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

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

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through the purchased gas adjustment 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 sells to its customers. These charges may be adjusted monthly based on a cap approved annually in an FPSC hearing. The cap is based on estimated costs of purchased gas and pipeline capacity, and estimated customer usage for a specific recovery period, with a true-up adjustment to reflect the variance of actual costs and usage from the projected charges for prior periods.

Due to higher operating costs, higher depreciation expense due to a routine depreciation study approved by the FPSC in January 2007, continued investment in the distribution system and higher costs associated with recently required safety requirements, such as pipeline integrity safety, PGS' return on equity levels are below the bottom of its allowed range and therefore it expects to file for a base rate increase in 2008. For a description of the most recent adjustment, see the **Regulation – PGS Cost Recovery Clauses** section of **MD&A**.

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

The FPSC requires natural gas utilities to offer transportation-only service to all non-residential customers. As a result, PGS receives its base rate for distribution regardless of whether a customer decides to opt for transportation-only service or continue bundled service. PGS had approximately 13,600 transportation customers as of Dec. 31, 2007 out of 29,900 eligible customers.

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

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

Competition

PGS is not in direct competition with any other distributors of natural gas for customers within its service areas. 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. In general, PGS faces competition from other energy source suppliers offering fuel oil, electricity and, in some cases, propane. PGS has taken actions to retain and expand its commodity and transportation business, including managing costs and providing high quality service to customers.

In Florida, gas service is unbundled for all non-residential customers. In 2000, PGS implemented its "NaturalChoice" program offering unbundled transportation service to all eligible customers. This means that non-residential customers can purchase commodity gas from a third party but continue to pay PGS for the transportation of the gas.

Competition is most prevalent in the large commercial and industrial markets. In recent years, these classes of customers have been targeted by competing companies seeking to sell alternate fuels or transport gas through other facilities, thereby bypassing PGS facilities. In response to this competition, PGS has developed various programs, including the provision of transportation services at discounted rates. See the **Regulation—Utility Competition—Gas** section of **MD&A**.

Gas Supplies

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

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

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

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

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

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

Franchises

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

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

PGS' franchise agreements with the incorporated municipalities within its service area have various expiration dates ranging from the present through 2032. PGS expects to negotiate 10 to 12 franchises in 2008, the majority of which will be renewals of existing agreements. Franchise fees payable by PGS, which totaled $9.7 million in 2007, are calculated using various formulas which are based principally on natural gas revenues. Franchise fees are collected from only those customers within each franchise area.

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

Environmental Matters

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

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

Capital Expenditures

During the five years ended Dec. 31, 2007, PGS has not incurred any material capital expenditures to meet environmental requirements, nor are any anticipated for 2008 through 2012.

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 (either directly or indirectly through its subsidiaries) all of the common stock of Gatliff Coal Company, Rich Mountain Coal Company, Clintwood Elkhorn Mining Company, Pike-Letcher Land Company, Premier Elkhorn Coal Company, Perry County Coal Corporation, Bear Branch Coal Company, and all of the membership interests in TECO Synfuel Administration, LLC, TECO Synfuel Holdings, LLC and TECO Synfuel Operations, LLC. The TECO Coal subsidiaries own or control, by lease, mineral rights, and own or operate surface and underground mines, synthetic fuel production facilities and coal processing and loading facilities. TECO Coal produces, processes and sells bituminous, predominately low sulfur coal of steam, industrial and metallurgical grades.

TECO Coal subsidiaries currently operate 23 underground mines which employ the room and pillar mining method and 14 surface mines.

In 2007, TECO Coal subsidiaries sold 9.2 million tons of coal. All of this coal was sold to customers other than Tampa Electric. Of the total sold, 6.0 million tons were produced as part of the synthetic fuel program that ended on Dec. 31, 2007. As of Dec. 31, 2007, the TECO Coal operating companies had a combined estimated 277.1 million tons of proven and probable recoverable reserves.

History

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

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

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

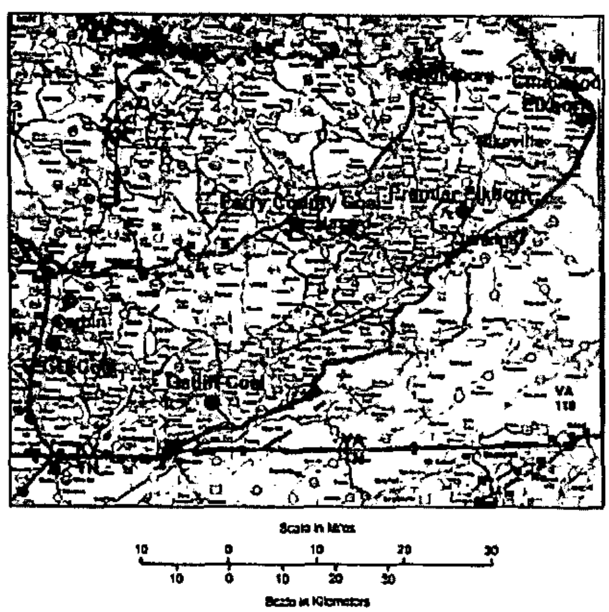
The newest mining company in the TECO Coal family is Perry County Coal Corporation, which was purchased in 2000 and is located in Perry, Knott and Leslie Counties, Kentucky.

TECO Synfuel Holdings, LLC and TECO Synfuel Operations, LLC were formed in 2003 to administer the production and sale of synfuel product at various TECO Coal subsidiaries. A related subsidiary, TECO Synfuel Administration, LLC, was formed in 2007.

In 2004, the acquisition of properties and the Millard Preparation Facilities (currently idle) from AEP, Kentucky Coal, LLC was completed. The property and facility are located in Pike County, Kentucky.

Mining Operations

TECO Coal currently has four mining complexes, all operating in Kentucky with a portion of Clintwood Elkhorn Mining Company operating in Virginia as well. A mining complex is defined as all mines that supply a single wash plant, except in the case of Clintwood Elkhorn Mining Company and Premier Elkhorn Coal Company, which provide production for two 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 14 individual underground or surface mines. TECO Coal uses two distinct extraction techniques: continuous underground mining and dozer and front-end loader surface mining. The complexes have been developed at strategic locations in close proximity to the TECO Coal preparation plants and rail shipping facilities. Coal is transported from TECO Coal's mining complexes to customers by means of railroad cars, trucks, barge or vessels, with rail shipments representing approximately 89% of 2007 coal shipments. The map below shows the locations of the four mining complexes and TECO Coal's offices in Corbin, Kentucky.



Facilities

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

PROCESSING FACILITIES SUMMARY
Table 1

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

Significant Projects

Significant projects for 2007 included the following:

Perry County Coal

- Construction of the E4-2 mine slope and shaft was completed and production began in the E4-2 underground mine. This is the access to the reserves in the Elkhorn 4 seam, which is generally a high-quality steam coal.

Premier Elkhorn Coal

- Two significant surface disturbance permits were issued allowing work to begin that will access over 8 million tons of recoverable coal.

Clintwood Elkhorn Mining

- The Clintwood #2 preparation plant is in the process of modifying the existing circuit which will result in a 15% capacity increase in the raw coal feed.

Mining Complexes

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

MINING COMPLEXES
Table 2

	Location	Mine Type	Mining Equipment	Trans-portation	Tons Produced (in millions) 2007	2006	2005	Tons Sold (in millions) 2007	Year Established Or Acquired
Gatliff Coal Company	Bell County, KY/Knox County, KY/Campbell County, TN	S	D/L	T	0.26	0.36	0.34	0.27	1974
Clintwood Elkhorn Mining	Pike County, KY/ Buchanan County, VA	U, S	CM, D/L, HM, A	R, R/V	2.66	2.63	2.18	2.87	1988
Premier Elkhorn Coal	Pike County, KY/Letcher County, KY/ Floyd County, KY	U, S	CM, D/L	R,T,R/ B,T/B	3.15	3.33	3.31	3.04	1991
Perry County Coal	Perry County, KY/ Leslie County, KY/ Knott County, KY	U, S	CM, D/L, HM	R,T,R/ B,T/B	3.05	3.57	3.37	3.04	2000
TOTAL					9.12	9.89	9.20	9.22	

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

Gatliff Coal Company

Located in Bell County, Kentucky, Gatliff Coal Company is supplied by one surface mine. Principal products at this location consist primarily of high quality steam coal for utilities. Products from this operation are transported by trucking contractors. Rich Mountain Coal Company formerly operated as a contractor for Gatliff Coal Company's Tennessee production which is currently in non-producing reclamation status. Two leases associated with the Moores Creek reserve area were terminated, resulting in a 2.0 million ton decrease in mineable reserves. Gatliff Coal Company produced 0.26 million tons of coal in 2007, leaving a reserve base of 6.8 million recoverable tons.

Clintwood Elkhorn Mining Company

Clintwood Elkhorn Mining Company has two facilities. One is located near Biggs, Kentucky in Pike County, and is supplied by 11 underground mines and three surface mines. Principal products at the Biggs, Kentucky location include high volatile metallurgical coals and steam coals. The second Clintwood Elkhorn Mining Company facility is located near Hurley, Virginia and is supplied by two underground mines and three surface mines. The Hurley Virginia operation facility also supplies high-volatile metallurgical coal as well as steam coal products. Products from both locations are shipped domestically to customers in North America via Norfolk Southern Corporation and vessels via the Great Lakes. International customers receive their products via ocean vessels from Lamberts Point, Virginia. A transfer of reserves from Premier Elkhorn Coal Company to Clintwood Elkhorn Mining Company totaling over 12 million tons of recoverable coal was completed in 2007. In total, Clintwood Elkhorn Mining Company produced 2.7 million tons of coal in 2007, leaving a reserve base of 51.5 million recoverable tons.

Premier Elkhorn Coal Company

Located near Myra, in Pike County, Kentucky, Premier Elkhorn Coal Company is supplied by production from seven underground mines and six surface mines. Principal products include high-quality steam coal for utilities, specialty stoker products for ferro-silicon and industrial customers, PCI and metallurgical coal for the steel mills. Facilities include a unit train load-out with 200 car siding capable of loading at 6,000 tons per hour as well as a single car siding. Products from this location are shipped domestically via CSXT Railroad and trucking contractors. All production is performed by Premier Elkhorn Coal Company even though Pike Letcher Land Company controls by fee and lease all of the recoverable reserves. Premier Elkhorn Coal Company transferred over 12 million tons of recoverable coal to Clintwood Elkhorn Mining Company in 2007 and increased its own reserve base by securing surface property necessary to reclassify mineable coal from resource to reserve. Premier Elkhorn Coal Company produced 3.1 million tons of coal in 2007, leaving a reserve base of 81 million recoverable tons.

Perry County Coal Corporation

Located near Hazard, Kentucky in Perry County, Perry County Coal Corporation is supplied by three underground mines and one surface mine. Principal products include high quality steam coal for utilities, industrial stoker and PCI products. Facilities include an upgraded 1,350 ton per hour preparation plant and two unit train load-outs, each capable of loading at 5,000 tons per hour. Products from this location are shipped domestically via CSXT Railroad and trucking contractors. Perry County Coal Corporation produced 3.0 million tons of coal in 2007, leaving a reserve base of 137.8 million recoverable tons.

TECO Synfuel Operations, LLC

In April 2003, TECO Coal sold a 49.5 percent ownership interest in its synthetic fuel production facilities, an additional 40.5 percent in June 2004 and 8 percent in July 2005 (See the **TECO Coal** section of **MD&A**). Sales of the fuel processed through these types of facilities were eligible for non-conventional fuels tax credits under the Internal Revenue Code. The program to obtain these tax credits ended on Dec. 31, 2007, also ending further production. TECO Coal had received Private Letter Rulings from the Internal Revenue Service confirming that the facilities produced a qualified fuel eligible for synthetic fuel tax credits available for the production of such non-conventional fuels and resolved any uncertainty related to the sale of its interest in the production facilities.

The synthetic fuel tax credit is determined annually and was estimated to be $1.21 per million Btu in 2007, $1.17 per million Btu in 2006 and $1.15 per million Btu in 2005. This rate escalated with inflation but was limited by domestic oil prices. The weighted average price of domestic oil for 2007 exceeded $72.00 per barrel resulting in a 67% phase-out of the credits allowed for 2007. See the **TECO Coal** section of the **MD&A** for further discussion of the synthetic fuel tax credit.

Sales and Marketing

The TECO Coal marketing and sales force includes sales managers, distribution/transportation managers and administrative personnel. Primary customers are utilities, steel companies 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 less than 12 months.

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

Distribution

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

Competition

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

Employees

As of Dec. 31, 2007, TECO Coal and its subsidiaries employed a total of 1,052 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 Jul. 1, 1973. Historically, a small percentage of the miners currently seeking federal black lung benefits are awarded these benefits by the federal government. The trust fund is funded by an excise tax on coal production of up to \$1.10 per ton for deep-mined coal and up to \$0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price.

In 2000, the Department of Labor issued 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 have increased the percentage of claims approved and the overall cost of black lung to coal operators. TECO Coal, with the help of its consulting actuaries, intends to continue monitoring claims very closely.

Workers' Compensation

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

Environmental Laws

Surface Mining Control and Reclamation Act

Coal mining operations are subject to the Surface Mining Control and Reclamation Act of 1977 which places a charge of $0.15 and $0.35 on every net ton of underground and surface coal mined, respectively, to create a 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 2007, TECO Coal spent approximately $2.6 million on environmental protection and reclamation programs. TECO Coal expects to spend a similar amount in 2008 on these programs.

CERCLA (Superfund)

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

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

Glossary of Selected Mining Terms

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

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

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

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

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

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

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

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

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

Deep mine. An underground coal mine.

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

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

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

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

Highwall miner. An auger-like apparatus that drives parallel rectangular entries from the surface down 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 of one year or longer.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

TECO GUATEMALA

TECO Guatemala, Inc. (formerly TWG Non-Merchant, Inc.), has subsidiaries that have interests in independent power projects in Guatemala and a minority ownership interest in an electrical distribution utility and affiliated entities. The TECO Guatemala subsidiaries had 133 employees as of Dec. 31, 2007.

TECO Guatemala indirectly owns 100% of Central Generadora Eléctrica San José, Limitada (CGESJ), the owner of a project located in Guatemala, which consists of a single-unit pulverized-coal baseload facility (the San José Power Station). This facility was the first coal-fueled plant in Central America and meets environmental standards set by the World Bank. In 1996, CGESJ signed a U.S. dollar-denominated power purchase agreement (PPA) with Empresa Eléctrica de Guatemala, S.A. (EEGSA), the largest private distribution and generation company in Central America, to provide 120 megawatts of capacity and energy for 15 years beginning in 2000. In 2001, CGESJ signed an option with EEGSA to extend that PPA for five years at the end of its current term for approximately $2.5 million. Tecnología Marítima, S.A. (TEMSA), an indirect wholly-owned subsidiary, in addition to receiving the coal shipments for CGESJ, provides unloading services to third parties. Affiliates of TECO Guatemala had originally obtained $114 million of limited recourse financing from Bank of America (BOA), Overseas Private Investment Corporation (OPIC) and Trust Company of the West (TCW) for the San José Power Station. In 2004, CGESJ paid off its loans with BOA, OPIC and TCW with proceeds from a non-recourse $120 million loan from a syndication led by Banco Industrial.

Tampa Centro Americana de Electricidad, Limitada (TCAE), an entity 96.06% owned by TPS Guatemala One, Inc., a subsidiary of TECO Guatemala, and the owner of a natural gas-powered facility (the Alborada Power Station), has a U.S. dollar-denominated PPA with EEGSA to provide 78 megawatts of capacity for a 15-year period ending in 2010. In 2001, TCAE signed an option with EEGSA to extend that PPA for five years at the end of its current term for approximately $2.9 million. EEGSA is responsible for providing the fuel for the plant, with a subsidiary of TECO Guatemala providing assistance in fuel administration. Affiliates of TECO Guatemala had originally obtained $29 million of limited recourse financing from OPIC for the Alborada Power Station. In 2002, TCAE paid off its loan with OPIC with a portion of the proceeds from a non-recourse $25 million loan from Banco Industrial, a local bank in Guatemala.

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

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

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

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

TECO TRANSPORT

On Dec. 4, 2007, TECO Energy completed its sale of TECO Transport for cash to an unaffiliated investment group. The selling price of $405 million resulted in an after-tax gain of $149.4 million, before transaction related costs of $16.3 million after tax. As a result of its continuing involvement via a water-borne transportation contract with Tampa Electric, all results through Dec. 3, 2007 are accounted for in continuing operations.

TECO Transport directly or indirectly owned an interest in nine subsidiaries involved in water-borne transportation, storage and transfer of coal and other dry-bulk commodities. These subsidiaries included TECO Ocean Shipping, Inc. (Ocean Shipping), TECO Barge Line, Inc. (Barge Line), TECO Bulk Terminal, LLC (Bulk Terminal) and TECO Towing Company.

TECO Transport's subsidiaries performed substantial services for Tampa Electric. Through Dec. 3, 2007, approximately 32% of TECO Transport's revenues were from Tampa Electric and approximately 68% were from third-party customers including phosphate customers, steel industry customers, grain customers, coal and petroleum coke customers, and participation in the U.S. Government's cargo preference programs. The pricing for services performed by TECO Transport's operating companies for Tampa Electric was based on a market-based fixed-price per ton, generally adjusted quarterly for changes in certain fuel and price indices. Most of the third-party utilization of the ocean-going vessels (ships and barges) were for domestic and international movements of dry-bulk commodities and domestic phosphate movements. Both the terminal and river transport operations handled a variety of dry-bulk commodities for third-party customers.

Competition within TECO Transport's markets was based primarily on geographic markets served, pricing, and service level. The majority of the ocean business and all of the river business was subject to the Jones Act, which prohibits the use of non-U.S. flag vessels for movement between U.S. ports. The business of TECO Transport's subsidiaries, taken as a whole, was not subject to significant seasonal fluctuation, but was sensitive to weather and economic conditions.

The Interstate Commerce Act exempts from regulation water transportation of certain dry-bulk commodities. In 2007, all transportation services provided by TECO Transport's subsidiaries were within this exemption. TECO Transport's subsidiaries were subject to the provisions of the Clean Water Act of 1977 which authorizes the Coast Guard and the EPA to assess penalties for oil and hazardous substance discharges. Under this Act, these agencies are also empowered to assess clean-up costs for such discharges. In 2007, TECO Transport spent $0.5 million for environmental compliance.

TWG MERCHANT, INC.

The TWG Merchant entity was created to own interests in merchant power projects. In 2003, TECO Energy announced that its strategy going forward was to focus on the Florida utilities and profitable unregulated businesses and to reduce the company's exposure to the merchant power markets. As of Dec. 31, 2006, TWG Merchant had sold its interests in all independent power projects and had effectively reduced the company's exposure. Any residual results of operations starting with the fiscal year ending Dec. 31, 2006, are reported in "Other and eliminations", removing TWG Merchant as a reportable segment. Also effective as of Dec. 31, 2006, TWG Merchant had no remaining employees.

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, the projected growth in Tampa Electric's service area and in Florida is important to the realization of Tampa Electric's and PGS' respective forecasts for annual energy sales growth. An unanticipated downturn or a failure of market conditions to improve, such as the current slowdown in the housing markets, in the Tampa Electric service areas or in Florida's economy could adversely affect Tampa Electric's or PGS' expected performance.

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

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

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

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

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

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

PGS is currently earning below the bottom of its allowed ROE range, and Tampa Electric's earnings may decrease and it may not be able to earn its allowed return with the current base rates.

PGS is currently earning below the bottom of its allowed ROE range, and expects to file for base rate relief in 2008. Tampa Electric's profitability may decrease and it may not be able to earn within its allowed ROE range under its current base rates due to higher recurring capital spending primarily in the transmission and distribution areas and generally higher levels of non-fuel operations and maintenance spending, even without the construction of new generating capacity.

Our financial results could be adversely affected if the base rate proceedings expected by Tampa Electric and PGS do not have the expected outcomes.

Tampa Electric and PGS expect to seek base rate increases to recover higher levels of non-fuel operations and maintenance spending and the increased level of capital investments in facilities and infrastructure. While the FPSC has a history of constructive regulation, we cannot predict the outcome of any such regulatory proceeding. If cost recovery is not granted or if the allowed return on equity is reduced, our financial results could be adversely affected.

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

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

There is increasing debate and discussion regarding the regulation of GHG, emissions and some states have already proposed or enacted regulations relating to these emissions, which if enacted could increase our costs or the costs of our customers or curtail sales.

Among our companies, Tampa Electric has the most significant number of stationary sources with air emissions. The form of any GHG emission regulation, either federal or state, is unknown at this time and potential costs to reduce GHGs are unknown. Presently there is no viable technology to remove CO_2 post-combustion from conventional coal-fired units such as Tampa Electric's Big Bend units.

Regulation in Florida allows utility companies to recover from customers prudently incurred costs for compliance with new environmental regulations. Tampa Electric would expect to recover from customers the costs of power plant modifications or other costs required to comply with new GHG emission regulation, but increased costs for electricity may cause customers to change usage patterns, which would impact Tampa

Electric's sales. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the Environmental Cost Recovery Clause, 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 greenhouse gas emissions. New regulations, depending on final form, could cause the consumption of coal to decrease or the cost of sales to increase, which could negatively impact TECO Coal's earnings.

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

In 2007, the governor of Florida signed three executive orders aimed at reducing GHG in the state. The executive orders call for GHG emissions by the utility sector in Florida of not greater than 2000 levels by 2017, not greater than 1990 levels by 2025, and not greater than 20% of 1990 levels by 2050. Although we believe Tampa Electric's repowering of the coal-fired Gannon Station to the natural gas-fired H. L. Culbreath Bayside Station should position the company well to meet the 2017 target, Tampa Electric is still evaluating whether it will be able to meet the 2025 and 2050 targets.

The executive orders charge the Florida Department of Environmental Protection (FDEP) with developing detailed rules to implement these emissions limits. The FDEP has started the rule making process, but it is expected to take an extended period of time to reach completion. Until the final rules are developed, the impact on Tampa Electric and its customers cannot be determined. However, if the final rules result in increased costs to Tampa Electric, or further changes in customer usage patterns in response to higher rates, Tampa Electric's operating results could be adversely affected.

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

In connection with the executive orders signed by the Governor of Florida in July 2007, the FPSC was tasked with evaluating a renewable portfolio target of 20% by 2020. In addition, there is proposed legislation in the U.S. Congress to introduce a renewable energy portfolio standard at the federal level. It remains unclear, however, if or when action on such legislation would be completed. Tampa Electric could incur significant costs to comply with a renewable energy portfolio standard, as proposed. Tampa Electric's operating results could be adversely affected if Tampa Electric were not permitted to recover these costs from customers, or if customers change usage patterns in response to increased rates.

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

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

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

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

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

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

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

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

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

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

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

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

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

Changes in customer energy usage patterns may affect sales at our utility companies.

The average energy usage per Tampa Electric and PGS' residential customer declined in 2006 and 2007. We believe that this was in response to mild weather, higher energy prices reflected both through the fuel charge on bills and for higher energy prices in general, increased appliance efficiency, and to changes in residential construction patterns in Tampa Electric's service area. In addition, the current slowdown in the Florida housing market has increased the number of vacant residences which have active meters but minimal energy consumption.

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

The number of new multi-family homes has increased relative to traditional detached single-family homes in 2006 and 2007. New multi-family residential construction tends to be smaller and more energy efficient than traditional detached residences; therefore, the per-residential customer usage is lower for these residences. The number of multi-family building permits issued in the Tampa area increased in 2007 compared to detached single-family residences, which indicates that this trend may continue. A higher percentage of multi-family residences may cause a further decline in per-residential customer usage.

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

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

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

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

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

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

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

Problems with operations could cause us to incur substantial costs.

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

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

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

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

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

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

Financing Risks

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

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

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

As of Dec. 31, 2007, we were in compliance with required financial covenants, but we cannot assure you that we will be in compliance with these financial covenants in the future. Our failure to comply with any of these covenants or to meet our payment obligations could result in an event of default which, if not cured or waived, could result in the acceleration of other outstanding debt obligations. We may not have sufficient working capital or liquidity to satisfy our debt obligations in the event of an acceleration of all or a portion of our outstanding obligations.

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

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

We are forecasting higher levels of capital expenditures, primarily at Tampa Electric, for compliance with our environmental consent decree, to support normal customer growth, to comply with the design changes mandated by the FPSC to harden transmission and distribution facilities against hurricane damage, to improve transmission and distribution system reliability, to improve coal-fired generating unit reliability, and to install peaking combustion turbines to meet peaking capacity needs. Tampa Electric plans to meet its 2013 baseload generating need with a combined cycle natural gas plant with an estimated capital cost of approximately $550 million, excluding AFUDC.

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

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

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

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

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

We are a holding company and are dependent on cash flow from our subsidiaries to meet our cash requirements that are not satisfied from external funding sources. Some of our subsidiaries have indebtedness containing restrictive covenants which, if violated, would prevent them from making cash distributions to us. In particular, certain long-term debt at PGS prohibits payment of dividends to us if Tampa Electric Company's consolidated shareholders' equity is lower than $500 million. At Dec. 31, 2007, Tampa Electric Company's consolidated shareholders' equity was approximately $1.8 billion. Also, our wholly owned subsidiary, TECO Diversified, Inc., the holding company for TECO Coal, has a guarantee related to a coal supply agreement that could limit the payment of dividends by TECO Diversified to us (see the **Significant Financial Covenants** table in the **Liquidity, Capital Resources** sections of MD&A).

Various factors could affect our ability to sustain our dividend.

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

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

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

Item 1B. UNRESOLVED STAFF COMMENTS.

None.

Item 2. PROPERTIES.

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

TAMPA ELECTRIC

Tampa Electric has seven electric generating plants and seven combustion turbine units in service with a total net winter generating capability of 4,602 megawatts, including Big Bend (1,605-MW capability from four coal units), Bayside (1,837-MW capability from two natural gas units), Phillips (35.4-MW capability from two diesel units), Polk (255-MW capability from one integrated gasification combined cycle (IGCC) unit), three combustion turbine units (CTs) located at Big Bend (129-MW) and four CTs at Polk (734.4-MW). Additionally, Tampa Electric has 6-MW of generating capability from generation units located at the Howard Curren Advanced Waste Water Treatment Plant in the City of Tampa.

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

Tampa Electric owns 177 substations having an aggregate transformer capacity of 21,101 Mega Volts Amps (MVA). The transmission system consists of approximately 1,309 pole miles (including underground and double-circuit) of high voltage transmission lines, and the distribution system consists of 6,137 pole miles of overhead lines and 7,893 trench miles of underground lines. As of Dec. 31, 2007, there were 668,721 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 is subject to easements, leases, contracts, covenants and similar encumbrances and minor defects of a nature common to properties of the size and character of those of Tampa Electric.

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

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

PEOPLES GAS SYSTEM

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

PGS' operations are located in 15 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 nearly 250,000 acres in Kentucky, Tennessee and Virginia. TECO Coal's current practice is to obtain a title review from a licensed attorney prior to purchasing or leasing property. As is typical in the coal mining industry, TECO Coal generally has not obtained title insurance in connection with its acquisitions of coal reserves and/or related surface properties. In many cases, the seller or lessor will grant the purchasing or leasing entity a warranty of property title. When leasing coal reserves and/or related surface properties where mining has previously occurred, TECO Coal may opt not to perform a separate title confirmation due to the previous mining activities on such a property. In cases involving less significant properties and consistent with industry practices, title and boundaries to less significant properties are verified during lease or purchase negotiations.

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

Coal Reserves

As of Dec. 31, 2007, the TECO Coal operating companies had a combined estimated 277.1 million tons of proven and probable recoverable reserves. All of the reserves consist of High Vol A Bituminous Coal. Reserves are the portion of the proven and probable tonnage that meet TECO Coal's economic criteria regarding mining height, preparation plant recovery, depth of overburden and stripping ratio. Generally, these reserves would be commercially mineable at year-end price and cost levels. Additionally, 64 million tons of coal classified as "resource" were identified in earlier third-party audit reports. By securing additional surface property leases in 2007, we were able to reclassify some of the coal previously listed in the "resource" category as "reserves". The total identified resource now stands at 51.5 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.

Our reserve estimates are prepared by our staff of geologists, whose experience range from 15 years to 30 years. We also have two chief geologists with the responsibility to track changes in reserve estimates, supervise TECO Coal's other geologists and coordinate third party reviews of our reserve estimates by qualified mining consultants. In 2007, a third-party reserve audit was performed by Marshall Miller & Associates on the portion of reserves acquired during 2007. The results of that audit are reflected in the numbers within this report.

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

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

Mining Complex	Location	Total	Proven	Probable	Owned	Leased	Assigned (2) 2007	Assigned (2) 2006	Unassigned (2) 2007	Unassigned (2) 2006
Gatliff Coal Company	Bell County, KY/Knox County, KY/Campbell County, TN	6.8	6.2	0.6	1.0	5.8	0.4	0.7	6.4	8.4
Clintwood Elkhorn Mining	Pike County, KY/ Buchanan County, VA	51.5	43.8	7.7	3.9	47.6	51.5	39.0	—	—
Premier Elkhorn Coal	Pike County, KY/Letcher County, KY/ Floyd County, KY	81.0	64.9	16.1	46.7	34.3	72.1	84.9	8.9	—
Perry County Coal	Perry County, KY/ Leslie County, KY/ Knott County, KY	137.8	52.6	85.2	—	137.8	137.8	140.9	—	—
Total		277.1	167.5	109.6	51.6	225.5	261.8	265.5	15.3	8.4

Notes:

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

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

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

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

Mining Complex	Recoverable Reserves (Millions of tons)	Sulfur Content < 1% (2)	Sulfur Content >1% (2)	Compliance Tons (3)	Average BTU/lb As received	Coal Type (4)
Gatliff Coal Company	6.8	6.2	0.6	—	13,500	LSU
Clintwood Elkhorn Mining	51.5	23.0	28.5	23.0	13,400	HVM, LSU, PCI
Premier Elkhorn Coal	81.0	29.0	52.0	22.1	13,350	IS, LSU, PCI
Perry County Coal	137.8	130.1	7.7	76.8	13,195	LSU, PCI, V
Total	277.1			121.9		

Notes:

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

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

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

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

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

Reserve Estimation Procedure

TECO Coal's reserves are based on over 2,800 data points, including drill holes, prospect measurements, and mine measurements. Our reserve estimates also include information obtained from our on-going exploration drilling and in-mine channel sampling programs. Reserve classification is determined by evaluation of engineering and geologic information along with economic analysis. These reserves are adjusted periodically to reflect fluctuations in the economics in the market and/or changes in engineering parameters and/or geologic conditions. Additionally, the information is constantly being updated to reflect new data for existing property as well as new acquisitions and depleted reserves.

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

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

TECO GUATEMALA

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

TECO TRANSPORT

Effective Dec. 4, 2007, TECO Transport was sold to an unaffiliated investment group. This section describes its properties as of that date. Bulk Terminal's storage and transfer terminal was on a 1,070-acre site fronting on the Mississippi River, approximately 40 miles south of New Orleans. Bulk Terminal owned 342 of these acres in fee, with the remainder held under long-term leases.

Barge Line operated a fleet of 14 line vessels, 6 harbor vessels, and 627 river barges, approximately 74% of which it owned, on the Mississippi, Ohio and Illinois rivers and their tributaries. TECO Barge owned 15 acres of land fronting on the Ohio River at Metropolis, Illinois on which its operating offices, warehouse and repair facilities were located. Fleeting and repair services for its barges and those of other barge lines were performed at this location. Additionally, Barge Line performed fleeting activities in Davant, Louisiana, where Bulk Terminal was located.

Item 3. LEGAL PROCEEDINGS.

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

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

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

No matter was submitted during the fourth quarter of 2007 to a vote of TECO Energy's security holders, through the solicitation of proxies or otherwise.

EXECUTIVE OFFICERS OF THE REGISTRANT

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

Name	Age	Current Positions and Principal Occupations During Last Five Years
Sherrill W. Hudson	65	Chairman of the Board and Chief Executive Officer, TECO Energy, Inc. and Tampa Electric Company, July 2004 to date; and prior thereto, Managing Partner for South Florida, Deloitte & Touche, LLP (public accounting), Miami, Florida.
Charles A. Attal, III	48	Vice President-General Counsel and Chief Legal Officer, TECO Energy, Inc., and General Counsel of Tampa Electric Company, July 2007 to date; and prior thereto, Vice President and Deputy General Counsel, TECO Energy, Inc., since prior to 2003.
Charles R. Black	56	President, Tampa Electric Company, October 2004 to date; Senior Vice President-Generation, TECO Energy, Inc. and Tampa Electric Company, September 2003 to October 2004; and prior thereto, Vice President-Energy Supply, Engineering and Construction, Tampa Electric Company.
William N. Cantrell	55	President, Peoples Gas System, since prior to 2003; President, Tampa Electric Company, September 2003 to October 2004.
Clinton E. Childress	59	Senior Vice President-Corporate Services and Chief Human Resources Officer, TECO Energy, Inc., October 2004 to date and Chief Human Resources Officer and Procurement Officer, Tampa Electric Company, September 2003 to date; and prior thereto, Chief Human Resources Officer, TECO Energy, Inc. and Vice President-Human Resources, Tampa Electric Company.
Gordon L. Gillette	48	Executive Vice President and Chief Financial Officer, TECO Energy, Inc., July 2004 to date; President, TECO Guatemala, October 2004 to date; Senior Vice President-Finance and Chief Financial Officer, TECO Energy, Inc., April 2001 to July 2004; Senior Vice President-Finance and Chief Financial Officer, Tampa Electric Company, since prior to 2003.
John B. Ramil	52	President and Chief Operating Officer, TECO Energy, Inc., July 2004 to date; Executive Vice President and Chief Operating Officer, TECO Energy, Inc., September 2003 to July 2004; Executive Vice President, TECO Energy, Inc., December 2002 to September 2003; President, Tampa Electric Company, April 1998 to September 2003.
J. J. Shackleford	61	President of TECO Coal Corporation, since prior to 2003.

There is no family relationship between any of the persons named above or between executive officers and any director of the company. The term of office of each officer extends to the meeting of the Board of Directors following the next annual meeting of shareholders, scheduled to be held on Apr. 30, 2008, and until such officer's successor is elected and qualified.

PART II

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

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

	1st Quarter	*2nd Quarter*	*3rd Quarter*	*4th Quarter*
2007				
High	$17.49	$18.58	$17.71	$17.91
Low	$16.22	$16.40	$14.84	$15.58
Close	$17.21	$17.18	$16.43	$17.21
Dividend	$ 0.19	$0.195	$0.195	$0.195
2006				
High	$17.73	$16.75	$16.20	$17.50
Low	$15.97	$14.40	$14.86	$15.57
Close	$16.12	$14.94	$15.65	$17.23
Dividend	$ 0.19	$ 0.19	$ 0.19	$ 0.19

The approximate number of shareholders of record of common stock of TECO Energy as of Feb. 25, 2008 was 16,601. Dividends on TECO Energy's common stock are declared and paid at the discretion of its Board of Directors. The primary sources of funds to pay dividends to its common shareholders are dividends and other distributions from its operating companies. TECO Energy's $200 million credit facility contains a covenant that could limit the payment of dividends exceeding $50 million, subject to increase in the event TECO Energy issues additional shares of common stock, in any quarter, under certain circumstances. Certain long-term debt at PGS contains restrictions that limit the payment of dividends and distributions on the common stock of Tampa Electric Company.

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

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

All of Tampa Electric Company's common stock is owned by TECO Energy, Inc. and, therefore, there is no market for the stock. Tampa Electric Company pays dividends substantially equal to its net income applicable to common stock to TECO Energy. Such dividends totaled $166.1 million in 2007, $169.4 million in 2006, and $173.4 million in 2005. 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.

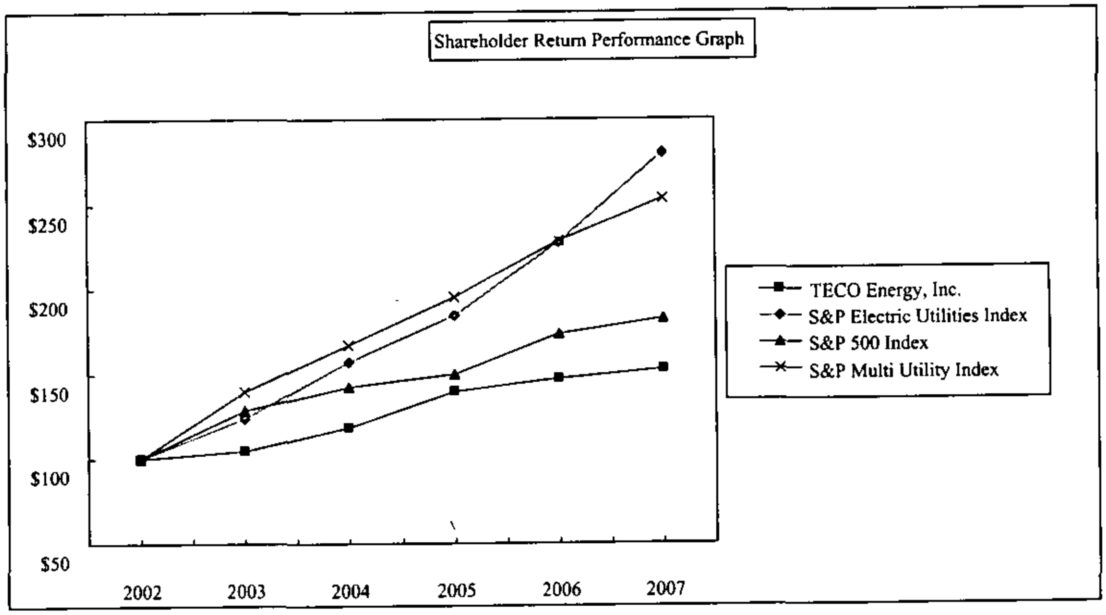
Set forth below is a table showing shares of TECO Energy common stock deemed repurchased by the issuer.

	(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, 2007—Oct. 31, 2007	2,593	$16.46	—	—
Nov. 1, 2007—Nov. 30, 2007	7,873	$17.29	—	—
Dec. 1, 2007—Dec. 31, 2007	19,484	$17.45	—	—
Total 4th Quarter 2007	29,950	$17.32	—	—

(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, 2007, and compares this return with that of the S&P 500 Index, the S&P Electric Utilities Index and the S&P Multi Utility Index. The S&P Electric Utilities Index is being replaced by the S&P Multi Utility Index because TECO Energy is included in the S&P Multi Utility Index for having both electric and gas utilities. The Graph assumes that the value of the investment in our common stock and each index was $100 on Dec. 31, 2002 and that all dividends were reinvested.



December 31,	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*
TECO Energy, Inc.	$100	$105	$119	$140	$147	$153
S&P Electric Utilities Index	$100	$124	$157	$185	$228	$280
S&P 500 Index	$100	$129	$143	$150	$173	$183
S&P Multi Utility Index	$100	$140	$167	$196	$228	$253

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

(millions, except per share amounts) *Years ended Dec. 31,*	*2007*	*2006*	*2005*	*2004*	*2003*
Revenues [1]	$3,536.1	$3,448.1	$3,010.1	$2,639.4	$ 2,562.9
Net income (loss) from continuing operations [1]	$ 398.9	$ 244.4	$ 211.0	$ (355.5)	$ 100.7
Net income (loss) from discontinued operations [1][2]	14.3	1.9	63.5	(196.5)	(1,005.8)
Cumulative effect of change in accounting principle, net	—	—	—	—	(4.3)
Net income (loss)	$ 413.2	$ 246.3	$ 274.5	$ (552.0)	$ (909.4)
Total assets	$6,765.2	$7,361.8	$7,170.1	$8,972.4	$ 9,964.3
Long-term debt	$3,158.4	$3,212.6	$3,709.2	$3,880.0	$ 4,392.6
Earnings per share (EPS)—basic;					
From continuing operations [1]	$ 1.91	$ 1.18	$ 1.02	$ (1.85)	$ 0.56
From discontinued operations [1]	0.07	0.01	0.31	(1.02)	(5.59)
From cumulative effect of change in accounting principle	—	—	—	—	(0.02)
EPS basic	$ 1.98	$ 1.19	$ 1.33	$ (2.87)	$ (5.05)
Earnings per share (EPS)—diluted;					
From continuing operations [1]	$ 1.90	$ 1.17	$ 1.00	$ (1.85)	$ 0.56
From discontinued operations [1]	0.07	0.01	0.31	(1.02)	(5.58)
From cumulative effect of change in accounting principle	—	—	—	—	(0.02)
EPS diluted	$ 1.97	$ 1.18	$ 1.31	$ (2.87)	$ (5.04)
Dividends declared per common share	$ 0.775	$ 0.760	$ 0.760	$ 0.760	$ 0.925

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

(2) 2007 includes a $14.3 million gain on the 2005 sale of Union and Gila after reaching a favorable conclusion with taxing authorities. 2004 and 2003 include impairment charges of $558.6 million and $100.1 million, respectively. See **Notes 16** and **18** to the TECO Energy **Consolidated Financial Statements.**

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

This Management's Discussion and Analysis contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. Actual results may differ materially from those forecasted. Such statements are based on our current expectations, and we do not undertake to update or revise such forward-looking statements, except as may be required by law. These forward-looking statements include references to our anticipated capital expenditures, liquidity and financing requirements, projected operating results, 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 and Analysis, "we," "our," "ours" and "us" refer to TECO Energy, Inc. and its consolidated group of companies, unless the context otherwise requires.

