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March 29, 2006

HAND DELIVERED

Ms. Blanca S. Bayo, Director
Division of Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Application of Tampa Electric Company for authority to issue and sell securities pursuant to Section 366.04, F.S. and Chapter 25-8, F.A.C. during the twelve months ending December 31, 2005; Docket No. 041103-EI

Dear Ms. Bayo:

Pursuant to Rule 25-8.009, Florida Administrative Code, and this Commission's Order No. PSC-04-1030-FOF-EI issued October 25, 2004, we enclose an original and three copies of Tampa Electric Company's Consummation Report regarding the issuance and sale of securities during the fiscal year ended December 31, 2005.

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

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Enclosures

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

IN RE: APPLICATION OF TAMPA ELECTRIC COMPANY FOR AUTHORITY TO ISSUE AND SELL SECURITIES PURSUANT TO SECTION 366.04, F.S., AND CHAPTER 25-8, F.A.C. DURING THE TWELVE MONTHS ENDING DECEMBER 31, 2005.	DOCKET NO. 041103-EI FILED: 03/29/06

CONSUMMATION REPORT

The applicant, Tampa Electric Company (the "Company"), pursuant to Commission Order No. PSC-04-1030-FOF-EI dated October 25, 2004 submits the following information.

1. Facts of Issues

The Company utilizes its credit facilities for its short-term borrowing needs. The Company currently has in place a $325 million five-year credit facility that matures in October 2010 and a $150 million one-year accounts receivable securitization borrowing facility that matures in January 2007.

Given the frequency of these short-term borrowing transactions, it is not practicable to give the details of each transaction. However, the Company's short-term borrowing activity in 2005 can be summarized as follows:

Short-term Borrowing Activity for the period beginning January 1, 2005 and ending December 31, 2005 - ($ 000)

Minimum Outstanding:	$ - 0 -
Maximum Outstanding:	$ 245,000
Average Outstanding:	$ 65,742
Weighted Average Interest Cost:	3.51 %

2. Terms and Conditions

Inasmuch as no securities were issued during the fiscal year ended December 31, 2005, there is no information to include in this consummation report information field.

3. Net Cash

Inasmuch as no securities were issued during the fiscal year ended December 31, 2005, there is no information to include in this consummation report information field.

4. Statement of Capitalization

Statements of capitalization, pretax interest coverage, debt interest requirements and preferred stock dividend requirements for the Company as of and for the year ending December 31, 2005 are as follows:

Capital Structure - ($000)	
Short-term debt	$ 215,000
Long-term debt	1,514,437
Preferred stock	- 0 -
Common equity	1,665,547
	$ 3,394,984

Pretax interest coverage	
Including AFUDC	3.52 times
Excluding AFUDC	3.52 times

Debt interest requirements ($000)	$ 113,394
Preferred stock dividends	$ - 0 -

5. Expenses of the Issues

Inasmuch as no securities were issued during the fiscal year ended December 31, 2005, there is no information to include in this consummation report information field.

The Company also submits the following exhibit:

Annual Report on Form 10-K for the year ended December 31, 2005 filed with the SEC on March 6, 2006

Respectfully submitted this
28th day of March 2006

TAMPA ELECTRIC COMPANY

By: Deirdre A. Brown

Deirdre A. Brown
Vice President Customer Service and
Regulatory Affairs

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

FORM 10-K

X Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2005

OR

___ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from _____ to _____

Commission File No.	Exact name of each Registrant as specified in its charter, state of incorporation, address of principal executive offices, telephone number	I.R.S. Employer Identification Number
1-8180	**TECO ENERGY, INC.** (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	**59-2052286**
1-5007	**TAMPA ELECTRIC COMPANY** (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	**59-0475140**

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

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

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

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

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

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

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.
YES [X] NO [ ]

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

Indicate by check mark whether TECO Energy, Inc. is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Exchange Act Rule 12b-2).

Large Accelerated filer [X] Accelerated filer [ ] Non-Accelerated filer [ ]

Indicate by check mark whether Tampa Electric Company is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Exchange Act Rule 12b-2).

Large Accelerated filer [] Accelerated filer [ ] Non-Accelerated filer [X]

Indicate by check mark whether TECO Energy, Inc. is a shell company (as defined in Rule 12b-2 of the Act).

YES [ ] NO [X]

Indicate by check mark whether Tampa Electric Company is a shell company (as defined in Rule 12b-2 of the Act).

YES [ ] NO [X]

The aggregate market value of TECO Energy, Inc.'s common stock held by nonaffiliates of the registrant as of June 30, 2005 was $3,929,550,154 based on the closing sale price as reported on the New York Stock Exchange.

The aggregate market value of Tampa Electric Company's common stock held by nonaffiliates of the registrant as of June 30, 2005 was zero.

The number of shares of TECO Energy, Inc.'s common stock outstanding as of Feb. 28, 2006 was 208,330,408. As of Feb. 28, 2006, there were 10 shares of Tampa Electric Company's common stock issued and outstanding, all of which were held, beneficially and of record, by TECO Energy, Inc.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement relating to the 2006 Annual Meeting of Shareholders of TECO Energy, Inc. are incorporated by reference into Part III.

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

This combined Form 10-K represents separate filings by TECO Energy, Inc. and Tampa Electric Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Tampa Electric Company makes no representations as to the information relating to TECO Energy, Inc.'s other operations.

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Index to Exhibits begins on page 175

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 4,998 employees as of Dec. 31, 2005.

TECO Energy's Corporate Governance Guidelines, the charter of each committee of the Board of Directors, and the code of ethics applicable to all directors, officers and employees, *the Standards of Integrity*, are available on the Investor Relations page 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 Investor Relations page of TECO Energy's website.

TECO Energy currently owns no operating assets but holds all of the common stock of Tampa Electric Company and through its subsidiaries TECO Diversified, Inc. or TECO Wholesale Generation, Inc., the other subsidiaries listed below. 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 is a holding company for regulated utilities and other unregulated businesses. As of Dec. 31, 2005, TECO Energy was exempt from registration under the Public Utility Holding Company Act of 1935 (PUHCA), which was repealed effective Feb. 8, 2006 by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. TECO Energy is currently subject to regulation under the Energy Policy Act of 2005, and plans to apply for a waiver in accordance with the regulations promulgated thereunder.

TECO Energy's significant 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 645,000 customers in West Central Florida with a net winter system generating capability of 4,423 megawatts (MW). **Peoples Gas System (PGS)**, a division of Tampa Electric Company, is engaged in the purchase and distribution of natural gas for residential, commercial, industrial and electric power generation customers in Florida. With more than 321,000 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 2005 was 1.1 billion therms.

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

TECO Transport Corporation (TECO Transport), a Florida corporation, owns no operating assets but owns all of the common stock of, or membership interests in, nine subsidiaries which provide waterborne transportation, storage and transfer services of coal and other dry-bulk commodities.

TECO Guatemala, Inc. (TECO Guatemala), a Florida corporation, primarily has investments in unconsolidated subsidiaries that participate in independent power projects and electric distribution in Guatemala.

TECO Energy's other unregulated companies with continuing operations include TECO Solutions, Inc. (TECO Solutions), TECO Properties, Inc. (TECO Properties), and TECO Investments, Inc. TECO Solutions' subsidiaries, many of which were sold in 2004 as part of TECO Energy's renewed focus on core utility and profitable operations, primarily provided mechanical contracting, air conditioning, electrical and plumbing systems and repair and maintenance services in Florida (see the **Discontinued Operations** discussion below).

TWG Merchant, Inc. (TWG Merchant), a Florida corporation, has subsidiaries that have formerly held interests in merchant power projects. TWG Merchant continuing operations includes the results of operations for the Dell power plant, which was sold in 2005; the uncompleted McAdams power plant, the turbines from which were sold to Tampa Electric in 2006; and TECO EnergySource, Inc. (TES), the energy marketing operation for the merchant plants, which has been inactive since the 2005 disposition of the Union and Gila River power stations.

Revenues from Continuing Operations (millions)	2005	2004	2003
Tampa Electric	$ 1,746.8	$ 1,687.4	$ 1,586.1
PGS	549.5	417.2	408.4
Total regulated businesses	2,296.3	2,104.6	1,994.5
TECO Coal	505.1	327.6	296.3
TECO Transport	278.2	249.6	260.6
TECO Guatemala	7.7[1]	11.5	158.4
TWG Merchant	0.4	7.6	(2.5)
	3,087.7	2,700.9	2,707.3
Other and eliminations	(77.6)	(61.5)	(144.4)
	$ 3,010.1	$ 2,639.4	$ 2,562.9

(1) Revenues for 2005 and 2004 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 Guatemalan entities not affected by FIN 46R.