OVERVIEW

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

Our regulated utility companies, Tampa Electric and Peoples Gas System (PGS) operate in the Florida market. Tampa Electric serves more than 668,000 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 4,602 megawatts. PGS, Florida's largest gas distribution utility, serves more than 334,000 residential, commercial, industrial and electric power generating customers in all of the major metropolitan areas of the state, with a total natural gas throughput of 1.4 billion therms in 2007.

TECO Coal, through its subsidiaries, operates surface and underground mines and related coal processing facilities in eastern Kentucky, Tennessee and southwestern Virginia, producing metallurgical-grade and high-quality steam coals. Sales in 2007 were 9.2 million tons, of which 6.0 million tons were sold as synthetic fuel. TECO Guatemala, through its subsidiaries, owns a coal-fired generating facility and has a 96% ownership interest in an oil-fired peaking power generating plant, both under long-term contracts with a regulated distribution utility in Guatemala. It also has a 24% ownership interest in Guatemala's largest distribution utility, Empresa Eléctrica de Guatemala (EEGSA), and in affiliated companies (in combination called DECA II), which provide, among other things, electricity transmission services, telecommunication services, power sales to large electric customers and engineering services.

Since 2003, after deciding to exit the merchant power business, our business strategy has been to focus on these businesses and TECO Transport, an affiliated dry-bulk shipping company, until its sale in late 2007. TECO Transport was sold to generate cash to accelerate parent company debt retirement and for investment in our Florida utilities.

With our parent level debt significantly reduced, our balance sheet much stronger, our business risk profile reduced and our credit rating improved, we remain focused on our cash priorities, which are to invest in our regulated utilities and to further reduce parent debt. Since we began our exit from the merchant power business, we have reduced parent and parent-guaranteed debt from a peak level of $2.7 billion in 2002 to $1.3 billion at the end of 2007.

Following a series of major investments in unregulated domestic power generation facilities outside Florida and smaller unregulated energy services providers in Florida in the 2000 through 2003 period, we implemented our current business strategy, which is focused on our regulated utilities. The investments in 2000 – 2003 were made in anticipation of a movement toward competitive energy markets. However, the wholesale power markets evolved in a manner that was much different than we expected at the time the investment decisions were made, and the independent power business changed dramatically (see the **TWG Merchant** section). In the exiting of the merchant power business, we sold assets at prices below those we paid and recorded large write-offs. We had issued significant amounts of debt at the TECO Energy parent level to fund portions of these investments, which negatively impacted our balance sheet and credit ratings. In 2003 and 2004, we decided to divest our merchant power and unregulated energy services businesses, which was completed in 2005.

2007 PERFORMANCE

Our businesses performed well in 2007 and our per-share results improved over 2006 levels. Net income and earnings per share were $413.2 million or $1.98 per share in 2007, compared to $246.3 million or $1.19 per share in 2006. Net income included the $149.4 million after-tax gain from the sale of TECO Transport, $16.3 million of after-tax costs related to the sale of TECO Transport, $20.2 million of after-tax charges related to the debt extinguishment/exchange transaction, and $52.6 million of after-tax benefits from the production of synthetic fuel. As a result of the closing of the sale, net income reflects TECO Transport's results through Dec. 3, 2007.

Our non-GAAP results in 2007, which exclude charges, gains and synthetic fuel results, on a per share basis were $1.07 per share. Our earnings in 2007 reflected improved results at Tampa Electric and TECO Guatemala, lower parent interest expense as a result of our debt retirement actions, and the results of TECO Transport only through Dec. 3, 2007. The non-GAAP results exclude the gain and costs associated with the sale of TECO Transport and the debt extinguishment charge.

In 2007, we remained focused on supporting the growth of Tampa Electric and retiring parent debt. Tampa Electric has capital requirements associated with its growing customer base, environmental compliance, peaking generation and future baseload generation. To accomplish our objectives of supporting Tampa Electric's growth and reducing parent debt, in 2007 we announced our plan to sell TECO Transport, our well-established water transportation subsidiary. In December we completed the sale of TECO Transport to an investment group led by Greenstreet Equity Partners, L.P. for $405 million of gross proceeds. The sale allowed us to accelerate the retirement in 2007 of almost $300 million of parent debt and $111 million of parent-guaranteed debt. The accelerated debt retirement will allow us to deploy future cash generation that would otherwise have been applied solely to debt reduction to a combination of investment in Tampa Electric and continued parent debt reduction. In 2007 we made an $82 million cash equity contribution to Tampa Electric to support its capital program.

In early 2007, Tampa Electric announced that it planned to meet its 2013 baseload generation needs with a 630-megawatt integrated gasification combined cycle (IGCC) plant with an estimated cost of $2.0 billion. In mid-2007, the Florida Legislature enacted legislation that allows advanced cost recovery during the construction of an IGCC unit, similar to legislation enacted for the construction of new nuclear units in 2006. In addition, Tampa Electric was successful in obtaining $133 million of federal tax credits for clean coal technology that were expected to reduce the impact to customers. However, during the certification of need process and after filing the required environmental permit applications, it became apparent that there would be uncertainty related to carbon dioxide (CO_2) regulations, particularly capture and sequestration (CCS) issues for an extended period of time. (CCS is the process of separating CO_2 from a gas stream, compressing it and pumping it to a suitable geologic formation, typically deep underground, for long-term storage.) Given the significant potential for the project cost to increase and the economic risk of these factors to customers and investors, the project was deferred in October 2007. At this time, Tampa Electric plans to meet its 2013 capacity need with a natural gas-fired combined cycle plant.

We continue to support IGCC as a critical component of future generation capacity in Florida and the nation, and believe the technology offers fuel diversity, is the most environmentally responsible way to utilize coal, and provides the best platform to capture and then sequester CO_2. Once public policy issues regarding long-term CCS are resolved, demonstration projects can be conducted that will lead to a better understanding of the science, technologies and economics of sequestration.

OUTLOOK

We estimate our 2008 earnings per share to be in a range of $0.95 to $1.10, compared to our 2007 non-GAAP results of $1.07, which excluded charges, gains and synthetic fuel results. This forecast is for earnings from continuing operations, excluding any charges or gains that might occur. We expect our two Florida utilities to produce net income that is essentially unchanged from 2007 results. We expect somewhat higher results from TECO Coal, compared to 2007 results excluding synthetic fuel, and we expect lower results at TECO Guatemala in 2008 after a very strong 2007. In 2008, we expect the loss of earnings from TECO Transport will be partially offset by lower parent interest expense following the $297 million early debt retirement we accomplished with the proceeds from the sale of TECO Transport. In addition, we expect lower interest expense from the other $300 million of TECO Energy notes that were retired in May 2007. In all, we expect $30 million lower pretax interest expense at TECO Energy parent and TECO Finance in 2008 compared to 2007 as a result of our aggressive liability management actions. These forecasted results are based on our current assumptions described in each operating company discussion, which are subject to risks and uncertainties (see the **Risk Factors** section).

In 2007, we reported net income calculated in accordance with Generally Accepted Accounting Principles (GAAP) that included $0.25 per share of benefits from synthetic fuel production. Since July 2006, we have provided two measures to allow comparison of our results with and without synthetic fuel. They are non-GAAP results from continuing operations including benefits from the production of synthetic fuel (Non-GAAP Results With Synthetic Fuel), which exclude certain charges and gains but include synthetic fuel, and non-GAAP results excluding synthetic fuel (Non-GAAP Results Excluding Synthetic Fuel), which exclude charges, gains and benefits associated with the production of synthetic fuel (see the **Non-GAAP Information** section). Although, with the expiration of the synthetic fuel tax credits at the end of 2007, we will no longer produce synthetic fuel, we are continuing to provide both non-GAAP measures for historical comparison purposes.

We are maintaining our priorities for the use of cash, which include investment in the utility companies and continued retirement of parent-level debt. We expect to make an additional $190 million of equity contributions to Tampa Electric in 2008 to support its continued capital spending for environmental controls and to serve its growing customer base. Our debt reduction plans include the retirement in 2008 of the $100 million of floating-rate parent debt maturing in 2010.

Capital expenditures increased in 2007, primarily at Tampa Electric for equipment to control NO_x emissions, to comply with the Florida Public Service Commission (FPSC)-mandated transmission and distribution system storm hardening requirements, distribution system reliability improvement, and heat rate and capacity factor improvements to our coal-fired units. We also invested in new mining equipment and continued development of lower cost mines at TECO Coal. We forecast capital expenditures to increase further in the 2008 through 2012 period at Tampa Electric to meet customer growth and generation plant maintenance, for peak load and baseload generating capacity expansion, for distribution system improvements to provide higher reliability, for its portion of transmission system expansion and upgrades in the Central Florida area to meet the new National Electric Reliability Council (NERC) reliability standards, for modest distribution system expansion at Peoples Gas, and for the normal maintenance capital at TECO Coal (see the **Liquidity, Capital Resources** section).

RESULTS SUMMARY

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

Results Comparisons

(millions)	*2007*	*2006*	*2005*
Net income	**$413.2**	$246.3	$274.5
Net income from continuing operations	**$398.9**	$244.4	$211.0
Non-GAAP Results With Synthetic Fuel	**$276.3**	$233.6	$254.7
Non-GAAP Results Excluding Synthetic Fuel	**$223.7**	$201.5	$172.3

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

Results in 2007 included a $52.6 million, or $0.25 per share, benefit to earnings from synthetic fuel production, compared to $32.1 million, or $0.16 per share, in the 2006 period. In 2006, results from continuing operations also included an $8.1 million after-tax gain from the sale of the McAdams Power Station assets, $5.7 million of after-tax gains from the sale of two unused steam turbines, and $3.0 million of after-tax charges net of insurance recoveries related to Hurricane Katrina damage at TECO Transport. Results from discontinued operations in 2006 primarily included the recovery of amounts that had been previously written off and tax adjustments at the small energy services companies.

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

Compared to 2005, our results in 2006 reflected lower earnings from the production of synthetic fuel at TECO Coal, lower earnings at Tampa Electric and lower earnings at TECO Guatemala, partially offset by improved results at TECO Transport, slightly higher results at PGS, the elimination of operating losses related to merchant power activities, and lower parent-level interest expense. In 2006, net income and earnings per share were $246.3 million, or $1.19 per share, compared to $274.5 million, or $1.33 per share, in 2005. Net income and earnings per share from continuing operations were $244.4 million, or $1.18 per share in 2006, compared to $211.0 million, or $1.02 per share, in 2005. Results in 2006 included a $32.1 million, or $0.16 per share, benefit to earnings from synthetic fuel production, compared to $82.4 million, or $0.40 per share, in the 2005 period. In 2006, results from continuing operations also included an $8.1 million after-tax gain from the sale of the McAdams Power Station assets, $5.7 million of after-tax gains from the sale of two unused steam turbines, and

$3.0 million of after-tax charges related to Hurricane Katrina damage at TECO Transport. In 2005, results from continuing operations included $46.7 million, or $0.23 per share, of after-tax charges for early debt retirement, and a $14.6 million after-tax, or $0.07 per share, loss at TWG Merchant related primarily to the unfinished Dell and McAdams merchant power plants. Results from discontinued operations in 2006 primarily included the recovery of amounts that had been previously written off and tax adjustments at the small energy services companies.

2007 Earnings Summary

(millions) Except per-share amounts	*2007*	*2006*	*2005*
Consolidated revenues	**$3,536.1**	$3,448.1	$3,010.1
Earnings per share—basic			
Earnings per share	**$ 1.98**	$ 1.19	$ 1.33
Discontinued operations	**0.07**	0.01	0.31
Earnings from continuing operations	**$ 1.91**	$ 1.18	$ 1.02
Earnings per share—diluted			
Earnings per share	**$ 1.97**	$ 1.18	$ 1.31
Discontinued operations	**0.07**	0.01	0.31
Earnings from continuing operations	**$ 1.90**	$ 1.17	$ 1.00
Net income	**$ 413.2**	$ 246.3	$ 274.5
Net income from discontinued operations	**(14.3)**	(1.9)	(63.5)
Charges and (gains) from continuing operations (1)	**(122.6)**	(10.8)	43.7
Non-GAAP results with synthetic fuel (2)	**276.3**	233.6	254.7
Synthetic fuel impact (1)	**(52.6)**	(32.1)	(82.4)
Non-GAAP results excluding synthetic fuel (2)	**$ 223.7**	$ 201.5	$ 172.3
Average common shares outstanding			
Basic	**209.1**	207.9	206.3(3)
Diluted	**209.9**	208.7	208.2(3)

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

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

(3) Average shares outstanding for 2005 include the issuance of 6.85 million shares in conjunction with the final settlement of the 9.5% adjustable conversion-rate equity security units.

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

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

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

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

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

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

2005 Reconciliation of GAAP net income from continuing operations to non-GAAP results

Net income impact (millions)	*Tampa Electric*	*Peoples Gas*	*TECO Coal*	*TECO Transport*	*TECO Guatemala*	*TWG Merchant*	*Parent/ Other*	*Total*
GAAP Net income (loss) from continuing operations	$147.1	$29.6	$115.4	$ 20.2	$40.4	$(14.6)	$(127.1)	$211.0
Debt extinguishment charges	—	—	—	—	—	—	46.7	46.7
Hurricane costs	—	—	—	12.6	—	—	—	12.6
Hurricane insurance recoveries	—	—	—	(13.7)	—	—	—	(13.7)
Dell & McAdams valuation adjustment	—	—	—	—	—	(1.9)	—	(1.9)
Total charges and (gains)	—	—	—	(1.1)	—	(1.9)	46.7	43.7
Non-GAAP results with synthetic fuel	147.1	29.6	115.4	19.1	40.4	(16.5)	(80.4)	254.7
Synthetic fuel impact	—	—	(82.4)	—	—	—	—	(82.4)
Non-GAAP results excluding synthetic fuel	$147.1	$29.6	$ 33.0	$ 19.1	$40.4	$(16.5)	$ (80.4)	$172.3

Non-GAAP Information

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

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

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

OPERATING RESULTS

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

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

(millions) Except per share amounts		*2007*	*2006*	*2005*
Segment Revenues (1)				
Regulated companies	Tampa Electric	**$2,188.4**	$2,084.9	$1,746.8
	Peoples Gas	**599.7**	577.6	549.5
Total regulated		**$2,788.1**	$2,662.5	$2,296.3
Unregulated companies	TECO Coal	**$ 544.5**	$ 574.9	$ 505.1
	TECO Transport (2)	**290.3**	308.5	278.2
	TECO Guatemala (3)	**8.0**	7.6	7.7
	TWG Merchant (4)	**—**	—	0.4
Total unregulated		**$ 842.8**	$ 891.0	$ 791.4
Net Income (loss) (5)				
Regulated companies	Tampa Electric	**$ 150.3**	$ 135.9	$ 147.1
	Peoples Gas	**26.5**	29.7	29.6
Total regulated		**176.8**	165.6	176.7
Unregulated companies	TECO Coal	**90.9**	78.8	115.4
	TECO Transport (2)(6)	**34.0**	22.8	20.2
	TECO Guatemala	**44.7**	37.6	40.4
	TWG Merchant (4)	**—**	—	(14.6)
Total unregulated		**169.6**	139.2	161.4
Parent/other		**52.5**	(60.4)	(127.1)
Net income from continuing operations		**398.9**	244.4	211.0
Discontinued operations		**14.3**	1.9	63.5
Net income (loss)		**$ 413.2**	$ 246.3	$ 274.5
Earnings per Share—Basic (7)				
Regulated companies	Tampa Electric	**$ 0.72**	$ 0.65	$ 0.71
	Peoples Gas	**0.13**	0.14	0.14
Total regulated		**0.85**	0.79	0.85
Unregulated companies	TECO Coal	**0.44**	0.38	0.56
	TECO Transport (2) (6)	**0.16**	0.11	0.10
	TECO Guatemala	**0.21**	0.18	0.20
	TWG Merchant (4)	**—**	—	(0.07)
Total unregulated		**0.81**	0.67	0.79
Parent/other		**0.25**	(0.28)	(0.62)
Earnings (loss) from continuing operations		**1.91**	1.18	1.02
Discontinued operations		**0.07**	0.01	0.31
EPS Total		**$ 1.98**	$ 1.19	$ 1.33

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

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

(3) TECO Guatemala was deconsolidated under FIN 46R effective Jan. 1, 2004. Actual revenues in 2007, 2006 and 2005, which are not included in this table due to the effects of deconsolidation, were $114.4 million, $106.1 million, and $96.4 million, respectively.
(4) Effective with 2006, only historical information is provided for TWG Merchant. Any remaining results are included in Parent/other.
(5) Segment net income and earnings are reported on a basis that includes internally allocated financing costs to the non-utility companies. Internally allocated finance costs for 2007 and 2006 were at a pretax rate of 7.5%, and in 2005 were at a pretax rate of 8%, based on the average investment in each unregulated subsidiary.
(6) Results at TECO Transport reflect the $9.7 million after-tax benefit in depreciation expense from not recording depreciation expense due to its classification as Assets Held for Sale effective Apr. 1, 2007 through Dec. 3, 2007.
(7) The number of shares used in the earnings-per-share calculations is basic shares.

TAMPA ELECTRIC

Electric Operations Results

Tampa Electric is entering a period of investment and increasing capital expenditures to support customer growth, statewide transmission system reliability standards, implementation of the storm- hardening plans mandated by the FPSC and additional baseload generating capacity needs.

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

Tampa Electric's 2006 net income was $135.9 million, compared to $147.1 million in 2005. These results were driven by the planned increase in non-fuel operations expense, which more than offset continued strong customer growth and slightly higher energy sales. Weather patterns in 2006 resulted in 3% lower total degree-days than normal but 1% higher total degree-days than 2005, when total degree-days were 5% below normal.

Tampa Electric has not sought a base rate increase since 1992. Since that last rate proceeding it has earned within its allowed return on equity (ROE) range while adding more than 200,000 customers and making significant investments in facilities and infrastructure, including baseload and peaking generating capacity additions to reliably serve its growing customer base. Tampa Electric expects a continued high level of capital investment and higher levels of non-fuel operations and maintenance expenditures. After dropping to the bottom of its allowed ROE range of 10.75% to 12.75% in the middle of 2007, at the end of 2007 Tampa Electric's 13-month moving average regulatory ROE was 11.4% as a result of the positive impact of favorable weather in the second half of 2007, as well as lower depreciation expense and lower property taxes in the second half of the year. However, based on its current lower forecast for energy sales growth, expected higher operations and maintenance expenses and ongoing higher levels of capital investment, Tampa Electric expects its forecasted ROE to go below the bottom of its allowed range for the full year 2008. This is expected to cause a need for base rate relief for Tampa Electric in 2009.

Summary of Operating Results

(millions)	*2007*	*% Change*	*2006*	*% Change*	*2005*
Revenues	**$2,188.4**	5.0	$2,084.9	19.4	$1,746.8
Other operating expenses	**208.4**	-5.4	220.3	9.7	200.8
Maintenance	**109.3**	1.5	107.7	22.2	88.1
Depreciation	**178.6**	-4.1	186.3	-0.4	187.1
Taxes, other than income	**140.4**	1.7	138.1	9.8	125.8
Non-fuel operating expenses	**636.7**	-2.4	652.4	8.4	601.8
Fuel	**947.9**	4.5	906.8	65.8	546.8
Purchased power	**271.9**	22.9	221.3	-17.9	269.7
Total fuel expense	**1,219.8**	8.1	1,128.1	38.2	816.5
Total operating expenses	**1,856.5**	4.3	1,780.5	25.5	1,418.3
Operating income	**331.9**	9.0	304.4	-7.3	328.5
AFUDC equity	**4.5**	66.7	2.7	—	—
Net income	**$ 150.3**	10.6	$ 135.9	-7.6	$ 147.1
Megawatt-Hour Sales (thousands)					
Residential	**8,871**	1.7	8,721	1.9	8,558
Commercial	**6,542**	2.9	6,357	2.0	6,234
Industrial	**2,366**	3.8	2,279	-8.0	2,478
Other	**1,754**	5.2	1,668	1.6	1,642
Total retail	**19,533**	2.7	19,025	0.6	18,912
Sales for resale	**905**	5.0	862	11.5	773
Total energy sold	**20,438**	2.8	19,887	1.0	19,685
Retail customers-thousands (average)	**666.4**	1.9	653.7	2.8	635.7

Operating Revenues

Retail megawatt-hour sales rose 2.7% in 2007, driven by customer growth, total degree days above normal and 2006 and a rebound in the phosphate industry. In 2007, average annual customer growth of 1.9% (almost 13,000 new customers) was partially offset by weather normalized lower average residential per-customer energy usage. Total heating and cooling degree days in Tampa Electric's service area were 2% above normal and 5% above 2006.

In 2007, weather-normalized energy consumption per residential customer declined due to the combined effects of price elasticity, more efficient appliances and changes in residential building trends. One of the factors contributing to this phenomenon is an increase in the number of multi-family units, such as apartments and condominiums, completed in the Tampa metropolitan area. Multi-family units tend to have fewer square feet of air conditioned space per residence and use less energy per square foot due to more energy efficient construction. In addition, the higher costs for natural gas and coal, which are reflected in customers' bills through the fuel adjustment clause, have caused customers to use less electricity in general. On a weather-normalized basis, retail energy sales to residential customers on a per-customer basis decreased 0.6% in 2007 compared to 2006.

Electricity sales to the lower-margin industrial customers in the phosphate industry increased 12.2% in 2007 following a decrease of 18.5% in 2006. The increase in sales to phosphate customers was driven by increased demand for their product due to higher levels of U.S. corn planting to meet demand by the ethanol industry and greater international demand for grains. The 2006 decrease was a result of the idling of some mining operations in 2006 due to market conditions for the product at that time. The longer-term decline in sales to phosphate customers reflects the natural reserve depletion and migration of mining operations out of Tampa Electric's service area. Base revenues from phosphate sales represented less than 2% of base revenues in 2007 and 2006. Sales to commercial customers increased 2.9% in 2007, driven by the strong local economy.

Base rates for all customers were unchanged in 2007. Fuel-related revenues increased in 2007 and 2006 under the FPSC-approved fuel cost recovery clause, due to the recovery of previous under-recoveries of fuel expense in 2006 and 2005 and higher natural gas prices. Customers' rates under the fuel clause increased in 2007 in accordance with the rates approved by the FPSC in November 2006, to reflect higher fuel costs, the under-recovery of $51 million of 2006 fuel cost due to higher cost of natural gas early in the year and the remaining $107 million portion of previously under-recovered 2005 fuel costs. The impact of higher fuel clause recovery was partially offset by the planned sale of a net $72 million of excess sulfur dioxide (SO_2) emission credits, which appears as a credit on customers' bills through the Environmental Cost Recovery Clause (see the **Regulation** section).

Energy sold to other utilities for resale increased 5% in 2007, due to a planned increase under a contract with an existing customer. Energy sold to other utilities for resale increased 11% in 2006 due to a new contract for wholesale energy sales with a new customer and wholesale sales volumes above the contract amount to an existing customer.

Energy Sales Growth Forecast

In 2008, we expect about 2% customer growth to drive 2% energy sales growth. Tampa Electric's 2008 customer growth and energy sales growth forecasts reflect a weakened Florida housing market, but do not reflect an extended depressed housing market or any potential local, state or national economic recessions (see the **Risk Factors** section). Longer-term, based on its projected growth from continued population increases and business expansion, Tampa Electric expects average annual customer and weather-normalized average retail energy sales growth of 2.1% and 2.3%, respectively, over the next five years. This energy sales growth projection is lower than previous projections, reflecting changes in usage patterns that were first experienced in 2006 and continued in 2007, and changes in population trends. Tampa Electric's forecasts indicate that summer retail peak demand growth is expected to average 110 megawatts per year for the next five years. These growth projections assume continued 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 2007, albeit at a slower pace than 2006, aided by continued population growth in Florida and the region's relatively low labor costs. The Tampa metropolitan area's non-farm employment grew 1.0% in 2007, which is in line with national averages but greater than statewide growth in Florida, despite a leveling off in construction employment. The local Tampa area unemployment rate increased to 4.7% at year-end 2007, compared with 3.0% in December 2006, and 3.2% in December 2005. These rates are similar to the 4.7% unemployment rate for the State of Florida but lower than the 5.0% for the nation at Dec. 31, 2007.

As in many areas of the country, the housing market in Tampa Electric's service area remained weak in 2007 after an initial slowdown in 2006 following significant growth in 2004 and 2005. The numbers of existing homes for sale and unsold new homes has increased significantly, driven by excess builder inventory, the curtailment of speculative investing and sub-prime mortgage issues. The number of vacant homes is also a factor in the lower per-residential customer usage trends. Florida is often cited in economic reports as one of the states experiencing the most overbuilding during the housing boom and experiencing the most significant downturn. Residential building permit activity declined by more than 40% in 2007, compared to 2006, which is expected to reduce the excess inventory over time. Economists and real estate associations indicate that the housing market is expected to remain weak throughout 2008 and into 2009, depending on the absorption of excess inventory.

At the same time, Florida continues to experience relatively good population growth. According to the most recent U.S. Census Bureau data, Florida added 194,000 new residents in 2007, and while this is the first time this decade that growth in new residents was less than 200,000 in a given year, it still represents very substantial growth.

Operating Expenses

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

Total operating expenses increased in 2006 due to the higher cost for coal, partially offset by lower purchased power expenses due to increased coal-fired generation from improved coal-fired unit availability. Non-fuel operating and maintenance expenses increased, as planned, by $24.3 million after tax. This increase reflected, among other items, after-tax increases of $8.3 million of additional spending on transmission and distribution system reliability and customer service enhancements, $5.3 million of additional spending on coal-fired unit performance improvements, $6.3 million of higher employee-related costs and $3.3 million of increased property insurance cost.

Operations and maintenance expenses, excluding those costs recovered through FPSC-approved cost recovery clauses, such as fuel, purchased power and conservation, are expected to increase at a more than 6% rate in 2008 after 1.9% growth in 2007 and significant growth in 2006. The 2008 non-fuel operations and maintenance expense increase is expected to be driven by the generally higher costs for copper and steel products and subcontracted labor, major generating unit outages during the installation of NO_x control equipment, and higher employee benefits costs.

Depreciation expense decreased $4.7 million after tax in 2007 primarily due to a depreciation study approved by the FPSC, which lowered depreciation rates on power generation assets due to longer lives. Depreciation expense decreased slightly in 2006 due to the retirement of short-lived fully depreciated assets, such as telecommunications equipment, tools and test equipment, which more than offset the additional depreciation associated with normal plant additions. Depreciation expense is projected to increase in 2008, due to routine plant additions to serve Tampa Electric's growing customer base and maintain system reliability, a partial year of additional depreciation on two combustion turbines placed in service in May 2007 and a partial year of depreciation on the second NO_x control project to be completed on Big Bend Unit 3, which is expected to enter service in May.

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

Fuel Prices and Fuel Cost Recovery

Included in Tampa Electric's fuel adjustment filing for rates effective in 2008 was $18 million of 2007 over-recovered fuel cost net of a $2 million final adjustment to the under recovery related to 2006 fuel filing. In November 2007, the FPSC authorized the return of this amount and the recovery of the full projected 2008 fuel expense. An increase in amounts recovered through the Environmental Cost Recovery Clause is expected to occur in 2008 due to the completion of an additional NO_x control project and lower sales of excess SO_2 emission credits (see the **Regulation** section).

Fuel prices increased in 2007 primarily due to the shift to higher usage of higher cost natural gas from lower cost coal despite delivered natural gas costs declining slightly to $9.52 per million BTU (/mmBTU) in 2007 from $9.61/mmBTU in 2006. Average delivered coal prices increased in 2007 to $2.57/mmBTU, compared to $2.49/mmBTU in 2006.

Natural gas prices were extremely volatile during the 2005 through 2006 period, as a result of supply constraints due to hurricane-related damage to production and transportation infrastructure and increased demand nationwide due to the higher percentage of electricity now being generated from natural gas-fired generation, particularly during peak load periods. Absent the hurricane-related supply disruptions experienced in 2005, natural gas prices have been more stable in 2006 and 2007, but at consistently higher levels in 2007 due to the balance in supply and demand and are expected to remain stable in 2008, assuming no major supply disruptions. Coal prices, while less volatile, increased in 2007 and 2006. Tampa Electric's primary coal supplies are from the Illinois Basin, which did not experience the same downturn in prices in 2006 and 2007 as the Central Appalachian coal producing region. Coal prices are expected to increase in 2008 due to increased international demand for U.S. steam coal and the expectation of more normal inventory levels at utilities in the U.S. (see the **TECO Coal** section).

Energy Supply

On a retail energy supply basis, Tampa Electric generation accounted for 93%, 95% and 92% of the total retail energy sales in 2007, 2006 and 2005, respectively, with the remainder of the energy supplied by purchased power. Purchased power expense increased 23% and the volume of power purchased increased 17% in 2007 as a result of lower coal-fired unit availability, resulting in lower coal-fired generation during the major unit outages to install the NO_x control equipment (see the **Environmental Compliance** section). Per unit purchased power expense increased in addition to the volume increase due to purchasing power from higher-cost natural gas fired generating sources. In 2006, the cost of power purchased by Tampa Electric to serve its customers decreased 18% and the volume of power purchased decreased 11% from improved coal-fired unit availability and generation. The cost decreased more than the volume due to lower natural gas prices in 2006 than in 2005. The cost for purchased power is expected to decrease slightly in 2008 due to the duration of the planned extended maintenance period for the completion of the SCR project on Big Bend Unit 3.

Prior to 2003, nearly all of Tampa Electric's generation was from coal. Starting in April 2003, the mix started to shift with increased use of natural gas at the Bayside Power Station, which was converted from the coal-fired Gannon Station. Nevertheless, coal is expected to continue to represent more than half of Tampa Electric's fuel mix due to the baseload units at Big Bend and the coal gasification unit, Polk Unit One. In 2008 through 2010, one of the remaining three Big Bend coal-fired units will undergo an extensive outage each year to complete the construction of the NO_x control equipment (see the **Environmental Compliance** section), which is expected to reduce the generation from coal in those years.

Hurricane Storm Hardening

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

The FPSC subsequently issued an order requiring all investor owned utilities (IOUs) to implement a 10-point storm preparedness plan designed to improve the statewide electric infrastructure to better withstand severe storms and expedite recovery from future storms. In addition to a wood pole inspection program instituted separately, the plans address vegetation management, audits of pole attachments, transmission structure inspections and hardening, data gathering and analysis, natural disaster planning, coordination with local governmental agencies and collaborative research. In October 2006, the FPSC approved Tampa Electric's plan to comply with the directive. Tampa Electric implemented its plan in 2007 and estimates the average non-fuel operations and maintenance expense of this plan to be approximately $20 million annually for the foreseeable future.

The FPSC also modified its rule regarding the design standards for new and replacement transmission and distribution line construction, including certain critical circuits in a utility's system. Beyond employing accepted engineering practices and complying with the applicable edition of the National Electric Safety Code (NESC), the new design standard requires adoption of the NESC extreme wind loading standards for distribution facilities. The new design standards also encourage the placement of new or modified facilities underground when feasible. In 2008, Tampa Electric expects to invest approximately $22 million of capital for higher levels of transmission and distribution pole replacement, improvements to circuits serving critical infrastructure and the completion of the global information system required under the storm hardening program. Future capital expenditures required under the storm hardening program are expected to average approximately $19 million annually for the foreseeable future (see the **Regulation** section).

Higher Capital Spending

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

Based on its current forecast of long-term energy demand and sales growth, Tampa Electric has identified a need for new baseload capacity in early 2013 due to continued customer growth and the expiration of a long-term power purchase agreement with Hardee Power Partners. Its options to satisfy the baseload capacity need range from purchasing power to constructing its own generating facility. Tampa Electric has in place contracts to meet its interim peak capacity needs for 2008 and plans to construct simple-cycle combustion turbine units to meet its peaking capacity needs in the 2009 through 2012 period.

In early 2007, Tampa Electric announced that its preferred technology to meet the 2013 baseload requirement was a solid fuel IGCC unit. However, during the certification of need process and after filing the required environmental permit applications it became apparent that continued uncertainty related to CO_2 regulations, particularly carbon capture and sequestration issues, and the potential for related project cost increases posed unacceptable economic risk to customers and investors, and the project was deferred. As a result of the decision to defer the use of IGCC unit, Tampa Electric now expects to utilize combined cycle natural gas-fired technology to meet its expected 2013 generation expansion need. In Florida, the construction of baseload capacity is subject to certain regulatory approvals that must be received prior to commencement of construction (see the **Capital Expenditures** and **Regulation** sections).

PEOPLES GAS (PGS)

Operating Results

PGS reported net income of $26.5 million in 2007 compared to $29.7 million in 2006. These results reflect 1.6% average customer growth, lower 2007 volumes for retail customers due to one of the warmest months of

January on record, which limited the number of heating degree days, and changes in customer usage patterns. Sales to industrial customers, such as wallboard, asphalt and concrete producers, which are impacted by the slowdown in the Florida housing market, were lower. Results also reflect $0.7 million lower after-tax property tax expense due to lower property tax rates from legislation passed in Florida to reduce property taxes; $2.2 million higher after-tax depreciation expense due to a routine depreciation study approved by the FPSC in January 2007 and routine property additions; and higher low-margin off-system sales and volumes transported for power generation customers.

In 2007, the total throughput for PGS was 1.4 billion therms. Of this total throughput, 9% was gas purchased and resold to retail customers by PGS, 69% was third-party supplied gas that was delivered for retail transportation-only customers, and 22% was gas sold off-system. Industrial and power generation customers consumed approximately 69% of PGS' annual therm volume, commercial customers used approximately 26%, and the balance was consumed by residential customers.

Due to the higher operating costs, continued investment in the distribution system and higher costs associated with recently required safety requirements, such as pipeline integrity safety, PGS' return on equity levels are below the bottom of its allowed range and therefore it expects to file for a base rate increase in 2008.

PGS reported net income of $29.7 million in 2006, compared to $29.6 million in 2005. Customer growth of 3.3%, increased sales to residential customers and strong sales to power generating and off-system customers due to declining natural gas prices were partially offset by non-fuel operation and maintenance expenses that were $1.4 million higher after tax. The higher off-system sales and increased volumes transported for power generation customers helped offset the impact of mild winter weather early in 2006 and then again in December 2006. After a very strong 2005 performance, sales to commercial customers declined slightly due to higher natural gas prices in early 2006.

In 2006, the total throughput for PGS was 1.3 billion therms. Of this total throughput, 11% was gas purchased and resold to retail customers by PGS, 70% was third-party supplied gas that was delivered for retail transportation-only customers and 19% was gas sold off-system. Industrial and power generation customers consumed approximately 65% of PGS' annual therm volume, commercial customers used approximately 29%, and the balance was consumed by residential customers.

While the residential market represents only a small percentage of total therm volume, residential operations generally comprise almost 25% of total revenues. New residential construction that includes natural gas and conversions of existing residences to gas had steadily increased since the late 1980s, but slowed starting in 2006 and further in 2007 due to the weak Florida housing market conditions. Like all natural gas distribution utilities, PGS is adjusting to lower per-customer usage due to improving appliance efficiency. As customers replace existing gas appliances with newer more efficient models, per-customer usage tends to decline.

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

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

Summary of Operating Results

(millions)	*2007*	*% Change*	*2006*	*% Change*	*2005*
Revenues	**$ 599.7**	3.8	$ 577.6	5.1	$ 549.5
Cost of gas sold	**389.9**	6.7	365.3	4.3	350.2
Operating expenses	**150.9**	1.6	148.5	9.0	136.2
Operating income	**58.9**	-7.7	63.8	1.1	63.1
Net income	**26.5**	-10.8	29.7	0.3	29.6
Therms sold—by customer segment					
Residential	**70.1**	-4.0	73.0	3.3	70.7
Commercial	**370.9**	-1.3	375.7	-1.2	380.3
Industrial	**489.8**	7.3	456.6	15.7	394.6
Power generation	**471.7**	19.2	395.7	35.7	291.7
Total	**1,402.5**	7.8	1,301.0	14.4	1,137.3
Therms sold—by sales type					
System supply	**437.8**	11.9	391.1	16.0	337.1
Transportation	**964.7**	6.0	909.9	13.7	800.2
Total	**1,402.5**	7.8	1,301.0	14.4	1,137.3
Customer (thousands)—average	**334.3**	1.6	329.0	3.3	318.4

In Florida, natural gas service is unbundled for non-residential customers that elect this option, affording these customers the opportunity to purchase gas from any provider. The net result of unbundling is a shift from bundled transportation and commodity sales to transportation sales. Because the commodity portion of bundled sales is included in operating revenues at the cost of the gas on a pass-through basis, there is no net financial 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 2007, approximately 46% of PGS' non-residential customers elected to take service under this program.

Total operating expenses were 1.6% higher in 2007. Non-fuel operations and maintenance expense decreased slightly in 2007, primarily due to lower employee-related costs from more efficient operations and lower actuarially determined self-insurance reserves more than offsetting the increased use of contract labor and higher cost of supplies such as gasoline to operate vehicles. Non-fuel operations and maintenance expense had increased in 2006 primarily due to higher employee-related costs. Depreciation expense increased $2.2 million after tax in 2007 due to higher depreciation rates resulting from a routine depreciation study approved by the FPSC in January 2007 and routine plant additions. Depreciation expense had increased in 2006 in line with the capital expenditures made to expand the system.

PGS expects the effect on its operating income of assumed normal weather, and customer and therm sales growth in 2008 will be offset by the effects of higher operation and maintenance expense and higher depreciation expense. Depreciation is expected to increase in 2008 from routine plant additions. Operations and maintenance expense, excluding costs related to FPSC-approved energy conservation programs recovered separately, are expected to increase at about a 4.5% rate in 2008.

PGS forecasts customer growth of approximately 1.0% in 2008, which is lower than the average customer growth experienced for the past five years. A major contributor to the slower growth is the slowdown in the housing market. PGS provides service in areas of Florida that experienced some of the most rapid growth and price appreciation in 2005 and 2006, including the Miami, Ft. Myers and Naples areas. These areas are now experiencing the most significant impacts of the slowdown in the housing market.

Since its acquisition by TECO Energy in 1997, PGS has expanded its gas distribution system through system extensions into areas of Florida not previously served by natural gas, such as the lower southwest coast in the Ft. Myers and Naples areas and the northeast coast in the Jacksonville area. PGS' expansion strategy for the past several years has been to take advantage of the significant capital investments in main pipeline expansions to connect customers to that existing infrastructure. In 2008, PGS expects its capital spending to support modest system expansion. It also expects continued customer additions and related revenues from its build-out efforts throughout the state of Florida, assuming continued local economic growth, normal weather, and other factors (see the **Risk Factors** section).

Gas Supplies

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

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

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

TECO COAL

TECO Coal recorded net income of $90.9 million in 2007, compared to $78.8 million in 2006. TECO Coal's 2007 Non-GAAP results excluding synthetic fuel, which exclude the $52.6 million benefit associated with the production of synthetic fuel, were $38.3 million, compared to $46.7 million in 2006, which excluded $32.1 million of synthetic fuel benefits. (See the **2007 and 2006 GAAP Results Reconciliation to Non-GAAP** table.)

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

TECO Coal recorded 2006 net income of $78.8 million, compared to $115.4 million in 2005. Excluding the $32.1 million benefit associated with the production of synthetic fuel, TECO Coal's full-year 2006 Non-GAAP results excluding synthetic fuel were $46.7 million, compared to $33.0 million in 2005, which excluded $82.4 million of earnings benefits from the production of synthetic fuel, (see the **2006 GAAP Results Reconciliation to Non-GAAP** table). Compared to 2005, results reflect a 13% higher average net per-ton selling price across all products, excluding transportation allowances, partially offset by higher production costs. Results also reflect a $3.8 million after-tax charge to reduce deferred tax assets consistent with a reduction in the Kentucky state income tax rate and a $2.7 million after-tax benefit from the true-up in 2006 of the 2005 synthetic fuel tax credit rate.

Total sales were 9.8 million tons in 2006, including 5.3 million tons of synthetic fuel, compared to 9.7 million tons, including 6.4 million tons of synthetic fuel in 2005. Lower synthetic fuel sales volumes in 2006 reflected the idling of production facilities from late July through mid-September due to estimated average annual oil prices above the break-even level. Total coal sales were not impacted as synthetic fuel sales contracts permitted the substitution of conventional coal for synthetic fuel while the synthetic fuel production was idled.

In 2006, the cash cost of production increased 12% over 2005. Higher production costs reflected higher costs associated with: new safety regulations; relocating mining equipment from high cost mining areas and areas where the reserves were depleted; additional exploration expenses to optimize future mining plans; and diesel fuel, explosives, conveyor belts and steel-related products.

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

In 2007, TECO Coal had in place oil price hedge instruments to protect against the risk of high oil prices reducing the value of the tax credits related to the production of synthetic fuel. Because these oil price hedges were intended to provide approximately a dollar-for-dollar recovery of lost synthetic fuel revenues in the event of a tax credit phase-out, TECO Coal previously forecast full-year benefits from the production of synthetic fuel to be approximately $100 million of net cash and $65 million of net income, regardless of oil price levels. Although the oil price hedges were calibrated to fully compensate for any potential phase-out, the final phase-out estimate exceeded the final hedge settlement by approximately $12.0 million after tax. This difference occurred because the 2007 relationship between the U.S. Department of Energy's Producer First Purchase Prices and the NYMEX oil prices, which was the basis for the hedges, diverged from the historical norm in the second half of 2007, as oil prices continued to increase. The phase out reduced cash received from the investors in 2007, and the cash from the hedges was received in January 2008.

In 2007, the benefits from the production of synthetic fuel reflect the estimated 67% reduction in revenues from third-party synthetic fuel investors related to tax credit phase-outs due to high oil prices. The phase-out range is based on oil prices represented by the annual average of Producer First Purchase Prices reported by the U.S. Department of Energy. Based on the actual relationship of these prices reported through October and NYMEX prices, TECO Coal estimates the initial phase-out level for 2007 to begin at $62 per barrel of oil (/Bbl) on a NYMEX basis, and that the tax credits would be fully phased out at $78/Bbl on a NYMEX basis. Actual Department of Energy Producer First Purchase Prices for the full year, which are normally reported in late March of the following year, and the actual inflation rate for 2007 may cause positive or negative adjustments to estimated 2007 results and would be recorded in the results for the first quarter of 2008, but is not expected to be material.

TECO Synfuel Holdings, LLC sold 90% of its ownership interest to two third party investors by the end of 2004, along with associated percentage rights to benefits in the business that adjusted from time to time. Allocation of the benefits in 2005 was temporarily increased 8% in the first and second quarters such that 98% of the benefits went to the third parties. In July 2005, a permanent increase in the third-party ownership of the synthetic fuel facilities to 98% was achieved through the sale of an additional 8% interest to a new participant.

Under these third-party ownership transactions, TECO Coal was paid to provide feedstock, operate the synthetic fuel production facilities and sell the output; TECO Coal also recognized a gain on the sale of the ownership interests in the facilities for each ton of synthetic fuel sold. The purchasers had the risks and rewards of ownership and were allocated 98% of the tax credits and operating costs.

TECO Coal recorded $1.4 million and $2.1 million of after-tax benefits from the production associated with its remaining synthetic fuel ownership interest in 2007 and 2006, respectively, but recorded no synthetic fuel tax credits in earnings for 2005 because of TECO Energy's actual 2005 tax position.

TECO Coal Outlook

We expect TECO Coal's 2008 net income to exceed its 2007 non-GAAP results excluding synthetic fuel. Total sales are expected to be in a range between 9.5 million and 10 million tons in 2008 with no synthetic fuel production, compared to 9.2 million tons in 2007. The higher expected sales volume reflects the somewhat improved coal market, which has been driven by supply and demand in the international coal market and the expectation of more normal inventory levels at U.S. utilities. Due to the signing of steam coal contracts for 2008 delivery during periods of lower prices in 2006 and 2007 and its metallurgical coal contracts early in the renewal cycle, TECO Coal expects its average realized price per ton in 2008 to be higher than in 2007, but lower than the current market prices. Although the average selling price for all products is expected to increase in 2008, the cost of production is expected to increase at a higher rate. The benefits from closing higher cost facilities in 2006 and 2007 are expected to be more than offset by higher diesel fuel prices and higher safety costs than in 2007. Fully-loaded cash margins per ton in 2008 are expected to be about $10 per ton, and after-tax margins are expected to be about $4 per ton.

Coal Markets

Following the very robust markets for Central Appalachian coal in 2004 and 2005, a mild 2006 summer and a mild 2007 winter caused utilities to burn less coal and increased inventories at utility users to above normal levels for much of 2007. As a result, spot market prices for Central Appalachian utility steam coal declined more than 40% between the summers of 2006 and 2007. Contracts for delivery of steam coal in 2007 signed in the last six months of 2006 and the first nine months of 2007 were at prices below those experienced in 2005 and early 2006.

Beginning in the fall of 2007, prices for Central Appalachian coal, especially metallurgical coal, strengthened due to international supply and demand pressure. Continued strong demand for coal in China and India, bottlenecks in ports in Australia, high oceangoing freight rates and the temporary closures of several major metallurgical coal mines caused prices for coal sold in international markets to increase.

Many of the same factors caused the international demand for steam coal to increase in the fall of 2007. As a result of higher international demand and industry-wide expectations for declining inventories and potential for lower supplies from Central Appalachia due to rising safety costs and delays in issuance of required environmental permits for new mines. Through early February 2008, spot prices for domestic steam coal increased approximately 48% since October 2007.

TECO Coal sells almost all of its annual production under either multi-year contracts or contracts that are finalized late in the previous year or early in the delivery year. In 2007, TECO Coal benefited from contracts, which included some multi-year contracts, signed in the stronger 2005 price environment. It currently has 100% of its planned 2008 sales under contracts that were signed primarily in 2006 and 2007 before the significant price increases late in 2007. The multi-year approach to contracting reduced the impact of the weaker coal markets in 2006 and 2007, but is limiting the upside from the very strong coal markets in 2008. For 2009, TECO Coal currently has 40% of its expected sales contracted, primarily utility steam coal.

The significant factors that could influence TECO Coal's results in 2008 are cost of production and the ability to sell coal at attractive prices in the spot market. Longer-term factors that could influence results include inventories at steam coal users, weather, general economic conditions, the level of oil and natural gas prices, commodity price changes which impact the cost of production, and CO_2 reductions if required (see the **Environmental Compliance** and **Risk Factors** sections).

TECO GUATEMALA

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

The Guatemalan operations are utility-like in nature due to the long-term power sales contracts and stable operations of the power generating facilities. The San José Power Station is a baseload coal-fired station with high capacity and availability factors.

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

In 2007, net income was $44.7 million, compared to $37.6 million in 2006. Earnings for EEGSA increased due to customer growth and higher energy sales at EEGSA and increased earnings from the affiliated companies. EEGSA had 3.8% customer growth in 2007, increasing its customer base by 31,000 to over 840,000 at year-end. Net income for DECA II reflected a $1.9 million after-tax benefit related to an adjustment to previously estimated year-end results. The San José Power Station realized increased revenues in 2007 from both contract and spot sales with volumes up 2% and 5%, respectively, and prices up 3% for contract and spot sales. Higher energy sales were a result of 99.5% availability, as calculated under its power sales agreement, and the highest net generation and capacity factor (92.2%) ever experienced for the San José Power Station. It also recorded its best heat rate in three years and a continuous run of 117 days. In a comparison made with coal units of similar size operating in the United States, the San José Power Station's capacity factor and overall availability (94.9%) were in the top 10% and top 1%, respectively. The Alborada Power Station benefited from higher capacity payments as scheduled under its contract and a 99.9% availability as calculated under its power sales agreement. Interest expense decreased due to lower interest rates and lower project debt balances, and interest income increased on higher offshore cash balances .

TECO Guatemala had net income of $37.6 million in 2006, compared to $40.4 million in 2005, which was driven by 4.3% customer growth at EEGSA, 3% higher generation at the San José Power Station, higher capacity payments at the Alborada Power Station, lower insurance and interest expense, and operating and maintenance expenses essentially unchanged from 2005 levels more than offset by a higher tax rate.

At TECO Guatemala, we expect 2008 net income to decrease from 2007 levels. Results in 2007 reflect outstanding performance of the San Jose Power Station with extremely high availability and capacity factors. In 2008, increased scheduled maintenance is expected to reduce the availability and capacity factors, which will result in lower spot energy sales and increased costs. Results at DECA II are expected to be driven by higher energy sales to retail customers being more than offset by the absence of the $1.9 million after-tax benefit recorded in 2007 to adjust previously estimated results.

The Comisión Nacional de Energia Eléctrica (CNEE) was created under the General Electricity Law of 1996 as a branch of the Ministry of Energy and Mines in Guatemala and regulates the energy sector in Guatemala. EEGSA is undergoing a new rate setting process to determine the Value Added Distribution (VAD) charge applicable in the tariffs, leading to new rates effective in the summer of 2008. The new VAD rates that EEGSA can charge its customers for the use of its distribution lines will be set for a term of five years. The current VAD rates were established in May 2003. It is not possible to predict the outcome of the VAD review, but TECO Guatemala personnel are monitoring and participating in this process.

The two distribution companies serving rural Guatemala, DEOCSA and DEORSA, which are owned and operated by the Spanish utility, Union Fenosa, have issued a combined request for proposals for a 200-megawatt baseload coal-fired unit to be constructed in Guatemala with commercial operation expected in 2012. TECO Guatemala is evaluating this opportunity and expects to submit a bid in the spring of 2008, either individually or in a partnership with others, to build, own and operate the plant. If successful, TECO Guatemala would expect to sign a 15-year power sales agreement with DEOCSA and DEORSA. The plant would be constructed to meet World Bank and Guatemala Environmental Guidelines and is expected to be financed with non-recourse project debt, similar to the existing TECO Guatemala plants.

PARENT/OTHER

In 2007, Parent/other net income was $52.5 million, compared to a cost of $60.4 million in 2006. In 2007, the non-GAAP cost was $60.4 million, compared to $74.2 million in 2006. Non-GAAP costs in 2007 exclude the $149.4 million gain on the sale of TECO Transport, $16.3 million of after-tax charges related to the sale of TECO Transport and the $20.2 million after-tax charge related to the debt extinguishment/exchanges completed in December. Non-GAAP costs in 2006 exclude the $5.7 million after-tax gain on the unused steam turbines and the $8.1 million gain on the sale of the remaining assets of the unfinished McAdams Power Station, which had been previously impaired. In 2007, parent interest expense declined $29.2 million, or $18.1 million after tax, reflecting parent debt retirement, which more than offset the $11.0 million lower parent interest income due to lower cash balances. (See the 2007 **GAAP to non-GAAP reconciliation** table.)

In 2006, the Parent/other cost was $60.4 million, compared to $127.1 million in 2005. In 2006, the Parent/other non-GAAP cost was $74.2 million, compared to $80.4 million in 2005. 2006 Non-GAAP results in Parent/other excluded the after-tax gains described above. Non-GAAP results in 2005 excluded $46.7 million of after-tax charges associated with the early retirement of debt (see the **2005** and **2006 GAAP to non-GAAP reconciliation** tables). Results in 2006 were driven by parent interest expense which was $18.1 million, or $11.2 million after tax, lower than in 2005 due to the debt redemption and refinancing actions initiated in mid-2005. This was offset, in part, by no longer allocating interest to TWG Merchant. Pretax parent-level interest allocated to the operating companies was $23.1 million in 2006, compared to $36.2 million in 2005. Investment income on cash and short-term investments increased $6.6 million over 2005 as a result of higher interest rates and higher investment balances.

We expect costs at TECO Energy parent-level to decline again in 2008 due to the debt retirement actions taken in 2007 and our plans for additional parent debt retirement in 2008.

TECO TRANSPORT

As a result of the sale closing, TECO Transport's 2007 net income of $34.0 million reflects activities through Dec. 3, 2007, compared to $22.8 million in 2006. Non-GAAP results were $24.3 million in 2007, compared to $25.8 million for the full-year period in 2006. TECO Transport's 2007 non-GAAP results include $9.7 million of after-tax depreciation that was excluded from reported net income. Non-GAAP results in 2006 excluded $3.0 million of after-tax direct costs associated with damage from Hurricane Katrina, net of insurance recovery. (See the **2007** and **2006 GAAP to non-GAAP reconciliation** tables.) Because of the Assets Held for Sale classification of TECO Transport, the recording of depreciation was discontinued as of Apr. 1, 2007. Results in 2007 reflect increased third-party volumes at TECO Bulk Terminal, the impact of low water conditions on the rivers, which limited tow sizes, lower river rates when compared to the near record levels in 2006, and higher earnings from third-party business at the oceangoing operations.

In 2006, TECO Transport recorded net income of $22.8 million, compared to $20.2 million in 2005. The 2006 results reflected higher river barge rates and equipment utilization, improved oceangoing equipment utilization, lower repair costs at TECO Ocean Shipping, and higher Tampa Electric movements, partially offset by higher fuel costs and lower tonnage for third-party customers. Non-GAAP results of $25.8 million in 2006 excluded $4.5 million of after-tax direct costs associated with damage from Hurricane Katrina at TECO Bulk Terminal and TECO Barge Line, and $1.5 million of after-tax insurance recovery at TECO Barge Line, compared to 2005 non-GAAP results of $19.1 million, which excluded $12.6 million of direct Hurricane Katrina costs and $13.7 million of insurance recovery (see the **2006** and **2005 GAAP to non-GAAP reconciliation** tables).

As discussed in the **Overview** section, we completed the sale of TECO Transport to an investment group led by Greenstreet Equity Partners, L.P. for gross proceeds of $405 million. The sale resulted in an after-tax net book gain of $149.4 million, before $16.3 of after-tax transaction related costs recorded at TECO Energy parent. Proceeds from the sale of TECO Transport were used to pay down parent level debt on an accelerated basis.

TWG MERCHANT

Since 2003, our strategy has been to focus on our Florida utilities and our profitable unregulated businesses and to reduce our exposure to the merchant power markets. In 2005, we essentially completed our exit from the merchant power business and the sales of the minor remaining assets were completed in 2006 (see the **Overview** section). Beginning in 2006, only historical information is provided for TWG Merchant. Any remaining results are included in Parent/other.

In 1999, we began to expand our presence in the domestic independent energy industry. From 2000 through 2003 we purchased unregulated generating plants and built other unregulated generating plants. After we had committed to the major investments in unregulated power, conditions in energy markets changed, and the prospects for operating losses and negative cash flow at most of the merchant facilities we were constructing caused us to delay some projects and sell others commencing in 2003.

In 2004 and 2005, we took aggressive actions to complete our exit from the merchant power business. We sold plants at a loss, and in the case of the large Union and Gila River projects, we sold and transferred the ownership to the lenders, which caused us to write-off our equity investment. These actions resulted in significant write-offs of the equity investments in the projects, in the generation of net operating losses for tax purposes (see the **Income Tax** section), and left us with a high level of parent debt that we have been retiring.

OTHER ITEMS IMPACTING NET INCOME

Other Income (Expense)

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

In 2006, Other income or (expense) of $153.6 million reflected the $46.6 million from the installment sale of the 98% interest in the synthetic fuel production facilities at TECO Coal; $58.6 million of pretax income from the Guatemalan operations, which are accounted for as equity investments; $34.8 million of pretax interest income on invested cash balances; and $6.0 million of pretax gains on the smaller assets sold in 2006. Income from the sale of the interests in TECO Coal's synthetic fuel production facilities was reduced in 2006 by the 35% limitation on the tax credits due to high oil prices and lower production in 2006 (see the **TECO Coal** section).

AFUDC equity at Tampa Electric, which is included in Other Income (expense), was $4.5 million and $2.7 million in 2007 and 2006, respectively, and there was no AFUDC recorded in 2005. AFUDC is expected to increase in 2008 due to the installation of combustion turbines to meet peak load capacity needs, the initial spending on baseload capacity and for NO_x control at Tampa Electric's Big Bend Station (see the **Environmental Compliance** and **Liquidity, Capital Resources** sections).

Interest Expense

Total interest expense was $257.8 million in 2007 compared to $278.3 million in 2006 and $288.7 million in 2005. In 2007, interest expense was reduced by the December 2006 retirement of the remaining 8.5% trust preferred securities (TruPS) outstanding, the repayment in January 2007 of $57 million of 5.93% junior subordinated notes, the repayment of $300 million of 6.125% notes in May 2007, and the repayment of $111 million of 5% Dock and Wharf bonds in September. In 2006, interest expense was reduced by the repayment in June 2005 of $380 million of 10.5% notes and the December 2005 repayment of $100 million of 8.5% TruPS . Interest expense also reflects Tampa Electric Company's issuance of $250 million of 6.15% notes in May 2007 and use of proceeds to repay $150 million of maturing notes and reduce short-term borrowings (see the **Financing Activity** section).

Interest expense is expected to decrease in 2008 due to the full-year benefits from the debt retirement actions taken in 2007 and the planned retirement of the $100 million of floating rate notes in 2008, partially offset by Tampa Electric Company's increased borrowings to support its capital spending program (see the **Liquidity, Capital Resources** section).

Income Taxes

The provision for income taxes increased in 2007 due to higher operating income, the gain recognized on the sale of TECO Transport, and the hedge settlement at TECO Coal. The provision for income taxes increased in 2006 from higher operating income primarily due to lower debt extinguishment costs and lower interest expense. Income tax expense as a percentage of income from continuing operations before taxes was 34.9% in 2007, 32.7% in 2006 and 32.6% in 2005. For 2008, we expect the effective tax rate to be in the range of 30% to 35%.

The cash payments for income taxes, as required by the Alternative Minimum Tax Rules (AMT), state income taxes and payments (refunds) related to prior years' audits was $(10.5 million), $10.4 million, and $27.4 million in 2007, 2006 and 2005, respectively. The 2007 refund was a result of a 2003 and 2004 foreign tax-credit carryback claim.

Due to the generation of deferred income tax assets related to the net operating loss (NOL) carry-forward from disposition of the TWG Merchant generating assets (see the **TWG Merchant** section), we expect future cash tax payments for income taxes to be limited to approximately 10% of the AMT rate, reduced by AMT foreign tax credits and various state taxes. We currently expect to utilize these NOLs through 2011. Beyond 2011, we expect to use more than $200 million of AMT carry-forward to limit future cash tax payments for federal income taxes to the level of AMT. Our current projection of cash income tax payments in 2008 is approximately $8 million, including amounts owed to jurisdictions where we do not have NOLs. For the 2009-2011 period, we estimate tax payments to be in the range of $2 million to $4 million annually.

The synthetic fuel tax credit is determined annually and is estimated to be $0.4034 per million Btu for 2007 after phase-out ($1.2310 per million Btu with no phase-out), and was $0.8138 per million Btu in 2006 ($1.2121 per million Btu with no phase-out) and $1.17 per million Btu in 2005. This rate escalated with inflation but was limited by the tax credit phase-out due to high domestic oil prices. (See the discussion of the reference oil price in the **TECO Coal** section.)

In 2007, 2006 and 2005, income tax expense also reflected a decrease due to the impact of increased overseas operations with deferred U.S. tax structures. The decrease related to these deferrals was $11.0 million, $9.2 million and $9.4 million for 2007, 2006 and 2005, respectively.

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

DISCONTINUED OPERATIONS

Discontinued Operations

(millions - after-tax)	*2007*	*2006*	*2005*
Loss on operations	$—	$—	$(11.6)
Gain on disposition of Union and Gila River	—	—	76.5
Commonwealth Chesapeake write-off	—	—	1.8
TECO Solutions/other	14.3	1.9	(3.2)
Total discontinued operations	**$14.3**	$ 1.9	$ 63.5

In 2007, net income from discontinued operations reflects a $14.3 million tax benefit recorded in discontinued operations in the second quarter as a result of reaching a favorable conclusion with taxing authorities related to the 2005 disposition of the Union and Gila River merchant power plants. TECO Transport was not classified as a discontinued operation due to the ongoing contractual relationship with Tampa Electric for solid fuel waterborne transportation services.

In 2006, net income from discontinued operations was $1.9 million, reflecting primarily the recovery of receivables and adjustments for estimates for businesses that had been previously written off. In 2005, net income from discontinued operations was $63.5 million.

The 2005 results include the operating results from the Union and Gila River power stations (TPGC) through the end of May 2005 and the $76.5 million after-tax gain recorded upon the final disposition of the plants. Discontinued operations also include results for the Commonwealth Chesapeake Power Station until its sale in April 2005 and adjustments to estimates for impairments on previously divested assets.

Discontinued Operations/Asset Dispositions

TECO Energy completed a number of asset dispositions in 2006 and 2005 as part of a revised business strategy to focus on the electric and gas utilities and long-term profitable unregulated businesses and to reduce exposure to the merchant power sector. This process was completed with the sale in 2006 of TECO Thermal and of the uncompleted McAdams Power Station. In 2005, TWG Merchant sold its membership interest in Commonwealth Chesapeake Power Station (CCC) in Virginia and substantially all the assets of the Dell Power Station in Arkansas. BCH Mechanical, Inc. (BCH Mechanical) was also sold in 2005. In 2005, TECO Energy completed the sale and transfer of the Union and Gila River project companies (see **Notes 16** and **21** to the TECO Energy **Consolidated Financial Statements**). TPGC's results are accounted for as discontinued operations for all periods reported. Revenues from the discontinued operations of TPGC in 2005 were $109.1 million. Net income (loss) from the discontinued operations of TPGC was $65.1 million in 2005.

LIQUIDITY, CAPITAL RESOURCES

The table below sets forth the Dec. 31, 2007 consolidated liquidity and cash balances, the cash balances at the operating companies and TECO Energy parent, and amounts available under the TECO Finance and Tampa Electric credit facilities.

(millions)	*Consolidated*	*Tampa Electric Company*	*Other operating companies*	*Parent/ Finance*
Credit facilities	$675.0	$475.0	$ —	$200.0
Drawn amounts/Letters of credit	34.5	25.0	—	9.5
Available credit facilities	640.5	450.0	—	190.5
Cash	162.6	11.9	50.9	99.8
Other investments	15.0	—	15.0	—
Total liquidity	$818.1	$461.9	$65.9	$290.3
Consolidated restricted cash (not included above)	$ 7.4	$ —	$ 0.2	$ 7.2

Cash at the other operating companies includes $35.8 million at TECO Guatemala held offshore due to the tax deferral structure associated with EEGSA and its affiliated companies. Other investments reflect an additional $15.0 million held offshore at TECO Guatemala with longer term maturity dates. In addition to consolidated cash, as of Dec. 31, 2007, unconsolidated affiliates owned by TECO Guatemala, CGESJ (San José) and TCAE (Alborada), had unrestricted cash balances of $19.9 million and restricted cash of $4.9 million, which are not included in the table above, as these project companies were deconsolidated due to the adoption of FIN 46R, *Consolidation of Variable Interest Entities,* effective Jan. 1, 2004.

Other investments in the table above reflects $15 million invested in two auction rate securities, $5 million maturing June 2032 and $10 million maturing June 2041. Both are rated AAA by all three rating agencies and are not insured by any bond insurance company. The $10 million investment consists of notes backed by loans made under the Federal Family Educational Loan program, a federally guaranteed loan program. These investments represent funds held offshore and not repatriated due to the tax-deferral structure associated with EEGSA and its affiliated companies. TECO Guatemala does not expect to need access to these funds over the next year. In the event the company needed to access these funds quickly, it could have to sell the securities at an amount below par value.

In 2007, we met our cash needs from a mix of internal sources and long-term notes issued at Tampa Electric Company. We received cash from the sale of TECO Transport and used those proceeds primarily to accelerate the retirement of parent debt. Cash from operations was $554 million in 2007. Other sources of cash in 2007 included $405 million from the sale of TECO Transport, $78 million of proceeds from third-party investors for ownership interests in TECO Coal's synthetic fuel production facilities, $37 million repatriated from TECO Guatemala, and $250 million from the issuance of long-term debt at Tampa Electric Company. We used cash to retire $357 million of TECO Energy parent debt at maturity, $111 million of TECO Energy parent-guaranteed TECO Transport Dock and Wharf bonds at maturity, and $297 million of TECO Energy parent debt prior to maturity, and the regulated companies reduced short-term borrowings $23 million and repaid $150 million of long-term debt at maturity. We paid dividends in 2007 of $163 million on TECO Energy common stock. Our capital expenditures for the year were $494 million.

In 2006, we met our cash needs from a mix of internal sources, asset sales and long-term notes issued at Tampa Electric Company. Cash from operations was $567 million in 2006. Other sources of cash in 2006 included $123 million of proceeds from third-party investors for ownership interests in TECO Coal's synthetic fuel production facilities, $250 million from the issuance of long-term debt at Tampa Electric, and $42 million from the sale of land at TECO Properties and the remaining merchant power and energy services assets. We used cash to retire the remaining $100 million of 8.5% trust preferred securities prior to maturity, and the regulated companies reduced short-term borrowings $167 million. We paid dividends in 2006 of $159 million on TECO Energy common stock. Our capital expenditures for the year were $456 million.

Cash from Operations

In 2007, consolidated cash flow from operations was $554 million, which included, among normal operating items, net cash of $124 million reflecting the FPSC-approved recovery of previously under-recovered 2006 and 2005 fuel costs, which was partially offset by Tampa Electric's sale of excess SO_2 emissions credits. In addition, cash from operations reflects a $30 million contribution to the pension plan in 2007, and premiums paid in the early extinguishment/exchange of parent debt. The accounting treatment of the sale of interests in the synthetic fuel production facilities at TECO Coal includes the costs associated with synthetic fuel production in cash flow from operations, but the proceeds from the third-party synthetic fuel investors are reported as cash from investing and financing activities.

TECO Coal had previously sold a total of 98% of the ownership interests in its synthetic fuel production facilities to third-party investors. In 2007, cash flow from operations includes the operating losses of approximately $65 million (pretax) associated with the production of synthetic fuel, while the cash benefits from the sale of the synthetic fuel production facilities and the net hedge proceeds are included in the investing and financing activities on the Consolidated Statement of Cash Flows.

We expect cash from operations in 2008 at a level similar to 2007. We expect that reduced cash flows from the sale of TECO Transport and lower fuel recoveries will be offset by lower interest expense and the elimination of costs associated with TECO Coal's synfuel operations and the premiums paid for the early extinguishment of parent debt in 2007.

We contributed $30 million to our pension plan in 2007, as planned, following a voluntary $30 million contribution to the plan in 2006 to accelerate improvement in the plan's funded status. We expect to contribute $9 million in 2008, and estimate that our contribution will average about $11 million annually in 2009 through 2012 (see **Note 5** to the TECO Energy **Consolidated Financial Statements**).

Cash from Investing Activities

Our investing activities in 2007 resulted in a net use of cash of $28 million, including, among other items, capital expenditures totaling $494 million and the $405 million of gross proceeds from the sale of TECO Transport. In 2007, proceeds related to the sale of the 98% ownership interests in TECO Coal's synthetic fuel facilities were eliminated due to the 67% phase-out of the tax credits. TECO Coal received in 2007 synfuel proceeds of $30 million that had been held in escrow for several years. In 2007 we placed hedges to protect against the phase-out of synfuel proceeds due to high oil prices and paid premiums of approximately $31 million. We received $42 million associated with the oil price hedges in 2007 with the remaining hedge net settlement of $79 million received in January 2008. Investing activity in 2007 also included $27.5 million received primarily from the unconsolidated Guatemalan affiliates, less $15 million of investments in a tax-deferred status.

We expect capital spending for the next several years to be higher, primarily at Tampa Electric due to spending on combustion turbines to meet peak load needs and the initial spending on its next baseload generating capacity addition, which is expected to be required in early 2013 (see the **Tampa Electric** and **Capital Expenditures** sections).

Cash from Financing Activities

Our financing activities in 2007 resulted in net use of cash of $805 million. Major items included the retirement of $357 million of parent debt at maturity, the retirement of $111 million of parent-guaranteed TECO Transport Dock and Wharf bonds at maturity, the early retirement of $297 million of TECO Energy parent debt due in 2010, and Tampa Electric Company's issuance of $250 million of long-term notes and repayment of $150 million of notes at maturity (see the **Financing Activity** section) and $23 million reduction of short-term borrowings. We paid $163 million in common stock dividends, and we received $81 million for providing the feedstock and reimbursement of the operating costs of TECO Coal's synthetic fuel production facilities in the form of minority interest payments from the third-party owners.

In 2008, Tampa Electric Company expects to utilize equity contributions from TECO Energy, and long- and short-term borrowings under its credit facilities to support its capital spending program for normal working capital fluctuations, and to implement its plans to address the disruptions in the auction-rate debt markets for its custom-rate securities (See the **Financing** section). We have no significant debt maturities in 2008. See the **Cash and Liquidity Outlook** section below for a discussion of financing expectations beyond 2008.

Cash and Liquidity Outlook

In general, we target consolidated liquidity (unrestricted cash on hand plus undrawn credit facilities) of at least $500 million, comprised of $300 million for Tampa Electric Company and $200 million for TECO Energy. At Dec. 31, 2007 our consolidated liquidity was $818 million, consisting of $462 million at Tampa Electric Company, $290 million at TECO Energy parent and $66 million at the other consolidated operating companies. Of this amount, $51 million was held offshore due to the tax deferral structure associated with EEGSA and its affiliated companies. In addition, there was $20 million of unrestricted cash at the unconsolidated TECO Guatemala operating companies.

We expect our sources of cash in 2008 to include cash from operations at levels similar to 2007 as described above, net proceeds of $80 million associated with our 2007 oil price hedges and net borrowings at the regulated Florida utilities of approximately $175 million. As our synthetic fuel production ended in 2007 with the expiration of the tax credits, no cash flows associated with this program are expected in 2008. We plan to use cash in 2008 for capital spending estimated at $631 million and dividends to shareholders. Although we have no significant debt maturities in 2008, we plan to retire early the $100 million of parent debt due in 2010.

We expect TECO Energy parent to have a net use of cash of approximately $90 million in 2008 after dividends to shareholders and the $100 million early debt retirement. This forecast is based on the assumptions described above and also assumes that we make $190 million of equity contributions to Tampa Electric.

TECO Energy does not expect to access the capital markets. Tampa Electric Company expects to access the debt capital markets for long-term debt to support its capital spending program, and expects to utilize its credit facilities for normal working capital fluctuations, and to implement its plans to address the disruptions in the auction-rate debt markets for its auction-rate securities (see the **Financing** section).

Our expected cash flow could be affected by variables discussed in the individual operating company sections, such as customer growth and usage changes at our regulated businesses, coal production levels and coal sales prices. In addition, actual fuel and other regulatory clause net recoveries will typically vary from those forecasts; however, these 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 or to require external capital to meet future TECO Energy parent debt maturities (see the **Risk Factors** section). In addition, both PGS and Tampa Electric, as a result of capital investments and increased operating cost, have determined that they will need to seek base rate relief. The outcome of future base rate proceedings, which we cannot predict, could impact our liquidity and capital resources (see the **Tampa Electric, Peoples Gas** and **Regulatory** sections).

The higher capital expenditures expected at Tampa Electric over the next several years will require additional equity contributions from TECO Energy in order to support the capital structure and financial integrity of the utility. Tampa Electric funds its capital needs with a combination of internally generated cash, external borrowing and equity contributions from TECO Energy parent. The sale of TECO Transport allowed us to use proceeds for the early implementation of our parent debt retirement plans. This positions us to redeploy cash that was planned for debt retirement in those years to Tampa Electric in the form of parent equity contributions to fund its generation expansion and other capital needs.

Credit Facilities

At Dec. 31, 2007 and 2006, the following credit facilities and related borrowings existed:

		December 31, 2007			*December 31, 2006*		
		Credit Facilities	*Borrowings Outstanding*	*Letters of Credit Outstanding*	*Credit Facilities*	*Borrowings Outstanding*	*Letters of Credit Outstanding*
Tampa Electric	5-year facility	**$325.0**	**$ —**	**$—**	$325.0	$13.0	$—
	1-year accounts receivable facility	**150.0**	**25.0**	**—**	150.0	35.0	—
TECO Finance (1)	5-year facility	**200.0**	**—**	**9.5**	200.0	—	9.5
Total		**$675.0**	**$25.0**(2)	**$ 9.5**	$675.0	$48.0(2)	$ 9.5

(1) Prior to May 2007, TECO Energy was the borrower under this facility.

(2) Borrowings outstanding are reported as notes payable.

These credit facilities require commitment fees ranging from 9.0 to 17.5 basis points. The weighted average interest rate on outstanding notes payable under the credit facilities at Dec. 31, 2007 and 2006 were 4.76% and 5.45%, respectively.

At Dec. 31, 2007, TECO Finance had a $200 million bank credit facility in place guaranteed by TECO Energy with a maturity date of May 2012. Tampa Electric Company had a bank credit facility totaling $325 million, also maturing in May 2012. In addition, Tampa Electric Company had a $150 million accounts receivable securitized borrowing facility with a maturity date of December 2008. The TECO Finance and Tampa Electric Company bank credit facilities include sub-limits for letters of credit of $200 million and $50 million, respectively. The TECO Finance facility was undrawn at Dec. 31, 2007, except for $9.5 million of outstanding letters of credit. At Dec. 31, 2007, $25 million was drawn on the Tampa Electric Company credit facilities. These credit facilities have financial covenants as identified in **Covenants in Financing Agreements** section.

At current ratings, TECO Finance's and Tampa Electric Company's bank credit facilities require commitment fees of 12.5 basis points and 9.0 basis points, respectively, and drawn amounts are charged interest at LIBOR plus 112.5 – 125.0 basis points and 45.0 – 50.0 basis points, respectively. At Dec. 31, 2007, the LIBOR interest rate was 4.60%.

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

Under a Loan and Servicing Agreement, TRC may borrow up to $150 million to fund its acquisition of the receivables under the facility, and TRC secures such borrowings with a pledge of all of its assets, including the receivables. Tampa Electric Company acts as the servicer to service the collection of the receivables. TRC pays program and liquidity fees based on Tampa Electric Company's credit ratings, which total 35 basis points at its current ratings. Interest rates on the borrowings are based on prevailing asset-backed commercial paper rates, unless such rates are not available from conduit lenders, in which case the rates will be at an interest rate equal to either the London interbank deposit rate plus a margin of 100 basis points at Tampa Electric Company's current ratings or at Citibank's prime rate (or the federal funds rate plus 50 basis points, if higher). The facility includes the following financial covenants: (1) at each quarter-end, Tampa Electric Company's debt-to-capital ratio, as defined in the agreement, must not exceed 65%; and (2) certain dilution and delinquency ratios with respect to the receivables. At Dec. 31, 2007, the interest rate for borrowings under the Tampa Electric Company accounts receivable facility was 4.76%.

Subprime Exposure and Assessment

In the second half of 2007, investor concerns regarding losses on subprime mortgage investments in the U. S. triggered a shift to safer and lower-risk investments. As a result, borrowers, in general, experienced higher costs to borrow and lower levels of funds available to borrow. Our financial exposure to subprime mortgage investments is limited to our holdings in the non-contributory defined benefit retirement plan. At Dec. 31, 2007 this plan held less than 0.3% of total assets in subprime mortgage investments (approximately $1.0 million). However we cannot predict the impact that credit market concerns may have on the values of fixed income (typically bonds) or equity securities in general. Our plan assets of $510.5 million at Dec. 31, 2007 were invested 36% in fixed income securities and 64% in equity securities.

Covenants in Financing Agreements

In order to utilize their respective bank credit facilities, TECO Energy/Finance and Tampa Electric Company must meet certain financial tests as defined in the applicable agreements (see **Credit Facilities** above). In addition, TECO Energy, TECO Finance, Tampa Electric Company, and other operating companies have certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2007, TECO Energy, TECO Finance, Tampa Electric Company, and the other operating companies were in compliance with all required financial covenants. The table that follows lists the significant financial covenants and the performance relative to them at Dec. 31, 2007. Reference is made to the specific agreements and instruments for more details.

TECO Energy Significant Financial Covenants

(millions, unless otherwise indicated)

Instrument	*Financial Covenant* [1]	*Requirement/Restriction*	*Calculation at Dec. 31, 2007*
Tampa Electric Company			
PGS senior notes	EBIT/interest [2]	Minimum of 2.0 times	3.1 times
	Restricted payments	Shareholder equity at least $500	$1,801
	Funded debt/capital	Cannot exceed 65%	51.7%
	Sale of assets	Less than 20% of total assets	0%
Credit facility [3]	Debt/capital	Cannot exceed 65%	51.0%
Accounts receivable credit facility [3]	Debt/capital	Cannot exceed 65%	51.0%
6.25% senior notes	Debt/capital	Cannot exceed 60%	51.0%
	Limit on liens [5]	Cannot exceed $700	$0 liens outstanding
Insurance agreements relating to pollution bonds	Limit on liens [5]	Cannot exceed $370 (7.5% of net assets)	$0 liens outstanding
TECO Energy/ TECO Finance			
Credit facility [3]	Debt/EBITDA [2]	Cannot exceed 5.00 times	2.7 times
	EBITDA/interest [2]	Minimum of 2.60 times	4.8 times
	Limit on additional indebtedness	Cannot exceed $1,036	$0
	Dividend restriction [4]	Cannot exceed $50 per quarter	$41
TECO Energy 7.5% notes	Limit on liens [5]	Cannot exceed $276 (5% of tangible assets)	$0 outstanding
TECO Energy floating rate notes, TECO Energy and TECO Finance 6.75% notes	Restrictions on secured debt	[6]	[6]
TECO Diversified			
Coal supply agreement guarantee	Dividend restriction	Net worth not less than $498 (40% of tangible net assets)	$724

(1) As defined in each applicable instrument.

(2) EBIT generally represents earnings before interest and taxes. EBITDA generally represents EBIT before depreciation and amortization. However, in each circumstance, the term is subject to the definition prescribed under the relevant agreements.

(3) TECO Finance is the borrower and TECO Energy is the guarantor on this facility. See description of credit facilities in **Note 6** to the **TECO Energy Consolidated Financial Statements**.

(4) TECO Energy cannot declare quarterly dividends in excess of the restricted amount unless liquidity projections, demonstrating sufficient cash or cash equivalents to make each of the next three quarterly dividend payments, are delivered to the Administrative Agent.

(5) If the limitation on liens is exceeded the company is required to provide ratable security to the holders of these notes.

(6) The indentures for these notes contain restrictions which limit secured debt of TECO Energy if secured by Principal Property or Capital Stock or indebtedness of directly held subsidiaries (with exceptions as defined in the indentures) without equally and ratably securing these notes.

Credit Ratings of Senior Unsecured Debt at Dec. 31, 2007

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

In December 2007, upon completion of the sale of TECO Transport, Moody's Investor Service upgraded the rating on TECO Energy's senior unsecured debt to investment grade at Baa3. Standard & Poor's upgraded TECO Energy's corporate credit rating to BBB- in November 2007, the same as Tampa Electric Company's corporate credit rating. Fitch placed TECO Energy's ratings on review for possible upgrade in October 2007. Moody's and Standard & Poor's have assigned stable outlooks to our ratings. Moody's and Fitch have assigned positive outlooks to Tampa Electric Company's ratings, while Standard & Poor's reflects a stable outlook.