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 2** for additional information regarding the deconsolidation of the Guatemala segment and its related revenues as of Jan. 1, 2004.

Discontinued Operations/Asset Dispositions

TECO Energy completed a number of asset dispositions in 2005, 2004 and 2003 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. 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 2004, TWG Merchant completed both the sale of its 50% indirect interest in Texas Independent Energy, LP (TIE) and the sale of Frontera Generation Limited Partnership (Frontera), the owner of the Frontera Power Station in Texas. In 2004, TECO Guatemala sold its 50% indirect interest in the Hamakua Power Station (Hamakua) in Hawaii. TECO BGA, Inc. (TECO BGA), TECO AGC, Ltd. (TECO AGC), and substantially all the assets of Prior Energy were also sold in 2004. Also in 2004, TECO Energy completed the sale of its general and limited partnership interests in Heritage Propane Partners, L.P. as part of a larger transaction that involved the merging of privately held Energy Transfer Company with Heritage Propane Partners. Hardee Power Partners, Ltd. (HPP) and substantially all the net assets of TECO Gas Services were sold in 2003. Additionally, at Dec. 31, 2005, TECO Energy was committed to a plan to sell TECO Thermal, an investment of TECO Solutions. As such, the assets and liabilities of TECO Thermal are designated as held for sale at Dec. 31, 2005. Results for CCC, BCH Mechanical, TECO Thermal, Frontera, Prior Energy, TECO BGA, and TECO AGC have been accounted for as discontinued operations for all periods reported. Revenues from these discontinued operations were $10.6 million, $141.7 million and $198.5 million in 2005, 2004 and 2003, respectively (see **Notes 16** and **21** to the TECO Energy **Consolidated Financial Statements**). HPP, prior to its sale, was accounted for in continuing operations because of the continuing involvement of Tampa Electric through a pre-existing agreement to purchase power from HPP. Also included in continuing operations prior to their respective sales were the results of the Dell Power Station, TIE, Hamakua and Heritage Propane Partners.

TWG Merchant's interests in the Union and Gila River project companies, which owned merchant generation plants in Arkansas and Arizona, respectively, were held by an indirect wholly owned subsidiary of TWG Merchant, TECO-Panda Generating Company, L.P. (TPGC). TPGC was part of the TWG Merchant operating segment until designated as assets held for sale in December 2003. As of Dec. 31, 2003, TECO Energy management was committed to a plan to sell TECO Energy's indirect ownership of the equity or net assets of TPGC through a sale and transfer agreement to the lenders of ownership of these plants. 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, 2004 and 2003 were $109.1 million, $510.7 million and $319.4 million, respectively. Net income (loss) from the discontinued operations of TPGC were $65.1 million, $(96.0) million and $(918.7) million in 2005, 2004 and 2003, respectively.

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. Through 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 2,359 employees as of Dec. 31, 2005, of which 881 were represented by the International Brotherhood of Electrical Workers and 214 were represented by the Office and Professional Employees International Union.

In 2005, approximately 48% of Tampa Electric's total operating revenue was derived from residential sales, 30% from commercial sales, 9% from industrial sales and 13% 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)*	2005	2004	2003
Residential	$ 838.1	$ 820.2	$ 767.4
Commercial	516.4	505.5	460.1
Industrial – Phosphate	63.3	68.7	65.3
Industrial – Other	96.3	97.3	88.5
Other retail sales of electricity	140.3	139.2	124.9
Total retail	1,654.4	1,630.9	1,506.2
Sales for resale	50.6	41.1	41.6
Other	41.8	15.4	38.3
	$ 1,746.8	$ 1,687.4	$ 1,586.1

Megawatt-hour Sales *(millions)*	2005	2004	2003
Residential	8,558	8,293	8,265
Commercial	6,234	5,988	5,860
Industrial	2,478	2,556	2,579
Other retail sales of electricity	1,642	1,600	1,538
Total retail	18,912	18,437	18,242
Sales for resale	773	664	691
Total energy sold	19,685	19,101	18,933

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 represents less than 3% of Tampa Electric's 2005 base revenues.

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

Regulation

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

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

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

Tampa Electric's rates and allowed return on equity (ROE) range of 10.75% to 12.75% with a midpoint of 11.75% are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties. Tampa Electric expects to continue earning within its allowed ROE range without a base rate increase, even with the rate base additions associated with the repowering of the H. L. Culbreath Bayside Power Station (Bayside), which was completed in January 2004.

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 2005, Tampa Electric filed with the FPSC for approval of fuel and purchased power, capacity, environmental and conservation cost recovery rates for the period January through December 2006. In late October 2005, Tampa Electric filed updated fuel and purchased power rates which included significantly higher actual than projected costs for the third quarter of 2005 due to the rapid increase in natural gas prices as a result of hurricanes Dennis, Katrina and Rita. In November, the FPSC approved Tampa Electric's requested changes. The rates include the impacts that were estimated at the time of the FPSC filing of increased natural gas and coal prices expected in 2006, the collection of some of the underestimated 2005 fuel expenses, the proceeds from the sale of excess sulfur dioxide (SO_2) emissions allowances and the operating and maintenance (O&M) costs associated with the Big Bend Units 1 – 3 pre-selective catalytic reduction (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 Commission'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 **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. See also the **Regulation – Regional Transmission Organization (RTO)** section of **MD&A.**

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.

In November 2004, Tampa Electric and the market-based rate authorized entities within TECO Energy filed a triennial market power study update. On Mar. 2, 2005, after a review of that filing and supporting information, the FERC determined that Tampa Electric had failed certain tests for market power within certain regions of Florida. The FERC instituted an investigation of Tampa Electric's potential market power in those regions and ordered Tampa Electric to make a compliance filing to determine if Tampa Electric has market power in other regions of the state. Tampa Electric submitted compliance filings after which FERC staff requested additional information to rebut the presumption that Tampa Electric has generation market power, which Tampa Electric submitted in September 2005. In November 2005, FERC found that Tampa Electric did have generation market power in its own control and within the area served by Reedy Creek (Walt Disney World). Rather than continuing to contest FERC's conclusion, Tampa Electric has agreed to limit itself to only conducting wholesale cost-based transactions in these two parts of Florida. Tampa Electric can continue to make wholesale transactions at market-based rates everywhere else in Florida and throughout the country.

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, Standard Costs, 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 purposes of their own wholesale power transactions. 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.

In 2004, FERC also issued Standards of Conduct for Transmission Providers to ensure that all transmission customers, affiliated and non-affiliated, are treated on a non-discriminatory basis and required TECO Energy affiliates have implemented programs to ensure compliance.

In December 1999, the FERC issued Order No. 2000, dealing with FERC's continuing effort to affect open access to transmission facilities in large regional markets. In response, the peninsular Florida IOUs agreed to form an RTO to be known as GridFlorida LLC which would independently control the transmission assets of the filing utilities, as well as other utilities in the region that chose to join. In March 2001, the FERC conditionally approved GridFlorida, but in May 2001, the FPSC questioned the prudence of the three filing utilities joining GridFlorida. After an October 2001 hearing, the FPSC found that the companies were prudent in forming GridFlorida, but ordered the companies to modify their proposal to develop an RTO model that did not provide for the RTO to own the transmission assets. In August 2002, the FPSC voted to approve many of the compliance changes submitted, but set an October 2002 hearing on the market design changes proposed in the updated filing. In October 2002, the process was delayed when the Office of Public Counsel (OPC) filed an appeal with the Florida Supreme Court asserting that the FPSC could not relinquish its jurisdictional responsibility to regulate the IOUs and, by approving GridFlorida, they were doing just that. Oral arguments occurred in May 2003, and the Florida Supreme Court dismissed the OPC appeal citing that it was premature because certain portions of the FPSC GridFlorida order are not final. In September 2003, a joint meeting of the FERC and FPSC took place to discuss wholesale market and RTO issues related to GridFlorida and in particular, federal/state interactions. During 2004, deliberations by the FPSC were put on hold to allow a consulting firm, engaged by the GridFlorida applicants, to conduct a cost/benefit study of the GridFlorida RTO. As a result, the FPSC held a series of collaborative meetings during the year with all interested parties to facilitate the development of the study methodology as well as participate in the submission of data required to complete the study. The study results were submitted to the Commission in late 2005. The results of the study indicate significant benefits and savings that could accrue from the RTO design, but even larger costs for implementation. Therefore, the GridFlorida participants are exploring alternative designs in an effort to retain many of the benefits shown in the study while reducing the costs for implementation. In January 2006, the applicants filed a request with the FPSC to close the docket. The ultimate results of the process remain uncertain, but no final resolution is expected before late 2006.

Fuel

Approximately 58% of Tampa Electric's generation of electricity for 2005 was coal-fired, with natural gas representing approximately 41% and oil representing approximately 1%. Tampa Electric used its generating units to meet approximately 84% of the system load requirements, with the remaining 16% coming from purchased power. Tampa Electric's average delivered fuel cost per million Btu and average delivered cost per ton of coal burned have been as follows:

Average cost per million Btu:	*2005*	*2004*	*2003*	*2002*	*2001*
Coal	$ 2.25	$ 2.14	$ 2.02	$ 1.93	$ 2.06
Oil	$ 10.16	$ 6.81	$ 6.42	$ 5.33	$ 5.79
Gas (Natural)	$ 9.37	$ 7.14	$ 6.45	$ 5.86	$ 4.84
Composite	$ 4.79	$ 3.64	$ 2.83	$ 2.11	$ 2.19
Average cost per ton of coal burned	$ 53.00	$ 50.06	$ 48.32	$ 45.04	$ 47.53

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 low-sulfur coal, high-sulfur coal, and petroleum coke which is gasified and subject to sulfur and particulate matter removal prior to combustion, natural gas and oil; and Phillips Station burns residual fuel oil.

Coal. Tampa Electric burned approximately 4.4 million tons of coal and petroleum coke during 2005 and estimates that its combined coal and petroleum coke consumption will be about 4.8 million tons for 2006. During 2005, Tampa Electric purchased approximately 55% of its coal under long-term contracts with eight suppliers, and approximately 45% of its coal and petroleum coke in the spot market. Tampa Electric expects to obtain approximately 70% of its coal requirements in 2006 under long-term contracts with five suppliers and the remaining 30% 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.

For information concerning transportation services by affiliated companies to Tampa Electric, see the **TECO Transport** section below.

In 2005, approximately 59% of Tampa Electric's coal supply was deep-mined, approximately 34% 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. In 2005, Tampa Electric contracted for 80% of the expected gas needs for the January 2006 – April 2006 period and 51% of the May 2006 – October 2006 period. Tampa Electric will tender an RFP for supply requirements in February 2006 with responses due Mar. 15, 2006. Through the RFP process Tampa Electric expects to contract an additional 34% for May 2006 – October 2006, 80% for November 2006 – April 2007 and 60% for May 2007 – October 2007 periods. Additional volume requirements over term supply are expected to be 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 ranging from September 2006 to September 2021.

Franchise fees payable by Tampa Electric, which totaled $30.0 million in 2005, are calculated using a formula based primarily on electric revenues and are collected on customers' bills.

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

Environmental Matters

Consent Decree

Tampa Electric Company, as a result of negotiations with the Environmental Protection Agency (EPA), the U.S. Department of Justice 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, 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 NO_x 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 Bayside units 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.

In 2004, Tampa Electric decided to install SCRs for NO_x control on Big Bend Unit 4, with an expected in-service date by Jun. 1, 2007. Tampa Electric has also decided to install SCRs 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 SCRs is currently in progress. Tampa Electric's capital investment forecast includes amounts in the 2006 through 2010 period for compliance with the NO_x, SO_2 and particulate matter reduction requirements (see **Environmental Matter** – *Capital Expenditures* section below).

Emission Reductions

Projects that Tampa Electric has committed to under the Consent Decree and Consent Final Judgment will result in significant reductions in emissions. Since 1998, Tampa Electric has reduced annual SO_2, NO_x, and particulate matter (PM) emissions from its facilities by 161,600 tons, 39,500 tons, and 4,300 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 NO_x 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 NO_x by 60,000 tons per year.

To date, these projects have resulted in the reduction of SO_2, NO_x and PM emissions by 92%, 57%, and 83%, respectively, below 1998 levels. In total, Tampa Electric's emission reduction initiatives will result in the reduction of SO_2, NO_x and PM emissions by 89%, 89%, 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 NO_x controls at Big Bend Station, which would lead to a mercury removal efficiency of approximately 70%.

Tampa Electric has supported voluntary efforts to reduce carbon emissions and has taken significant steps to reduce its overall emissions at its facilities. Since 1998, Tampa Electric has reduced its systemwide emissions of CO_2 by approximately 24%, bringing emissions to below 1990 levels and through 2010, those reductions are expected to be very close to 1990 levels. Emissions of CO_2 should remain near 1990 levels until the addition of the next base load unit which is expected after 2012. As of 2005, the repowering resulted in a decrease in CO_2 emissions of approximately 4.0 million tons below 1998 levels. During this same timeframe, the numbers of retail customers and retail energy sales have risen by approximately 40%.

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, 2005, Tampa Electric Company has estimated its ultimate financial liability to be approximately $14.3 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 parties' 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

During the five years ended Dec. 31, 2005, Tampa Electric spent $80.7 million, excluding the Gannon repowering, on capital additions to meet environmental requirements.

In total, Tampa Electric spent an estimated $31.1 million in 2005 on environmental projects. Environmental expenditures are estimated at $87.7 million for 2006 and an additional $295.5 million in total for 2007 through 2010. These totals include the expenditures required to comply with the EPA Consent Decree and to undertake comprehensive environmental operations improvements at Big Bend Station.

In 2005, Tampa Electric spent approximately $3.9 million for compliance with the EPA Consent Decree requirements at Big Bend Station for early NO_x and PM emissions reductions and to improve the scrubber systems to reduce SO_2 emissions. Estimated expenditures for the on-going early NO_x reductions in 2006 are estimated at $3.6 million and an additional $22.7

million in 2007-2010. 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 Selective Catalytic Reduction Systems (SCRs) for the reduction of NO_x. Based on this decision, $24.7 million was spent in 2005 to initiate the design, engineering and construction of the SCRs. Additional expenditures will be required in 2006, estimated at $77.5 million, and it is forecast that $210.4 million will be spent from 2007 through 2010.

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 upgrades to 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 by-products from the existing systems in conjunction with construction of the new/replacement systems. In 2005, Tampa Electric spent approximately $5.3 million on these environmental operations projects. Estimated expenditures for the continued implementation of these projects in 2006 are estimated at $6.5 million an additional $62.4 million in 2007-2010.

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.

PGS uses three interstate pipelines to receive gas for sale or other delivery to customers connected to its distribution system. PGS does not engage in the exploration for or production of natural gas. PGS operates a natural gas distribution system that serves over 321,000 customers. The system includes approximately 10,000 miles of mains and 6,000 miles of service lines. (See PGS' **Franchises** section below.)

In 2005, the total throughput for PGS was 1.1 billion therms. Of this total throughput, 13% 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 17% was gas sold off-system. Industrial and power generation customers consumed approximately 60% of PGS' annual therm volume, commercial customers used approximately 34%, 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 25% of total revenues. New residential construction including natural gas and conversions of existing residences to gas have steadily increased since the late 1980's.

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

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

	Revenues			*Therms*		
(millions)	*2005*	*2004*	*2003*	*2005*	*2004*	*2003*
Residential	$ 138.9	$ 115.0	$ 105.7	70.7	65.8	64.2
Commercial	173.8	151.8	143.7	380.3	368.1	354.8
Industrial	187.6	106.5	114.9	394.6	399.4	406.2
Power Generation	13.7	11.1	10.1	291.7	291.7	363.7
Other revenues	35.5	32.8	34.0	—	—	—
Total	$ 549.5	$ 417.2	$ 408.4	1,137.3	1,125.0	1,188.9

PGS had 566 employees as of Dec. 31, 2005. A total of 88 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 – Peoples Gas 2002 Rate Proceeding** 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. For a description of the most recent adjustment, see the **Regulation – Cost Recovery Clauses – Peoples Gas** 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 11,700 transportation customers as of Dec. 31, 2005 out of 28,300 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 regulated 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 57 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 initiated gas delivery in 2003 through five gate stations. The addition of the Gulfstream pipeline enhances reliability of service and helps meet the capacity needs for PGS' growing customer base.