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

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

Summary of Contractual Obligations

The following table lists the obligations of TECO Energy and its subsidiaries for cash payments for debt service, lease payments, pension contributions 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, 2007

		Payments Due by Period				
(millions)	*Total*	*2008*	*2009*	*2010*	*2011-2012*	*After 2012*
Long-term debt (1)						
Recourse	$3,158.3	$ 5.7	$ 5.5	$106.5	$1,356.8	$1,683.8
Non-recourse (2)	10.4	1.4	1.4	1.4	3.0	3.2
Operating leases/rentals (6)	41.7	5.5	3.2	2.4	4.4	26.2
Net purchase obligations/commitments (3)	381.2	183.3	64.1	30.4	60.2	43.2
Interest payment obligations (4)	2,124.4	195.4	203.4	199.1	330.1	1,196.4
Pension plan (5)	54.3	9.0	15.5	11.7	18.1	—
Total contractual obligations (6)	$5,770.3	$400.3	$293.1	$351.5	$1,772.6	$2,952.8

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

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

(3) Reflects those contractual obligations and commitments considered material to the respective operating companies, individually. At the end of 2007, these commitments included Tampa Electric's outstanding

commitments of about $41.8 million for materials and contracts related to the NO_x control equipment, $85.7 million for peaking combustion turbines and $196.4 million for long-term capitalized maintenance agreements for its combustion turbines.

(4) Includes variable rate notes at interest rates as of Dec. 31, 2007.

(5) The total includes the estimated minimum required contributions through 2012 to the qualified pension plan as of the measurement date, without reduction for application of credit balances. 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—Cash from Operations** section and **Note 5** to the TECO Energy **Consolidated Financial Statements**).

(6) 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**).

Summary of Contingent Obligations

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

Contingent Obligations at Dec. 31, 2007

		Commitment Expiration					
(millions)		*Total*[2]	*2008*	*2009*	*2010*	*2011-2012*	*After 2012*
Letters of credit[1]		$ 9.5	$ 2.5	$—	$—	$—	$ 7.0
Guarantees	Fuel purchases/energy management	77.6	53.7	—	—	—	23.9[3]
	Other	6.9	5.5	—	—	—	1.4
Total contingent obligations		$94.0	$61.7	$—	$—	$—	$32.3

(1) Expected final expiration date with annual renewals.

(2) Expected maximum exposure.

(3) These guarantee amounts renew annually and are shown on the basis of our intent to renew beyond the current expiration date.

Capital Expenditures

(millions)	Actual 2007	Forecast 2008	2009	2010-2012	2008-2012 Total
Tampa Electric					
Transmission	**$ 19**	$ 55	$ 70	$ 187	$ 312
Distribution	**112**	134	127	399	660
Existing generation	**130**	84	127	239	450
Committed new generation	**12**	108	118	7	233
Proposed new generation	**—**	11	124	741	876
New generation	**12**	119	242	748	1,109
Other	**30**	47	35	96	178
NO_x control projects	**79**	72	52	13	137
Other environmental	**27**	23	8	25	56
	409	534	661	1,707	2,902
Net cash impact of accruals and retentions	**(40)**	9	—	—	9
Tampa Electric	**369**	543	661	1,707	2,911
Peoples Gas	**48**	59	61	180	300
TECO Coal	**44**	26	34	111	171
TECO Transport	**25**	—	—	—	—
TECO Guatemala (1)	**2**	1	4	5	10
Other	**—**	2	—	1	3
Total (1)	**$488**	$631	$760	$2,004	$3,395

(1) Represents only the capital expenditures of the consolidated operations of TECO Guatemala. Under FIN 46R the major operations of TECO Guatemala are unconsolidated, and the related capital expenditures are not included in this table.

TECO Energy's 2007 cash capital expenditures of $488 million included $369 million, excluding Allowance for Funds Used During Construction (AFUDC)–Equity and amounts for accruals and retentions, for Tampa Electric and $48 million for PGS. Tampa Electric's capital expenditures in 2007 were primarily for equipment and facilities to meet its growing customer base, generating equipment maintenance, capital expenditures required for the completion of additional generating capacity in the form of two peaking units, environmental compliance, and NO_x control projects (see the **Environmental Compliance** section). Capital expenditures for PGS were approximately $30 million for system expansion and approximately $18 million for maintenance of the existing system. TECO Coal's capital expenditures included $21 million primarily for normal mining equipment replacement, and $23 million for new mine development. TECO Transport invested $25 million in 2007, including $11 million for normal steel replacements and shipyard periods for oceangoing vessels, $6 million for river towboat improvements and refurbishments, and $3 million to purchase previously leased vessels.

TECO Energy estimates capital spending for ongoing operations to be $631 million for 2008 and approximately $2.8 billion during the 2009—2012 period.

For 2008, Tampa Electric expects to spend $543 million, consisting of about $320 million to support system growth and generation reliability. Included in this amount is $22 million for transmission and distribution system storm hardening, $37 million for new high-voltage transmission system improvements and to meet reliability requirements, and $84 million for generating system reliability, including approximately $30 million in major improvements to coal-fired units at Big Bend Station to take advantage of the extended outages to install NO_x

control equipment. In addition, Tampa Electric expects to spend $119 million for the generating capacity expansion primarily for the addition of five combustion turbines, $72 million for the addition of SCR equipment at the Big Bend Station for NO_x control, and $23 million for other environmental compliance programs in 2008. The five combustion turbines, one at the Big Bend Station and four at the Bayside Power Station, will meet peaking generation capacity needs and provide "black start" capability to meet NERC reliability requirements.

Tampa Electric's total capital expenditures over the 2009 – 2012 period are projected to be about $2.4 billion, including its next baseload generating capacity addition and new natural gas-fired combustion turbines to meet peak load generating capacity requirements in the 2009 – 2012 period (see the **Tampa Electric—Generating Capacity Additions** below). Tampa Electric expects to spend approximately $320 million annually to support normal system growth and reliability. This level of ongoing capital expenditures reflects the generally higher costs for materials and contractors, new long-term regulatory requirements for storm hardening, and an active program of transmission and distribution system upgrades which will occur over the forecast period. These new programs and requirements include: approximately $30 million annually for repair and refurbishments of combustion turbines under long-term agreements with equipment manufacturers; average annual expenditures of $19 million for transmission and distribution system storm hardening; more than $40 million annually for transmission and distribution system reliability and capacity improvements; and an average of $33 million annually for state-wide high-voltage transmission system improvements in Florida and to meet NERC reliability requirements. In addition to the $320 million of ongoing average annual capital expenditures, Tampa Electric expects to spend $65 million for compliance with the Environmental Consent Decree for the remaining SCR equipment and $33 million for other required environmental capital expenditures in the 2009 – 2012 period. The Environmental Consent Decree compliance expenditures are eligible for recovery of depreciation and a return on investment through the Environmental Cost Recovery Clause (see the Environmental Compliance section).

Capital expenditures for PGS are expected to be about $59 million in 2008 and $241 million during the 2009 – 2012 period. Included in these amounts is an average of approximately $40 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing renewal, replacement and system safety.

TECO Coal expects to invest $26 million in 2008 and $145 million during the 2009 – 2012 period. Included in these amounts is normal renewal and replacement capital, including coal mining equipment.

Tampa Electric—Generating Capacity Additions

Tampa Electric has committed to constructing five peaking capacity combustion turbines in 2008 and 2009 at the Bayside and Big Bend power stations with an expected total cost of $236 million, excluding AFUDC. These units will meet the expected peak demand requirements in 2009 and 2010, and several will be configured to meet the NERC black start requirements for system reliability.

Tampa Electric expects to need additional combustion turbines to meet peak load demand in 2011 and 2012. The total cost for these units is estimated to be $320 million. Tampa Electric continues to evaluate opportunities to purchase peaking capacity, and the decision to build or purchase peaking capacity will be determined based on cost-effectiveness.

Tampa Electric currently plans to meet its expected 2013 baseload capacity need with a combined-cycle natural gas-fired plant, which together with associated transmission system improvements is expected to cost approximately $555 million. While Tampa Electric expects to issue an RFP for this required baseload capacity in 2008, as required in Florida to determine the most cost-effective means of meeting the demand, the amounts to self-build a natural gas-fired combined-cycle plant are included in the 2008 – 2012 capital expenditure forecast (see the **Tampa Electric** and **Regulation** sections).

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

Financing Activity

Our 2007 consolidated year-end capital structure was 61.3% senior debt and 38.7% common equity. The debt-to-total-capital ratio improved significantly from 68.6% at Dec. 31, 2006, primarily due to the repayment of $468 million of parent and parent guaranteed debt at maturity and the accelerated retirement of $297 million of parent debt in 2007, as well as the increase in retained earnings due to the gain on the sale of TECO Transport.

In 2007, we completed debt tender and exchanges in which we retired early $297.2 million of TECO Energy notes due in 2010 and exchanged the following TECO Energy notes on par-for-par basis with TECO Finance notes with the same maturities: $171.8 million due 2011, $236.2 million due 2012 and $191.2 million due 2015. At the same time, we exchanged the following TECO Energy notes with TECO Finance notes due in 2017, thereby extending the maturities: $236.4 million due in 2011 and $63.6 million due in 2012.

In 2007, we issued no new debt at the TECO Energy parent level, but guaranteed the new TECO Finance notes. We raised $1.2 million of equity through our dividend reinvestment plan. In 2007, Tampa Electric refinanced $125.8 million of tax-exempt Hillsborough County Industrial Development Authority bonds and $75.0 million of tax-exempt Polk County Industrial Development Authority bonds in auction-rate modes. Tampa Electric Company also issued $250 million of 6.15% 30-year notes and used the proceeds to repay $150 million of 5.375% notes at maturity, to retire short-term borrowings under its credit facilities, for working capital needs and to support its capital spending program.

In 2006, Tampa Electric refinanced $86 million of tax-exempt bonds in an auction-rate mode, and issued $250 million of 6.55% 30-year notes to support its capital spending program, repay short-term borrowings, and for general working capital needs.

In April 2006, TECO Barge Line (a subsidiary of TECO Transport) entered into a 15-year charter agreement for the lease of 50 newly constructed river barges to replace barges that had either already been retired or were scheduled for retirement. In February 2007, the charter agreement was amended to include an additional 50 newly constructed replacement river barges. These obligations remained with TECO Barge Line when we sold TECO Transport.

The following table provides details of financings beginning in 2005.

Date	*Security*	*Company*	*Net proceeds/*	*Coupon*	*Use*
Dec. 2007	Notes due 2017	TECO Finance (1)	$ 300	6.572%	Debt for debt exchange of existing TECO Energy notes extending maturity
Dec. 2007	Notes due 2015	TECO Finance (1)	$ 191	6.75%	Debt for debt exchange of existing TECO Energy notes
Dec. 2007	Notes due 2012	TECO Finance (1)	$ 236	7.00%	Debt for debt exchange of existing TECO Energy notes
Dec. 2007	Notes due 2011	TECO Finance (1)	$ 172	7.20%	Debt for debt exchange of existing TECO Energy notes
July 2007	Tax-exempt bonds due 2018, 2020 and 2025	Tampa Electric	$ 126	Auction rate mode	Refinance existing bonds
May 2007	30-year notes	Tampa Electric Company	$ 250	6.15%	Repay maturing notes, repay short-term debt and general corporate purposes
May 2007	Tax-exempt bonds due 2030	Tampa Electric	$ 75	Auction rate mode	Refinance existing bonds
May 2006	30-year notes	Tampa Electric	$ 250	6.55%	Repay short-term debt and general corporate purposes
Jan. 2006	Tax-exempt bonds due 2034	Tampa Electric	$ 86	Auction rate mode	Refinance existing bonds
Jun. 2005	5-year notes	TECO Energy	$ 100	Floating rate	Initiate debt redemption /refinance program
May 2005	10-year notes	TECO Energy	$ 200	6.75%	Initiate debt redemption / refinance program
Jan. 2005	Common equity	TECO Energy	$180 (2)	—	Final settlement of equity security units

(1) These notes are guaranteed by TECO Energy.

(2) 6.8 million shares issued in the final settlement of the 9.5% convertible equity units.

Auction Rate Securities Remarketing

In 2006 and 2007, Tampa Electric issued five series of revenue refunding bonds through the Hillsborough County and Polk County Industrial Development Authorities (HCIDA and PCIDA, respectively). These refunding bonds, $286.8 million in aggregate, currently bear interest at an auction rate, which means that the interest rate is periodically reset in an auction process. These bonds are insured by two nationally recognized bond insurance companies. In late 2007 and early 2008, these insurance companies experienced credit rating downgrades due to their exposure to subprime mortgage investments. Due to the credit ratings downgrades of the bond insurance companies, the ratings on Tampa Electric's auction rate bonds were also lowered. Throughout the $360 billion auction rate securities market in February 2008 failed auctions have occurred with increasing frequency, reflecting diminished investor demand for both insured and uninsured auction rate securities. A failed auction occurs when there are an insufficient number of bidders to place all of the securities in the auction issue. In a failed auction, the interest rate on the securities is set at a predetermined interest rate as defined in the indenture for the particular issue, referred to as the "default rate", for the next interest period.

On Feb. 19 and Feb 26, 2008, two of the five tax-exempt auction-rate bond series described above, totaling $105.8 million, experienced failed auctions and, in accordance with the terms of the bond indentures, the interest rate on these series reset to 14% for the succeeding seven-day periods. Auctions on Feb. 19 for Tampa Electric's three other series of tax-exempt auction-rate bonds, totaling $181.0 million, settled at interest rates of 10% to 12%. The interest rates set in the Feb. 19 auction of 11% and 12% on the PCIDA Series 2007 and HCIDA Series 2007C, respectively, are in effect for a 35-day interest period until Mar. 26. On Feb. 26, the auction for the HCIDA Series 2006 settled at an interest rate of 7.55% for the succeeding seven-day interest period.

On Feb. 25, 2008, Tampa Electric Company notified the trustee for the tax-exempt bonds issued for the benefit of the company by the HCIDA and PCIDA that the company has elected to purchase in lieu of redemption the $75 million PCIDA Solid Waste Disposal Revenue Refunding Bonds (Tampa Electric Company Project) Series 2007, and the $125.8 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Project) Series 2007 A, B and C, on Mar. 26, 2008, which is an interest payment date. With respect to the company's remaining tax-exempt auction rate bonds, the $86 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Project) Series 2006, the company plans to convert such bonds to a fixed-rate mode. For each of the five series, the Loan and Trust Agreements governing the bonds allow for their conversion from an auction rate mode to other interest modes, including fixing the term and interest rate for any period from 9 months to the maturity dates of the bonds which range from 2018 to 2034. Tampa Electric does not expect the market for auction rate securities to improve in the near term and anticipates that it will remarket its notes with a fixed interest rate for a term of two years or more. The company expects to take actions to effect such remarketing of certain series potentially without bond insurance, which could require the write-off of capitalized bond insurance premiums and result in an after-tax charge of approximately $1.6 million. While Tampa Electric does not intend to extinguish or cancel the bonds upon its purchase in lieu of redemption on Mar. 26, 2008, it recognizes that market conditions could cause it to ultimately do so, in which case it would write off any unamortized issuance costs associated with the specific series. Tampa Electric expects to finance the purchase on an interim basis by drawing on its revolving credit facilities. At Dec. 31, 2007, Tampa Electric had liquidity of approximately $462 million, consisting of approximately $450 million in the aggregate available undrawn on its two credit facilities and approximately $12 million in cash and cash equivalents.

Off-Balancing Sheet Financing

Unconsolidated affiliates have project debt balances as follows at Dec. 31, 2007. The two power plant financings are non-recourse project loans, and the debt associated with DECA II is general corporate debt at DECA II; all of this debt is held at the project entity level. Although we are not directly obligated on the debt, our equity interest in those unconsolidated affiliates and its commitments with respect to those projects are at risk if interest and principal payments on these loans are not made timely. Our equity investment in TECO Guatemala was $413.5 million at Dec. 31, 2007.

Off-Balance Sheet Debt at Dec. 31, 2007

(millions)	*Long-term Debt*	*TECO Guatemala's Ownership Interest*
San José Power Station	$ 72.0	100%
Alborada Power Station	$ 8.7	96%
DECA II	$217.0	30%

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

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Synthetic Fuel and Section 29 Tax Credits

During 2007, the company earned income indirectly through the production of synthetic fuel at TECO Coal. TECO Coal sold its ownership interests in the synthetic fuel facilities to third-party investors based on the amount of future production, and the resulting gains are adjusted by the estimated value of the tax benefits provided under Section 45 (formerly Section 29) of the tax code. The tax credit begins to phase out when the average annual oil price exceeds a reference price, which was estimated to $61.79/Bbl on a NYMEX basis in 2007. The final determination of the actual 2007 reference price and any resulting phase-out of the tax credit benefits will not be made by the Internal Revenue Service until March of 2008; as a result, management is required to estimate the potential phase-out and adjust the payments expected for the sale of the ownership interests accordingly. At the end of 2007, the annual average oil price was calculated to be $72.37/Bbl on a NYMEX basis. Based on this average, a 91.8% actual Producer First Purchase Price to NYMEX adjustment factor and a 3.0% inflation rate, the phase-out was estimated to be 67%, resulting in a reduction in revenues from the third-party investors of $140.2 million on $208.6 million in sales. The company has also determined that a 0.10% increase in inflation would result in a reduction of 0.45% in the amount of the phase-out, which would result in a $0.9 million pretax increase in revenue from the third-party investors; a 0.10% decrease in inflation would reduce revenues by the same amount. The actual final inflation rates will be known in late March or early April. Any adjustments to 2007 earnings as a result of changes in the inflation rate will be reflected in 2008 results. The payments received for the sale of the synthetic fuel ownership interests are reflected as other income and minority interest classifications in the income statement.

Deferred Income Taxes

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

At Dec. 31, 2007, we had net deferred income tax assets of $424.9 million, attributable primarily to property-related items, alternative minimum tax credit, and operating loss carry-forwards. Based primarily on historical income levels and the steady growth expectations for future earnings of the company's core utility operations, management has determined that the net deferred tax assets recorded at Dec. 31, 2007 will be realized in future periods.

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

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

Employee Postretirement Benefits

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

Pension plan assets (plan assets) are invested in a mix of equity and fixed income securities. The assumptions for the expected return on plan assets are developed based on an analysis of historical market returns, the pension plan's actual past experience, and current market conditions. The expected return on assets assumption was based on expectations of long-term inflation, real growth in the economy, fixed income spreads and equity premiums consistent with our portfolio, with provision for active management and expenses paid from the trust. The discount rate assumption is based on a cash flow matching technique developed by our outside actuaries and current economic conditions. This technique matches the yields from high-quality (AA-graded, non-callable) corporate bonds to the company's projected cash flows for the pension plan to develop a present value that is converted to a discount rate assumption, which is subject to change each year. The salary increase assumption was based on the same underlying expectation of long-term inflation together with assumptions regarding real growth in wages and company-specific merit and promotion increases. Holding all other assumptions constant, a 1% increase or decrease in the assumed rate of return on plan assets would decrease or increase, respectively, 2007 net periodic expense by approximately $4.9 million. Likewise, a 0.71% increase or a 0.56% decrease in the discount rate assumption would result in an approximately $2.1 million after-tax change in the 2007 net periodic pension expense. This $2.1 million after-tax change represents a 1-cent change in earnings-per-share.

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

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

We adopted FSP 106-2 retroactive to the second quarter of 2004 for benefits provided that we believe to be actuarially equivalent to Medicare Part D. The expected subsidy reduced the accumulated postretirement benefit obligations (ABPO) at Dec. 31, 2007 by $31.9 million and net periodic cost for 2007 by $3.1 million. In 2007, we filed for and received a Part D subsidy of $0.9 million.

The assumed health care cost trend rate for medical costs was 9.5% in 2007 and decreases to 5.25% in 2016 and thereafter. A 1% increase in the health care trend rates would produce a 5.7% or $1.0 million, increase in the aggregate service and interest cost for 2007 and a 3.5% or $6.8 million increase in the accumulated postretirement benefit obligation as of Sep. 30, 2007, the measurement date.

A 1% decrease in the health care trend rates would produce a 4% or $0.7 million decrease in the aggregate service and interest cost for 2007 and a 2.9% or $5.6 million decrease in the accumulated postretirement benefit obligation as of Sep. 30, 2007, the measurement date.

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

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

Long-Lived Assets

In accordance with SFAS 144, *Accounting for the Impairment or Disposal of Long- Lived Assets*, we assess whether there has been an other than temporary impairment of our long-lived assets and certain intangibles held and used by us when such indicators exist. We annually review all long-lived assets in the last quarter of each year to ensure that any gradual change over the year and the seasonality of the markets are considered when determining which assets require an impairment analysis. We believe the accounting estimates related to asset impairments are critical estimates for the following reasons: (1) the estimates are highly susceptible to change, as management is required to make assumptions based on expectations of the results of operations for significant/ indefinite future periods and/or the then current market conditions in such periods; (2) markets can experience significant uncertainties; (3) the estimates are based on the ongoing expectations of management regarding probable future uses and holding periods of assets; and (4) the impact of an impairment on reported assets and earnings could be material. Our assumptions relating to future results of operations or other recoverable amounts are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. Our expectations regarding uses and holding periods of assets are based on internal long-term budgets and projections, which give consideration to external factors and market forces, as of the end of each reporting period. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities.

At the end of the 2007 fiscal year, impairment tests were conducted on our long-lived assets. At the conclusion of the analyses, it was determined that all asset carrying values were recoverable based on the reasonable estimates used and that no impairment adjustments were necessary.

During 2005, we reduced our fair market value assumption for the McAdams power project, based on a strategic review of the options to dispose of that investment, which resulted in a further impairment charge related to additional asset retirement obligations (see **Note 15** to the TECO Energy **Consolidated Financial Statements**). All the remaining assets associated with the McAdams power project were sold in 2006 (see **Note 16** to the TECO Energy **Consolidated Financial Statements**).

Regulatory Accounting

Tampa Electric's and PGS' retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by the Federal Energy Regulatory Commission (FERC). As a result, the regulated utilities qualify for the application of SFAS 71, *Accounting for the Effects of Certain Types of Regulation*. This statement recognizes that the actions of a regulator can provide reasonable assurance of the existence of an asset or liability. Regulatory assets and liabilities arise as a result of a difference between generally accepted accounting principles and the accounting principles imposed by the regulatory authorities. Regulatory assets generally represent incurred costs that have been deferred, as their future recovery in customer rates is probable. Regulatory liabilities generally represent obligations to make refunds to customers from previous collections for costs that are not likely to be incurred.

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

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

RECENTLY ISSUED ACCOUNTING STANDARDS

Noncontrolling Interests in Consolidated Financial Statements

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

Business Combinations (Revised)

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

Offsetting Amounts Related to Certain Contracts

In April 2007, the FASB issued FASB Staff Position (FSP) FIN 39-1. This FSP amends FASB Interpretation No. 39, *Offsetting of Amounts Related to Certain Contracts* by allowing an entity to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. The guidance in this FSP is effective for fiscal years beginning after Nov. 15, 2007. The Company adopted this FSP effective Jan. 1, 2008 without any effect on its results of operations, statement of position or cash flows.

Fair Value Option For Financial Assets and Financial Liabilities

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities—Including an amendment of FASB Statement No. 115* (FAS 159). FAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The objective of FAS 159 is to provide opportunities to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply hedge accounting provisions. FAS 159 is effective for fiscal years beginning after Nov. 15, 2007. The company adopted FAS 159 effective Jan. 1, 2008, but did not elect to measure any financial instruments at fair value. Accordingly, its adoption did not have any effect on its results of operations, statement of position or cash flows.

Fair Value Measurements

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

FAS 157, among other things, requires the company to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value, and specifies a hierarchy of valuation techniques based on whether the inputs to those valuation techniques are observable or unobservable. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect the company's market assumptions. SFAS 157 defines the following fair value hierarchy, based on these two types of inputs:

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

The effective date is for fiscal years beginning after Nov. 15, 2007. In November of 2007, the FASB granted a one year deferral for non-financial assets and liabilities. As a result, the company adopted FAS 157 effective Jan. 1, 2008 for financial assets and liabilities. Financial assets and liabilities of the company measured at fair value include derivatives and certain investments, for which fair values are primarily based on observable inputs.

During 2008, the company will continue to evaluate FAS 157 for the remaining non-financial assets and liabilities to be included effective Jan. 1, 2009. The company does not believe the impact of adoption for the remaining non-financial assets and liabilities will be material to its results of operations, statement of position or cash flows.

INFLATION

The effects of inflation on our results have not been significant for the past several years. The annual average rate of inflation, as measured by the Consumer Price Index (CPI-U), all items, all urban consumers as reported by the U.S. Department of Labor, was 2.8%, 2.5% and 3.4% in 2007, 2006 and 2005, respectively. Forecasts by economists that we use indicate that inflation is expected to be near 2.9% in 2008.

Prices for certain products and services used by TECO Energy's operating companies continued to increase at rates above the CPI in 2007, including prices for concrete, steel and copper products and petroleum-based products used extensively in all of our operating companies, and for subcontracted services used by Tampa Electric and subcontracted mining services used by TECO Coal. With the exception of petroleum based products, which are determined by international factors, price increases for construction related materials are expected to moderate in 2008 due to the slowdown in the housing industry and generally slower economic growth in the U.S. economy. Tampa Electric and PGS are eligible to recover the cost of commodity fuel through the respective FPSC-approved fuel-adjustment clauses. In those cases where the higher costs can not be passed directly to the customers, higher costs could reduce the profit margins at the operating companies.

ENVIRONMENTAL COMPLIANCE

Environmental Matters

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

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

Air Quality Control

Consent Decree

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

The emission reduction requirements included specific detail with respect to the availability of flue gas desulfurization systems (scrubbers) to help reduce SO_2, projects for NO_x reduction efforts on Big Bend Units 1 through 4, and the repowering of the coal-fired Gannon Power Station to natural gas. The commercial operation dates for the two repowered units, renamed as the H. L. Culbreath Bayside Power Station (Bayside), were Apr. 24, 2003 and Jan. 15, 2004. The completed station has total station capacity of about 1,800 megawatts (nominal) of natural gas-fueled, combined-cycle electric generation. The repowering has reduced the facility's NO_x and SO_2 emissions by approximately 99% and particulate matter (PM) emissions by approximately 92% from 1998 levels.

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

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

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

Emission Reductions

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

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

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

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

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

The EPA has recently proposed modifications to the 24-hour coarse and fine PM ambient air standards. Based on the reduced emissions of sulfates and nitrates resulting from projects associated with compliance with the Consent Decree, as well as local ambient air quality data, the Tampa Electric service area is expected to be in compliance with the proposed new PM standards without additional expenditures by Tampa Electric. Also, the EPA recently proposed changes to the ozone ambient air standards. The entire State of Florida is in compliance with the current standard. Depending on the outcome, many areas in the U.S., including the Tampa Bay area, could be classified as out of attainment with a more stringent standard. This could increase Tampa Electric's cost for environmental compliance.

Carbon Reductions

Tampa Electric has historically supported voluntary efforts to reduce carbon emissions and has taken significant steps to reduce overall emissions at Tampa Electric's facilities. Since 1998, Tampa Electric has reduced its system-wide emissions of CO_2 by approximately 20%, bringing emissions to near 1990 levels. Tampa Electric expects emissions of CO_2 should remain near 1990 levels until the addition of the next baseload unit, which is expected after 2012. Tampa Electric estimates that the repowering to natural gas and the shut-down of the Gannon Station coal-fired units resulted in a decrease in CO_2 emissions of approximately 4.8 million tons below 1998 levels. During this same timeframe, the numbers of retail customers and retail energy sales have risen by approximately 25%.

Tampa Electric's voluntary activities to reduce carbon emissions also include membership in the U.S. Department of Energy's Climate Challenge (now Power Partners) program since 1994, voluntary annual reporting of greenhouse gas (GHG) emissions through the EIA-1605(b) Report since 1995 and participation in the Chicago Climate Exchange (CCX), a voluntary but legally binding cap and trade program dedicated to reducing GHG emissions since 2003. Because of Tampa Electric's membership in the CCX, its reported CO_2

emissions are audited annually by the Financial Industry Regulatory Authority (formerly National Association of Securities Dealers), which has certified the results thus far. In January 2008, the CCX recognized Tampa Electric for achieving its Phase I GHG participation targets for CO_2 reduction. While the commitment required in Phase I was a reduction of 4% below the average of the year 1998 – 2001, Tampa Electric surpassed this level with an actual reduction of approximately 20%.

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

At the state level, the Governor signed three Executive Orders in July 2007 aimed at reducing Florida's emissions of GHG. The three orders include directives for reducing GHG emissions by electric utilities to 2000 levels by 2017; to 1990 levels by 2025; and by 80 percent of 1990 levels by 2050; and the creation of the Governor's Action Team on Energy and Climate Change to develop a plan to achieve the targets contained in the Executive Orders including any necessary legislative initiatives required. The Action Team submitted its Phase One report to the Governor on Nov. 1, 2007, which included recommendations incorporating GHG emission reduction targets and strategies into Florida's energy future as well as energy efficiency and conservation targets. The Action Team will continue to meet through 2008 to address the recommendations identified in the Phase I report and complete other tasks as outlined in the Executive Orders, including the issuance of a Final Report to the Governor by Oct. 1, 2008. Among other issues, this Final Report is expected to recommend a proposed structure for a market-based policy of cap and trade for GHG emissions.

In addition, the Executive Orders charge the FDEP with developing detailed rules to implement these emissions limits. DEP has started the rule making process, but it is expected to take an extended period of time to reach completion. Until the final rules are developed, the impact on Tampa Electric and its customers can not be determined.

Also at the state level, Florida has an Energy Commission charged by the legislature with developing a comprehensive energy policy for the state. The final report of the Commission was submitted to the legislature on Dec. 31, 2007 and drew on recommendations from their four advisory groups which have held meetings throughout Florida for a year. The report was issued on Dec. 31, 2007 and includes numerous recommendations on matters described above.

The company is examining various options relating to its carbon emissions. In the fall of 2007, Tampa Electric announced that it would not move forward with its previously announced coal-fired IGCC unit, because of the continued uncertainty related to carbon reduction regulations, particularly capture and sequestration issues. Tampa Electric now expects to meet its needs for baseload generating capacity in early 2013 with natural gas fired combined-cycle technology, as well as energy efficiency programs and renewable resources (see the **Tampa Electric** section). While natural gas has lower carbon emissions than coal, fuel prices can make natural gas generating facilities less economic than coal-fired facilities. Fuel switching from coal to natural gas, absent additional sources of supply, would increase natural gas prices, further reducing the economic efficiency of natural gas generation facilities. Increased costs for electricity may cause customers to change usage patterns, which would impact Tampa Electric's sales.

Tampa Electric currently emits approximately 16.6 million tons of CO_2 per year. With a projected long-term average annual load growth of more than 2.0%, Tampa Electric may emit approximately 19.8 million tons of CO_2 (an increase of approximately 19%) by 2020 due to planned generation additions to meet growing customer needs.

Tampa Electric expects that the costs to comply with new environmental regulations would be eligible for recovery through the ECRC. If approved as prudent, the costs required to comply with CO_2 emissions reductions would be reflected in customers' bills. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the ECRC, Tampa Electric could seek to recover those costs through a base-rate proceeding, but we can not predict whether the FPSC would grant such recovery. Although Tampa Electric's current coal-based generation has declined to 56% of its output in 2007 from 95% of its output in 2002, due primarily to the conversion of the coal-fired Gannon Station into the natural gas-fired Bayside Station, coal fired facilities remain a significant part of Tampa Electric's generation fleet and additional coal units could be used in the future.

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

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

Renewable Energy

Renewables are a component of Tampa Electric's environmental portfolio. Tampa Electric's renewable energy program offers to sell renewable energy as an option to customers and utilizes energy generated in the state from renewable sources (e.g. biomass and solar). To date, more than 10 million kWh of renewable energy have been produced to support participating customer requirements.

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

Despite the emphasis on the use of renewable energy sources to reduce GHG in the Governor's Executive Orders, prior studies have shown that Florida does not have significant resources for the production of renewable energy in volumes sufficient to meet load growth. While support for tax incentives for renewable energy development specific to regional disparities may facilitate the development of new sources, mandates for renewable portfolios at high percentages create concerns that credits will have to be purchased to meet the mandate, rates for customers will grow rapidly and such mandates are not likely to result in significant quantities of renewable energy sources to be developed in the state.

A mandatory renewable energy portfolio standard could add to Tampa Electric's costs and adversely affect its operating results. The executive orders tasked the FPSC with evaluating a renewable portfolio target of 20% by 2020. In addition, the U.S. Congress has considered, but has not passed, a federal renewable energy portfolio standard. Tampa Electric could incur significant costs to comply with a high percentage renewable energy portfolio standard, as proposed, and its operating results could be adversely affected if the company was not permitted to recover these costs from customers, or if customers change usage patterns in response to increased rates.

Water Supply and Quality

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

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

Conservation

Energy conservation is becoming increasingly important in a period of volatile energy prices and in the GHG emissions reduction debate. In 2007, the Governor signed three Executive Orders aimed at reducing Florida's emissions of GHG, which included a directive for the development of new policies to enhance energy efficiency and conservation statewide. The Climate Action Team described above has made initial recommendations; however, the final recommendations to the Governor are not required until Oct. 1, 2008.

Tampa Electric offers customers a number of programs to conserve energy. These programs are designed to reduce peak energy demand which allows Tampa Electric to delay construction of future generation facilities. Since their inception, these conservation programs have reduced the summer peak demand by 222 megawatts, and the winter peak demand by 659 megawatts. These programs and their costs are approved annually by the FPSC with the costs recovered through a clause on the customer's bill.

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

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and PGS divisions, is a potentially responsible party (PRP) for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2007, Tampa Electric Company has estimated its ultimate financial liability to be approximately $11.5 million (primarily related to PGS), and this amount has been reflected in the company's financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices. The amounts represent only the estimated portion of the cleanup costs attributable to Tampa Electric Company. The estimates to perform the work are based on actual estimates obtained from contractors or Tampa Electric Company's experience with similar work, adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

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

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

REGULATION

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

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

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

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

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

Tampa Electric Rates

Tampa Electric's rates and allowed return on equity (ROE) range of 10.75% to 12.75%, with a midpoint of 11.75%, are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties.

Tampa Electric has not sought a base rate increase since 1992. Since that last rate proceeding it has earned within its allowed ROE range while adding more than 200,000 customers and making significant investments in facilities and infrastructure. These facilities include baseload and peaking generating capacity additions, to reliably serve the growing customer base. Tampa Electric expects a continued high level of capital investment, and higher levels of non-fuel operations and maintenance expenditures. After dropping to the bottom of its allowed ROE range of 10.75% to 12.75% in the middle of 2007, at the end of 2007 Tampa Electric's 13-month moving average regulatory ROE was 11.4%, as a result of the positive impact of favorable weather in the second half of 2007 and lower depreciation expense and lower property taxes in the second half of the year. However, based on our current lower forecast for customer and energy sales growth, expected higher operations and maintenance expenses and ongoing higher levels of capital investment, we expect Tampa Electric's forecasted ROE to go below the bottom of its allowed range during 2008. This is expected to cause a need for base rate relief for Tampa Electric in 2009.

Cost Recovery Clauses—Tampa Electric

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

In September 2007, 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 2008. In November 2007, the FPSC approved Tampa Electric's requested rates. The rates include the cost for natural gas and coal expected in 2008, the net refund of $15.3 million of fuel and purchased power expenses, which were not collected in 2006 and overestimated in 2007, and the operating cost for and a return on the capital invested in the second SCR project to enter service on Big Bend Unit 3 as well as the operations and maintenance expense associated with the projects as required by the EPA Consent Decree and FDEP Consent Final Judgment (see the **Environmental Compliance** section). Rates in 2008 also reflect the projected sales of $29.4 million excess SO_2 emissions allowances in 2008. Accordingly, Tampa Electric's residential customer rate per 1,000 kilowatt-hours decreased $0.16 from $114.54 in 2007 to $114.38 in 2008. Rates in 2007 reflected expected coal and natural gas costs as well as $158 million of previously underestimated 2005 and 2006 fuel and purchased power expense that were recovered, and the $105.8 million of proceeds from the sale of SO_2 emissions allowances that were returned to customers.

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

Coal Transportation Contract

Tampa Electric's previous contract for coal transportation and storage services with TECO Transport expired on Dec. 31, 2003. TECO Transport had been providing river and cross-gulf transportation services and storage services under that contract since 1999 and under a series of contracts for more than 40 years. Following a RFP process, Tampa Electric executed a new five-year contract with TECO Transport, effective Jan. 1, 2004, for waterborne coal transportation and storage services at market rates supported by the results of the RFP and an independent expert in maritime transportation matters. Hearings regarding the prudence of the RFP process and final contract were held and a final order on the matter was issued in October 2004, which reduced the annual amount Tampa Electric can recover from its customers through the fuel adjustment clause for the water transportation services for coal and petroleum coke provided by TECO Transport. The annual after-tax disallowance is estimated to be $8 million to $10 million, depending on the volumes and origination points of the coal shipments, for as long as the contract is in effect.

Tampa Electric issued a RFP for solid fuel transportation services and bids were received in December 2007, which is a schedule that will facilitate having a new contract for these services in place at the expiration of the current contract. Tampa Electric structured the RFP to comply with the FPSC order issued in October 2004.

Hardening of Transmission and Distribution Facilities

Due to extensive storm damage to utility facilities during the 2004 and 2005 hurricane seasons and the resulting outages utility customers experienced throughout the state, the FPSC initiated a proceeding to explore methods of designing and building transmission and distribution systems that would minimize long-term outages and restoration costs. Following a series of FPSC workshops to review 2004 and 2005 hurricane damage, restoration practices and activities, and plans for the 2006 hurricane season, the FPSC issued an order that required utilities to inspect wooden distribution poles every eight years and report the results of the inspections to the FPSC annually. For many years, Tampa Electric has routinely inspected its wooden poles and adjusted its inspection schedule to comply with the FPSC's order.

The FPSC subsequently issued an order requiring all investor owned utilities (IOUs) to implement a 10-point storm preparedness plan designed to improve the statewide electric infrastructure to better withstand severe storms and expedite recovery from future storms. In addition to a wood pole inspection program instituted separately, the plans address vegetation management, audits of pole attachments, transmission structure inspections and hardening, data gathering and analysis, natural disaster planning, coordination with local governmental agencies and collaborative research. In October 2006 the FPSC approved Tampa Electric's plan to comply with the directive. Tampa Electric has implemented its plan and estimates the average incremental non-fuel operations and maintenance expense of this plan to be approximately $20 million annually.

The FPSC also modified its rule regarding the design standards for new and replacement transmission and distribution line construction, including certain critical circuits in a utility's system. Beyond employing accepted engineering practices and complying with the applicable edition of the National Electric Safety Code (NESC), the new design standard requires adoption of the NESC extreme wind loading standards for distribution facilities. The new design standards also encourage the placement of new or modified facilities underground when feasible. These new requirements are expected to increase the capital expenditures required to expand the system to meet growing customer demand and to maintain system reliability by an average of $19 million annually.

Florida's Energy Plan

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

Utility Competition—Electric

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

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

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

PGS Rates

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

Due to higher operating costs, higher depreciation expense due to a routine depreciation study approved by the FPSC in January 2007, continued investment in the distribution system and higher costs associated with recently required safety requirements PGS' ROE levels are below the bottom of its allowed range; therefore, it expects to file for a base rate increase in 2008.

PGS Cost Recovery Clauses

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through the purchased gas adjustment 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 sells to its customers. These charges may be adjusted monthly based on a cap approved annually in an FPSC hearing. The cap is based on estimated costs of purchased gas and pipeline capacity, and estimated customer usage for a specific recovery period, with a true-up adjustment to reflect the variance of actual costs and usage from the projected charges for prior periods.

In November 2007, the FPSC approved rates under PGS' PGA for the period January 2008 through December 2008 for the recovery of the costs of natural gas purchased for its distribution customers.