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 6 to 8 franchises in 2006, the majority of which will be renewals of existing agreements. Franchise fees payable by PGS, which totaled $9.9 million in 2005, 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.**

Expenditures

During the five years ended Dec. 31, 2005, PGS has not incurred any material capital expenditures to meet environmental requirements, nor are any anticipated for 2006 through 2010.

TECO COAL

Overview

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

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

The Company currently operates 29 underground mines which employ the room and pillar mining method and 11 surface mines.

In 2005, TECO Coal subsidiaries sold 9.69 million tons of coal. All of this coal was sold to customers other than

Tampa Electric. Of the total sold, 6.36 million tons were produced and sold as synthetic fuel. As of Dec. 31, 2005, the TECO Coal operating companies had a combined estimated 258.2 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 addition, in that year properties were also acquired in Pike County, Kentucky and Clintwood Elkhorn Mining Company was formed. Premier Elkhorn Coal Company and Pike Letcher Land Company were formed in 1991, when additional property was acquired in Pike and Letcher Counties, Kentucky.

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

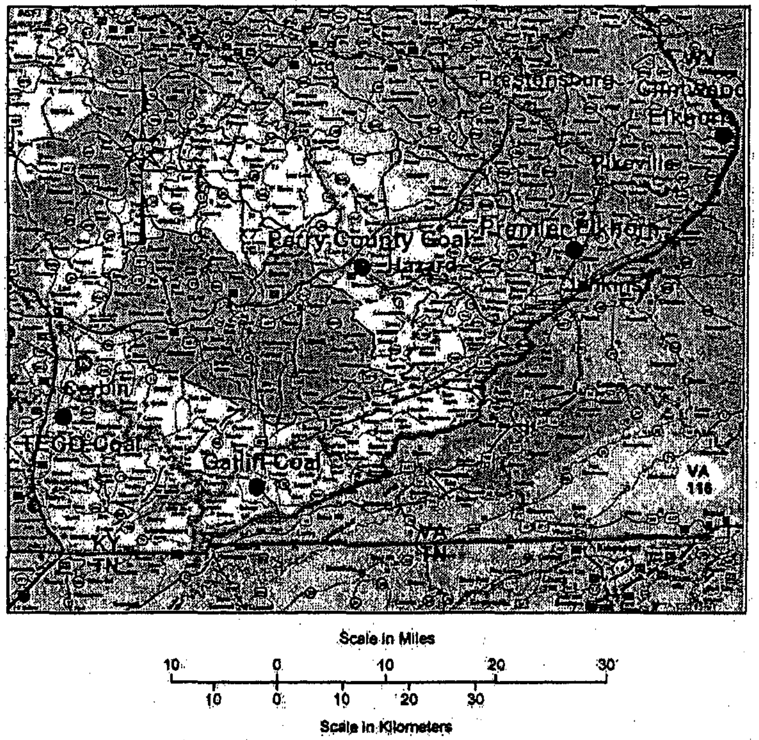
The newest mining company in the TECO Coal family is Perry County Coal Corporation, which was purchased in 2000 and is located in Perry, Knott and Leslie Counties, Kentucky.

TECO Synfuel Holdings, LLC and TECO Synfuel Operations, LLC were formed in 2003 to administer the production and sale of synthetic fuel product at various TECO Coal subsidiaries.

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 17 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 91% of 2005 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, 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

Significant Projects

COMPANY	FACILITY	LOCATION	RAILROAD SERVICE	UTILITY SERVICE
Gatliff Coal	Ada Tipple	Himyar, KY	CSXT Railroad	Cumberland Valley Electric
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	Burk 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

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Significant projects completed in 2005 included the following:

Perry County Coal

- Startup of production from two additional sections in the Elkhorn #3 seam, bringing the total to three production sections.

- Explored and identified major reserves in the Elkhorn #4 seam located to the southwest of the current Perry County Coal facilities. Several major leases were acquired on this project.

Premier Elkhorn Coal

- Completed the acquisition of several properties adjacent to the Millard project area, totaling over 18,000 mineral acres.

Clintwood Elkhorn Mining

- Opened the Cedar Branch surface mine, adding twenty-five employees, as well as a contract Highwall miner.

Mining Complexes

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

MINING COMPLEXES
Table 2

	Location	Mine Type	Mining Equipment	Transportation	Tons Produced (in Millions) 2005	2004	2003	Tons Sold (in millions) 2005	Year Established Or Acquired
Gatliff Coal Company	Bell County, KY/ Knox County, KY/ Campbell County, TN	S	D/L	T	0.34	0.29	0.39	0.37	1974
Clintwood Elkhorn Mining	Pike County, KY Buchanan County, VA	U, S	CM, D/L, HM, A	R, R/V	2.18	1.75	1.59	2.34	1988
Premier Elkhorn Coal	Pike County, KY/Letcher County, KY/ Floyd County, KY	U, S	CM, D/L	R,T,R/B,T/B	3.31	3.65	3.69	3.57	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	3.37	2.81	2.64	3.39	2000
TOTAL					9.20	8.50	8.31	9.67	

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

Gatliff Coal Company

Located in Bell County, Kentucky, Gatliff Coal Company is supplied by one surface mine. Principal products at this location consist primarily of high quality steam coal for utilities. Products from this operation are transported by trucking contractors. Rich Mountain Coal Company formerly operated as a contractor for Gatliff Coal Company's Tennessee production which is currently in non-producing reclamation status. Gatliff Coal Company produced 0.34 million tons of coal in 2005, leaving a reserve base of 9.5 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 eight 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 three underground mines and two surface mines. The Hurley Virginia operation facility also supplies high-volatile metallurgical coal as well as steam coal products. Products from both locations are shipped domestically to customers in North America via Norfolk Southern Corporation and vessels via the Great Lakes. International customers receive their products via ocean vessels from Lamberts Point, Virginia. In total, Clintwood Elkhorn Mining Company produced 2.18 million tons of coal in 2005, leaving a reserve base of 35.6 million recoverable tons.

Premier Elkhorn Coal Company

Located near Myra, in Pike County, Kentucky, Premier Elkhorn Coal Company is supplied by production from thirteen underground mines and four 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. Internationally, products are shipped via TECO Coal's sister company, TECO Bulk Terminal, in Davant, Louisiana. 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. During 2005, over 18,000 mineral acres adjacent to the Millard property (acquired in 2004) were leased or optioned. Premier Elkhorn Coal Company produced 3.31 million tons of coal in 2005, leaving a reserve base of 83.1 million recoverable tons.

Perry County Coal Corporation

Located near Hazard, Kentucky in Perry County, Perry County Coal Corporation is supplied by five underground mines and one surface mine. Principal products include high quality steam coal for utilities and industrial stoker products. Facilities include a 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. During 2005, additional reserves in the Southwest Elkhorn #4 Project area were identified and significant leases totaling over 1,000 acres were acquired. Exploration for this project will continue in 2006. Perry County Coal Corporation produced 3.37 million tons of coal in 2005, leaving a reserve base of 130 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 May 2004 and an additional 8 percent in July 2005 (see the **TECO Coal** section of **MD&A**). Sales of the fuel processed through these types of facilities are eligible for non-conventional fuels tax credits under the Internal Revenue Code, which are available through 2007. TECO Coal received Private Letter Rulings from the Internal Revenue Service confirming that the facilities produce 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 is estimated to be $1.15 per million Btu in 2005, $1.13 per million Btu in 2004 and $1.11 per million Btu in 2003. This rate escalates with inflation but could be limited by domestic oil prices. The weighted average price of domestic oil for 2005 would have had to exceed $59.00 per barrel to have adversely impacted the credits allowed for 2005. See the **Outlook – Synthethic Fuel** 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 subsidiaries sell 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. We employ 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 and by effectively managing production and processing costs.

Employees

As of Dec. 31, 2005, TECO Coal and its subsidiaries employed a total of 940 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 1977. TECO Coal's subsidiaries are also subject to various Kentucky, Tennessee and Virginia mining laws which require approval of roof control, ventilation, dust control and other facets of the coal mining business. Federal and state inspectors inspect the mines to ensure compliance with these laws. TECO Coal believes it is in substantial compliance with the standards of the various enforcement agencies. It is unaware of any mining laws or regulations that would materially affect the market price of coal sold by its subsidiaries, although recent mining accidents within the industry could lead to new legislation that could impose additional costs on TECO Coal.