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

Utility Competition—Gas

Although PGS is not in direct competition with any other regulated distributors of natural gas for customers within its service areas, there are other forms of competition. At the present time, the principal form of competition for residential and small commercial customers is from companies providing other sources of energy, including electricity.

In Florida, gas service is unbundled for all non-residential customers. In 2000, PGS implemented its "NaturalChoice" program, offering unbundled transportation service to all eligible customers. This means that non-residential customers can purchase commodity gas from a third party but continue to pay PGS for the transportation of the gas. As a result, PGS receives its base rate for distribution regardless of whether a customer decides to opt for transportation-only service or continue bundled service. PGS had approximately 13,600 transportation customers as of Dec. 31, 2007 out of approximately 29,900 eligible customers.

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

In general, PGS faces competition from other energy source suppliers offering fuel oil, electricity and, in some cases, propane. PGS has taken actions to retain and expand its commodity and transportation business, including managing costs and providing high quality service to customers.

CORPORATE GOVERNANCE

CEO and CFO Certifications

The most recent certifications by our Chief Executive Officer and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 are filed as exhibits to TECO Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2007. The certification of TECO Energy's Chief Executive Officer regarding compliance with the New York Stock Exchange (NYSE) corporate governance listing standards required by NYSE will be filed with NYSE following the 2008 Annual Meeting of Shareholders. Last year, we filed this certification with the NYSE after the 2007 Annual Meeting of Shareholders, in compliance with NYSE rules.

Item 7A Quantitative and Qualitative Disclosures about Market Risk.

Risk Management Infrastructure

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

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

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

Risk Management Objectives

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

- Price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric and PGS;
- Interest rate fluctuations on debt at TECO Energy and its affiliates;
- Price fluctuations for physical purchases of fuel at TECO Coal;
- Price fluctuations for crude oil and the resulting reduction of synthetic fuel proceeds if crude oil prices exceed phase-out threshold levels.

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

Derivatives and Hedge Accounting

FAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as subsequently amended and interpreted, requires us and our affiliates to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as components of other comprehensive income or net income, depending on the designation of those instruments.

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

Credit Risk

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

Contracts with different legal entities affiliated with the same counterparty are consolidated 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.

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, 2007 and 2006, a hypothetical 10% increase in the consolidated group's weighted average interest rate on its variable rate debt during the subsequent year, would not result in a material impact on pretax earnings. This is driven by the low amounts of variable rate debt at either TECO Energy or Tampa Electric Company.

A significant portion of our variable interest rate debt is Tampa Electric's auction-rate debt issued in 2006 and 2007. Due to market disruptions in the auction rate debt markets in February 2008, Tampa Electric is implementing a plan to convert the interest rate mode to fixed-rate (see the Financing section).

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 3.2% at both Dec. 31, 2007 and 2006, respectively (see the **Financing Activity** section and **Notes 6** and **7** to the **TECO Energy Consolidated Financial Statements**). The above sensitivities assume no changes to our financial structure and could be affected by changes in our credit ratings, changes in general economic conditions or other external factors (see the **Risk Factors** section).

Commodity Risk

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

Regulated Utilities

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

Currently, Tampa Electric's and PGS' commodity price risk is largely mitigated by the fact that increases in the price of fuel and purchased power are recovered through cost recovery clauses, with no anticipated effect on earnings. However, increasing fuel cost recovery has the potential to affect total energy usage and the relative attractiveness of electricity and natural gas to consumers. To moderate the impacts of fuel price changes on customers, both Tampa Electric and PGS manage commodity price risk by entering into long-term fuel supply agreements, prudently operating plant facilities to optimize cost, and entering into derivative transactions designated as cash flow hedges of anticipated purchases of wholesale natural gas. At Dec. 31, 2007 and 2006, a change in commodity prices would not have had a material impact on earnings for Tampa Electric or PGS, but could have had an impact on the timing of the cash recovery of the cost of fuel (see the **Tampa Electric** and **Regulation** sections).

Unregulated Operating Companies

The other operating companies of TECO Energy, TECO Coal and TECO Guatemala are subject to significant commodity risk. The operating companies do not speculate using derivative instruments. However, not all derivative instruments 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's expected 2008 production was fully contracted at Dec. 31, 2007. 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, 2007, TECO Coal had no derivative instruments in place to reduce the price variability for its anticipated 2008 diesel oil purchases. A hypothetical 10% increase in the average annual price for diesel oil would add $3.9 million to TECO Coal's pretax cost of production.

Like Tampa Electric and PGS, TECO Guatemala has commodity price risk that is largely mitigated by the fact that increases in the price of fuel are passed through to the power purchasing distribution utility.

The following tables summarize the changes in and the fair value balances of derivative assets (liabilities) for the year ended Dec. 31, 2007:

Changes in Fair Value of Derivatives

(millions)	
Net fair value of derivatives as of Dec. 31, 2006	$(66.8)
Net change in unrealized fair value of derivatives	89.6
Realized net settlement of derivatives	(46.7)
Net fair value of derivatives as of Dec. 31, 2007	$(23.9)

Roll-Forward of Derivative Net Assets (Liabilities)

(millions)	
Total derivative net assets (liabilities) as of Dec. 31, 2006	$(66.8)
Change in fair value of net derivative assets (liabilities):	
Recorded as regulatory assets and liabilities or OCI	(24.2)
Recorded in earnings	82.7
Realized net settlement of derivatives	(46.7)
Net option premium payments	31.1
Net fair value of derivatives at Dec. 31, 2007	$(23.9)

When available, the company uses quoted market prices to record the fair value of derivative contracts. However, many derivative contracts are not traded in sufficient volume or with sufficient market transparency to establish a representative quotation. In those cases, we use industry-accepted valuation techniques based on pricing models or matrix pricing for energy derivative contracts. Prices, inputs, assumptions and the results of valuation techniques are validated by the Middle Office, independently of the Front Office, on a daily basis. Significant inputs and assumptions used by the company to determine the fair value of energy derivative contracts are: 1) the physical delivery location of the commodity; 2) the correlation between different basis points and/or different commodities; 3) rational, economic behavior in the markets and by counterparties; 4) on- and off-peak curve shapes and correlations; 5) observed market information; and 6) volatility forecasts and estimates for and between commodities. Mathematical approaches are applied on a frequent basis to validate and corroborate the results of valuation calculations.

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

The following is a summary table of sources of fair value, by maturity period, for derivative contracts at Dec. 31, 2007.

Maturity and Source of Derivative Contracts Net Assets (Liabilities) at Dec. 31, 2007

(millions)	*Current*	*Non-current*	*Total Fair Value*
Source of fair value			
Actively quoted prices	$(25.7)	$ 1.8	$(23.9)
Model prices [(1)]	—	—	—
Total	$(25.7)	$ 1.8	$(23.9)

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

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

TECO ENERGY, INC.

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

TECO ENERGY, INC.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) of the Securities Exchange Act of 1934, as amended. We conducted an evaluation of the effectiveness of TECO Energy, Inc.'s internal control over financial reporting as of December 31, 2007 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 December 31, 2007.

Report of Independent Registered Certified Public Accounting Firm

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

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of TECO Energy, Inc. and its subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 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, 2007, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 4 to the financial statements, the Company changed its method of evaluating its uncertain tax positions as of January 1, 2007. Also, as discussed in Note 5 to the financial statements, the Company changed its method of accounting for its defined benefit pension and other postretirement plans as of December 31, 2006. Further, as discussed in Note 1 to the financial statements, the Company changed its method of accounting for stock-based compensation as of January 1, 2006.

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

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

/s/ PricewaterhouseCoopers LLP

Tampa, Florida
February 27, 2008

TECO ENERGY, INC.

Consolidated Balance Sheets

Assets

(millions)	*Dec. 31, 2007*	*Dec. 31, 2006*
Current assets		
Cash and cash equivalents	$ 162.6	$ 441.6
Restricted cash	7.4	37.3
Receivables, less allowance for uncollectibles of $3.3 and $4.6 at Dec. 31, 2007 and Dec. 31, 2006, respectively	295.9	334.9
Crude oil options receivable, net	78.5	3.4
Inventories, at average cost		
Fuel	85.8	85.0
Materials and supplies	68.2	74.6
Current regulatory assets	67.4	255.7
Current derivative assets	0.3	7.1
Income tax receivables	0.7	18.8
Prepayments and other current assets	23.0	27.3
Total current assets	789.8	1,285.7
Property, plant and equipment		
Utility plant in service		
Electric	5,275.2	5,030.4
Gas	917.4	877.7
Construction work in progress	364.8	334.1
Other property	336.4	841.9
Property, plant and equipment	6,893.8	7,084.1
Accumulated depreciation	(2,005.6)	(2,317.2)
Total property, plant and equipment, net	4,888.2	4,766.9
Other assets		
Deferred income taxes	424.9	630.2
Other investments	22.9	8.0
Long-term regulatory assets	186.8	231.3
Long-term derivative assets	1.9	0.1
Investment in unconsolidated affiliates	275.5	292.9
Goodwill	59.4	59.4
Deferred charges and other assets	115.8	87.3
Total other assets	1,087.2	1,309.2
Total assets	$ 6,765.2	$ 7,361.8

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, 2007*	*Dec. 31, 2006*
Current liabilities		
Long-term debt due within one year		
Recourse	$ 5.7	$ 566.7
Non-recourse	1.4	1.3
Junior subordinated notes	—	71.4
Notes payable	25.0	48.0
Accounts payable	302.1	326.5
Customer deposits	138.1	129.5
Current regulatory liabilities	35.4	46.7
Current derivative liabilities	26.0	70.3
Interest accrued	32.7	50.5
Taxes accrued	33.2	25.3
Other current liabilites	18.0	14.2
Total current liabilities	617.6	1,350.4
Other liabilities		
Investment tax credits	12.2	14.7
Long-term regulatory liabilities	582.7	555.3
Long-term derivative liabilities	0.1	3.7
Deferred credits and other liabilities	377.2	496.1
Long-term debt, less amount due within one year		
Recourse	3,149.4	3,202.2
Non-recourse	9.0	10.4
Total other liabilities	4,130.6	4,282.4
Commitments and contingencies (see **Note 12**)		
Capital		
Common equity (400.0 million shares authorized; par value $1; 210.9 million shares and 209.5 million shares outstanding at Dec. 31, 2007 and Dec. 31, 2006, respectively)	210.9	209.5
Additional paid in capital	1,489.2	1,466.3
Retained earnings	334.1	83.7
Accumulated other comprehensive loss	(17.2)	(30.5)
Total capital	2,017.0	1,729.0
Total liabilities and capital	$6,765.2	$7,361.8

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,*		*2007*	*2006*	*2005*
Revenues				
Regulated electric and gas (includes franchise fees and gross receipts taxes of $111.2 in 2007, $104.2 in 2006 and $87.2 in 2005)		$2,786.3	$2,660.3	$2,293.8
Unregulated		749.8	787.8	716.3
Total revenues		3,536.1	3,448.1	3,010.1
Expenses				
Regulated operations				
Fuel		854.7	803.4	461.1
Purchased power		271.9	221.3	269.7
Cost of natural gas sold		389.9	365.3	350.2
Other		280.4	294.0	270.3
Operation other expense				
Mining related costs		435.4	450.2	412.5
Waterborne transportation costs		206.4	217.8	191.8
Other		16.6	15.6	49.3
Maintenance		183.5	183.3	168.4
Depreciation and amortization		263.7	282.2	282.2
Gain on sale, net of transaction related costs		(221.3)	—	—
Taxes, other than income		218.3	217.5	194.7
Sale of previously impaired assets / asset impairments		—	(20.7)	3.2
Total expenses		2,899.5	3,029.9	2,653.4
Income from operations		636.6	418.2	356.7
Other income (expense)				
Allowance for other funds used during construction		4.5	2.7	—
Other income		112.0	94.5	171.6
Loss on debt exchange/extinguishment		(32.9)	(2.5)	(74.2)
Income from equity investments		68.5	58.9	60.4
Total other income		152.1	153.6	157.8
Interest charges				
Interest expense		259.5	279.4	288.7
Allowance for borrowed funds used during construction		(1.7)	(1.1)	—
Total interest charges		257.8	278.3	288.7
Income before provision for income taxes		530.9	293.5	225.8
Provision for income taxes		214.2	118.7	101.9
Income from continuing operations before minority interest		316.7	174.8	123.9
Minority interest		82.2	69.6	87.1
Income from continuing operations		398.9	244.4	211.0
Discontinued operations				
Income from discontinued operations		—	2.3	88.2
Income tax (benefit) provision		(14.3)	0.4	24.7
Total discontinued operations		14.3	1.9	63.5
Net income		$ 413.2	$ 246.3	$ 274.5
Average common shares outstanding	— Basic	209.1	207.9	206.3
	— Diluted	209.9	208.7	208.2
Earnings per share from continuing operations	— Basic	$ 1.91	$ 1.18	$ 1.02
	— Diluted	$ 1.90	$ 1.17	$ 1.00
Earnings per share from discontinued operations	— Basic	$ 0.07	$ 0.01	$ 0.31
	— Diluted	$ 0.07	$ 0.01	$ 0.31
Earnings per share	— Basic	$ 1.98	$ 1.19	$ 1.33
	— Diluted	$ 1.97	$ 1.18	$ 1.31
Dividends declared and paid per common share outstanding		$ 0.775	$ 0.760	$ 0.760

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

TECO ENERGY, INC.

Consolidated Statements of Comprehensive Income

(millions) *For the years ended Dec. 31,*	*2007*	*2006*	*2005*
Net income	$413.2	$246.3	$274.5
Other comprehensive income (loss), net of tax			
Net unrealized losses on cash flow hedges	(6.3)	(0.3)	(0.1)
Amortization of unrecognized benefit costs	2.4	—	—
Recognized benefit costs due to curtailment	8.7	—	—
Change in benefit obligation due to annual remeasurement	8.5	42.7	(7.2)
Other comprehensive income (loss), net of tax	13.3	42.4	(7.3)
Comprehensive income	$426.5	$288.7	$267.2

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,*	*2007*	*2006*	*2005*
Cash flows from operating activities			
Net income	$ 413.2	$ 246.3	$ 274.5
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	263.7	282.2	282.2
Deferred income taxes	184.8	112.5	110.8
Investment tax credits, net	(2.5)	(2.6)	(2.7)
Allowance for other funds used during construction	(4.5)	(2.7)	—
Non-cash stock compensation	11.6	11.5	5.5
Gain on sales of business / assets, pretax	(246.1)	(67.0)	(261.6)
Equity in earnings of unconsolidated affiliates, net of cash distributions on earnings	(18.0)	(3.4)	(35.9)
Minority interest	(82.2)	(69.6)	(87.1)
Non-cash debt extinguishment / exchange	2.6	2.5	19.8
Asset impairment	—	—	3.2
Derivatives marked to market	(82.7)	2.0	(2.9)
Deferred recovery clause	123.7	53.4	(154.3)
Receivables, less allowance for uncollectibles	51.0	(26.0)	(56.7)
Inventories	(9.6)	(5.8)	(38.1)
Prepayments and other deposits	3.2	11.4	(11.3)
Taxes accrued	26.6	(17.0)	(17.4)
Interest accrued	(17.8)	0.5	17.5
Accounts payable	(71.9)	(18.0)	119.0
Other	8.9	56.7	12.6
Cash flows from operating activities	554.0	566.9	177.1
Cash flows from investing activities			
Capital expenditures	(494.4)	(455.7)	(295.3)
Allowance for other funds used during construction	4.5	2.7	—
Net proceeds from sales of business / assets	405.2	100.4	278.3
Restricted cash	29.9	0.3	47.6
Distributions from unconsolidated affiliates	27.5	7.3	2.8
Other investments	(0.4)	(6.7)	0.9
Cash flows (used in) from investing activities	(27.7)	(351.7)	34.3
Cash flows from financing activities			
Dividends	(163.0)	(158.7)	(157.7)
Proceeds from sale of common stock	14.0	12.5	16.2
Proceeds from long-term debt	444.1	327.5	311.9
Repayment of long-term debt	(1,137.5)	(199.3)	(494.1)
Contributions from minority interests	81.3	65.7	83.1
Debt exchange premiums	(21.2)	—	—
Exchange of equity units	—	—	180.2
Net (decrease) increase in short-term debt	(23.0)	(167.0)	100.0
Other	—	—	(2.0)
Cash flows (used in) from financing activities	(805.3)	(119.3)	37.6
Net (decrease) increase in cash and cash equivalents	(279.0)	95.9	249.0
Cash and cash equivalents at beginning of the year	441.6	345.7	96.7
Cash and cash equivalents at end of the year	$ 162.6	$ 441.6	$ 345.7
Supplemental disclosure of cash flow information			
Cash paid during the year for:			
Interest (net of amounts capitalized) (1)	$ 262.1	$ 259.4	$ 288.9
Income taxes (refund) paid	$ (10.5)	$ 10.4	$ 27.4

(1) Included in interest paid during the year is interest paid on debt obligation for discontinued operations of $12.0 million for 2005. No interest was paid in 2007 or 2006 for debt related to discontinued operations.

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

TECO ENERGY, INC.

Consolidated Statements of Capital

(millions)	*Shares* [1]	*Common Stock*	*Additional Paid-in Capital*	*Retained Earnings (Deficit)*	*Accumulated Other Comprehensive Income (Loss)*	*Unearned Compensation*	*Total Capital*
Balance, Dec. 31, 2004	199.7	$199.7	$1,489.4	$(357.6)	$(43.8)	$(3.8)	$1,283.9
Net income				274.5			274.5
Other comprehensive loss, after tax					(7.3)		(7.3)
Common stock issued	1.6	1.6	19.6			(5.0)	16.2
Cash dividends declared			(157.7)				(157.7)
Final settlement of equity security units	6.9	6.9	173.3				180.2
Amortization of unearned compensation						5.5	5.5
Tax benefits—stock options			2.4				2.4
Performance shares						(6.0)	(6.0)
Balance, Dec. 31, 2005	208.2	$208.2	$1,527.0	$ (83.1)	$(51.1)	$(9.3)	$1,591.7
Net income				246.3			246.3
Other comprehensive income, after tax					42.4		42.4
Common stock issued	1.3	1.3	9.4				10.7
Cash dividends declared			(79.2)	(79.5)			(158.7)
Stock compensation expense			11.5				11.5
Adoption FAS 123R			(9.3)			9.3	—
Tax benefits—stock options			1.4				1.4
Adoption FAS 158					(21.8)		(21.8)
Performance shares			5.5				5.5
Balance, Dec. 31, 2006	209.5	$209.5	$1,466.3	$ 83.7	$(30.5)	$—	$1,729.0
Net income				413.2			413.2
Other comprehensive income, after tax					13.3		13.3
Common stock issued	1.4	1.4	10.9				12.3
Cash dividends declared				(163.0)			(163.0)
Stock compensation expense			11.6				11.6
Implementation of FIN 48				0.2			0.2
Tax benefits—stock options			0.4				0.4
Balance, Dec. 31, 2007	210.9	$210.9	$1,489.2	$ 334.1	$(17.2)	$—	$2,017.0

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

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

1. Significant Accounting Policies

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

Principles of Consolidation

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

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

Use of Estimates

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

Segment Reporting

In 2005, only historical data is presented for TWG Merchant as all merchant assets have been divested. Any residual results for 2006 and 2007 are included in "Other and eliminations".

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, 2007 includes $7.1 million of cash held in escrow related to the 2003 sale of Hardee Power Partners (HPP). The $7.1 million will be released from escrow in 2012, upon maturity of debt financing currently held by the purchaser of HPP. Restricted cash also included other unrelated amounts totaling approximately $0.3 million at Dec. 31, 2007.

Restricted cash at Dec. 31, 2006 included $30.0 million of cash held in escrow related to the 2003 sale of TECO Coal Corporation's (TECO Coal) indirectly owned synthetic fuel production facilities, the $7.1 million related to HPP discussed above, and other unrelated amounts totaling approximately $0.2 million. The $30.0 million of cash from the synthetic fuel facility sale was retained in escrow to support the company's obligation under the sale agreement until the expiration of that agreement or TECO Energy achieved investment-grade credit ratings. The funds were released in December 2007 upon the attainment of the required credit ratings.

Cost Capitalization

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

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

Capitalized interest expense—Interest costs for the construction of non-utility facilities are capitalized and depreciated over the service lives of the related property. TECO Energy capitalized $0.1 million of interest costs in 2005. No interest costs were capitalized in 2007 or 2006.

Planned Major Maintenance

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

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

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

Depreciation

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

Total depreciation expense for the years ended Dec. 31, 2007, 2006, and 2005 was $254.0 million, $270.3 million and $267.6 million, respectively. There were no plant acquisition adjustments in 2007 or 2006, however acquisition adjustments of $10.0 million occurred in 2005. The provision for total regulated utility plant in service, expressed as a percentage of the original cost of depreciable property, was 3.7% for 2007, 3.9% for 2006, and 4.0% for 2005.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is a non-cash credit to income with a corresponding charge to utility plant which represents the cost of borrowed funds and a reasonable return on other funds used for construction. AFUDC is recorded in years when the capital expenditures on eligible projects exceed approximately $36 million. The base on which AFUDC is calculated excludes construction work-in-progress which has been included in rate base. The rate used to calculate AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. The rate was 7.79% for 2007 and 2006. No projects qualified for AFUDC in 2005 while total AFUDC for 2007 and 2006 was $6.2 million and $3.8 million, respectively.

Other Investments

As of Dec. 31, 2007, the company had a total of $15.0 million invested in two auction rate securities, including a $5.0 million security maturing on Jun. 15, 2032 and a $10.0 million security maturing on Jun. 1, 2041. These securities earn an interest rate set in an auction every 28 days. Both the carrying amount and interest received are included under the same caption "Other investments", on TECO Energy's Consolidated Balance Sheet and Consolidated Statement of Cash Flows, respectively.

Although the final maturities of these securities are considered long-term, the company has the opportunity to sell the securities at par at each auction date. As required by Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 115, *Accounting for Certain Investments in Debt and Equity Securities,* any unrealized change in fair value of available-for-sale securities is reflected in other comprehensive income. Because of the auction frequency, the fair value of these securities has not fluctuated, and accordingly, no adjustments to fair value have been recorded.

Inventory

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

Investments in Unconsolidated Affiliates

Investments in unconsolidated affiliates are accounted for using the equity method of accounting. The percentage ownership interests for each investment at Dec. 31, 2007 and 2006 are presented in the following table:

TECO Energy's Percent Ownership in Unconsolidated Affiliates (4)

Dec. 31,	*2007*	*2006*
TECO Transport		
Ocean Dry Bulk, LLC (1)	—	50%
TECO Guatemala		
Distribucion Electrica CentroAmericana II, S.A. (DECA II)	30%	30%
Central Generadora Electrica San José, Limitada (San José or CGESJ)	100%	100%
Tampa Centro Americana de Electricidad, Limitada (Alborada or TCAE)	96%	96%
Other		
Litestream Technologies, LLC (2)	—	36%
Walden Woods Business Center, Ltd.	50%	50%
TECO Funding Company I, LLC (3)	—	100%
TECO Funding Company II, LLC (3)	—	100%

(1) TECO Transport was sold to an unaffiliated third party effective Dec. 4, 2007.

(2) In 2004, the assets of Litestream Technologies, LLC were sold in bankruptcy. The company indirectly owned a 36% interest in Litestream Technologies, LLC as of Dec. 31, 2006. In 2007, the final disbursement to creditors was made.

(3) On Dec. 20, 2005, all outstanding subordinated notes held by TECO Funding Company I, LLC were redeemed and the LLC was subsequently dissolved. On Jan. 16, 2007, all outstanding subordinated notes held by TECO Funding Company II, LLC matured.

(4) TECO Energy, Inc. received $63.2 million, $56.6 million and $27.0 million during the years ended Dec. 31, 2007, 2006 and 2005, respectively, as dividends from unconsolidated affiliates.

Regulatory Assets and Liabilities

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

Deferred Income Taxes

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

Investment Tax Credits

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

Revenue Recognition

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

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

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

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

Revenues for energy marketing operations at TECO Gas Services are presented on a net basis in accordance with Emerging Issues Task Force No. (EITF) 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent*, and EITF 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under Issues No. 98-10 and 00-17*, to reflect the nature of the contractual relationships with customers and suppliers. As a result, costs netted against revenues for the years ended Dec. 31, 2007, 2006 and 2005 were \$2.1 million, \$0.8 million and \$3.8 million, respectively.

Shipping and Handling

TECO Coal includes the costs to ship product to customers in "Operation other expense—Mining related costs" on the Consolidated Statements of Income for the periods ended Dec. 31, 2007, 2006 and 2005.

Derivatives and Hedging Activities

The company classifies cash inflows and outflows related to derivative and hedging instruments in the appropriate cash flow sections associated with the item being hedged. In the case of heating oil swaps that are used to mitigate the fluctuations in the price of diesel fuel, the cash inflows and outflows are included in the operations section. Settlements for crude oil options that protect the cash flows related to the sales of investor interests in the synthetic fuel production facilities are included in the investing section.

Other Income and Minority Interest

TECO Energy earned a significant portion of its income indirectly through the synthetic fuel operations at TECO Coal. At the end of 2007, 2006 and 2005, TECO Coal had sold ownership interests in the synthetic fuel facilities to unrelated third-party investors equal to 98%. These investors paid for the purchase of the ownership interests as synthetic fuel is produced. The payments were based on the amount of production and sales of synthetic fuel and the related underlying value of the tax credit, which was subject to potential limitation based on the price of domestic crude oil. These payments are recorded in "Other income" in the Consolidated Statements of Income. The program that provided federal income tax credits for the production of synthetic fuel expired Dec. 31, 2007.

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

For the year ended Dec. 31, 2007, "Other income" reflected a phase-out of approximately 67%, or $140.2 million, of the benefit of the underlying value of any 2007 tax credits based on an estimate of the average annual price of domestic crude oil during 2007. Should the final actual average annual price of domestic crude oil be different than this estimate, the cash payments and the benefits recognized in "Other income" and "Minority interest" will be adjusted, either positively or negatively, in the first quarter of 2008. A phase-out of approximately 35%, or $61.1 million after-tax, was recognized in 2006 and no phase-out of the benefit was recognized in 2005.

To protect the cash proceeds derived from the sale of ownership interests, TECO Energy had in place crude oil options to hedge against the risk of high oil prices reducing the value of the tax credits related to the production of synthetic fuel. These instruments were marked-to-market with fair value gains and losses recognized in "Other income" on the Consolidated Statements of Income. For the years ended Dec. 31, 2007, 2006 and 2005, the company recognized gains on marked-to-market derivatives of $82.7 million, $2.9 million and $0.5 million, respectively. The increase in the gain from 2006 to 2007 was reflective of the increase in oil prices and the total volume of barrels hedged, which was 2.8 million barrels in 2006 compared to 25.1 million barrels in 2007.

Revenues and Cost Recovery

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

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, 2007 and 2006, unbilled revenues of $46.6 million and $47.8 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 $271.9 million, $221.3 million and $269.7 million, for the years ended Dec. 31, 2007, 2006 and 2005, 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 and TECO Transport incur most of TECO Energy's total excise taxes, which are accrued as an expense and reconciled to the actual cash payment of excise taxes. As general expenses, they are not specifically recovered through revenues. Excise taxes paid by the regulated utilities are not material and are expensed when incurred.

The regulated utilities are allowed to recover certain costs incurred from customers through prices approved by the FPSC. The amounts included in customers' bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Statements of Income. These amounts totaled $111.2 million, $104.2 million and $87.2 million for the years ended Dec. 31, 2007, 2006 and 2005, respectively. Franchise fees and gross receipt taxes payable by the regulated utilities are included as an expense on the Consolidated Statements of Income in "Taxes, other than income". For the years ended Dec. 31, 2007, 2006 and 2005, these totaled $110.9 million, $104.0 million and $87.0 million, respectively.

Asset Impairments

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

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

Deferred Charges and Other Assets

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

Deferred Credits and Other Liabilities

Other deferred credits primarily include the accrued post-retirement and pension liabilities, and medical and general liability claims incurred but not reported. The company and its subsidiaries' have a self-insurance program supplemented by excess insurance coverage for the cost of claims whose ultimate value exceeds the company's retention amounts. The company estimates its liabilities for auto, general, marine protection & indemnity, and workers' compensation using discount rates mandated by statute or otherwise deemed appropriate for the circumstances. Discount rates used in estimating these liabilities at both Dec. 31, 2007 and 2006 ranged from 4.00% to 4.75%.

Stock-based Compensation

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

Restrictions on Dividend Payments and Transfer of Assets

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

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

Foreign Operations

The functional currency of the company's foreign investments is primarily the U.S. dollar. Transactions in the local currency are re-measured to the U.S. dollar for financial reporting purposes. The aggregate re-measurement gains or losses included in net income in 2007, 2006 and 2005 were not material. The foreign investments are generally protected from any significant currency gains or losses by the terms of the power sales agreements and other related contracts, in which payments are defined in U.S. dollars.

2. New Accounting Pronouncements

Noncontrolling Interests in Consolidated Financial Statements

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

Business Combinations (Revised)

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

Offsetting Amounts Related to Certain Contracts

In April 2007, the FASB issued FASB Staff Position (FSP) FIN 39-1. This FSP amends FASB Interpretation No. 39, *Offsetting of Amounts Related to Certain Contracts* by allowing an entity to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. The guidance in this FSP is effective for fiscal years beginning after Nov. 15, 2007. The Company adopted this FSP effective Jan. 1, 2008 without any effect on its results of operations, statement of position or cash flows.

Fair Value Option For Financial Assets and Financial Liabilities

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities—Including an amendment of FASB Statement No. 115* (FAS 159). FAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The objective of FAS 159 is to provide opportunities to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply hedge accounting provisions. FAS 159 is effective for fiscal years beginning after Nov. 15, 2007. The company adopted FAS 159 effective Jan. 1, 2008, but did not elect to measure any financial instruments at fair value. Accordingly, its adoption did not have any effect on its results of operations, statement of position or cash flows.

Fair Value Measurements

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

FAS 157, among other things, requires the company to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value, and specifies a hierarchy of valuation techniques based on whether the inputs to those valuation techniques are observable or unobservable. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect the company's market assumptions. FAS 157 defines the following fair value hierarchy, based on these two types of inputs:

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

The effective date is for fiscal years beginning after Nov. 15, 2007. In November of 2007, the FASB granted a one year deferral for non-financial assets and liabilities. As a result, the company adopted FAS 157 effective Jan. 1, 2008 for financial assets and liabilities. Financial assets and liabilities of the company measured at fair value include derivatives and certain investments, for which fair values are primarily based on observable inputs.

During 2008, the company will continue to evaluate FAS 157 for the remaining non-financial assets and liabilities to be included effective Jan. 1, 2009. The company does not believe the impact of adoption for the remaining non-financial assets and liabilities will be material to its results of operations, statement of position or cash flows.

3. Regulatory

As discussed in **Note 1**, Tampa Electric's and PGS's retail businesses are regulated by the FPSC. Tampa Electric is subject to regulation by the Federal Energy Regulatory Commission ("FERC") under the Public Utility Holding Company Act of 2005 ("PUHCA 2005"), which replaced the Public Utility Holding Company Act of 1935 which was repealed. However, pursuant to a waiver granted in accordance with FERC's regulations, TECO Energy is not subject to certain of the accounting, record-keeping, and reporting requirements prescribed by FERC's regulations under PUHCA 2005.

Base Rates—Tampa Electric

Tampa Electric's rates and allowed return on equity (ROE) range of 10.75% to 12.75% with a midpoint of 11.75% are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions resulting from rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties. Tampa Electric's base rates were last set in a 1992 proceeding.

Cost Recovery—Tampa Electric

In September 2007, Tampa Electric filed with the FPSC for approval of fuel and purchased power, capacity, environmental and conservation cost recovery rates for the period January 2008 through December 2008. In November 2007, the FPSC approved Tampa Electric's requested changes. The rates include the impacts of natural gas and coal prices expected in 2008, the refund of the overestimated 2007 fuel and purchased power expenses, the collection of previously unrecovered 2006 fuel and purchased power expenses, the proceeds from the actual and projected sale of excess sulfur dioxide (SO_2) emissions allowances in 2007 and 2008 and the operating cost for and a return on the capital invested on the selective catalytic reduction (SCR) projects to enter service on Big Bend Units 3 and 4 as well as the operating and maintenance (O&M) costs associated with the Big Bend Units 1 and 2 pre-SCR projects, which are required by the Environmental Protection Agency (EPA) Consent Decree and Florida Department of Environmental Protection (FDEP) Consent Final Judgment. In addition, the rates reflect the FPSC's September 2004 decision to reduce the annual cost recovery amount for water transportation services for coal and petroleum coke provided under Tampa Electric's contract with TECO Transport described below. As part of the regulatory process, it is reasonably likely that third parties may intervene on similar matters in the future. The company is unable to predict the timing, nature or impact of such future actions.

Base Rates—PGS

PGS' rates and allowed ROE range of 10.25% to 12.25% with a midpoint of 11.25% are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions resulting from rate or other proceedings initiated by PGS, FPSC staff or other interested parties. PGS' current base rates have been in effect since 2003.

Cost Recovery—PGS

In September 2007, PGS filed its annual request with the FPSC to change its Purchased Gas Adjustment (PGA) cap factor for 2008. The PGA rate can vary monthly due to changes in actual fuel costs but is not expected to exceed the FPSC approved annual cap. In November 2007, the FPSC approved the cap factor under PGS' PGA for the period January 2008 through December 2008.

SO_2 Emission Allowances

The Clean Air Act Amendments of 1990 established SO_2 allowances to manage the achievement of SO_2 emissions requirements. The legislation also established a market-based SO_2 allowance trading component.

An allowance authorizes a utility to emit one ton of SO_2 during a given year. The EPA allocates allowances to utilities based on mandated emissions reductions. At the end of each year, a utility must hold an amount of allowances at least equal to its annual emissions. Allowances are fully marketable and, once allocated, may be bought, sold, traded or banked for use currently or in future years. In addition, the EPA withholds a small percentage of the annual SO_2 allowances it allocates to utilities for auction sales. Any resulting auction proceeds are then forwarded to the respective utilities. Allowances may not be used for compliance prior to the calendar year for which they are allocated. Tampa Electric accounts for these using an inventory model with a zero basis for those allowances allocated to the company. Tampa Electric recognizes a gain at the time of sale, approximately 95% of which accrues to retail customers through the environmental cost recovery clause.

Over the years, Tampa Electric has acquired allowances through EPA allocations. Also, over time, Tampa Electric has sold unneeded allowances based on compliance and allowances available. The SO_2 allowances unneeded and sold resulted from lower emissions at Tampa Electric brought about by environmental actions taken by the company under the Clean Air Act.

For the year ended Dec. 31, 2007, Tampa Electric sold approximately 168,000 allowances, resulting in proceeds of $91.1 million, the majority of which is included as a cost recovery clause regulatory liability. In the years ended Dec. 31, 2006 and 2005, approximately 44,500 and 100,000 allowances were sold for $45.0 million and $79.7 million in proceeds, respectively.

Other Items

Storm Damage Cost Recovery

Tampa Electric accrues $4 million annually to fund a FERC-authorized, self-insured storm damage reserve. This reserve was created after Florida's investor owned utilities (IOUs) were unable to obtain transmission and distribution insurance coverage due to destructive acts of nature.

The FPSC approved Tampa Electric to reclassify approximately $39 million of 2004 hurricane restoration costs as plant in service (rate base). With this adjustment and the normal $4 million annual storm accrual, Tampa Electric's storm reserve was $20.0 and $16.0 million as of Dec. 31, 2007 and 2006, respectively.

Coal Transportation Contract

In September 2004, the FPSC voted to disallow a portion of the costs that Tampa Electric can recover from its customers for water transportation services under a five year transportation agreement ending Dec. 31, 2008. The amounts disallowed, and excluded from the recovery under the fuel adjustment clause, were $15.1 million, $15.3 million and $14.1 million for the years ended Dec. 31, 2007, 2006 and 2005, respectively.

Regulatory Assets and Liabilities

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

Tampa Electric and PGS apply the accounting treatment permitted by FAS 71. Areas of applicability include: deferral of revenues and expenses 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, 2007 and 2006 are presented in the following table:

Regulatory Assets and Liabilities

(millions)	*Dec. 31, 2007*	*Dec. 31, 2006*
Regulatory assets:		
Regulatory tax asset (1)	$ 62.5	$ 49.5
Other:		
Cost recovery clauses	47.2	239.2
Post-retirement benefit asset	97.5	148.9
Deferred bond refinancing costs (2)	25.5	26.7
Environmental remediation	11.4	12.3
Competitive rate adjustment	5.4	5.5
Other	4.7	4.9
Total other regulatory assets	191.7	437.5
Total regulatory assets	254.2	487.0
Less: Current portion	67.4	255.7
Long-term regulatory assets	$186.8	$231.3
Regulatory liabilities:		
Regulatory tax liability (1)	$ 18.8	$ 20.6
Other:		
Deferred allowance auction credits	0.1	0.8
Cost recovery clauses	18.9	28.9
Environmental remediation	11.4	12.3
Transmission and delivery storm reserve	20.3	16.3
Deferred gain on property sales (3)	4.7	6.8
Accumulated reserve-cost of removal	543.5	516.1
Other	0.4	0.2
Total other regulatory liabilities	599.3	581.4
Total regulatory liabilities	618.1	602.0
Less: Current portion	35.4	46.7
Long-term regulatory liabilities	$582.7	$555.3

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

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

Regulatory assets

(millions) Dec. 31,	*2007*	*2006*
Clause recoverable [1]	$ 52.6	$244.7
Earning a rate of return [2]	101.7	152.6
Regulatory tax assets [3]	62.5	49.5
Capital structure and other [3]	37.4	40.2
Total	$254.2	$487.0

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

(2) Primarily reflects allowed working capital, which is included in rate base and earns an 8.2% rate of return as permitted by the FPSC.

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

4. Income Tax Expense

Income tax expense consists of the following components:

Income Tax Expense (Benefit)

(millions)	*Federal*	*Foreign*	*State*	*Total*
2007				
Continuing operations				
Current payable	$ 2.8	$ 0.7	$ 14.1	$ 17.6
Deferred	178.6	—	20.5	199.1
Amortization of investment tax credits	(2.5)	—	—	(2.5)
Income tax expense from continuing operations	178.9	0.7	34.6	214.2
Discontinued operations				
Deferred	(14.3)	—	—	(14.3)
Income tax benefit from discontinued operations	(14.3)	—	—	(14.3)
Total income tax expense	$164.6	$ 0.7	$ 34.6	$199.9
2006				
Continuing operations				
Current payable	$ 1.0	$ 2.8	$ 5.4	$ 9.2
Deferred	87.2	0.2	24.7	112.1
Amortization of investment tax credits	(2.6)	—	—	(2.6)
Income tax expense from continuing operations	85.6	3.0	30.1	118.7
Discontinued operations				
Deferred	8.5	—	(8.1)	0.4
Income tax expense (benefit) from discontinued operations	8.5	—	(8.1)	0.4
Total income tax expense	$ 94.1	$ 3.0	$ 22.0	$119.1
2005				
Continuing operations				
Current payable	$ 2.0	$ 7.5	$ 9.0	$ 18.5
Deferred	63.7	0.8	21.6	86.1
Amortization of investment tax credits	(2.7)	—	—	(2.7)
Income tax expense from continuing operations	63.0	8.3	30.6	101.9
Discontinued operations				
Deferred	35.3	—	(10.6)	24.7
Income tax expense (benefit) from discontinued operations	35.3	—	(10.6)	24.7
Total income tax expense	$ 98.3	$ 8.3	$ 20.0	$126.6

As discussed in **Note 1**, TECO Energy uses the liability method to determine deferred income taxes. Based primarily on the reversal of deferred income tax liabilities and future earnings of the company's core utility operations, management has determined that the net deferred tax assets recorded at Dec. 31, 2007 will be realized in future periods.