Black Lung Legislation

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each coal mine operator must make payment of federal black lung benefits to claimants who are current and former employees, certain survivors of a miner who dies from black lung disease, and to a trust fund for the payment of benefits and medical expenses to claimants who last worked in the coal industry prior to July 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 will increase the percentage of claims approved and the overall cost of Black Lung to coal operators. TECO Coal, with the help of its consulting actuaries, intends to continue aggressively monitoring claims very closely.

Workers' Compensation

The TECO Coal subsidiaries are liable for worker's 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 2005, TECO Coal spent approximately \$2.8 million on environmental protection and reclamation programs. TECO Coal expects to spend a similar amount in 2006 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 0.72% sulfur per pound of 12,000 Btu coal. Compliance coal requires no mixing with other coals or use of sulfur dioxide reduction technologies by generators of electricity to comply with the requirements of the federal Clean Air Act.

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

Continuous mining. One of two major underground mining methods now used in the United States. This process utilizes a continuous miner. The continuous miner removes or "cuts" the coal from the seam. The loosened coal then falls 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.

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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 the impurities that become gaseous when heated to certain temperatures.

Highwall miner. An auger-like apparatus that drives parallel rectangular entries from the surface up to 1000 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 2450 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 the Company'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. 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 TRANSPORT

TECO Transport directly or indirectly owns an interest in nine subsidiaries which transport, store and transfer coal and other dry-bulk commodities. These subsidiaries include TECO Ocean Shipping, Inc. (Ocean Shipping), TECO Barge Line, Inc. (TECO Barge), TECO Bulk Terminal, LLC (Bulk Terminal) and TECO Towing Company. TECO Transport currently owns no operating assets. TECO Transport and its subsidiaries had 849 employees as of Dec. 31, 2005.

TECO Transport's subsidiaries perform substantial services for Tampa Electric. In 2005, approximately 31% of TECO Transport's revenues were from Tampa Electric and approximately 69% 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 is 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) is for domestic and international movements of dry-bulk commodities and domestic phosphate movements. Both the terminal and river transport operations handle a variety of dry-bulk commodities for third-party customers.

Ocean Shipping transports products in the Gulf of Mexico and worldwide, and TECO Barge operates on the Mississippi, Ohio and Illinois rivers and their tributaries. Their primary competitors are other barge and shipping lines and railroads, as well as a number of other companies offering transportation services on the waterways used by TECO Transport's subsidiaries. Ocean Shipping is the largest U.S. flag coastwise dry-bulk operator based on capacity, while TECO Barge is one of the ten largest companies in its business, based on number of barges. To date, physical and technological improvements have allowed ship and barge operators to maintain competitive rate structures with alternate methods of transporting bulk commodities when the origin and destination of such shipments are contiguous to navigable waterways.

Bulk Terminal operates the largest transfer and storage terminal on the Gulf coast. Demand for the use of such terminals is dependent upon customers' use of water transportation versus alternate means of moving bulk commodities and the demand for these commodities. Competition consists primarily of mid-stream operators who operate floating cranes or other floating discharge and loading equipment, and other land-based terminals.

Competition within TECO Transport's markets is based primarily on geographic markets served, pricing, and service level. The majority of the ocean business and all of the river business is 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, is not subject to significant seasonal fluctuation, but is sensitive to weather and economic conditions.

The Interstate Commerce Act exempts from regulation water transportation of certain dry-bulk commodities. In 2005, all transportation services provided by TECO Transport's subsidiaries were within this exemption.

TECO Transport's subsidiaries are 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 2005, TECO Transport spent $0.3 million for environmental compliance. Environmental expenditures are estimated at $0.4 million in 2006, primarily for work on solid waste disposal and storm water drainage at the Bulk Terminal facility in Louisiana and for expenses related to oil and bilge water disposal at its river-barge repair facility in Illinois.

TECO GUATEMALA

TECO Guatemala, Inc. (TECO Guatemala) (formerly TWG Non-Merchant, Inc.), has subsidiaries that have interests in independent power projects in Guatemala and a minority ownership interest in a distribution center. The TECO Guatemala subsidiaries had 123 employees as of Dec. 31, 2005.

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), a private distribution and generation company, 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. In 2002, CGESJ transferred the port assets to Tecnología Marítima, S.A. (TEMSA), a new indirect wholly-owned subsidiary. TEMSA, 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, a local bank in Guatemala. Political risk insurance has been obtained for currency inconvertibility, expropriation and political violence covering up to 100% of TECO Guatemala's indirect equity investment and economic returns.

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 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. Political risk insurance has been obtained for currency inconvertibility, expropriation and political violence covering up to 100% of TECO Guatemala's indirect equity investment and economic returns.

In 1998, a consortium that includes affiliates of TECO Energy, Iberdrola, an electric utility in Spain, and Electricidade de Portugal, an electric utility in Portugal, completed the purchase of an 80% ownership interest in EEGSA for $520 million. The company indirectly owns a 24% interest in this consortium and contributed $100 million in equity. EEGSA serves more than 776,000 customers. EEGSA's service territory includes the capital of Guatemala, Guatemala City. The consortium obtained limited-recourse debt financing for a portion of the purchase price. TECO Guatemala has obtained political risk insurance for currency inconvertibility, expropriation and political violence covering up to 100% of TECO Guatemala's indirect equity investment and economic returns.

As a result of the adoption of FIN 46R, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51*, effective Jan. 1, 2004, CGESJ and TCAE were deconsolidated. See **Note 2** to the TECO Energy **Consolidated Financial Statements** for additional information about the adoption of FIN 46R.

For financial information about geographic areas, see **Note 14** to the TECO Energy **Consolidated Financial Statements.**

TECO SOLUTIONS

TECO Solutions was formed when it appeared that Florida was moving toward more competitive energy markets to offer customers (primarily in Florida) a comprehensive package of energy services and products. The subsequent move away from proposed deregulation and TECO Energy's renewed focus on the core utility operations caused the company to reexamine its participation in these lines of business. The result was the sale of several of the entities within TECO Solutions (see **Note 16** to the TECO Energy **Consolidated Financial Statements** for detailed information about these sale transactions). Operating companies under TECO Solutions include TECO Gas Services Inc. and TECO Partners, Inc., with 50 total employees as of Dec. 31, 2005.

TECO Solutions sold BCH Mechanical effective Dec. 31, 2004. BCH's results of operations are accounted for as discontinued operations for all periods reported.

In 2003, TECO Solutions sold TECO Gas Services' commercial and industrial book of business. TECO Gas Services will continue to provide services to their cogeneration customers. TECO Gas Services owns no operating assets.

In 2004, TECO Solutions completed the sale of substantially all the assets of Prior Energy, a leading natural gas management company. Prior Energy's results are accounted for as discontinued operations for all periods reported.

TECO Propane Ventures (TPV) held TECO Energy's propane business investment. In 2000, TECO Energy combined its propane operations with three other southeastern propane companies to form U.S. Propane. In a series of transactions, U.S. Propane combined with Heritage Holdings, Inc. In 2004, U.S. Propane completed the sale of its direct and indirect equity investments in Heritage Propane Partners, L.P. (Heritage). TPV owns no operating assets.

In December 2005, TECO Thermal Systems, Inc. (TECO Thermal), a subsidiary of TECO Solutions, signed a contract for the sale of a district cooling facility located in Miami, Florida that provides chilled water for air conditioning to certain commercial customers. This transaction is expected to close in 2006. TECO Thermal's results are accounted for as discontinued operations for all periods presented.

TWG MERCHANT, INC.

The TWG Merchant entity was created to own interests in merchant power projets. 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. Since that time, TECO Energy has continued the steps in implementing that strategy, including the sale of merchant power assets as discussed below in the **Summary of Projects.** As of Dec. 31, 2005, TWG Merchant has sold its interests in all independent power projects with the exception of one independent power project in Mississippi (McAdams). This project has halted construction, and is currently undergoing dismantlement, including the sale of turbines and associated equipment to Tampa Electric. TWG Merchant had 3 employees as of Dec. 31, 2005.

As discussed above under **TECO Energy,** the TWG Merchant operating segment has been comprised of the continuing merchant operations, including the direct and indirect results from continuing operations of the independent power projects in Virginia, Mississippi and Arkansas, as well as the energy marketing operations for these plants, TECO Energy Source, Inc. (TES). Prior to its sale in December 2004, the results of operations for Frontera were included in TWG Merchant. Also, prior to Dec. 31, 2003, the results of operations of Union and Gila River's independent power projects in Arkansas and Arizona, respectively, (TPGC) were included in TWG Merchant. These are now reported in discontinued operations. The results of TWG Merchant's investment in the Texas Independent Energy, L.P. (TIE) projects were also included in the TWG Merchant segment, prior to its sale in August 2004.

TWG Merchant operations are subject to federal, state and local environmental laws and regulations covering air quality, water quality, land use, power plant, substation and transmission line siting, noise and aesthetics, solid waste and other environmental matters.

See **Note 14** to the TECO Energy **Consolidated Financial Statements** for specific details of the results of operations for the TWG Merchant operating segment.

Summary of Projects

Union and Gila River Projects (TPGC)

In 2000, TWG Wholesale Generation, Inc. (TWG) announced a joint venture with Panda Energy International (Panda) to build, own and operate two natural gas power plants located in Arkansas and Arizona, respectively, known as the Union and Gila River projects. In February 2002, subsidiaries of TWG entered into an agreement requiring those subsidiaries to purchase 100% of Panda's interest in the joint venture for $60 million in 2007, unless Panda chose to remain a partner by canceling the agreement and paying a cancellation fee. In April 2003, subsidiaries of TWG Merchant and Panda agreed to amendments to this agreement which resulted in TWG Merchant indirectly consolidating the joint venture (TPGC) at that time. In June 2003, subsidiaries of TWG Merchant terminated Panda's continued involvement in the partnership, resulting in the recognition of after-tax charges in the second quarter of 2003 of $155.9 million, as a direct result of the consolidation of TPGC (see **Note 20** to the TECO Energy **Consolidated Financial Statements**).

In 2001, the project entities owned by TWG and Panda closed on a $2,175 million financing for the Union and Gila River power stations, including $1,675 million in five-year non-recourse debt and $500 million in equity bridge loans. The equity bridge loans were guaranteed by TECO Energy and were repaid in 2002 and 2003. As a result of events in October 2003 and December 2003 (see the **TWG Merchant** section of **MD&A**), and other economic factors impacting the general market conditions for independent power projects, TWG Merchant recognized an after-tax asset impairment charge of $762.0 million ($1,185.7 million pretax) in 2003. In 2004, discussions with the steering committee of the lending group resulted in an agreement on all material terms and forms of definitive agreements for a sale and transfer of ownership of the project companies to the lending group. However, during the process of seeking the required 100% approval from the lenders, two lenders dissented. The lending group indicated that a pre-negotiated Chapter 11 bankruptcy for the project companies was likely to be required. In January 2005, the lending group approved a pre-negotiated Chapter 11 filing of the project companies in order to facilitate the completion of this transaction. The transaction was completed on Jun. 1, 2005. See also **Notes 16, 20** and **21** to the TECO Energy **Consolidated Financial Statements** for additional details of the results of operations for these project companies.

PLC Development/TIE

A TWG Merchant subsidiary acquired ownership interests in PLC in January 2003 and September 2003, (see **Notes 13 and 16** to the TECO Energy **Consolidated Financial Statements**). Through PLC, TWG Merchant obtained an indirect effective economic interest of 50% in the aggregate of 2,000-megawatts in TIE. On Aug. 30, 2004, a TWG Merchant subsidiary completed the sale of its 50% indirect interest in TIE. The company recorded a $152.3 million pretax impairment charge ($99.0 million after tax) to write off the value of the investment as a result of the sale (see **Note 16** to the TECO Energy **Consolidated Financial Statements**).

Dell and McAdams Projects

In 2000, subsidiaries of TWG Merchant acquired full ownership of two independent power projects, the Dell and McAdams projects, being developed in Arkansas and Mississippi, respectively, with combined capacity of the two plants to be nearly 1,200 megawatts. Construction on these plants was suspended at the end of 2002 due to low energy prices in the markets that these plants were expected to serve. As of Dec. 31, 2003, approximately $685 million had been invested in these plants. In December 2004, TWG Merchant recorded an after-tax impairment charge of approximately $391 million related to these projects, and the Dell project was sold to a third party. In December 2005, an additional after tax impairment charge related to additional asset retirement obligations of $2.1 million was recorded related to McAdams (see **Note 18** to the TECO Energy **Consolidated Financial Statements**). As stated above, the Dell project was sold on Aug. 16, 2005. At this time, TWG Merchant has made the decision that the McAdams project will not be completed. The two combustion turbines have been sold to Tampa Electric for use in meeting its generation needs, and options for the sale or removal of the remaining assets are under consideration.

Frontera Power Station

In March 2001, subsidiaries of TWG Merchant acquired the Frontera Power Station, a 477-megawatt natural gas-fired combined-cycle plant located near McAllen, Texas. In December 2004, subsidiaries of TWG Merchant sold their 100% interest in Frontera. As a result of the sale, an after-tax loss of approximately $27 million was recorded in addition to the $69.0 million asset impairment recognized in 2003. See also **Notes 16** and **21** to the TECO Energy **Consolidated Financial Statements** for additional information.

Commonwealth Chesapeake Power Station

TWG Merchant, through TM Delmarva Power, LLC (TMDP), had a 100% economic interest in CCC, a 315-megawatt power plant on the Delmarva Peninsula of Virginia prior to its sale in April 2005. In 2003, an after-tax charge of $26.7 million was recognized to establish a reserve against an arbitration award against TMDP by NCP of Virginia, L.L.C. (NCP), which held a minority interest in CCC. In August 2004, TMDP entered into an agreement with NCP and its owners under which TMDP purchased NCP's interest in CCC for $30 million in cash plus TECO Energy stock valued at $10 million. This transaction resulted in a positive after-tax impact on earnings of approximately $4.3 million. In December 2004, TWG Merchant recorded an after-tax impairment charge of approximately $52 million related to CCC. On Apr. 19, 2005 TMDP sold its membership interests in CCC. See also **Notes 16** and **21** to the TECO Energy **Consolidated Financial Statements** for additional information.

Competition and Markets

In 2003 TWG Merchant ceased work on any new power plant developments, and has been active in its efforts to reduce its merchant exposure (see **Strategy and Outlook** section of **MD&A**).

As announced previously in April 2003, TECO Energy's renewed focus is on core utility operations and profitable unregulated businesses. TECO Energy sought to increase its flexibility to be able to mitigate the risk from the merchant portfolio through a number of steps, including the termination of joint ventures with Panda Energy in the TPGC plants and in the TIE plants, and to exit from existing merchant projects. Significant steps were achieved in 2005, 2004 and 2003, as discussed above with respect to TWG Merchant's ownership exit plan from merchant activities. See the discussion of the risks applicable to TWG Merchant in the **Risk Factors** section below.

Item 1A. RISK FACTORS.

The following are certain factors that could affect our future results. They should be considered in connection with evaluating forward-looking statements, and are otherwise made by, or on behalf of, us, because these factors could cause actual results and conditions to differ materially from those projected in those forward-looking statements.

Financing Risks

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

We have significant indebtedness, which has resulted in an increase in the amount of 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 or refinance existing debt and could prevent the repayment of subordinated debt and the payment of dividends if those payments would cause a violation of the covenants.

We and Tampa Electric must meet certain financial tests as defined in the applicable agreements to use our and its respective credit facilities. Also, we, Tampa Electric 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, 2005, 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. In addition, if we had to defer interest payments on our subordinated notes underlying the outstanding trust preferred securities, we would be prohibited from paying cash dividends on our common stock until all unpaid distributions on those subordinated notes were made.

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**. In addition, our unconsolidated affiliates have incurred non-recourse debt. Although we are not obligated on that debt, our investments in those unconsolidated affiliates are at risk if the affiliates default on their debt.

Our financial condition and ability to access capital may be materially adversely affected by ratings downgrades.

Our senior unsecured debt is rated below investment grade by Standard & Poor's, or S&P, at BB with a stable outlook, by Moody's Investor's Services, or Moody's, at Ba2 with a stable outlook and by Fitch Ratings, or Fitch, at BB+ with a stable outlook. The senior unsecured debt of Tampa Electric Company is rated by S&P at BBB- with a stable outlook, by Moody's at Baa2 with a stable outlook and by Fitch at BBB+ with a stable outlook. Any downgrades by the rating agencies may affect our ability to borrow, may change requirements for future collateral or margin postings, and may increase our financing costs, which may decrease our earnings. We also may experience greater interest expense than we may have otherwise if, in future periods, we replace maturing debt with new debt bearing higher interest rates due to any such downgrades. In addition, downgrades could adversely affect our relationships with customers and counterparties.