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

Deferred Income Tax Assets and Liabilities

(millions) Dec. 31,	*2007*	*2006*
Deferred income tax assets		
Alternative minimum tax credit carryforward	$ 196.6	$ 197.6
Investment in partnership	61.8	55.3
Net operating loss carryforward	508.2	763.4
Other	160.1	147.9
Total deferred income tax assets	$ 926.7	$1,164.2
Deferred income tax liabilities		
Property related	(487.2)	(468.5)
Deferred fuel	(14.6)	(65.5)
Total deferred income tax liabilities	(501.8)	(534.0)
Net deferred tax assets	$ 424.9	$ 630.2

At Dec. 31, 2007, the company has cumulative unused federal and state (Florida) net operating losses of approximately $1,322.9 million and $663.2 million, respectively, expiring in 2026 and 2027, respectively. In addition, the company has unused general business credits of $2.2 million and unused foreign tax credits of $6.4 million expiring in 2026 and 2016, respectively. The company also has available alternative minimum tax credit carryforwards for tax purposes of approximately $197.0 million which may be used indefinitely to reduce federal income taxes.

Effective Income Tax Rate

(millions) For the years ended Dec. 31,	*2007*	*2006*	*2005*
Net income from continuing operations before minority interest	$316.7	$174.8	$123.9
Plus: minority interest	82.2	69.6	87.1
Net income from continuing operations	398.9	244.4	211.0
Total income tax provision	214.2	118.7	101.9
Income from continuing operations before income taxes	613.1	363.1	312.9
Income taxes on above at federal statutory rate of 35%	214.6	127.1	109.5
Increase (decrease) due to			
State income tax, net of federal income tax	22.5	18.7	18.1
Foreign income taxes	1.9	2.2	6.6
Amortization of investment tax credits	(2.5)	(2.6)	(2.7)
Permanent reinvestment—foreign income	(11.0)	(9.2)	(9.4)
Non-conventional fuels tax credit	(1.4)	(2.1)	—
AFUDC equity	(1.6)	(1.0)	—
Dividend income	—	—	1.6
State rate change	—	2.7	2.4
State valuation allowance	2.0	2.1	—
Depletion	(7.8)	(9.8)	(8.4)
Other	(2.5)	(9.4)	(15.8)
Total income tax provision from continuing operations	$214.2	$118.7	$101.9
Provision for income taxes as a percent of income from continuing operations, before income taxes	34.9%	32.7%	32.6%

For the three years presented, we experienced a number of events that have impacted the overall effective tax rate on continuing operations. These events included permanent reinvestment of foreign income under APB Opinion No. 23, *Accounting for Taxes—Special Areas* (APB 23), adjustment of deferred tax assets for the effect of an enacted change in state tax rates, depletion, repatriation of foreign source income to the United States, and reduction of income tax expense under the new "tonnage tax" regime. The change in the 2007 effective tax rate is principally due to the taxation of earnings as a result of the sale of TECO Transport in consolidated filing states with higher tax rates, the projected state tax rate at which various deferred items will reverse as a result of this sale, and lower depletion. See below for a discussion of discontinued operations in 2007.

At Dec. 31, 2007, the portion of cumulative undistributed earnings from our investments in EEGSA was approximately $87.8 million. With the exception of the earnings repatriated in 2005, these earnings have been, and are intended to be, indefinitely invested in foreign operations. Therefore, no provision has been made for U.S. taxes or foreign withholding taxes that may be applicable upon actual or deemed repatriation.

On Oct. 22, 2004, the President of the United States signed the American Jobs Creation Act of 2004 (the Act). The Act creates a temporary incentive for U.S. corporations to repatriate accumulated income earned abroad by providing an 85% dividend received deduction for certain dividends from controlled foreign corporations. The company elected to apply Code Section 965 with respect to its 2005 dividends. For the twelve months ended Dec. 31, 2005, the company repatriated $38.9 million, resulting in $1.0 million of additional tax expense net of foreign tax credits. The tax savings related to the repatriation provision of the Act are reflected in the "Other" category in the effective income tax rate.

Code Section 248 of the Act also introduced a new "tonnage tax" which allows corporations to elect to exclude from gross income certain income from activities connected with the operation of a U.S. flag vessel in U.S. foreign trade and become subject to a tax imposed on the per-ton weight of the qualified vessel instead. The company elected to apply Code Section 248 for qualified vessels in 2006 and 2005. The tax savings related to the tonnage tax regime are reflected in the "Other" category in the effective income tax rate.

The actual cash (refunded) paid for income taxes as required for the alternative minimum tax, state income taxes and prior year audits in 2007, 2006 and 2005 was $(10.5) million, $10.4 million and $27.4 million, respectively.

In June 2006, the FASB issued FASB Interpretation Number 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109, Accounting for Income Taxes* (FIN 48). FIN 48 addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, the company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods, and requires increased disclosures.

The company adopted the provisions of FIN 48 effective Jan. 1, 2007. As a result of the implementation of FIN 48, the company recognized a $0.1 million decrease in the deferred tax liability for uncertain tax benefits with a corresponding increase to the Jan. 1, 2007 balance of retained earnings. Subsequent to the implementation of FIN 48, the company recognized in the second quarter $14.3 million of tax benefits in discontinued operations as a result of reaching favorable conclusions with taxing authorities. Additionally, during the fourth quarter of 2007, the company recognized $1.9 million of current tax expense from an uncertain tax position that did not meet the "more likely than not" criteria. Lastly, the company has had on-going discussions with state tax authorities related to tax issues addressed prior to the adoption of FIN 48. The principle remaining issues relate to how a state taxes the sale of various revenue components and how it treats the nature of the sale of various partnership interests. There is a reasonable possibility that these issues may be resolved in the next twelve months. At this time, the Company does not have sufficient information to determine whether these issues will be resolved favorably. As a result, the Company has recorded a full valuation allowance as the most probable outcome. If these matters are positively settled, they would increase earnings in the period of settlement. If unfavorably resolved, they would have no impact on earnings, but they would result in a decrease in operating cash flows. The gross exposure on this issue as of Dec. 31, 2007 is approximately $12.7 million.

The following table provides a reconciliation of Unrecognized Tax Benefits at the beginning and end of 2007:

Unrecognized Tax Benefits

(in millions)	
Balance, Jan. 1, 2007	$11.2
Addition for tax positions of the current year	2.9
Additions for tax provision of prior years	0.8
Reductions for tax positions of prior years for:	
Changes in judgement	—
Settlements during the period	—
Lapses of applicable statute of limitation	—
Balance, Dec. 31, 2007	$14.9

The company recognizes interest and penalties associated with uncertain tax positions in "Operation other expense—Other" in the Consolidated Statements of Income. In 2007, the company recorded approximately $0.9 million of pre-tax charges for interest only. Additionally, the company has recognized approximately $2.0 million and $1.1 million of interest on the balance sheet as of Dec. 31, 2007 and 2006, respectively. No amounts have been recorded for penalties.

The company's U.S. subsidiaries join in the filing of a U.S. federal consolidated income tax return. The Internal Revenue Service (IRS) concluded its examination of the company's consolidated federal income tax returns for the 2005 and 2006 tax years during 2007. The U.S. federal statute of limitations remains open for the year 2007 and onward. Year 2007 is currently under examination by the IRS under the Compliance Assurance Program, a program in which the company is a participant. The company does not expect the settlement of current IRS examinations to significantly change the total amount of unrecognized tax benefits for the 2007 tax year. Foreign and U.S. state jurisdictions have statutes of limitations generally ranging from 3 to 5 years from the filing of an income tax return. The state impact of any federal changes remains subject to examination by various states for a period of up to one year after formal notification to the states. Years still open to examination by taxing authorities in major state and foreign jurisdictions include 2002 and onward.

5. Employee Postretirement Benefits

In September 2006, the FASB issued SFAS No.158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)* (FAS 158). The company adopted FAS 158 on Dec. 31, 2006. This standard requires the recognition in the statement of financial position the over-funded or under-funded status of a defined benefit postretirement plan, measured as the difference between the fair value of plan assets and the benefit obligation in the case of a defined benefit plan, or the accumulated postretirement benefit obligation in the case of other postretirement benefit plans. As a result of this standard, the company reported as of Dec. 31, 2006, a $125.8 million increase in benefit liabilities on the balance sheet and a $21.8 million accumulated other comprehensive loss, net of estimated tax benefits. In addition, as a result of the application of FAS 71 to the impacts of FAS 158, Tampa Electric Company recorded $91.9 million in both benefit liabilities and regulatory assets as of Dec. 31, 2006. This standard did not affect the results of operations.

Pension Benefits

TECO Energy has a non-contributory defined benefit retirement plan that covers substantially all employees. Benefits are based on employees' age, years of service and final average earnings.

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

TECO Energy reported other comprehensive income of $42.7 million in 2006 for adjustments to the minimum pension liability. The adjustments to other comprehensive income related to the minimum pension liability in 2006 are net of $35.1 million of after-tax charges that, for regulatory purposes prescribed by FAS 71, were recorded as regulatory assets for Tampa Electric and PGS. TECO Energy had recorded other comprehensive losses of $7.2 million in 2005 related to adjustments to the minimum pension liability associated with the pension plans; there were no impacts of FAS 71 in 2005 related to the additional minimum pension liability adjustments (see **Note 10**).

Other Postretirement Benefits

TECO Energy and its subsidiaries currently provide certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 meeting certain service requirements. The company contribution toward health care coverage for most employees who retired after the age of 55 between Jan. 1, 1990 and Jun. 30, 2001 is limited to a defined dollar benefit based on service. The company contribution toward pre-65 and post-65 health care coverage for most employees retiring on or after Jul. 1, 2001 is limited to a defined dollar benefit based on an age and service schedule. In 2008, the company expects to make a contribution of about $13.5 million to this program. Postretirement benefit levels are substantially unrelated to salary. The company reserves the right to terminate or modify the plans in whole or in part at any time.

On Dec. 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the MMA) was signed into law. Beginning in 2006, the new law added prescription drug coverage to Medicare, with a 28% tax-free subsidy to encourage employers to retain their prescription drug programs for retirees, along with other key provisions. TECO Energy's current retiree medical program for those eligible for Medicare (generally over age 65) includes coverage for prescription drugs. The company has determined that prescription drug benefits available to certain Medicare-eligible participants under its defined-dollar-benefit postretirement health care plan are at least "actuarially equivalent" to the standard drug benefits that are offered under Medicare Part D.

On May 19, 2004, the FASB issued FASB Staff Position No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* (FSP 106-2). The guidance in FSP 106-2 requires (a) that the effects of the federal subsidy be considered an actuarial gain and recognized in the same manner as other actuarial gains and losses and (b) certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits. TECO Energy adopted FSP 106-2 retroactive for the second quarter of 2004.

The company received its first subsidy payment under Part D in 2006 for the 2006 plan year. It has filed and is awaiting approval for its 2007 Part D subsidy application with the Centers for Medicare and Medicaid Services (CMS).

Obligations and Funded Status

(millions)	Pension Benefits 2007	Pension Benefits 2006	Other Benefits 2007	Other Benefits 2006
Change in benefit obligation				
Net benefit obligation at prior measurement date (1)	$569.9	$ 562.1	$ 202.8	$ 206.2
Service cost	16.0	15.8	5.3	5.9
Interest cost	33.0	30.7	12.2	11.3
Plan participants' contributions	—	—	3.6	3.3
Actuarial (gain) loss	(21.9)	(4.5)	(8.4)	(9.9)
Plan amendments	0.3	—	(3.8)	—
Curtailment	(6.1)	—	(2.1)	—
Special termination benefits	0.6	—	—	—
Gross benefits paid	(34.6)	(34.2)	(14.8)	(13.4)
Federal subsidy on benefits paid	n/a	n/a	0.9	(0.6)
Net benefit obligation at measurement date (1)	$557.2	$ 569.9	$ 195.7	$ 202.8
Change in plan assets				
Fair value of plan assets at prior measurement date (1)	$435.2	$ 434.7	$ —	$ —
Actual return on plan assets	56.6	27.0	—	—
Employer contributions	35.5	7.7	11.2	10.1
Plan participants' contributions	—	—	3.6	3.3
Gross benefits paid	(34.6)	(34.2)	(14.8)	(13.4)
Fair value of plan assets at measurement date (1)	$492.7	$ 435.2	$ —	$ —
Funded status				
Fair value of plan assets	$492.7	$ 435.2	$ —	$ —
Benefit obligation	557.2	569.9	195.7	202.8
Funded status at measurement date (1)	(64.5)	(134.7)	(195.7)	(202.8)
Net contributions after measurement date	26.1	30.8	2.6	2.1
Unrecognized net actuarial loss	81.9	138.8	5.9	15.6
Unrecognized prior service (benefit) cost	(3.2)	(4.5)	18.9	29.7
Unrecognized net transition (asset) obligation	—	—	11.7	16.5
Accrued liability at end of year	$ 40.3	$ 30.4	$(156.6)	$(138.9)
Amounts Recognized in Balance Sheet				
Long-term regulatory assets	$ 57.2	$ 99.1	$ 40.3	$ 49.8
Accrued benefit costs and other current liabilities	(4.5)	(1.3)	(13.6)	(12.8)
Deferred credits and other liabilities	(34.0)	(103.3)	(179.5)	(190.0)
Accumulated other comprehensive loss (income) (pretax)	21.6	35.9	(3.8)	14.1
Net amount recognized at end of year	$ 40.3	$ 30.4	$(156.6)	$(138.9)

(1) The measurement date was Sep. 30, 2007 and 2006. In accordance with FAS 158, the company will move to a year-end measurement date effective Dec. 31, 2008 under the 15-month transition approach.

Amounts recognized in accumulated other comprehensive income consist of:

	Pension Benefits 2007	Pension Benefits 2006	Other Benefits 2007	Other Benefits 2006
Net actuarial loss (gain)	$20.4	$35.4	$(15.0)	$(5.5)
Prior service cost (credit)	1.2	0.5	8.6	15.9
Transition obligation (asset)	—	—	2.6	3.7
	$21.6	$35.9	$ (3.8)	$14.1

The accumulated benefit obligation for all defined benefit pension plans was $493.0 million and $508.3 million at Sep. 30, 2007 and 2006, respectively.

Information for pension plans with an accumulated benefit obligation in excess of plan assets:

Accumulated benefit in excess of plan assets

(millions)	2007	2006
Projected benefit obligation, measurement date	$557.2	$569.9
Accumulated benefit obligation, measurement date	493.0	508.3
Fair Value of plan assets, measurement date	492.7	435.2

Components of Net Periodic Benefit Cost and Other Amounts Recognized in Other Comprehensive Income:

	Pension Benefits			Other Benefits		
(millions)	2007	2006	2005	2007	2006	2005
Net periodic benefit cost:						
Service cost	$ 16.0	$ 15.8	$ 16.2	$ 5.3	$ 6.0	$ 6.5
Interest cost	33.0	30.7	32.7	12.2	11.3	11.2
Expected return on plan assets	(36.3)	(35.7)	(37.2)	—	—	—
Amortization of:						
Actuarial loss	9.1	8.8	4.3	—	0.5	—
Prior service (benefit) cost	(0.5)	(0.5)	(0.5)	2.8	3.0	3.0
Transition (asset) obligation	—	—	(0.2)	2.5	2.7	2.7
Curtailment loss	(0.4)	—	—	6.4	—	—
Settlement loss	—	—	1.4	—	—	—
Net periodic benefit cost	$ 20.9	$ 19.1	$ 16.7	$29.2	$23.5	$23.4

In addition to the costs shown above, $0.6 million of special termination benefit costs were recognized in 2007 related to pension benefits.

Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income[(1)]:

(millions)	Balance at Dec. 31, 2005	Movement for the year ended Dec. 31, 2006	Adjustment to implement FAS 158	Balance at Dec. 31, 2006
Additional minimum pension liability	$(51.5)	$42.7	$ 8.8	$ —
Unrecognized pension losses and prior service costs	—	—	(22.0)	(22.0)
Unrecognized other benefit losses, prior service costs and transition obligations	—	—	(8.6)	(8.6)
Total accumulated other comprehensive income, net of taxes	$(51.5)	$42.7	$(21.8)	$(30.6)

(1) These balances exclude the pretax amounts recognized as Regulated Assets by Tampa Electric and Peoples Gas System as detailed as follows on a pretax basis:

Related to additional minimum pension liability	
Unrecognized pension losses and prior service costs	$ 57.0
Related to the adoption of FAS 158	
Unrecognized pension losses and prior service costs	$ 42.1
Unrecognized other benefit losses, prior service costs and transition obligations	49.8
Total related to the adoption of FAS 158, pretax	91.9
Total postretirement benefits included in regulated assets, pretax	$148.9

The estimated net loss and prior service net cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are $0.9 million and $0.1 million, respectively. The estimated prior service cost and transition obligation for the other postretirement benefit plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year is $0.5 million and $0.5 million, respectively.

In addition, the estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from regulatory assets into net periodic benefit cost over the next fiscal year totals $1.5 million. The estimated prior service cost and transition obligation for the other postretirement benefit plan that will be amortized from regulatory asset into net periodic benefit cost over the next fiscal year totals $3.2 million.

Additional Information

	Pension Benefits		Other Benefits	
(millions)	2007	2006	2007	2006
Increase in minimum liability included in other comprehensive income, net of tax	$—	$42.7	$—	$—

Weighted-average assumptions used to determine benefit obligations at Sep. 30, the measurement date for the pension and other postretirement benefit plans

	Pension Benefits		Other Benefits	
	2007	2006	2007	2006
Discount rate	6.20%	5.85%	6.20%	5.85%
Rate of compensation increase	4.25%	4.00%	4.25%	4.00%

Weighted-average assumptions used to determine net periodic benefit cost for years ended Dec. 31,

	Pension Benefits			Other Benefits		
	2007	2006	2005	2007	2006	2005
Discount rate	5.85%	5.50%	6.00%	5.85%	5.50%	6.00%
Expected long-term return on plan assets	8.25%	8.50%	8.75%	n/a	n/a	n/a
Rate of compensation increase	4.00%	3.75%	4.25%	4.00%	3.75%	4.25%

The expected return on assets assumption was based on expectations of long-term inflation, real growth in the economy, fixed income spreads, and equity premiums consistent with our portfolio, with provision for active management and expenses paid. The compensation increase assumption was based on the same underlying expectation of long-term inflation together with assumptions regarding real growth in wages and company-specific merit and promotion increases. The discount rate assumption was based on a cash flow matching technique developed by our outside actuaries and a review of current economic conditions. This technique matches the yields from high-quality (Aa-graded, non-callable) corporate bonds to the company's projected cash flows for the pension plan to develop a present value that is converted to a discount rate.

	2007	2006	2005
Healthcare cost trend rate			
Initial rate	9.25%	9.50%	9.50%
Ultimate rate	5.25%	5.00%	5.00%
Year rate reaches ultimate	2015	2014	2013

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(millions)	1% Increase	1% Decrease
Effect on total service and interest cost	$1.0	$(0.7)
Effect on postretirement benefit obligation	$6.8	$(5.6)

Asset Allocation

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

Pension Plan Assets	Target Allocation	Actual Allocation, End of Year	
		2007	*2006*
Asset Category			
Equity securities	55-65%	64%	66%
Fixed income securities	35-45%	36%	34%
Total		100%	100%

Other Postretirement Benefit Plan Assets

There are no assets associated with TECO Energy's postretirement benefit plan.

Contributions

On Aug. 17, 2006, the President signed the Pension Protection Act of 2006, which generally introduces new minimum funding requirements beginning Jan. 1, 2008. The company's policy is to fund the plan at or above amounts determined by the company's actuaries to meet ERISA guidelines for minimum annual contributions and minimize PBGC premiums paid by the plan. The company contributed $30.0 million to the plan in 2007, which included a $25.8 million contribution in addition to the $4.2 million minimum contribution required. TECO Energy expects to make a $9.0 million contribution in 2008 and average annual contributions of $11 million in 2009 – 2012.

The supplemental executive retirement plan is funded annually to meet the benefit obligations. In 2007, the company made a contribution of $1.3 million to this plan. In 2008, the company expects to make a contribution of about $4.5 million to this plan.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

	Pension Benefits	Other Postretirement Benefits	
		Gross	Expected Federal Subsidy
Expected benefit payments (millions):			
2008	$ 65.4	$14.6	$ (1.1)
2009	44.3	15.8	(1.2)
2010	45.7	16.8	(1.4)
2011	47.0	17.7	(1.5)
2012	48.0	18.2	(1.7)
2013-2017	258.5	93.1	(11.1)

Defined Contribution Plan

The company has a defined contribution savings plan covering substantially all employees of TECO Energy and its subsidiaries (the Employers) that enables participants to save a portion of their compensation up to the limits allowed by IRS guidelines. The company and its subsidiaries match up to 6% of the participant's payroll savings deductions. Effective July 2004, employer matching contributions were 30% of eligible participant contributions with additional incentive match of up to 70% of eligible participant contributions based on the achievement of certain operating company financial goals. In April 2007, the employer matching contributions were changed to 50% of eligible participant contributions, with an additional incentive match of up to 50%. For the years ended Dec. 31, 2007, 2006 and 2005, the company and its subsidiaries recognized expense totaling \$8.6 million, \$9.0 million and \$10.2 million, respectively, related to the matching contributions made to this plan.

6. Short-Term Debt

At Dec. 31, 2007 and 2006, the following credit facilities and related borrowings existed:

Credit Facilities

	Dec. 31, 2007			*Dec. 31, 2006*		
(millions)	*Credit Facilities*	*Borrowings Outstanding*[1]	*Letters of Credit Outstanding*	*Credit Facilities*	*Borrowings Outstanding*[1]	*Letters of Credit Outstanding*
Tampa Electric Company:						
5-year facility	\$325.0	\$ —	\$—	\$325.0	\$13.0	\$—
1-year accounts receivable facility	150.0	25.0	—	150.0	35.0	—
TECO Energy/TECO Finance:						
5-year facility	200.0	—	9.5	200.0	—	9.5
Total	\$675.0	\$25.0	\$ 9.5	\$675.0	\$48.0	\$ 9.5

(1) Borrowings outstanding are reported as notes payable.

These credit facilities require commitment fees ranging from 9.0 to 17.5 basis points. The weighted average interest rate on outstanding notes payable at Dec. 31, 2007 and 2006 was 4.76% and 5.45%, respectively.

TECO Energy/TECO Finance Credit Facility

On May 9, 2007, TECO Energy amended its \$200 million bank credit facility, entering into a Second Amended and Restated Credit Agreement. The amendment (i) extended the maturity date of the credit facility from Oct. 11, 2010 to May 9, 2012 (subject to further extension with the consent of each lender); (ii) removed the stock of TECO Transport Corporation as security for the facility; (iii) made TECO Energy the Guarantor and its wholly-owned subsidiary, TECO Finance, Inc. (TECO Finance), the Borrower; (iv) allowed TECO Finance to borrow funds at an interest rate equal to the federal funds rate, as defined in the agreement, plus a margin, as well as a rate equal to either the London interbank deposit rate plus a margin or JPMorgan Chase Bank's prime rate (or the federal funds rate plus 50 basis points, if higher) plus a margin; (v) allowed TECO Finance to request the lenders to increase their commitments under the credit facility by up to \$50 million in the aggregate; (vi) included a \$200 million letter of credit facility (compared to \$100 million under the previous agreement); (vii) reduced the commitment fees and borrowing margins; and (viii) made other technical changes.

The facility requires that at the end of each quarter the ratio of debt to earnings before interest, taxes, depreciation and amortization (EBITDA), as defined in the agreement, not exceed 5.00 times from Apr. 1, 2007 through Dec. 31, 2009 and 4.50 times from and after Jan. 1, 2010, and TECO Energy's EBITDA to interest coverage ratio, as defined in the agreement, to be not less than 2.60 times. As of Dec. 31, 2007, the company was in compliance with both requirements. The facility places certain limitations on the ability to sell core assets and limits the ability of TECO Energy and certain of its subsidiaries, excluding Tampa Electric Company, to issue additional indebtedness in excess of a calculated level (initially $300 million), unless the indebtedness refinances currently outstanding indebtedness or meets certain other conditions. The facility also provides that, in the event the aggregate quarterly dividend payments on TECO Energy common stock were to equal or exceed a calculated amount (initially $50 million), subject to increase in the event TECO Energy issues additional shares of common stock, TECO Energy would not be able to declare or pay cash dividends on the common stock or make certain other distributions unless it had previously delivered liquidity projections satisfactory to the administrative agent under the credit facility demonstrating that TECO Energy will have sufficient cash to pay such dividends and distributions and the three succeeding quarterly dividends. The limitations described above on the ability to sell core assets, issue additional indebtedness and pay cash dividends will be released if TECO Energy achieves investment grade ratings and stable outlooks from both Moody's and Standard & Poor's.

Tampa Electric Company Credit Facility

On May 9, 2007, Tampa Electric Company amended its $325 million bank credit facility, entering into a Second Amended and Restated Credit Agreement. The amendment (i) extended the maturity date of the credit facility from Oct. 11, 2010 to May 9, 2012 (subject to further extension with the consent of each lender); (ii) continued to allow Tampa Electric Company to borrow funds at an interest rate equal to the federal funds rate, as defined in the agreement, plus a margin, as well as a rate equal to either the London interbank deposit rate plus a margin or Citibank's prime rate (or the federal funds rate plus 50 basis points, if higher) plus a margin; (iii) allowed Tampa Electric Company to request the lenders to increase their commitments under the credit facility by up to $175 million in the aggregate (compared to $50 million under the previous agreement); (iv) continued to include a $50 million letter of credit facility; (v) reduced the commitment fees and borrowing margins; and (vi) made other technical changes. The facility requires that at the end of each quarter the ratio of debt to capital, as defined in the agreement, not exceed 65%. As of Dec. 31, 2007, Tampa Electric Company was in compliance with this requirement.

Tampa Electric Company Accounts Receivable Facility

On Jan. 6, 2005, Tampa Electric Company and TEC Receivables Corp (TRC), a wholly-owned subsidiary of Tampa Electric Company, entered into a $150 million accounts receivable collateralized borrowing facility. The assets of TRC are not intended to be generally available to the creditors of Tampa Electric Company. Under the Purchase and Contribution Agreement entered into in connection with that facility, Tampa Electric Company sells and/or contributes to TRC all of its receivables for the sale of electricity or gas to its retail customers and related rights (the Receivables), with the exception of certain excluded receivables and related rights defined in the agreement, and assigns to TRC the deposit accounts into which the proceeds of such Receivables are paid. The Receivables are sold by Tampa Electric Company to TRC at a discount. Under the Loan and Servicing Agreement among Tampa Electric Company as Servicer, TRC as Borrower, certain lenders named therein and Citicorp North America, Inc. as Program Agent, TRC may borrow up to $150 million to fund its acquisition of the Receivables under the Purchase Agreement. TRC has secured such borrowings with a pledge of all of its assets including the Receivables and deposit accounts assigned to it. Tampa Electric Company acts as Servicer to service the collection of the Receivables. TRC pays program and liquidity fees based on Tampa Electric Company's credit ratings. The receivables and the debt of TRC are included in the consolidated financial statements of TECO Energy and Tampa Electric Company.

On Dec. 20, 2007, Tampa Electric Company and TRC extended the maturity of Tampa Electric Company's $150 million accounts receivable collateralized borrowing facility from Dec. 21, 2007 to Dec. 19, 2008.

7. Long-Term Debt

At Dec. 31, 2007, total long-term debt had a carrying amount of $3,168.7 million and an estimated fair market value of $3,270.1 million. At Dec. 31, 2006, total long-term debt had a carrying amount of $3,855.4 million and an estimated fair market value of $3,979.7 million. The estimated fair market value of long-term debt was based on quoted market prices for the same or similar issues, on the current rates offered for debt of the same remaining maturities, or for long-term debt issues with variable rates that approximate market rates, at carrying amounts.

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

TECO Energy's maturities and annual sinking fund requirements of long-term debt for 2008 through 2012 and thereafter are as follows:

Long-Term Debt Maturities

Dec. 31, 2007 (millions)	*2008*	*2009*	*2010*	*2011*	*2012*	*Thereafter*	*Total Long-term debt*
TECO Energy	$—	$—	$102.8	$191.7	$100.2	$ 8.8	$ 403.5
TECO Finance	—	—	—	171.8	236.2	491.2	899.2
Tampa Electric	—	—	—	—	540.0	1,123.9	1,663.9
Peoples Gas	5.7	5.5	3.7	3.4	113.4	60.0	191.7
TECO Guatemala	1.4	1.4	1.4	1.5	1.5	3.2	10.4
Total long-term debt maturities	$ 7.1	$ 6.9	$107.9	$368.4	$991.3	$1,687.1	$3,168.7

Debt Securities

TECO Energy—Debt Tender and Exchange Offers

In December 2007, TECO Energy completed debt tender and exchange offers (Offers) which resulted in the redemption of $297.2 million principal amount of TECO Energy notes for cash and the exchange of $899.3 million principal amount of TECO Energy notes for TECO Finance notes. TECO Finance is a wholly owned subsidiary of TECO Energy whose business activities consist solely of providing funds to TECO Energy for its diversified activities. The TECO Finance notes are fully and unconditionally guaranteed by TECO Energy.

The Offers resulted in:

- The purchase for cash and retirement of $297.2 million principal amount of TECO Energy 7.5% notes due 2010.
- The exchange of $236.4 million principal amount of TECO Energy 7.20% notes due 2011 and $63.6 million principal amount of TECO Energy 7.00% notes due 2012 together for $300 million principal amount of TECO Finance 6.572% notes due 2017 with substantially similar terms as the exchanged TECO Energy notes.
- The exchange of $171.8 million principal amount of TECO Energy 7.20% notes due 2011 for a like principal amount of TECO Finance 7.20% notes due 2011.
- The exchange of $236.2 million principal amount of TECO Energy 7.00% notes due 2012 for a like principal amount of TECO Finance 7.00% notes due 2012.
- The exchange of $191.2 million principal amount of TECO Energy 6.75% notes due 2015 for a like principal amount of TECO Finance 6.75% notes due 2015.

In connection with these debt tender and exchange transactions, $32.9 million of premiums and fees were expensed, and are included in "Loss on debt exchange/extinguishment" on the Consolidated Statement of Income and as part of the "Cash Flows from Operating Activities" in the Consolidated Statement of Cash Flows for the year ended Dec. 31, 2007. As discussed in **Note 1,** $21.2 million of fees paid to the holders of the exchanged notes were capitalized, and included in "Deferred charges and other assets" on the Consolidated Balance Sheet as of Dec. 31, 2007 and as part of the "Cash Flows from Financing Activities" in the Consolidated Statement of Cash Flows for the year then ended. These capitalized costs will be amortized and included in "Interest expense" on the Consolidated Statement of Income over the remaining lives of the related debt.

The TECO Finance notes due 2011, 2012 and 2015 have the same interest rate, interest payment dates, maturity and covenants as the corresponding series of TECO Energy notes.

TECO Energy may redeem some or all of each series of the TECO Finance notes at a price equal to the greater of (i) 100% of the principal amount of the applicable TECO Finance notes to be redeemed, plus accrued and unpaid interest, or (ii) the net present value of the remaining payments of principal and interest on the applicable TECO Finance notes, discounted at the applicable Treasury Rate (as defined in the applicable supplemental indenture), plus 50 basis points for the TECO Finance 6.572% notes due 2017 and the TECO Finance 6.75% notes due 2015 and 25 basis points for the TECO Finance 7.20% notes due 2011 and the TECO Finance 7.00% notes due 2012. In each case, the redemption price would include accrued and unpaid interest to the redemption date.

Pursuant to a negative pledge contained in the second supplemental indenture governing the TECO Finance 6.75% notes due 2015, if TECO Energy incurs, issues, assumes or guarantees any debt that is secured by a mortgage, pledge or other lien on (i) certain property having a net book value in excess of 2% of consolidated net assets (as defined in the supplemental indenture), or (ii) capital stock or debt of any direct subsidiary of TECO Energy, TECO Energy will, subject to certain exceptions set forth therein, secure the TECO Finance 6.75% notes due 2015 equally and ratably with such debt.

Retirement of $110.6 million Plaquemines Port, Harbor, and Terminal District (Louisiana) Marine Terminal Facilities Revenue Refunding Bonds due Sep. 1, 2007

On Sep. 1, 2007, pursuant to the terms of the indenture governing $110.6 million of Plaquemines Port, Harbor, and Terminal District (Louisiana) Marine Terminal Facilities Revenue Refunding Bonds, Series 1985 A, B, C and D, $110.6 million principal amount of bonds were retired at maturity.

Retirement of $150 million Tampa Electric Company 5.375% notes due Aug. 15, 2007

On Aug. 15, 2007, pursuant to the terms of the indenture, $150 million principal amount of 5.375% Notes due Aug. 15, 2007 were retired at maturity.

Issuance of Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 and Redemption of Series 1990 Bonds, Series 1992 Bonds and Series 1993 Bonds

On Jul. 25, 2007, the Hillsborough County Industrial Development Authority (HCIDA) issued $125.8 million of HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 (the Series 2007 Bonds) for the benefit of Tampa Electric Company, consisting of (a) $54.2 million Series 2007A Bonds due May 15, 2018, (b) $51.6 million of Series 2007B Bonds due Sep. 1, 2025, and (c) $20 million of Series 2007C Bonds due Nov. 1, 2020. Tampa Electric Company is responsible for payment of the interest and principal associated with the Series 2007 Bonds. The proceeds of this issuance, together with available cash, were used to call and retire on Aug. 1, 2007, at a redemption price equal to 100% of par plus accumulated but unpaid distributions to that date, (a) $54.2 million of the existing HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Gannon Coal Conversion Project), Series 1992 (the Series 1992 Bonds), which had a maturity date of May 15, 2018, (b) $51.605 million of the existing HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 1990 (the Series 1990 Bonds), which had a maturity date of Sep. 1, 2025, and (c) $20 million of the existing HCIDA Pollution Control Revenue Bonds (Tampa

Electric Company Project), Series 1993 (the Series 1993 Bonds), which had a maturity date of Nov. 1, 2020. Costs of the issuance were paid from available funds of Tampa Electric Company. Tampa Electric Company entered into a Loan and Trust Agreement with the HCIDA, as issuer, and The Bank of New York Trust Company, N.A., as trustee, in connection with the issuance of the Series 2007 Bonds.

The Series 2007 Bonds bear interest at an auction rate that will be reset pursuant to an auction procedure at the end of every auction period (initially set at 7 days for the Series 2007A Bonds and the Series 2007B Bonds and 35 days for the Series 2007C Bonds). In connection with the issuance of the Series 2007 Bonds, Tampa Electric Company also entered into an insurance agreement with Financial Guaranty Insurance Company (FGIC) (Insurance Agreement) pursuant to which FGIC issued a financial guaranty insurance policy (Policy). The Policy provides insurance for Tampa Electric Company's obligation for payment on the Series 2007 Bonds and allowed the Series 2007 Bonds to be issued at a lower interest rate than without such insurance in place. The terms of the Insurance Agreement will, among other things, limit Tampa Electric Company's ability to incur certain liens without ratably securing the Series 2007 Bonds, subject to a number of exceptions.

At the end of any auction period, Tampa Electric Company may redeem all or any part of the Series 2007 Bonds at its option at a redemption price equal to the sum of the accrued and unpaid interest to the redemption date on the principal amount of the Series 2007 Bonds to be redeemed, plus 100% of the principal amount of the Series 2007 Bonds to be redeemed. The Series 2007 Bonds are also subject to special mandatory redemption in the event that interest payable on any Series 2007 Bonds has become subject to federal income tax in accordance with the Loan and Trust Agreement. (See **Note 25** for an update on the Series 2007 Bonds as of the date of this filing.)

Issuance of Tampa Electric Company 6.15% Notes due 2037

On May 15, 2007, Tampa Electric Company issued $250 million aggregate principal amount of 6.15% Notes due May 15, 2037. The offering resulted in net proceeds to Tampa Electric Company (after deducting underwriting discounts and commissions and estimated offering expenses) of approximately $246.1 million. Net proceeds were used to repay short-term debt, repay maturing long-term debt and for general corporate purposes. Tampa Electric Company may redeem all or any part of the 6.15% Notes at its option at any time and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of 6.15% Notes to be redeemed or (ii) the present value of the remaining payments of principal and interest on the 6.15% Notes to be redeemed, discounted at an applicable treasury rate (as defined in the applicable indenture), plus 25 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date.

Issuance of Polk County Industrial Development Authority Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 and Redemption of Polk County Industrial Development Authority Solid Waste Disposal Facility Revenue Bonds (Tampa Electric Company Project, Series 1993)

On May 14; 2007, the Polk County Industrial Development Authority (PCIDA) issued $75 million of PCIDA Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 (the Polk Series 2007 Bonds) for the benefit of Tampa Electric Company. Tampa Electric Company is responsible for payment of the interest and principal associated with the Polk Series 2007 Bonds. The proceeds of this issuance, together with available cash, were used to call and retire on Jun. 29, 2007, at a redemption price equal to 102% of par plus accumulated but unpaid interest to that date, $75 million of the existing PCIDA Solid Waste Disposal Facility Revenue Bonds (Tampa Electric Company Project), Series 1993 (the Polk Series 1993 Bonds), which had a maturity date of Dec. 1, 2030. Costs of the issuance were paid from available funds of Tampa Electric Company. Tampa Electric Company entered into a Loan and Trust Agreement with the PCIDA, as issuer, and The Bank of New York Trust Company, N.A., as trustee, in connection with the issuance of the Polk Series 2007 Bonds.

The Polk Series 2007 Bonds mature on Dec. 1, 2030 and bear interest at an auction rate that will be reset pursuant to an auction procedure at the end of every auction period (initially set at 35 days). In connection with the issuance of the Polk Series 2007 Bonds, Tampa Electric Company also entered into an insurance agreement with FGIC (Insurance Agreement) pursuant to which FGIC issued a financial guaranty insurance policy (Policy). The Policy provides insurance for Tampa Electric Company's obligation for payment on the Bonds and allowed the Bonds to be issued at a lower interest rate than without such insurance in place. The terms of the Insurance Agreement will, among other things, limit Tampa Electric Company's ability to incur certain liens without ratably securing the Bonds, subject to a number of exceptions.

At the end of any auction period, Tampa Electric Company may redeem all or any part of the Polk Series 2007 Bonds at its option at a redemption price equal to the sum of the accrued and unpaid interest to the redemption date on the principal amount of the Polk Series 2007 Bonds to be redeemed, plus 100% of the principal amount of the Polk Series 2007 Bonds to be redeemed. The Polk Series 2007 Bonds are also subject to special mandatory redemption in the event that interest payable on any Polk Series 2007 Bonds has become subject to federal income tax in accordance with the Loan and Trust Agreement. (See **Note 25** for an update on the Polk Series 2007 Bonds as of the date of this filing.)

Retirement of $300 million TECO Energy 6.125% notes due May 1, 2007

On May 1, 2007, pursuant to the terms of the indenture, $300 million principal amount of 6.125% Notes due May 1, 2007 were retired at maturity.

TECO Capital Trust II

On Jan. 16, 2007, all $71.4 million outstanding subordinated notes were retired at maturity pursuant to their original terms. This caused the retirement of $57.5 million trust preferred securities of TECO Capital Trust II, pursuant to their original terms.

At Dec. 31, 2007 and 2006, TECO Energy had the following long-term debt outstanding:

Long-Term Debt (millions) Dec. 31,		*Due*	*2007*	*2006*
TECO Energy	Notes: 6.125%	2007	$ —	$ 300.0
	Floating rate 7.23% for 2007 and 7.37% for 2006 (effective rate 7.4% for 2007) (1)(2)(6)	2010	100.0	100.0
	7.5% (effective rate of 7.8%) (1)(2)	2010	2.8	300.0
	7.2% (effective rate of 7.4%) (1)	2011	191.7	600.0
	7.0% (effective rate of 7.1%) (1)	2012	100.2	400.0
	6.75% (effective rate of 6.9%) (1)(2)	2015	8.8	200.0
	Junior subordinated notes:			
	5.93% (Capital Trust II)	2007	—	71.4
			403.5	1,971.4
TECO Finance	Notes: 7.2% (effective rate of 7.4%) (1)(3)	2011	171.8	$ —
	7.0% (effective rate of 7.1%) (1)(3)	2012	236.2	—
	6.75% (effective rate of 6.9%) (1)(2)(3)	2015	191.2	—
	6.572% (effective rate of 7.3%) (1)(3)	2017	300.0	—
			899.2	—
Tampa Electric	Installment contracts payable: (4)			
	5.1% Refunding bonds (effective rate of 5.7%)	2013	60.7	60.7
	4.4% Variable rate for 2007(6)(7) (effective rate of 4.60%) and fixed rate 4.0% for 2006(5)	2018	54.2	54.2
	4.6% Variable rate for 2007(6)(7) (effective rate of 4.81%) and fixed rate 4.25% for 2006(5)	2020	20.0	20.0
	5.5% Refunding bonds (effective rate of 6.27%)	2023	86.4	86.4
	4.7% Variable rate for 2007(6)(7) (effective rate of 4.72%) and fixed rate 4.0% for 2006(5)	2025	51.6	51.6
	5.3% Variable rate for 2007(6)(7) (effective rate of 5.52%) and fixed rate 5.85% for 2006	2030	75.0	75.0
	4.6% Variable rate for 2007(6)(8) (effective rate of 5.30%) and 3.89% for 2006	2034	86.0	86.0
	Notes: 5.375%	2007	—	125.0
	6.875% (effective rate of 6.98%)(1)	2012	210.0	210.0
	6.375% (effective rate of 7.35%)(1)	2012	330.0	330.0
	6.25% (effective rate of 6.3%)(1)(2)	2014-2016	250.0	250.0
	6.55% (effective rate of 6.6%) (1)	2036	250.0	250.0
	6.15% (effective rate of 6.6%) (1)	2037	190.0	—
			1,663.9	1,598.9
Peoples Gas System	Senior Notes: (1)(2) 10.35%	2007	—	1.0
	10.33%	2008	1.0	2.0
	10.30%	2008-2009	2.8	3.8
	9.93%	2008-2010	3.0	4.0
	8.00%	2008-2012	14.9	17.0
	Notes: 5.375%	2007	—	25.0
	6.875% (effective rate of 6.98%) (1)	2012	40.0	40.0
	6.375% (effective rate of 7.35%) (1)	2012	70.0	70.0
	6.15% (effective rate of 6.28%) (1)	2037	60.0	—
			191.7	162.8
TECO Guatemala	Note: 3.0%	2008-2014	10.4	11.7
Other Unregulated	Dock and Wharf bonds, 5.0% (4)	2007	—	110.6
Unamortized debt discount, net			(3.2)	(3.4)
			3,165.5	3,852.0
Less amount due within one year			7.1	639.4
Total long-term debt			$3,158.4	$3,212.6

(1) These securities are subject to redemption in whole or in part, at any time, at the option of the company.
(2) These long-term debt agreements contain various restrictive financial covenants.
(3) Guaranteed by TECO Energy.
(4) Tax-exempt securities.
(5) The interest rate on these bonds was fixed for a five-year term on Aug. 5, 2002; upon expiration of that term the bonds were issued in an auction-rate mode.
(6) Composite year-end interest rate.
(7) The notes pay interest at an auction rate since refinancing in 2007.
(8) The notes pay interest at an auction rate since refinancing in 2006.

8. Preferred Stock

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

9. Common Stock

Stock-Based Compensation

On Jan. 1, 2006, TECO Energy adopted FAS 123R, requiring the company to recognize expense related to the fair value of its stock-based compensation awards. Prior to this, the company accounted for its share-based payments under APB 25 and related interpretations. The company adopted FAS 123R using the modified-prospective transition method. Under this transition method, compensation cost recognized beginning Jan. 1, 2006 includes compensation cost for all share-based payments granted prior to, but not yet vested as of Dec. 31, 2005 (based on the grant-date fair market value estimated in accordance with the original provisions of FAS 123), and compensation cost for all share-based payments granted on or after Jan. 1, 2006 (based on the grant date fair market value estimated in accordance with the provisions of FAS 123R). Results for prior periods have not been restated.

TECO Energy has two share-based compensation plans, the Equity Plan and the Director Equity Plan (Plans), which are described below. The types of awards granted under these Plans include stock options, stock grants, time-vested restricted stock and performance-based restricted stock. Stock options have been granted with an exercise price greater than or equal to the fair market value of the common stock on the date of grant and have a 10-year contractual term. Stock options for the Director Equity Plan vest immediately and stock options for the Equity Plan have graded vesting over a three-year period, with the first 33% becoming exercisable one year after the date of grant. Stock options were last awarded in 2006. Stock grants and time-vested restricted stock are valued at the fair market value on the date of grant, with expense recognized over the vesting period, which is normally three years. Beginning in 2006, the company granted time-vested restricted stock to directors that vests one-third each year. Performance-based restricted stock has been granted to officers and employees, with shares potentially vesting after three years. The total awards for performance-based restricted stock vest based on the total return of TECO Energy common stock compared to a peer group of utility stocks. The 2005 and 2006 grants can vest between 0% to 200% of the original grant and the 2007 grant can vest between 0% to 150% of the original grant. Dividends are paid on all time-vested and performance-based restricted stock awards.

TECO Energy recognized total stock compensation expense for 2007 and 2006 of $11.6 million pretax, or $7.1 million after-tax and $11.5 million pretax, or $7.1 million after-tax, respectively. Total stock compensation expense is reflected in "Operation other expense-Other" on the Consolidated Statements of Income. Cash received from option exercises under all share-based payment arrangements was $9.2 million, $7.3 million and $11.5 million for the periods ended Dec. 31, 2007, 2006 and 2005 respectively. The aggregate intrinsic value of stock options exercised was $3.6 million, $2.7 million and $5.5 million for the periods ended Dec. 31, 2007, 2006 and 2005, respectively. The total fair market value of awards vesting during 2007 was $3.6 million, which includes stock grants, time-vested restricted stock and performance-based restricted stock. As of Dec. 31, 2007, there was $8.7 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. Prior to the adoption of FAS 123R, TECO Energy presented all tax benefits of deductions resulting from the exercise of stock options as operating cash flows in the Consolidated Condensed Statement of Cash Flows. Beginning on Jan. 1, 2006, the company changed its cash flow presentation in accordance with FAS 123R, which requires the cash flows resulting from excess tax deductions on share-based payments to be classified as financing cash flows.

Previously under APB 25, the company recognized or disclosed expenses for retirement-eligible employees over the nominal vesting period. Beginning Jan. 1, 2006 under FAS 123R, any new awards made to retirement-eligible employees are recognized immediately or over the period from the grant date to the date of retirement eligibility (non-substantive approach). The impact on net income for 2006 and 2005 of applying the nominal vesting period approach versus the non-substantive vesting period approach to awards granted prior to Jan. 1, 2006, for retirement-eligible employees would not have been material.

The fair market value of stock options is determined using the Black-Scholes valuation model, and the company uses the following methods to determine its underlying assumptions: expected volatilities are based on the historical volatilities; the expected term of options granted is based on the Staff Accounting Bulletin No. 107 (SAB 107) simplified method of averaging the vesting term and the original contractual term; the risk-free interest rate is based on the U.S. Treasury implied yield on zero-coupon issues (with a remaining term equal to the expected term of the option); and the expected dividend yield is based on the current annual dividend amount divided by the stock price on the date of grant.

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

The value of time-vested restricted stock and stock grants are based on the fair market value of TECO Energy common stock at the time of grant.

Stock-based compensation expense reduced the Company's results of operations as follows:

(millions, except per share amounts)	**Dec. 31, 2007**	**Dec. 31, 2006**
Income before income taxes	$11.6	$11.5
Net income	$ 7.1	$ 7.1
EPS—Basic:	$0.03	$0.03
EPS—Diluted:	$0.03	$0.03

The following table illustrates the effect on net income and earnings per share as if the company had applied the fair-value recognition provisions of FAS 123 to all share-based payments, prior to the adoption of FAS 123R. As all share-based payments have been expensed in 2007 and 2006 in accordance with FAS 123R, no pro forma is required.

Pro Forma Stock-Based Compensation Expense

(millions, except per share amounts) *For the year ended Dec. 31,*	*2005*
Net income from continuing operations	
As reported	$211.0
Add: Unearned compensation expense (1)	3.4
Less: Pro forma expense (2)	6.8
Pro forma	$207.6
Net income	
As reported	$274.5
Add: Unearned compensation expense (1)	3.4
Less: Pro forma expense (2)	6.8
Pro forma	$271.1
Net income from continuing operations—EPS, basic	
As reported	$ 1.02
Pro forma	$ 1.01
Net income from continuing operations—EPS, diluted	
As reported	$ 1.00
Pro. forma	$ 0.99
Net income—EPS, basic	
As reported	$ 1.33
Pro forma	$ 1.31
Net income—EPS, diluted	
As reported	$ 1.31
Pro forma	$ 1.29

(1) Unearned compensation expense reflects the compensation expense of time-vested and performance-based restricted stock awards, after-tax.

(2) Includes compensation expense for stock options and performance-based restricted stock, determined using a fair-value based method, after-tax, plus compensation expense associated with time-vested restricted stock awards, determined based on fair market value at the time of grant, after-tax.

Assumptions	*2007*	*2006*	*2005*
Assumptions applicable to stock options			
Risk-free interest rate	—	4.92%	4.02%
Expected lives (in years)	—	6	7
Expected stock volatility	—	27.00%	34.12%
Dividend yield	—	4.66%	4.66%
Assumptions applicable to performance-based restricted stock			
Risk-free interest rate	4.53%	4.92%	3.74%
Expected lives (in years)	3	3	3
Expected stock volatility	16.71%	18.22%	45.31%
Dividend yield	4.25%	4.64%	4.49%

Equity Plans

In April 2004, the company's shareholders approved the 2004 Equity Incentive Plan (2004 Plan). The 2004 Plan superseded the 1996 Equity Incentive Plan (1996 Plan), and no additional grants will be made under the 1996 Plan. Under the 2004 Plan, the Compensation Committee of the Board of Directors authorized 10 million shares of TECO Energy common stock that may be awarded as stock grants, stock options and/or stock equivalents to officers, key employees and consultants of TECO Energy and its subsidiaries. The Compensation Committee has discretion to determine the terms and conditions of each award, which may be subject to conditions relating to continued employment, restrictions on transfer or performance criteria.

Under the 2004 Plan and the 1996 Plan (collectively referred to as the "Equity Plans"), 1.1 million and 0.9 million stock options were granted to employees in 2006 and 2005, respectively, with weighted average fair values of $3.26 and $3.93. (No stock options were granted in 2007.) In addition, 0.6 million, 0.5 million and 0.4 million shares of restricted stock were granted in 2007, 2006 and 2005, respectively, with weighted average fair values of $18.14, $16.85 and $21.57, respectively. In 2006, 17,962 shares of unrestricted common stock were granted with a weighted average fair value of $17.54. A summary of non-vested shares of restricted stock and stock options for 2007 under the Equity Plans are shown as follows:

Nonvested Restricted Stock and Stock Options-Equity Plans

	Nonvested Restricted Stock (1)		Nonvested Stock Options (2)	
	Number of Shares (thousands)	*Weighted Avg. Grant Date Fair Value (per share)*	*Number of Shares (thousands)*	*Weighted Avg. Grant Date Fair Value (per share)*
Nonvested balance at Dec. 31, 2006	970	$18.62	2,241	$3.30
Granted	571	18.14	—	—
Vested	(196)	15.82	(1,323)	3.20
Forfeited	(163)	18.27	(51)	3.31
Nonvested balance at Dec. 31, 2007	1,182	$18.90	867	$3.45

(1) The weighted average remaining contractual term of restricted stock is 2 years.
(2) All nonvested stock options are expected to vest.

Stock option transactions during 2007 under the Equity Plans are summarized as follows:

Stock Options—Equity Plans

	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, 2006	9,806	$20.30		
Granted	—	—		
Exercised	(712)	12.56		
Cancelled	(366)	23.94		
Outstanding balance at Dec. 31, 2007 (1)	8,728	$20.77	5	$11.8
Exercisable at Dec. 31, 2007 (2)	3,204	$13.77	7	$11.0
Available for future grant at Dec. 31, 2007	7,501			

(1) Option prices range from $11.09 to $31.58.
(2) Option prices range from $11.09 to $16.30.

As of Dec. 31, 2007, the options outstanding under the Equity Plans are summarized below:

	Stock Options Outstanding			Stock Options Exercisable		
Range of Option Prices	Option Shares (thousands)	Weighted Avg. Option Price	Weighted Avg. Remaining Contractual Life	Option Shares (thousands)	Weighted Avg. Option Price	Weighted Avg. Remaining Contractual Life
$11.09 – $13.50 ...	2,248	$12.71	6 Years	2,248	$12.71	6 Years
$16.21 – $18.87 ...	1,838	$16.29	8 Years	956	$16.24	8 Years
$21.25 – $22.48 ...	1,544	$21.36	2 Years	—	—	—
$23.55 – $25.97 ...	67	$24.27	2 Years	—	—	—
$27.56 – $31.58 ...	3,031	$29.10	3 Years	—	—	—
Total	8,728	$20.77	5 Years	3,204	$13.77	7 Years

Director Equity Plan

In April 1997, the company's shareholders approved the 1997 Director Equity Plan (1997 Plan), as an amendment and restatement of the 1991 Director Stock Option Plan (1991 Plan). The 1997 Plan superseded the 1991 Plan, and no additional grants will be made under the 1991 Plan. The purpose of the 1997 Plan is to attract and retain highly qualified non-employee directors of the company and to encourage them to own shares of TECO Energy common stock. The 1997 Plan, administered by the Board of Directors, authorized 250,000 shares of TECO Energy common stock to be awarded as stock grants, stock options and/or stock equivalents.

Under the 1997 Plan, 25,000 shares of restricted stock were awarded in 2007, with a weighted average fair value of $18.35. Restricted stock transactions for the year ended Dec. 31, 2007 under the 1997 Plan are summarized as follows:

Nonvested Restricted Stock—Director Equity Plans

	Number of Shares (thousands)	*Weighted Avg. Grant Date Fair Value (per share)*
Nonvested balance at Dec. 31, 2006	27	$16.30
Granted	25	18.35
Vested	(10)	16.30
Forfeited	—	—
Nonvested balance at Dec. 31, 2007 (1)	42	$17.52

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

Under the 1997 Plan, 35,000 stock options were granted in 2005 with a weighted average fair value of \$3.95. In addition, 5,000 shares of unrestricted common stock were granted in 2005, with a weighted average fair value of \$16.21. No stock options were granted in 2007 or 2006. Stock option transactions during the year ended Dec. 31, 2007 under the 1997 Plan are summarized as follows:

Stock Options—Director Equity Plans [1]

	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, 2006	221	\$20.99		
Granted	—	—		
Exercised	(15)	13.62		
Expired	(33)	25.24		
Outstanding balance at Dec. 31, 2007 [2]	173	\$20.82	4	\$0.2
Exerciseable at Dec. 31, 2007 [3]	68	\$13.52	6	
Available for future grant at Dec. 31, 2007	189			

(1) Stock options granted under the Director Equity Plans vest immediately.
(2) Option prices range from \$11.09 to \$31.58 per share.
(3) Option prices range from \$11.09 to \$16.21 per share.

Dividend Reinvestment Plan

In 1992, TECO Energy implemented a Dividend Reinvestment and Common Stock Purchase Plan. TECO Energy raised \$3.9 million and \$4.4 million of common equity from this plan in 2007 and 2006, respectively.

Common Stock

On Jan. 18, 2005, TECO Energy issued 6.85 million shares of common stock as part of the final settlement for the remaining outstanding equity security units of TECO Capital Trust II, receiving approximately \$180 million of proceeds from the settlement.

Shareholder Rights Plan

In accordance with the company's Shareholder Rights Plan, a Right to purchase one additional share of the company's common stock at a price of \$90 per share is attached to each outstanding share of the company's common stock. The Rights expire in May 2009, subject to extension. The Rights will become exercisable 10 business days after a person acquires 10% or more of the company's outstanding common stock or commences a tender offer that would result in such person owning 10% or more of such stock. If any person acquires 10% or more of the outstanding common stock, the rights of holders, other than the acquiring person, become rights to buy shares of common stock of the company (or of the acquiring company if the company is involved in a merger or other business combination and is not the surviving corporation) having a market value of twice the exercise price of each Right.

The company may redeem the Rights at a nominal price per Right until 10 business days after a person acquires 10% or more of the outstanding common stock.

10. Other Comprehensive Income

TECO Energy reported the following other comprehensive income (loss) (OCI) for the years ended Dec. 31, 2007, 2006 and 2005, related to changes in the fair value of cash flow hedges and amortization of unrecognized benefit costs associated with the company's pension plans:

Other comprehensive income (loss)

(millions)	*Gross*	*Tax*	*Net*
2007			
Unrealized loss on cash flow hedges	$ (3.7)	$ (1.4)	$ (2.3)
Less: Gain reclassified to net income	(6.5)	(2.5)	(4.0)
Loss on cash flow hedges	(10.2)	(3.9)	(6.3)
Amortization of unrecognized benefit costs	4.3	1.9	2.4
Recognized benefit costs due to curtailment	14.2	5.5	8.7
Unrecognized benefits due to remeasurement	13.7	5.2	8.5
Total other comprehensive income	$ 22.0	$ 8.7	$13.3
2006			
Unrealized gain on cash flow hedges	$ —	$ —	$ —
Less: Gain reclassified to net income	(0.5)	(0.2)	(0.3)
Gain (loss) on cash flow hedges	(0.5)	(0.2)	(0.3)
Additional minimum pension liability	69.5	26.8	42.7
Total other comprehensive income	$ 69.0	$26.6	$42.4
2005			
Unrealized gain on cash flow hedges	$ 7.3	$ 3.7	$ 3.6
Less: Gain reclassified to net income	(5.7)	(2.0)	(3.7)
Gain (loss) on cash flow hedges	1.6	1.7	(0.1)
Additional minimum pension liability	(11.8)	(4.6)	(7.2)
Total other comprehensive loss	$(10.2)	$ (2.9)	$ (7.3)

Accumulated other comprehensive loss

(millions) Dec. 31,	*2007*	*2006*
Unrecognized pension losses and prior service costs (1)	$(13.3)	$(22.0)
Unrecognized other benefit losses, prior service costs and transition obligations (2)	2.3	(8.6)
Net unrealized (losses) gains from cash flow hedges (3)	(6.2)	0.1
Total accumulated other comprehensive loss	$(17.2)	$(30.5)

(1) Net of tax benefit of $8.3 million and $13.9 million as of Dec. 31, 2007 and 2006, respectively.

(2) Net of tax (expense) benefit of $(1.5) million and $5.5 million as of Dec. 31, 2007 and 2006, respectively.

(3) Net of tax benefit (expense) of $3.8 million and $(0.2) million as of Dec. 31, 2007 and 2006, respectively.

11. Earnings Per Share

For the years ended Dec. 31, 2007, 2006 and 2005, stock options for 5.8 million shares, 7.0 million shares and 5.4 million shares, respectively, were excluded from the computation of diluted earnings per share due to their anti-dilutive effect.

Earnings per Share

(millions, except per share amounts) *For the years ended Dec. 31,*		*2007*	*2006*	*2005*
Numerator				
Net income from continuing operations, basic		$398.9	$244.4	$211.0
Effect of contingent performance shares, net of tax		—	—	(2.0)
Net income from continuing operations, diluted		398.9	244.4	209.0
Discontinued operations, net of tax		14.3	1.9	63.5
Net income, diluted		$413.2	$246.3	$272.5
Denominator				
Average number of shares outstanding—basic		209.1	207.9	206.3
Plus: Incremental shares for unvested restricted stock and assumed conversions: Stock options at end of period, unvested unrestricted stock and contingent performance shares		3.6	3.3	5.4
Less: Treasury shares which could be purchased		(2.8)	(2.5)	(3.5)
Average number of shares outstanding—diluted		209.9	208.7	208.2
Earnings per share from continuing operations	Basic	$ 1.91	$ 1.18	$ 1.02
	Diluted	$ 1.90	$ 1.17	$ 1.00
Earnings per share from discontinued operations, net	Basic	$ 0.07	$ 0.01	$ 0.31
	Diluted	$ 0.07	$ 0.01	$ 0.31
Earnings per share	Basic	$ 1.98	$ 1.19	$ 1.33
	Diluted	$ 1.97	$ 1.18	$ 1.31

12. Commitments and Contingencies

Legal Contingencies

Settlement of the Securities Class Action

A number of securities class action lawsuits (which were subsequently consolidated) were filed in 2004 against the company and certain current and former officers by purchasers of TECO Energy securities (the Securities Class Action). On Jul. 12, 2007, the U.S. District Court entered a preliminary order approving the settlement of the Securities Class Action. On Oct. 18, 2007, the U.S. District Court entered a final order approving the settlement. The matter is now closed.

West LB Letter of Credit Litigation

In February 2005, West LB sued TPS McAdams LLC (TPS McAdams), an indirect wholly-owned subsidiary of the company, as a result of the a third party default under the McAdams construction contract in 2002. On Jul. 9, 2007, the U.S. Bankruptcy Court Judge ruled in favor of TPS McAdams and granted its motion to dismiss West LB's amended complaint that TPS McAdams presented for payment pursuant to a letter of credit fraudulently. West LB appealed the dismissal of its amended complaint and TPS McAdams filed a motion to recover its attorneys fees for defending the lawsuit in the event West LB was unsuccessful in its appeal. TPS McAdams and West LB entered into a settlement agreement and the case has been dismissed with prejudice. The matter is now closed.

Grupo Arbitration

On Aug. 11, 2006, TPS International Power, Inc. (TPSI) received a favorable ruling from the Bogota Chamber of Commerce Arbitration Tribunal (the Tribunal) in the arbitration demand by a Colombian trade union regarding a 1996 transaction that was never consummated related to the potential purchase and financing of a power plant. The Tribunal found no liability on the part of TPSI and found that it had no jurisdiction over TECO Energy or any of its subsidiaries.

Following the Tribunal's finding, the union filed a petition for annulment in the ordinary courts on Aug. 31, 2006. The union was ordered to file its detailed petition citing the record to substantiate its annulment claim on Oct. 12, 2006 but it failed to do so. The court-appointed Tribunal issued a confirmation that the matter was closed. In early December 2006, the union filed two separate procedural petitions asking the Tribunal to set aside its determination claiming that the union's petition was barred due to the missed deadline, on the basis that the Tribunal's "Notification of the Oct. 12 date" was technically deficient. On Mar. 20, 2007, the Court found against the union on procedural grounds on its petition to revoke the Court's action vacating the petition for annulment. On Mar. 27, 2007, the union filed a petition to review the Mar. 20, 2007 ruling and TPSI has opposed that petition. In late September 2007, the Court ruled in the Company's favor and denied the union's petition. Subsequently, the union filed an extraordinary procedural tactic which was also denied by the Court. Under Colombian law, the matter is considered closed.

Other Issues

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

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party (PRP) for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2007, Tampa Electric Company has estimated its ultimate financial liability to be approximately $11.5 million primarily at PGS, and this amount has been accrued in the company's financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

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

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

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

Long-Term Commitments

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

Total rental expense for these leases, included in "Operation other expense—Other" on the Consolidated Statements of Income for the years ended Dec. 31, 2007, 2006 and 2005, was $29.8 million, $30.0 million and $28.3 million, respectively, including leases of marine equipment at TECO Transport, which was sold on Dec. 4, 2007.

The following is a schedule of future minimum lease payments at Dec. 31, 2007 for all leases with non-cancelable lease terms in excess of one year:

Future Minimum Lease Payments of Leases (1)

Year ended Dec. 31:	*Amount (millions)*
2008	$ 5.4
2009	11.7
2010	11.1
2011	11.0
2012	11.1
Thereafter	83.7
Total minimum lease payments	$134.0

(1) This schedule includes the fixed capacity payments required under a capacity and tolling agreement of Tampa Electric which commences Jan.1, 2009. In accordance with the provisions of EITF 01-08, *Determining Whether an Arrangement Contains a Lease*, the company evaluated the agreement and concluded based on the criteria that the arrangement met the lease definition. Prudently incurred capacity payments are recoverable under an FPSC-approved cost recovery clause (See **Note 3**).

Guarantees and Letters of Credit

TECO Energy accounts for guarantees in accordance with FASB Interpretation No. (FIN) 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others (an interpretation of FASB Statements No. 5, 57 and 107 and rescission of FASB Interpretation No. 34)*. Upon issuance or modification of a guarantee the company determines if the obligation is subject to either or both of the following:

- Initial recognition and initial measurement of a liability; and/or
- Disclosure of specific details of the guarantee.

Generally, guarantees of the performance of a third party or guarantees that are based on an underlying (where such a guarantee is not a derivative subject to FAS 133) are likely to be subject to the recognition and measurement, as well as the disclosure provisions, of FIN 45. Such guarantees must initially be recorded at fair value, as determined in accordance with the interpretation.

Alternatively, guarantees between and on behalf of entities under common control or that are similar to product warranties are subject only to the disclosure provisions of the interpretation. The company must disclose information as to the term of the guarantee and the maximum potential amount of future gross payments (undiscounted) under the guarantee, even if the likelihood of a claim is remote.

A summary of the face amount or maximum theoretical obligation under TECO Energy's letters of credit and guarantees as of Dec. 31, 2007 are as follows:

Letters of Credit and Guarantees

(millions) *Letters of Credit and Guarantees for the Benefit of:*	*Maturing* 2008	2009	2010 - 2012	After 2012	*Total*	*Liabilities Recognized at Dec. 31, 2007*
Tampa Electric						
Letters of credit	$—	$—	$—	$ 0.3	$ 0.3	$—
Guarantees:						
Fuel purchase/energy management (1)(2)	—	—	—	20.0	20.0	1.4
	—	—	—	20.3	20.3	1.4
TECO Transport						
Letters of credit (3)	2.5	—	—	—	2.5	—
TECO Coal						
Letters of credit	—	—	—	6.7	6.7	—
Guarantees: Other (2)	5.5	—	—	1.4 (1)	6.9	2.4
	5.5	—	—	8.1	13.6	2.4
Other unregulated						
Guarantees:						
Fuel purchase/energy management (2)	53.7	—	—	3.9 (1)	57.6	—
Total	$61.7	$—	$—	$32.3	$94.0	$ 3.8

(1) These guarantees renew annually and are shown on the basis that they will continue to renew beyond 2012.
(2) The amounts shown are the maximum theoretical amount guaranteed under current agreements. Liabilities recognized represent the associated obligation of TECO Energy under these agreements at Dec. 31, 2007. The obligations under these letters of credit and guarantees include net accounts payable and net derivative liabilities.
(3) TECO Transport was sold effective Dec. 4, 2007. The terms of the sale required that these letters of credit be replaced by the purchaser; this was completed in 2008.

Financial Covenants

In order to utilize their respective bank facilities, TECO Energy/TECO Finance and Tampa Electric Company must meet certain financial tests as defined in the applicable agreements. In addition, TECO Energy, Tampa Electric Company and other operating companies have certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2007, TECO Energy, Tampa Electric Company and the other operating companies were in compliance with all required financial covenants.

13. Related Parties

The company and its subsidiaries had certain transactions, in the ordinary course of business, with entities in which directors of the company had interests. The company paid legal fees of $1.3 million, $1.2 million and $1.3 million for the years ended Dec. 31, 2007, 2006 and 2005, 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, 2007, 2006 and 2005. No material balances were payable as of Dec. 31, 2007 or 2006.

14. Segment Information

TECO Energy is an electric and gas utility holding company with significant diversified activities. Segments are determined based on how management evaluates, measures and makes decisions with respect to the operations of the entity. The management of TECO Energy reports segments based on each subsidiary's contribution of revenues, net income and total assets, as required by FAS 131, *Disclosures about Segments of an Enterprise and Related Information*. All significant intercompany transactions are eliminated in the consolidated financial statements of TECO Energy, but are included in determining reportable segments.

During the first quarter of 2005, the company revised internal reporting information for the purpose of evaluating, measuring and making decisions with respect to the components which previously comprised the "Other Unregulated" operating segment. The revised operating segment, "TECO Guatemala", is comprised of all Guatemalan operations. The remaining components are now included in "Other & Eliminations". Prior period segment results have been restated to reflect the revised segment structure. In 2007, only historical data is presented for TWG Merchant as all merchant assets have been divested. Any residual results for 2007 and 2006 are included in "Other and Eliminations".

The information presented in the following table excludes all discontinued operations. See **Note 20** for additional details of the components of discontinued operations.

Segment Information [1]

(millions)	Tampa Electric	Peoples Gas	TECO Coal	TECO Transport	TECO Guatemala	TWG Merchant	Other & Eliminations	Total TECO Energy
2007								
Revenues—outsiders	$2,186.6	$599.7	$544.5	$197.1	$ 8.0 [6]	$ —	$ 0.2	$3,536.1
Sales to affiliates	1.8			93.2			(95.0)	—
Total revenues	2,188.4	599.7	544.5	290.3	8.0	—	(94.8)	3,536.1
Earnings from unconsol. affiliates	—	—	—		68.5	—	—	68.5
Depreciation and amortization	178.6	40.1	38.4	5.6	0.5	—	0.5	263.7
Total interest charges [2]	112.2	17.1	12.5	4.8	15.2	—	96.0	257.8
Internally allocated interest [2]	—	—	11.6	0.8	14.9	—	(27.3)	—
Provision (benefit) for taxes	85.2	16.4	46.3	13.5	7.8	—	45.0	214.2
Net income from continuing operations [2]	$ 150.3	$ 26.5	$ 90.9	$ 34.0	$ 44.7 [8]	$ —	$ 52.5 [3]	$ 398.9
Goodwill, net	$ —	$ —	$ —	$ —	$ 59.4	$ —	$ —	$ 59.4
Investment in unconsolidated affiliates	—	—	—	—	275.5	—	—	275.5
Other non-current investments	—	—	—	—	15.0	—	8.0	23.0
Total assets	4,838.3	761.4	501.2 [5]	—	435.3 [9]	—	229.0	6,765.2
Capital expenditures	$ 373.8	$ 49.2	$ 43.8	$ 25.1	$ 2.3	$ —	$ 0.2	$ 494.4
2006								
Revenues—outsiders	$2,082.7	$577.6	$574.9	$205.1	$ 7.6 [6]	$ —	$ 0.2	$3,448.1
Sales to affiliates	2.2	—	—	103.4	—	—	(105.6)	—
Total revenues	2,084.9	577.6	574.9	308.5	7.6	—	(105.4)	3,448.1
Earnings from unconsol. affiliates	—	—	—	(0.3)	58.7	—	0.5	58.9
Depreciation and amortization	186.3	36.5	36.4	22.1	0.6	—	0.3	282.2
Total interest charges [2]	107.4	15.2	10.6	4.5	15.0	—	125.6	278.3
Internally allocated interest [2]	—	—	9.9	(1.4)	14.6	—	(23.1)	—
Provision (benefit) for taxes	80.3	18.8	35.6	10.9	8.7	—	(35.6)	118.7
Net income (loss) from continuing operations [2]	$ 135.9	$ 29.7	$ 78.8	$ 22.8	$ 37.6	$ —	$ (60.4) [3]	$ 244.4
Goodwill, net	$ —	$ —	$ —	$ —	$ 59.4	$ —	$ —	$ 59.4
Investment in unconsolidated affiliates	—	—	—	2.9	276.0	—	14.0	292.9
Other non-current investments	—	—	—	—	—	—	8.0	8.0
Total assets	4,813.7	765.2	389.4 [5]	333.9	424.6 [9]	—	635.0	7,361.8
Capital expenditures	$ 366.4	$ 54.0	$ 40.2	$ 16.5	$ 0.7	$ —	$ (22.1) [7]	$ 455.7
2005								
Revenues—outsiders	$1,744.3	$549.5	$505.1	$192.5	$ 7.7 [6]	$ 0.4	$ 10.6	$3,010.1
Sales to affiliates	2.5	—	—	85.7	—	—	(88.2)	—
Total revenues	1,746.8	549.5	505.1	278.2	7.7	0.4	(77.6)	3,010.1
Earnings from unconsol. affiliates	—	—	—	(0.3)	57.9	—	2.8	60.4
Depreciation and amortization	187.1	35.0	36.8	21.4	0.8	0.7	0.4	282.2
Total interest charges [2]	98.3	15.1	13.4	5.1	15.9	10.4	130.5	288.7
Internally allocated interest [2]	—	—	12.5	(0.6)	14.2	10.1	(36.2)	—
Provision (benefit) for taxes	90.6	18.5	64.9	8.1	(1.9)	(10.9)	(67.4)	101.9
Net income (loss) from continuing operations [2]	$ 147.1	$ 29.6	$115.4	$ 20.2	$ 40.4	$(14.6)	$(127.1) [3]	$ 211.0
Goodwill, net	$ —	$ —	$ —	$ —	$ 59.4	$ —	$ —	$ 59.4
Investment in unconsolidated affiliates	—	—	—	2.9	274.0	—	20.2	297.1
Other non-current investments	—	—	—	—	—	—	8.0	8.0
Total assets	4,554.0	721.5	385.6 [5]	322.4	408.4 [9]	233.0	545.2	7,170.1
Capital expenditures	$ 203.5	$ 42.5	$ 24.1	$ 18.1	$ 0.2	$ 6.9	$ —	$ 295.3

(1) From continuing operations. All periods have been adjusted to reflect the reclassification of results from operations to discontinued operations for CCC and BCH Mechanical, Inc.

(2) Segment net income is reported on a basis that includes internally allocated financing costs. Internally allocated costs for 2007, 2006 and 2005 were at pretax rates of 7.5%, 7.5% and 8%, respectively, based on the average of each subsidiary's equity and indebtedness to TECO Energy assuming a 50/50 debt/equity capital structure. Internally allocated interest charges are a component of total interest charges.

(3) Net income for 2007 includes $20.2 million of after-tax debt extinguishment costs, $149.4 million after-tax gain on the sale of TECO Transport and $16.3 million after-tax in transaction costs. Net income for 2006 includes after-tax gains of $8.1 million on the sale of McAdams and $5.7 million on the sale of two steam turbines. Net income for 2005 includes $46.7 million after-tax of debt extinguishment charges at TECO Energy parent (including a $19.8 million non-cash charge).
(4) 2007 results for TECO Transport are through Dec. 3, 2007.
(5) The carrying value of mineral rights as of Dec. 31, 2007, 2006 and 2005 was $18.9 million, $20.6 million and $22.5 million, respectively.
(6) Revenues for 2007, 2006 and 2005 are exclusive of entities deconsolidated as a result of FIN 46R and include only revenues for the consolidated Guatemalan entities.
(7) Included in other capital expenditures is a cash offset of $22.1 million, related to the sale of two combustion turbines by TPS McAdams to Tampa Electric. The corresponding capital expenditure is included in Tampa Electric's capital expenditures for 2006.
(8) Net income is comprised of earnings from unconsolidated affiliates less: depreciation, interest charges, taxes and other net expenses of $0.3 million.
(9) Total assets represent primarily equity and advances invested in unconsolidated affiliates. As of Dec. 31, 2007, the equity and advances balance due TECO Energy totaled $413.5 million.

Tampa Electric provides retail electric utility services to more than 668,000 customers in West Central Florida. PGS is engaged in the purchase and distribution of natural gas for more than 334,000 residential, commercial, industrial and electric power generation customers in the state of Florida.

TECO Coal, through its wholly-owned subsidiaries, owns mineral rights and owns or operates surface and underground mines and coal processing and loading facilities in Kentucky, Tennessee and Virginia. TECO Coal acquired and began operating two synthetic fuel facilities in 2000, whose production qualifies for the non-conventional fuels tax credit. In 2003, these synthetic fuel operations were transferred into a newly formed LLC for the purpose of continuing growth in the production and sale of synthetic fuel. In April 2003, TECO Coal sold 49.5% interest in this entity, with another 40.5% being sold in 2004, and an additional 8% sold in 2005.

TECO Transport, through its wholly-owned subsidiaries, transported, stored and transferred coal and other dry bulk commodities for third parties and Tampa Electric. TECO Transport's subsidiaries operated on the Mississippi, Ohio and Illinois rivers, in the Gulf of Mexico and worldwide. TECO Transport was sold on Dec. 4, 2007.

TECO Guatemala includes the equity investments in the San José and Alborada power plants, the equity investment in DECA II, and the TECO Guatemala parent company.

TWG Merchant's assets were entirely divested by the end of 2006.

15. Asset Retirement Obligations

TECO Energy accounts for asset retirement obligations under FAS 143, "Accounting for Asset Retirement Obligations" (FAS 143) and FIN 47 *Accounting for Conditional Asset Retirement Obligations*. An asset retirement obligation (ARO) for a long-lived asset is recognized at fair value at inception of the obligation if there is a legal obligation under an existing or enacted law or statute, a written or oral contract, or by legal construction under the doctrine of promissory estoppel. Retirement obligations are recognized only if the legal obligation exists in connection with or as a result of the permanent retirement, abandonment or sale of a long-lived asset.

When the liability is initially recorded, the carrying amount of the related long-lived asset is correspondingly increased. Over time, the liability is accreted to its estimated future value. The corresponding amount capitalized at inception is depreciated over the remaining useful life of the asset. The liability must be revalued each period based on current market prices.

TECO Energy has recognized asset retirement obligations for reclamation and site restoration obligations principally associated with coal mining, storage and transfer facilities. The majority of obligations arise from environmental remediation and restoration activities for coal-related operations. Prior to the adoption of FAS 143, TECO Coal accrued reclamation costs for such activities. For TECO Coal, the adoption of FAS 143 modified the valuation and accrual methods used to estimate the fair value of asset retirement obligations.

For the years ended Dec. 31, 2007, 2006 and 2005, TECO Energy recognized $1.4 million, $1.5 million, and $1.6 million of accretion expense, respectively, associated with asset retirement obligations in "Depreciation and amortization" on the Consolidated Statements of Income.

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

(millions)	Dec. 31, 2007	Dec. 31, 2006
Beginning balance	$52.7	$42.2
Additional liabilities	0.1	3.5
Liabilities settled	(7.0)	(2.4)
Accretion expense	1.4	1.5
Revisions to estimated cash flows	—	7.3
Other (1)	0.6	0.6
Ending balance	$47.8	$52.7

(1) Accretion expense reclassed as a deferred regulatory asset.

During 2006, estimated cash flows used in determining the recognized asset retirement obligations were adjusted by $7.3 million at Tampa Electric Company. The amount is related to the increased cost of removal of materials used for the generation and transmission of power. There were no adjustments to estimated cash flows in 2007.

As regulated utilities, Tampa Electric and PGS must file depreciation and dismantlement studies periodically and receive approval from the FPSC before implementing new depreciation rates. Included in approved depreciation rates is either an implicit net salvage factor or a cost of removal factor, expressed as a percentage. The net salvage factor is principally comprised of two components—a salvage factor and a cost of removal or dismantlement factor. The company uses current cost of removal or dismantlement factors as part of the estimation method to approximate the amount of cost of removal in accumulated depreciation.

For Tampa Electric and PGS, the original cost of utility plant retired or otherwise disposed of and the cost of removal, or dismantlement, less salvage value is charged to accumulated depreciation and the accumulated cost of removal reserve reported as a regulatory liability, respectively.

16. Mergers, Acquisitions and Dispositions

Sale of TECO Transport

On Dec. 4, 2007, TECO Diversified, Inc., a wholly-owned subsidiary of the company, sold its entire interest in TECO Transport Corporation for cash to an unaffiliated investment group. The selling price was $405 million, subject to a working capital adjustment and resulted in a pretax gain of $221.3 million, which is net of transaction-related costs. In accordance with the provisions of SFAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (FAS 144), as a result of its significant continuing involvement with Tampa Electric Company related to the waterborne transportation of solid fuel, the results of TECO Transport were reflected in continuing operations.

Sale of Properties

During the year ended Dec. 31, 2006, the company sold two lots adjacent to the corporate office in downtown Tampa, Florida to third party real estate developers. The sales included total proceeds of $15.0 million and resulted in pretax gains of $6.4 million. Included in each sale agreement was the ability to lease the properties until construction commenced and options to repurchase the properties after a certain period of time in the event the lots were not developed. As a result of this continuing involvement, the total gain was being deferred until such time as the continuing involvement terminates. During 2007, the option to repurchase one of the lots expired and construction commenced. As a result, $0.4 million related to that sale was recognized in "Other income" on the Consolidated Statement of Income.

Sale of Steam Turbines

In July 2006, the company sold a steam turbine generator located in Maricopa County, Arizona to a third party for a net after-tax gain of $2.6 million. In December 2006, the company sold a second steam turbine generator also located in Maricopa County, Arizona to a third party for a net after-tax gain of $3.1 million.