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

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, generation system additions to support normal customer growth for the next several years, and to improve system reliability. We cannot be sure that our capital expenditures will not exceed the planned amount. 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.

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, 2005, Tampa Electric Company's consolidated shareholders' equity was approximately $1.7 billion. Also, our wholly owned subsidiary, TECO Diversified, Inc., the holding company for TECO Transport, TECO Coal and TECO Solutions, has a guarantee related to a coal supply agreement that could limit the payment of dividends by TECO Diversified to us.

Various factors could affect our ability to sustain our dividend.

Our ability to pay a dividend, or sustain it at current levels, could be affected by such factors as the level of our earnings and therefore our dividend payout ratio, and pressures on our liquidity, including unplanned debt repayments, unexpected capital spending, shortfalls in operating cash flow and negative retained earnings. 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, including the floating rate notes we issued in June 2005. 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.

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 in the Tampa Electric service areas or in Florida's economy could adversely affect Tampa Electric's or PGS' expected performance.

Our unregulated businesses, TECO Transport, 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 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 regulatory structures 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.

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. TECO Transport is also impacted by weather because of its effects on the supply of and demand for the products transported. Severe weather conditions could interrupt or slow service and increase operating costs of those businesses.

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 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.

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. Additionally, our earnings from outside investors in the non-conventional fuels production facilities may be impacted by domestic oil prices.

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.

We derive a portion of our net income from synthetic fuel tax credits related to the production of non-conventional fuels. Although we have sold 98% of our interest in the synthetic fuel production facilities, the amounts we realize from the sales and our continuing operations of the facilities on behalf of the third-party owners are dependent on the continued availability to the purchasers of the tax credits. The availability of the synthetic fuel tax credits to those purchasers could be negatively impacted by administrative actions of the Internal Revenue Service or the U.S. Treasury or changes in law, regulation or administration. The tax credits to the purchasers of our non-conventional fuels production facilities could be limited if annual average domestic oil prices in 2006, as measured by the DOE reference price, exceed a threshold price. If the oil price limitation is reached, the level of the tax credits start to decline. The DOE index is based on the "Domestic First Purchase Price" not the NYMEX quoted oil futures prices, which in 2005 averaged about $6.00 per barrel less than the NYMEX price. The synthetic fuel tax credit phase-out range for 2006 based on the DOE oil prices is expected to be $54 to $68 per barrel, which is the equivalent of a NYMEX price of approximately $60 to $74 per barrel. Any such limitation could adversely affect our earnings and cash flows through the life of the tax credits, which are scheduled to expire at the end of 2007.

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.

TECO Transport does a significant amount of business under certain U.S. government programs that are dependent on annual appropriations.

TECO Transport participates in the U.S. Cargo Preference Program and the in PL480 program for shipments of U.S. aid grain, which are funded annually through the U.S. government's appropriation process. While these programs have been funded at stable levels for the many years, funding could be reduced by the actions of the Congress. Our outlook assumes that these programs continue to be funded at levels similar to the last several years.

TECO Transport is a U.S. flag carrier with a major portion of its business subject to the Jones Act.

The Jones Act restricts oceangoing shipments directly between U.S. ports and all inland waterway business to U.S. vessels built in U.S. shipyards, owned by citizens of the U.S., and with U.S. citizen crews and it has, on occasion, been cited as a cause for higher costs by certain domestic industries which have lobbied for repeal of the act or waivers for shipments carried by non-U.S. flag vessels under certain circumstances. A repeal or modification of the Jones Act opening this trade to non-U.S. flag vessels could potentially increase competition and reduce profitability.

Our international projects and the operations of TECO Transport are subject to risks that could result in losses or increased costs.

Our international projects 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. Our international subsidiaries attempt 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.

TECO Transport is exposed to operational risks in international ports, primarily due to its need for suitable labor and equipment to safely discharge its cargoes in a timely manner. TECO Transport attempts to manage these risks through a variety of risk mitigation measures, including retaining agents with local knowledge and experience in successfully discharging cargoes and vessels similar to those used by TECO Transport.

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.

We are currently defending lawsuits in which we could be liable for damages and responding to an informal inquiry of the SEC.

TECO Energy and certain of its subsidiaries have been named as defendants in lawsuits, as more fully described under **Legal Contingencies**, in **Note 12** to the **TECO Energy Consolidated Financial Statements,** regarding certain contracts, aspects of our business such as the location of transmission structures, and alleged disclosure violations under the Securities Exchange Act of 1934. We intend to vigorously defend all of these proceedings, however, we cannot predict the ultimate resolution of any of these matters at this time, and there can be no assurance that these matters will not have a material adverse impact on our financial condition or results of operations.

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

At Dec. 31, 2005, Tampa Electric had five electric generating plants and five combustion turbine units in service with a total net winter generating capability of 4,423 megawatts, including Big Bend (1,737-MW capability from four coal units), Bayside (1,841-MW capability from two natural gas units), Phillips (36-MW capability from two diesel units), Polk (260-MW capability from one integrated gasification combined cycle (IGCC) unit), three combustion turbine units (CTs) located at Big Bend (175-MW) and two CTs at Polk (368-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. The capability indicated represents the demonstrable dependable load carrying abilities of the generating units during winter peak periods. 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. The Bayside Unit 1 was completed in April 2003 and Bayside Unit 2 in January 2004.

Tampa Electric owns 184 substations having an aggregate transformer capacity of 20,890 Mega Volts Amps (MVA). The transmission system consists of approximately 1,301 pole miles (including underground and double-circuit) of high voltage transmission lines, and the distribution system consists of 7,072 pole miles of overhead lines and 3,401 trench miles of underground lines. As of Dec. 31, 2005, there were 645,264 meters in service. All of this property is located in Florida.

All plants and important fixed assets are held in fee except that title 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 has a long-term lease for the office building in downtown Tampa which serves as headquarters for TECO Energy, Tampa Electric and Peoples Gas, TECO Transport, and TECO Guatemala.

PEOPLES GAS SYSTEM

PGS' distribution system extends throughout the areas it serves in Florida and consists of approximately 16,000 miles of pipe, including approximately 10,000 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 TRANSPORT

TECO Bulk Terminal's storage and transfer terminal is on a 1,070-acre site fronting on the Mississippi River, approximately 40 miles south of New Orleans. Bulk Terminal owns 342 of these acres in fee, with the remainder held under long-term leases.

TECO Barge operates a fleet of 15 towboats and 581 river barges, approximately 81% of which it owns, on the Mississippi, Ohio and Illinois rivers and their tributaries. TECO Barge owns 15 acres of land fronting on the Ohio River at Metropolis, Illinois on which its operating offices, warehouse and repair facilities are located. Fleeting and repair services for its barges and those of other barge lines are performed at this location. Additionally, TECO Barge performs fleeting and supply activities at leased facilities in Cairo, Illinois.

As of Dec. 31, 2005, TECO Ocean Shipping owns or operates a fleet of 8 ocean-going tug/barge units, a 33,500 short ton ocean-going ship, a 40,900 short ton ocean-going ship, and a 41,400 short ton ocean-going ship, with a combined cargo capacity of over 376,500 tons.

TECO COAL

Property Control

Operations of TECO Coal and its subsidiaries are conducted on both owned and leased properties totaling nearly 240,000 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 not completely verified until such time as TECO Coal's subsidiaries prepare to disturb or mine such properties.