Sale of TPS McAdams, LLC

On Jun. 23, 2006, TPS McAdams, LLC, an indirect subsidiary of TECO Energy, was sold to Von Boyett Corporation for $1.2 million in cash. The assets of TPS McAdams, LLC had been impaired in 2004 to an estimate of salvage value, which included allowances for potential future site restoration costs. In the first quarter of 2006, TPS McAdams, LLC sold the combustion turbines at the site to Tampa Electric at the book value contemplated in the salvage estimate. The sale and transfer of TPS McAdams, LLC, including its remaining assets and any potential site restoration costs at terms better than contemplated in the salvage estimate, resulted in a pretax gain of $10.7 million ($8.1 million after-tax) being recognized in continuing operations.

Sale of TECO Thermal

In May 2006, the company sold the assets of TECO Thermal, an indirect subsidiary of TECO Energy, to a third party. Total proceeds on the sale were $8.1 million and resulted in an after-tax gain of $0.5 million.

Dell Power Station

On Aug. 16, 2005, an indirect subsidiary of TECO Energy completed the sale of substantially all of its assets, including the Dell Power Station, to Associated Electric Cooperative, Inc., a Missouri electric cooperative, for $75 million. The sale resulted in a pretax gain of $23.2 million ($14.9 million after-tax). TECO Energy retained certain other operating liabilities totaling $11.0 million pretax ($7.1 million after-tax). The net after-tax impact of $7.8 million is included in continuing operations.

Union and Gila River Project Companies

On Jun. 1, 2005, the company completed the sale and transfer of ownership of its indirect subsidiaries, Union Power Partners, L.P., Panda Gila River, L.P., Trans-Union Interstate Pipeline, L.P., and UPP Finance Co., LLC, owners of the Union and Gila River power stations in Arkansas and Arizona, respectively (collectively, the Projects) to an entity owned by the Projects' lenders in the manner set forth in the Projects' confirmed Joint Plan of Reorganization. In connection with the transfer and the related release of liability, the company and its indirect subsidiaries paid an aggregate of $31.8 million, consisting of $30.0 million to the Project's lenders as consideration for release of liability and $1.8 million as reimbursement of legal fees for two non-consenting lenders in the recently concluded Chapter 11 proceeding.

BCH Mechanical, Inc.

On Jan. 7, 2005, an indirect subsidiary of TECO Energy completed the disposal of its 100% interest in BCH Mechanical, Inc. (BCH) pursuant to a Stock Purchase Agreement dated as of Dec. 31, 2004. The purchaser of BCH was BCH Holdings, Inc., majority owned at that time by Daryl W. Blume, who was a Vice President of BCH and one of the owners of BCH when it was purchased by a subsidiary of TECO Energy in September 2000. Under the transaction, TECO Energy retained BCH's net working capital determined as of Dec. 31, 2004, and certain other existing obligations. During the third quarter of 2005, terms of the sale were modified from a sale of assets to a sale of stock. This modification resulted in an additional after-tax loss of $1.4 million on tax-related assets. The results of BCH are reflected in discontinued operations for all periods presented (see **Note 20**).

Synthetic Fuel Facilities

Effective Apr. 1, 2003, TECO Coal sold a 49.5% indirect interest in Pike Letcher Synfuel, LLC (PLS), which owns synthetic fuel production facilities located at TECO Coal's operations in eastern Kentucky. In May 2004, TECO Coal sold an additional 40.5% of its membership interest in the synthetic fuel facilities and another 8% in July 2005, under similar terms as the first transaction. On Dec. 29, 2005, the agreements with the investors were amended to permit the curtailment of synthetic fuel production when oil prices are above certain thresholds and to allow the company the right, but not the obligation, to cause PLS to reduce or halt synthetic fuel production should estimates for crude oil prices reach certain levels. This amendment also allowed for the release of $20 million of the $50 million restricted cash that had been held in escrow. Generally, revenue is recognized as the monthly installments are received. Because the purchase price for this sale, as well as the other sales of ownership interests, is related to the value of tax credits generated through December 2007, it was subject to a reduction to the extent the credit is limited due to the average domestic oil price for a particular year exceeding the benchmark designated for that year by the Department of Energy. In addition to retaining a 2% membership interest in the facilities, TECO Coal continued to supply the feedstock and operate the facilities through the expiration of the agreement on Dec. 31, 2007.

17. Goodwill and Other Intangible Assets

SFAS 141, *Business Combinations*, requires all business combinations be accounted for using the purchase method of accounting. Under SFAS 142 *Goodwill and Other Intangible Assets* (FAS 142), goodwill is not subject to amortization. Rather, goodwill and intangible assets, with an indefinite life, are subject to an annual assessment for impairment by applying a fair-value-based test. Intangible assets with a measurable useful life are required to be amortized.

As required under FAS 142, TECO Energy reviews recorded goodwill and intangible assets at least annually during the fourth quarter, for each reporting unit. Reporting units are generally determined as one level below the operating segment level; reporting units with similar characteristics are grouped for the purpose of determining the impairment, if any, of goodwill and other intangible assets. The fair value for the reporting units evaluated is generally determined using discounted cash flows appropriate for the business model of each significant group of assets within each reporting unit. The models incorporate assumptions relating to future results of operations that are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. Management periodically reviews and adjusts the assumptions, as necessary, to reflect current market conditions and observable activity. If a sale is expected in the near term or a similar transaction can be readily observed in the marketplace, then this information is used by management to estimate the fair value of the reporting unit.

At Dec. 31, 2007, the company has $59.4 million of goodwill on its balance sheet, which is reflected in the TECO Guatemala segment. In conducting its annual impairment assessment, the company determined the fair value of the Guatemalan reporting unit supported the goodwill. The balance of goodwill arose from the purchase of multiple entities as a result of the company's investment in its operations in Guatemala.

18. Asset Impairments

The company accounts for asset impairments in accordance with FAS 144, which requires that long-lived assets be tested for recoverability whenever events or changes in circumstances indicate that its carrying value may not be recoverable. If it is determined that the carrying value is not recoverable, an impairment charge is made and the value of the asset is reduced to the recoverable amount. When the impaired asset is disposed of, if the consideration received is in excess of the reduced carrying value, a gain would then be recorded. (See **Note 16**) In accordance with FAS 144, the company assesses whether there has been an impairment of its long-lived assets and certain intangibles held and used by the company when such impairment indicators exist. No such indicators of impairment existed as of Dec. 31, 2007 or 2006.

In the fourth quarter of 2005, a pretax impairment charge of $3.2 million ($2.1 million after tax) was recognized related to the company's investment in the McAdams power station. The reduction in fair value resulted from an updated strategic review of the potential salvage options (including asset retirement obligations as a result of exiting the facility) following the decision to sell the combustion turbines and certain ancillary equipment to Tampa Electric.

19. Variable Interest Entities

TECO Energy accounts for variable interest entities (VIEs) under FIN 46R, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51* (FIN 46R).

The company formed TCAE to own and construct the Alborada Power Station and the company formed CGESJ to own and construct the San José Power Station. Both power stations are located in Guatemala and both projects obtained long-term power purchase agreements (PPA) with EEGSA, a distribution utility in Guatemala. The terms of the two separate PPAs include EEGSA's right to the full capacity of the plants for 15 years, U.S. dollar based capacity payments, certain terms for providing fuel, and certain other terms including the right to extend the Alborada and San José contracts. Management believes that EEGSA is the primary beneficiary of the variable interests in TCAE and CGESJ due to the terms of the PPAs. Accordingly, both entities were deconsolidated as of Jan. 1, 2004. The TCAE deconsolidation resulted in the initial removal of $25 million of debt and $15.1 million of net assets from TECO Energy's Consolidated Balance Sheet. The San José deconsolidation resulted in the initial removal of $65.5 million of debt and $106.6 million of net assets from TECO Energy's Consolidated Balance Sheet. The results of operations for the two projects are classified as "Income from equity investments" on TECO Energy's Consolidated Statements of Income since the date of deconsolidation. TECO Energy's estimated maximum loss exposure is its equity investment of approximately $188.8 million in these entities. (See Note 14 for additional financial information related to these projects).

Pike Letcher Synfuel, LLC was established as part of the Apr. 1, 2003, sale of TECO Coal's synthetic fuel production facilities. While TECO Energy's maximum loss exposure in this entity was its investment of approximately $8.2 million, the company could have lost potential earnings and incurred losses related to the production costs for synthetic fuel, in the event that such production created non-conventional fuel tax credits in excess of TECO Energy's or the other buyers' capacity to generate sufficient taxable income to use such credits or fuel tax credits are reduced or eliminated due to high oil prices. Management believed that the company was the primary beneficiary of this VIE and continued to consolidate the entity under the guidance of FIN 46R through the expiration of synfuel production on Dec. 31, 2007.

In 1992, a subsidiary of the company, Hardee Power Partners, Ltd. commenced construction of the Hardee Power Station in central Florida. HPP obtained dual 20-year PPAs with Tampa Electric and another Florida utility company to provide peaking capacity. The company sold its interest in HPP to an affiliate of Invenergy LLC and GTCR Golder Rauner LLC in 2003. Under FIN 46R, the company is required to make an exhaustive effort to obtain sufficient information to determine if HPP is a VIE and which holder of the variable interests is the primary beneficiary. The new owners of HPP are not willing to provide the information necessary to make these determinations, have no obligation to do so and the information is not available publicly. As a result, the company is unable to determine if HPP is a VIE and if so, which variable interest holder, if any, is the primary beneficiary. The maximum exposure for the company is the ability to purchase electricity under terms of the PPA with HPP at rates unfavorable to the wholesale market.

20. Discontinued Operations and Assets Held for Sale

Union and Gila River Project Companies (TPGC)

Net income from discontinued operations in 2007 was $14.3 million, after-tax, reflecting a favorable conclusion reached in the second quarter with taxing authorities for the 2005 disposition of the Union and Gila River merchant power plants, discussed below.

On Jun. 1, 2005, the company completed the previously announced sale and transfer of ownership of its indirect subsidiaries Union Power Partners, L.P., Panda Gila River, L.P., Trans-Union Interstate Pipeline, L.P., and UPP Finance Co., LLC, owners of the Union and Gila River power stations in Arkansas and Arizona, respectively (collectively, the Projects) to an entity owned by the Projects' lenders in the manner set forth in the Projects' confirmed Joint Plan of Reorganization. In connection with the transfer and the related release of liability, the company and its indirect subsidiaries paid an aggregate of $31.8 million, consisting of $30.0 million to the Project's lenders as consideration for the release of liability and $1.8 million as reimbursement of legal fees for two non-consenting lenders in the Chapter 11 proceeding. As a result of the transaction, the company recorded a non-cash, pretax gain of $117.7 million ($76.5 million after tax), which is reflected in discontinued operations. Through the May 31, 2005 effective date of the transfer to the lending group, the net equity of the Projects was reduced by accumulated unfunded operating losses primarily related to unpaid accrued interest expense on the Projects. As a result of the recognition of these subsequent losses, the book value of the assets was less than the book value of non-recourse project financing at the effective date of the sale and transfer to the lending group. Accordingly, the gain on the disposition represents the transfer of equity in the projects and the related non-recourse debt and other liabilities in excess of the asset value of the projects.

As an asset held for sale, the assets and liabilities that were expected to be transferred as part of the sale were reclassified on the balance sheet. The results from operations and the gain on sale have been reflected in discontinued operations for all periods presented. The following table provides selected components of discontinued operations for the Union and Gila River project companies.

Components of income from discontinued operations—Union and Gila River Project Companies

(millions) *For the years ended Dec. 31,*	*2007*	*2006*	*2005*
Revenues	$ —	$—	$109.1
Loss from operations	—	—	(23.0)
Gain on sale before tax	—	—	117.7
Income (loss) before provision for income taxes	—	—	90.0
(Benefit) provision for income taxes	(14.3)	—	24.9
Net income from discontinued operations	$ 14.3	$—	$ 65.1

Interest Expense

In accordance with the Statement of Position 90-7, Financial Reporting by Entities in Reorganization Under the Bankruptcy Code (SOP 90-7), and the provisions of the U.S. bankruptcy code and the Joint Plan, interest expense on the Project entities' non-recourse debt subsequent to the bankruptcy filing was not to be paid and was therefore not recorded. Had the bankruptcy proceeding not occurred, the Project entities would have recorded additional pretax interest expense of $44.3 million during 2005, which would have been reported in income (loss) from discontinued operations.

Other transactions

Components of income from discontinued operations also include TECO Thermal (sold in 2006), CCC (sold in 2005), and BCH Mechanical (sold in 2005). See **Note 16** for additional details related to these sales. For all periods presented, the results from operations of each of these entities are presented as discontinued operations on the income statement.

The following table provides selected components of discontinued operations for transactions other than the Union and Gila River projects transactions:

Components of income from discontinued operations—Other

(millions) *For the years ended Dec. 31,*	*2007*	*2006*	*2005*
Revenues	$—	$0.8	$10.6
Income (loss) from operations	—	1.5	(0.3)
(Loss) gain on sale	—	0.8	(2.1)
Income (loss) before provision for income taxes	—	2.3	(1.8)
Provision (benefit) for income taxes	—	0.4	(0.2)
Net income (loss) from discontinued operations	$—	$1.9	$(1.6)

21. Derivatives and Hedging

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

- To limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric and PGS;
- To limit the exposure to interest rate fluctuations on debt securities at TECO Energy and its affiliates;
- To limit the exposure to price fluctuations for physical purchases of fuel at TECO Coal; and
- To limit the exposure to synthetic fuel tax credits from TECO Coal's synthetic fuel produced as a result of changes to the reference price of domestically produced oil.

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

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

The company applies the provisions of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by SFAS 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activity* and SFAS 149, *Amendment on Statement 133 on Derivative Instruments and Hedging Activities*. These standards require companies to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as either components of OCI or in net income, depending on the designation of those instruments. The changes in fair value that are recorded in OCI are not immediately recognized in current net income. As the underlying hedged transaction matures or the physical commodity is delivered, the deferred gain or loss on the related hedging instrument must be reclassified from OCI to earnings based on its value at the time of the instruments' settlement. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the amount paid or received on the underlying physical transaction.

At Dec. 31, 2007 and 2006, respectively, TECO Energy and its affiliates had derivative assets (current and non-current) totaling $2.2 million and $7.2 million, and liabilities (current and non-current) totaling $26.1 million and $74.0 million. At Dec. 31, 2007, $8.2 million of liabilities are related to interest rate swaps. The remaining $2.2 million of assets and $17.9 million in liabilities are related to natural gas swaps. At Dec. 31, 2006, $7.0 million in derivative assets were related to crude oil options. The remaining $0.2 million of assets and $74.0 million of liabilities were related to natural gas swaps.

At Dec. 31, 2007 and 2006, accumulated other comprehensive income (AOCI) included an after-tax $6.2 million unrealized loss and an after-tax $0.1 million unrealized loss, respectively, representing the fair value of cash flow hedges whose underlying transactions will occur within the next 12 months. Amounts recorded in AOCI reflect the estimated fair value based on market prices as of the balance sheet date, of interest rate derivative instruments designated as hedges. These amounts are expected to fluctuate with movements in market prices and may or may not be realized as a loss upon future reclassification from OCI to earnings. The company does not currently have any cash flow hedges for transactions forecasted to take place in periods subsequent to 2010.

For the years ended Dec. 31, 2007, 2006 and 2005, TECO Energy and its affiliates reclassified amounts from OCI and recognized net pretax gains of $6.5 million, $0.5 million and $5.7 million, respectively. (See **Note 10**) Amounts reclassified from OCI were primarily related to cash flow hedges for physical purchases of fuel oil at TECO Transport and TECO Coal. For these types of hedge relationships, the gain on the derivative at settlement is reclassified from OCI to earnings, which is offset by the increased cost of spot purchases for fuel oil.

As a result of applying the provisions of FAS 71 in accordance with the FPSC, the changes in value of natural gas derivatives of Tampa Electric and PGS are recorded as regulatory assets or liabilities to reflect the impact of the fuel recovery clause on the risks of hedging activities. (See **Note 3**) Based on the fair value of cash flow hedges at Dec. 31, 2007, net pretax losses of $17.3 million are expected to be reclassified from regulatory assets or liabilities to the Consolidated Statement of Income within the next twelve months.

At Dec. 31, 2007, TECO Energy had a "Crude oil options receivable, net" asset totaling $78.5 million for transactions that were not designated as either a cash flow or fair value hedge. This balance includes the full settlement value of the crude oil options of $120.8 million, offset by the $42.3 million of margin call collateral collected. These derivatives were marked-to-market with fair value gains and losses recognized in "Other income" on the Consolidated Statements of Income. For the years ended Dec. 31, 2007, 2006 and 2005, the company recognized gains on marked-to-market derivatives of $82.7 million, $2.9 million and $0.5 million, respectively. The increase in the gain from 2006 to 2007 is reflective of the increase in oil prices and the total volume of barrels hedged, 2.8 million barrels in 2006 compared to 25.1 million barrels in 2007.

22. TECO Finance, Inc.

TECO Finance is a wholly owned subsidiary of TECO Energy, Inc. TECO Finance's sole purpose is to raise capital for TECO Energy's diversified businesses. TECO Energy is a full and unconditional guarantor of TECO Finance's securities. (See **Note 7**)

TECO FINANCE, INC.

Condensed Balance Sheets

(in millions)	*Dec. 31, 2007*	*Dec. 31, 2006*
Assets		
Current Assets		
Cash	$ 0.2	$ 0.1
Advances-intercompany	737.6	—
Total Current Assets	737.8	0.1
Non-current Assets		
Deferred tax asset	1.8	0.9
Unamortized debt expense	29.0	—
Total Non-Current Assets	30.8	0.9
Total Assets	$ 768.6	$ 1.0
Liabilities and Capital		
Current Liabilities		
Interest payable	$ 1.8	$ —
Advances payable-intercompany	—	133.4
Non-current Liabilities		
Long-term debt	900.5	—
Total Liabilities	$ 902.3	$ 133.4
Capital		
Common stock and paid in capital	0.1	0.1
Retained deficit	(133.8)	(132.5)
Total Capital	(133.7)	(132.4)
Total Liabilities and Capital	$ 768.6	$ 1.0

TECO FINANCE, INC.

Condensed Statements of Operations

(in millions) *For the years ended Dec. 31,*	*2007*	*2006*	*2005*
Revenues	$—	$—	$—
Other Income			
Interest Expense	2.2	—	—
Loss before benefit from income taxes	(2.2)	—	—
Benefit (provision for) from income taxes	0.8	—	(0.9)
Net loss	$(1.4)	$—	$(0.9)

TECO FINANCE, INC.

Condensed Statements of Cash Flows

(in millions) *For the years ended Dec. 31,*	*2007*	*2006*	*2005*
Cash Flows from Operating Activities			
Net loss	$(1.4)	$—	$(0.9)
Adjustments to reconcile net loss to net cash from operating activities:			
Deferred taxes	(0.8)	—	0.9
Interest payable	1.8	—	—
Other assets	(1.7)	—	—
Cash Flows used in Operating Activities	(2.1)	—	—
Cash Flows from Financing Activities			
Advances	2.2	—	—
Cash Flows provided by Financing Activities	2.2	—	—
Net increase (decrease) in cash	0.1	—	—
Cash at the beginning of the year	0.1	0.1	0.1
Cash at end of the year	$ 0.2	$ 0.1	$ 0.1

23. Subsequent Events

Tax-Exempt Auction Rate Bonds

On Feb. 19 and Feb. 26, 2008 two series of tax-exempt auction-rate bonds totaling $105.8 million issued for the benefit of Tampa Electric Company by the Hillsborough County Industrial Development Authority (HCIDA) experienced failed auctions and, in accordance with the terms of the bond indentures, the seven day interest rate on these series reset to 14%. Auctions on Feb. 19 for Tampa Electric's three other series of tax-exempt auction-rate bonds with interest periods of 7 and 35 days totaling $181.0 million settled at interest rates of 10% to 12%. The interest rates set in the Feb. 19 auction of 11% and 12% on the Polk County Industrial Development Authority (PCIDA) Series 2007 and HCIDA Series 2007C, respectively, are in effect until Mar. 26. On Feb. 26, the auction for the HCIDA Series 2006 settled at an interest rate of 7.55% for the succeeding 7-day interest period. On Feb. 25 Tampa Electric Company notified the trustee for the tax-exempt bonds issued for the benefit of the company by the HCIDA and PCIDA that the company has elected to purchase in lieu of redemption the $75 million PCIDA Solid Waste Disposal Revenue Refunding Bonds (Tampa Electric Company Project) Series 2007, and the $125.8 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Project) Series 2007 A, B and C, on Mar. 26, 2008, which is an interest payment date. The company does not intend to extinguish or cancel the bonds upon such purchase.

With respect to the company's remaining tax-exempt auction rate bonds, the $86.0 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2006, the company plans to convert such bonds on or after Mar. 19, 2008 to a fixed-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds, which allows for their conversion from an auction rate mode to other interest rate modes.

Because the auction rates reset every 7 days for $191.8 million of these bonds, and every 35 days for $95.0 million, management determined that it would not be reasonable or practical to remeasure the fair value as of the date of this report, but that the values could be different than the amount included in the fair value disclosure in **Note 7**.

Working Capital Settlement-TECO Transport Sale

On Feb. 19, 2008, TECO Energy, through a wholly-owned subsidiary, paid $3.7 million to adjust the working capital estimated at Dec. 31, 2007 related to the sale of TECO Transport Corporation to an unaffiliated investment group (see **Note 16**).

24. Quarterly Data (unaudited)

Financial data by quarter is as follows:

(millions, except per share amounts) *Quarter ended*	*Dec. 31* (2)	*Sep. 30*	*Jun. 30*	*Mar. 31*
2007				
Revenues	$ 858.3	$990.0	$866.5	$821.3
Income from operations	$ 328.8	$141.7	$ 87.7	$ 78.4
Net income				
Net income from continuing operations	$ 173.9	$ 92.8	$ 59.4	$ 72.8
Net income	$ 173.9	$ 92.8	$ 73.7	$ 72.8
Earnings per share (EPS)—basic				
EPS from continuing operations	$ 0.83	$ 0.44	$ 0.28	$ 0.35
EPS	$ 0.83	$ 0.44	$ 0.35	$ 0.35
Earnings per share (EPS)—diluted				
EPS from continuing operations	$ 0.83	$ 0.44	$ 0.28	$ 0.35
EPS	$ 0.83	$ 0.44	$ 0.35	$ 0.35
Dividends paid per common share	$ 0.195	$0.195	$0.195	$ 0.19
Stock price per common share (1)				
High	$ 17.91	$17.71	$18.58	$17.49
Low	$ 15.58	$14.84	$16.40	$16.22
Close	$ 17.21	$16.43	$17.18	$17.21

Quarter ended	*Dec. 31*	*Sep. 30*	*Jun. 30*	*Mar. 31*
2006				
Revenues	$ 826.2	$922.9	$862.6	$836.4
Income from operations	$ 78.4	$135.3	$118.3	$ 86.2
Net income				
Net income from continuing operations	$ 48.4	$ 79.7	$ 61.1	$ 55.2
Net income	$ 48.9	$ 79.7	$ 62.5	$ 55.2
Earnings per share (EPS)—basic				
EPS from continuing operations	$ 0.23	$ 0.38	$ 0.29	$ 0.27
EPS	$ 0.23	$ 0.38	$ 0.30	$ 0.27
Earnings per share (EPS)—diluted				
EPS from continuing operations	$ 0.23	$ 0.38	$ 0.29	$ 0.26
EPS	$ 0.23	$ 0.38	$ 0.30	$ 0.26
Dividends paid per common share	$ 0.19	$ 0.19	$ 0.19	$ 0.19
Stock price per common share (1)				
High	$ 17.50	$16.20	$16.75	$17.73
Low	$ 15.57	$14.86	$14.40	$15.97
Close	$ 17.23	$15.65	$14.94	$16.12

(1) Trading prices for common shares

(2) Fourth quarter 2007 results include debt extinguishment charges and TECO Transport results through Dec. 3, 2007. See **Note 16** for information regarding the sale of TECO Transport.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

Item 9A. CONTROLS AND PROCEDURES.

Conclusions Regarding Effectiveness of Disclosure Controls and Procedures.

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

Management's Report on Internal Control over Financial Reporting.

TECO Energy's Management's Report on Internal Control Over Financial Reporting is on page 100 of this report.

TECO Energy, Inc.'s internal control over financial reporting as of Dec. 31, 2007 has been audited by PricewaterhouseCoopers LLP, an independent registered certified public accounting firm, as stated in their report which is on page 101 of this report.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. A control system, no matter how well designed and operated, can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Changes in Internal Control over Financial Reporting.

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

Item 9B. OTHER INFORMATION.

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

(a) The information required by Item 10 with respect to the directors of the registrant is included under the caption "Election of Directors" in TECO Energy's definitive proxy statement for its Annual Meeting of Shareholders to be held on April 30, 2008 (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 38 of this report.

(c) The information required by Item 10 concerning Section 16(a) Beneficial Ownership Reporting Compliance is included under that caption in the Proxy Statement and is incorporated herein by reference.

(d) Information regarding TECO Energy's Audit Committee, including the committee's financial experts, is included under the caption "Committees of the Board" in the Proxy Statement, and is incorporated herein by reference.

(e) TECO Energy has adopted a code of ethics applicable to all of its employees, officers and directors. The text of the *Standards of Integrity* is available in the Investors section of the company's website at www.tecoenergy.com. Any amendments to or waivers of the *Standards of Integrity* for the benefit of any executive officer or director will also be posted on the website.

Item 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is included in the Proxy Statement beginning with the caption "Compensation Discussion and Analysis" and ending with "Post-Termination Benefits" just above the caption "Ratification of Appointment of Auditor", and under the caption "Compensation of Directors" and is incorporated herein by reference.

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

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

Equity Compensation Plan Information

(thousands, except per share price) *Plan Category*	*(a)* *Number of securities to be issued upon exercise of outstanding options, warrants and rights* [1]	*(b)* *Weighted-average exercise price of outstanding options, warrants and rights*	*(c)* *Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)* [2]
Equity compensation plans/arrangements approved by the stockholders			
2004 Equity Incentive Plan	8,728	$20.77	7,501
1997 Director Equity Plan	173	$20.82	189
	8,901	$20.77	7,690
Equity compensation plans/arrangements not approved by the stockholders			
None	—	—	—
Total	8,901	$20.77	7,690

(1) The reported amount for the 2004 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 2004 Equity Incentive Plan includes shares which may be issued as restricted stock, performance shares, performance-accelerated restricted stock, bonus stock, phantom stock, performance units, dividend equivalents and other forms of award available for grant under the plan.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by Item 13 is included under the captions "Certain Relationships and Related Person Transactions" and "Director Independence" in the Proxy Statement, and is incorporated herein by reference.

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 for TECO Energy is included under the caption "Item 2—Ratification of Appointment of Auditor" in the Proxy Statement and is incorporated herein by reference.

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 99

2. Financial Statement Schedules

   Condensed Parent Company Financial Statements Schedule I—pages 164-167

   TECO Energy, Inc. Schedule II—page 168

(b) The exhibits filed as part of this Form 10-K are listed on the Exhibit Index immediately preceding such Exhibits. The Exhibit Index is incorporated herein by reference.

(c) The financial statement schedules filed as part of this Form 10-K are listed in paragraph (a)(2) above, and follow immediately.

SCHEDULE I—CONDENSED PARENT COMPANY FINANCIAL STATEMENTS

TECO ENERGY, INC.
PARENT COMPANY ONLY

Condensed Balance Sheets

(millions)	*Dec. 31, 2007*	*Dec. 31, 2006*
Assets		
Current assets		
Cash and cash equivalents	$ 99.8	$ 402.3
Restricted cash	7.3	7.1
Advances to affiliates	395.8	377.7
Accounts receivable from affiliates	4.4	5.2
Accounts receivable	—	0.2
Interest receivable from affiliates	2.3	1.9
Other current assets	1.2	5.8
Total current assets	510.8	800.2
Property, plant and equipment		
Property, plant and equipment	0.7	0.5
Accumulated depreciation	(0.1)	(0.1)
Total property, plant and equipment	0.6	0.4
Other assets		
Investment in subsidiaries	2,637.0	2,403.1
Deferred income taxes	782.2	912.1
Other assets	3.2	16.7
Total other assets	3,422.4	3,331.9
Total assets	$3,933.8	$4,132.5
Liabilities and capital		
Current liabilities		
Long-term debt, current	$ —	$ 371.4
Accounts payable to affiliates	1.0	1.3
Accounts payable	11.4	6.6
Margin call collateral	42.3	—
Interest payable	5.0	20.5
Taxes accrued	3.8	—
Advances from affiliates	1,416.9	358.8
Other current liabilities	4.4	0.5
Total current liabilities	1,484.8	759.1
Other liabilities		
Long-term debt-others	404.1	1,600.8
Other liabilities	12.3	21.2
Total other liabilities	416.4	1,622.0
Capital		
Common equity	210.9	209.5
Additional paid in capital	1,489.2	1,466.3
Retained earnings (deficit)	334.2	83.7
Accumulated other comprehensive income	(1.7)	(8.1)
Common equity	2,032.6	1,751.4
Total capital	2,032.6	1,751.4
Total liabilities and capital	$3,933.8	$4,132.5

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

SCHEDULE I—CONDENSED PARENT COMPANY FINANCIAL STATEMENTS

TECO ENERGY, INC.
PARENT COMPANY ONLY

Condensed Statements of Income

For the years ended Dec. 31, (millions)	2007	2006	2005
Revenues	$ —	$ —	$ —
Expenses			
Administrative and general expenses	5.7	6.8	10.1
Other taxes	0.9	—	—
Transaction costs related to sale of business	27.1	—	—
Depreciation and amortization	0.4	—	—
Restructuring charges	—	—	0.1
Total expenses	34.1	6.8	10.2
Income from operations	(34.1)	(6.8)	(10.2)
Loss on debt extinguishment	(32.9)	(2.5)	(74.2)
Other income	1.4	—	—
Earnings from investments in subsidiaries	504.6	319.4	433.6
Interest income (expense)			
Interest income			
Affiliates	27.3	23.1	36.8
Others	9.3	20.3	9.6
Interest expense			
Others	(121.3)	(148.7)	(166.7)
Total interest expense	(84.7)	(105.3)	(120.3)
Income before income taxes	354.3	204.8	228.9
Benefit for income taxes	(58.9)	(41.5)	(45.6)
Net income	$ 413.2	$ 246.3	$ 274.5

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

SCHEDULE I—CONDENSED PARENT COMPANY FINANCIAL STATEMENTS

TECO ENERGY, INC.
PARENT COMPANY ONLY

Condensed Statements of Cash Flows

For the years ended Dec. 31, (millions)	*2007*	*2006*	*2005*
Cash flows from operating activities	$ 56.8	$ 10.2	$ (59.9)
Cash flows from investing activities			
Restricted cash	(0.2)	0.1	(0.3)
Capital expenditures	(0.1)	—	—
Investment in subsidiaries	(67.8)	(43.3)	—
Dividends from subsidiaries	338.7	282.3	275.6
Net change in affiliate advances	166.7	75.4	189.7
Other non-current investments	42.3	—	—
Cash flows from investing activities	479.6	314.5	465.0
Cash flows from financing activities			
Dividends to shareholders	(163.0)	(158.7)	(157.7)
Common stock	14.0	12.5	196.4
Proceeds from long-term debt	—	—	297.8
Repayment of long-term debt	(668.7)	(106.2)	(480.0)
Debt exchange premium	(21.2)	—	—
Equity contract adjustment payments	—	—	(2.0)
Cash flows used in financing activities	(838.9)	(252.4)	(145.5)
Net (decrease) increase in cash and cash equivalents	(302.5)	72.3	259.6
Cash and cash equivalents at beginning of period	402.3	330.0	70.4
Cash and cash equivalents at end of period	$ 99.8	$ 402.3	$ 330.0

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

SCHEDULE I—CONDENSED PARENT COMPANY FINANCIAL STATEMENTS

TECO ENERGY, INC.
PARENT COMPANY ONLY

Notes to Condensed Financial Statements

1. Basis of Presentation

TECO Energy, Inc., on a stand alone basis, (the parent company) has accounted for majority-owned subsidiaries using the equity basis of accounting. These financial statements are presented on a condensed basis. Additional disclosures relating to the parent company financial statements are included under the TECO Energy **Notes to Consolidated Financial Statements**, which information is hereby incorporated by reference.

The use of estimates is inherent in the preparation of financial statements in accordance with generally accepted accounting principles. Actual results could differ from those estimates. Certain prior year amounts were reclassified to conform to the current year presentation.

2. Long-term Obligations

In connection with debt tender and exchange transactions, $32.9 million of premiums and fees were expensed and are included in "Loss on debt extinguishment" on the Condensed Parent Income Statement for the year ended Dec. 31, 2007. See **Note 7** to the TECO Energy **Consolidated Financial Statements** for a description and details of long-term debt obligations of the parent company.

3. Commitments and Contingencies

See **Note 12** to the TECO Energy **Consolidated Financial Statements** for a description of all material contingencies and guarantees outstanding of the parent company.

4. Derivatives and Hedging

At Dec. 31, 2007, TECO Energy had a "Crude oil options receivable, net" asset totaling $78.5 million for transactions that were not designated as either a cash flow or fair value hedge. This balance includes the full settlement value of the crude oil options of $120.8 million, offset by the $42.3 million of margin call collateral collected. (See **Note 2**, New Accounting Pronouncements—Offsetting Amounts Related to Certain Contracts and **Note 21**, Derivatives and Hedging, to the TECO Energy **Consolidated Financial Statements.**)

5. Sale of TECO Transport

On Dec. 4, 2007, TECO Diversified, Inc., a wholly-owned subsidiary of the company, sold its entire interest in TECO Transport Corporation for cash to an unaffiliated investment group. In connection with this sale, TECO Energy Parent Only incurred transaction-related charges of $27.1 million.

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

TECO ENERGY, INC.

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
For the Years Ended Dec. 31, 2007, 2006 and 2005
(millions)

	Balance at Beginning of Period	Additions		Payments & Deductions [1]	Balance at End of Period
		Charged to Income	Other Charges		
Allowance for Uncollectible Accounts:					
2007	$4.6	$6.8	$—	$8.1	$3.3
2006	$6.9	$6.9	$—	$9.2	$4.6
2005	$8.0	$7.0	$—	$8.1	$6.9

(1) Write-off of individual bad debt accounts

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

TECO ENERGY, INC.

Dated: February 28, 2008

By: /s/ SHERRILL W. HUDSON

SHERRILL W. HUDSON,
Chairman of the Board, Director
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on February 28, 2008:

Signature	Title
/s/ SHERRILL W. HUDSON **SHERRILL W. HUDSON**	Chairman of the Board, Director and Chief Executive Officer (Principal Executive Officer)
/s/ GORDON L. GILLETTE **GORDON L. GILLETTE**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ SANDRA W. CALLAHAN **SANDRA W. CALLAHAN**	Vice President-Treasury and Risk Management (Principal Accounting Officer)

Signature	Title	Signature	Title
/s/ C. DUBOSE AUSLEY **C. DUBOSE AUSLEY**	Director	/s/ WILLIAM D. ROCKFORD **WILLIAM D. ROCKFORD**	Director
/s/ JAMES L. FERMAN, JR. **JAMES L. FERMAN, JR.**	Director	/s/ WILLIAM P. SOVEY **WILLIAM P. SOVEY**	Director
/s/ LUIS GUINOT, JR. **LUIS GUINOT, JR**	Director	/s/ J. THOMAS TOUCHTON **J. THOMAS TOUCHTON**	Director
/s/ LORETTA A. PENN **LORETTA A. PENN**	Director	/s/ JOSEPH P. LACHER **JOSEPH P. LACHER**	Director
/s/ TOM L. RANKIN **TOM L. RANKIN**	Director	/s/ PAUL L. WHITING **PAUL L. WHITING**	Director
/s/ JOHN B. RAMIL **JOHN B. RAMIL**	Director		

This Annual Report to Shareholders includes our Form 10-K for the year ended December 31, 2007 as amended by Amendment No. 1 on Form 10-K/A filed on March 7, 2008.

Corporate Officers and Board of Directors

TECO ENERGY EXECUTIVE OFFICERS

SHERRILL W. HUDSON
Chairman of the Board and Chief Executive Officer

JOHN B. RAMIL
President and Chief Operating Officer

CHARLES R. BLACK
President, Tampa Electric

WILLIAM N. CANTRELL
President, Peoples Gas System

J.J. SHACKLEFORD
President, TECO Coal

CHARLES A. ATTAL III
Vice President -
General Counsel and Chief Legal Officer

CLINTON E. CHILDRESS
Senior Vice President -
Corporate Services and
Chief Human Resources Officer

GORDON L. GILLETTE
Executive Vice President and Chief Financial Officer
and President, TECO Guatemala

TECO ENERGY STAFF OFFICERS

PHIL L. BARRINGER
Vice President - Controller, Operations

SANDRA W. CALLAHAN
Vice President - Treasury and Risk Management
(Treasurer and Chief Accounting Officer)

R. BRUCE CHRISTMAS
Vice President - Fuels Management

CHARLES O. HINSON III
Vice President - State Government Affairs

BURNIS KILPATRICK, JR.
Corporate Ethics and Compliance Officer

KAREN M. MINCEY
Vice President - Information Technology and
Chief Information Officer

DAVID E. SCHWARTZ
Vice President - Governance and Compliance,
Associate General Counsel and Corporate Secretary

JANET L. SENA
Vice President - Federal Affairs

BOARD OF DIRECTORS

SHERRILL W. HUDSON(3)
Chairman of the Board and Chief Executive Officer,
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.

LUIS GUINOT, JR.(2)(4)
Attorney and former Equity Partner, Shapiro, Sher,
Guinot & Sandler, P.A. (attorneys), Washington, D.C.;
former United States Ambassador to the Republic
of Costa Rica.

JOSEPH P. LACHER(1)(4)
Former President of Florida Operations for BellSouth
Telecommunications, Inc., Miami, Florida.

LORETTA A. PENN(2)
Senior Vice President and Chief Service
Excellence Officer, Spherion Corporation
(staffing and professional services), McLean, Virginia.

JOHN B. RAMIL(3)
President and Chief Operating Officer,
TECO Energy, Inc.

TOM L. RANKIN(1)(3)
Independent Investment Manager, Tampa, Florida;
former Chief Executive Officer, Lykes Energy, Inc. (the
former holding company for Peoples Gas System).

WILLIAM D. ROCKFORD(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.

WILLIAM P. SOVEY(2)(4)
Former Chairman of the Board and Chief Executive
Officer, Newell Rubbermaid, Inc. (consumer products)
Freeport, Illinois.

J. THOMAS TOUCHTON(1)(4)
President, The Witt-Touchton Company LLC
(private investments), Tampa, Florida.

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

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

WILLIAM P. SOVEY, *a member of the TECO Energy Board of Directors for 12 years, is retiring in April 2008. The company thanks Bill for his leadership and service. His many contributions will be missed.*

Information for Investors

INTERNET

Current information about TECO Energy is 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 on April 30, 2008, 10:00 a.m. 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 212-815-3700 (outside the U.S. and Canada)
By e-mail: shareowners@bankofny.com
By Web: www.stockbny.com

TRANSFER AGENT & REGISTRAR

BNY Mellon Shareholder Services
Receive and Deliver Department
P.O. Box 11002
Church Street Station
New York, NY 10286-1002
www.stockbny.com

DIVIDEND REINVESTMENT

The company offers a Dividend Reinvestment and Common Stock Purchase Plan, which allows common shareholders of record to purchase additional shares of common stock. All correspondence concerning this Plan should be directed to the Plan Agent:
BNY Mellon Shareholder Services
Investment Services Department/TECO Energy, Inc.
P.O. Box 1958
Newark, NJ 07101-1958

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 www.sec.gov or through the "Investors" section of our Web site 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

Gordon L. Gillette, Executive Vice President and Chief Financial Officer
Sandra W. Callahan, Vice President - Treasury and Risk Management
Mark M. Kane, Director - Investor Relations
813-228-1111

TECO ENERGY

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

This annual report is printed on paper containing 10% post-consumer recycled fiber.

END