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, 2005, the TECO Coal operating companies had a combined estimated 258.2 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, 35.5 million tons of coal classified as "resource" were identified in a third-party audit report. Another 12.7 million tons of coal classified as "resource" were identified in the third-party audit report prepared by Marshall Miller & Associates, bringing the total identified resource to 48.2 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 2005, a third-party reserve audit was performed by Marshall Miller & Associates on the portion of reserves aquired during 2005. 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

							Assigned [2]		Unassigned[2]	
Mining Complex	**Location**	**Total**	**Proven**	**Probable**	**Owned**	**Leased**	**2005**	**2004**	**2005**	**2004**
Gatliff Coal Company	Bell County, KY/ Knox County, KY/ Campbell County, TN	9.5	6.9	2.6	1.0	8.5	1.1	1.4	8.4	8.4
Clintwood Elkhorn Mining	Pike County, KY Buchanan County, VA	35.6	28.4	7.2	3.8	31.8	35.6	37.8	—	—
Premier Elkhorn Coal	Pike County, KY/Letcher County, KY/ Floyd County, KY	83.1	63.2	19.9	47.8	35.3	83.1	56.6	—	—
Perry County Coal	Perry County, KY/ Leslie County, KY/ Knott County, KY	130.0	53.1	76.9	—	130.0	130.0	94.8	—	—

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 the company'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]
Table 4

		Sulfur Content				
Mining Complex	**Recoverable Reserves (Millions of tons)**	**< 1% [2]**	**>1% [2]**	**Compliance Tons [3]**	**Average BTU As received**	**Coal Type [4]**
Gatliff Coal Company	9.5	8.3	1.2	—	13,500	LSU
Clintwood Elkhorn Mining	35.6	13.1	22.5	13.8	13,400	HVM, LSU, PCI,SF
Premier Elkhorn Coal	83.1	29.8	53.3	23.2	13,350	IS, LSU, PCI, SF
Perry County Coal	130.0	121.8	8.2	71.5	13,195	LSU, PCI, SF, V

Notes:
(1) Reserve information reflects a moisture factor of 6.5 %. This moisture factor represents the average moisture present in the company'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
SF – Synthetic fuel Product
V - Various

Reserve Estimation Procedure

TECO Coal's reserves are based on over 2600 data points, including drill holes, prospect measurements, and mine measurements. Our reserve estimates also include information obtained from our on-going exploration drilling and in-mine channel sampling programs. Reserve classification is determined by evaluation of engineering and geologic information along with economic analysis. These reserves are adjusted periodically to reflect fluctuations in the economics in the market and/or changes in engineering parameters and/or geologic conditions. Additionally, the information is constantly being updated to reflect new data for existing property as well as new acquisitions and depleted reserves.

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

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

TECO GUATEMALA

TPS San José, LDC has a 100% ownership in a project entity, CGESJ, which owns approximately 190 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 7 acres in Escuintla, Guatemala on which the 78 MW oil-fired Alborada Power Station is located.

TWG MERCHANT

TPS McAdams, LLC, a subsidiary of TWG Merchant, owns approximately 210 acres of land in McAdams and Sallis in Attala County, Mississippi, on which the partially constructed 599-megawatt gas-fired combined cycle McAdams electric generation plant is located. Construction on this project was suspended at the end of 2002 due to projected low energy prices in the markets the plant was expected to serve and is currently undergoing dismantlement.

Item 3. LEGAL PROCEEDINGS.

Tampa Electric Transmission Litigation

Four lawsuits were filed in the Circuit Court in Hillsborough County against Tampa Electric in connection with the location of transmission structures and upgrades to a substation in certain residential areas by residents in the areas surrounding the structures and substation. The resident plaintiffs are seeking to remove the poles or to receive monetary damages. The plaintiffs were seeking class action status, which status was denied. Three cases (two, Jorrison and Acosta were consolidated) are pending before two separate judges. Tampa Electric's motion to dismiss the claim for injunctive relief (non-monetary relief) was granted in the Alvarez case (substation case). Tampa Electric has filed new motions for partial summary judgment in both the Shaw and Acosta cases with respect to property owners not located adjacent to or in close proximity to the poles ("Remote Plaintiffs'). Two of the three motions in the Shaw case were granted on Jan. 13, 2006 and the third was denied on Jan. 20, 2006. This is expected to result in a number of plaintiffs dropping out of the case unless the summary judgements are overturned on appeal. The Shaw case has been transferred to the Trial Division (cases expected to have trials lasting two weeks or more), and the parties have stipulated to a trial date of Sep. 11, 2006. The motion for summary judgment in the Acosta case was argued Feb. 21, 2006, and the court took it under advisement. At that time, plaintiff's counsel in the Acosta case dropped 65 plaintiffs.

McAdams Letter of Credit Litigation

Relating to the NEPCO default under the McAdams construction contract, in early 2002 TPS McAdams drew on a letter of credit in the amount of $19.95 million issued by West LB. In February 2003 West LB sued TPS McAdams SNC Lavalin and certain officers of NEPCO in federal district court in New York alleging that at the time of the TPS McAdams draw NEPCO had not yet failed to perform, but that performance was brought into question by Enron's bankruptcy. TPS McAdams has had a motion to dismiss pending since April 2003. In October, the case was referred to the bankruptcy court to be considered with the remains of the Enron bankruptcy. At a case status conference on Feb. 9, 2006, the bankruptcy judge scheduled a hearing on TPS McAdams' motion to dismiss for Mar. 23, 2006.

Grupo Litigation

In March 2001, TECO Wholesale Generation, Inc. (TWG) (under its former name of TECO Power Services Corporation) was served with a lawsuit in the Circuit Court for Hillsborough County by a Tampa-based firm named Grupo Interamerica, LLC (Grupo) seeking damages in connection with a potential investment in a power project in Colombia in 1996. Grupo alleged, among other things, that TWG breached an oral contract with Grupo. The trial court granted TWG's motion for summary judgment in the Grupo case in Hillsborough County Circuit Court in October 2004, and the plaintiffs appealed. The appellate court ruled in TWG's and TPSI's favor in September 2005; the appellants' motion for rehearing was denied, and the decision became final in late December 2005.

On Aug. 30, 2004, a Colombian trade union, Sindicato de Trabajadores de la Electricidad de Colombia (the Union), which was to be the owner/lessor of the power plant if the transaction had been consummated, filed a demand for arbitration in Colombia pursuant to provisions of a confidentiality and exclusivity agreement (the confidentiality agreement) between the trade union and an indirect subsidiary of TWG, TPS International Power, Inc. (TPSI), alleging breach of contract and seeking damages of approximately $50 million. The hearings before the Arbitration Tribunal (Tribunal) began in September 2005. The testimony phase of the proceeding has closed. The Tribunal has appointed experts on the subject of damages including the useful life of the facility and valuation of the project. The valuation report was due on Feb. 16, 2006. TPSI has also engaged its own expert. After receipt of the expert's report, both parties will have approximately four weeks to seek and obtain clarifications, if required. Liability is a matter of law to be determined by the Tribunal. Two U.S. based witnesses (one called by both parties and one called by TPSI) testified on Feb. 3, 2006. From the receipt of the clarifications to the expert's report, the parties have about four to six weeks to prepare and present written and oral closing arguments (May 2, 2006). After closing arguments, the Tribunal, although it has no deadlines, will likely take six to eight weeks to render its decision These dates are tentative based on the best judgment of TPSI's Colombian Counsel and can be modified by order of the Tribunal.

Securities Class Action Lawsuits & Related SEC Inquiry

A number of securities class action lawsuits were filed in August, September and October 2004 against the company and certain current and former officers (the defendants) by purchasers of TECO Energy securities. These suits, which were filed in the U.S. District Court for the Middle District of Florida, allege disclosure violations under the Securities Exchange Act of 1934. These actions, which seek unspecified damages, were consolidated, and, on Feb. 1, 2005, the Court entered its order appointing (i) the "TECO Lead Plaintiff Group," comprised of NECA-IBEW Pension Fund (The Decatur Plan), Monroe County Employees Retirement System, John Marder and Charles Korpak, as the Lead Plaintiff for the Class and (ii) the law firm of Lerach Coughlin Stoia Geller Rudman & Robbins LLP as Lead Counsel. The plaintiffs filed their Consolidated Class Action Complaint for Securities Fraud on May 3, 2005. The consolidated complaint maintains the same class period, Oct. 30, 2001 to Feb. 4, 2003, and the same parties as those contained in the original complaint. The nature of the claims, which relate to the adequacy of the company's disclosures and financial reporting, also remains the same. The defendants filed their motion to dismiss on Jul. 25, 2005, and the plaintiffs filed their response on Dec. 2, 2005. The company filed a reply on Jan. 13, 2006 and the plaintiffs filed their response on Jan. 25, 2006. The company continues to defend the litigation vigorously. In addition, in connection with the previously disclosed SEC informal inquiry resulting from a letter from the non-equity member in CCC raising issues related to the arbitration proceeding involving that project, the SEC has requested additional information primarily relating to the allegations made in these securities class action lawsuits focusing on various merchant plant investments and related matters. The company is cooperating and continues to provide information on an agreed schedule and pursuant to an agreed process. A derivative case has been filed against several officers and directors in state court in connection with their alleged actions during the same period that is the subject of the class action suit. This action was filed after a statutory demand which was being investigated by a special committee of the board. Motions to dismiss on behalf of all defendants have been filed.

Other Issues

The company cannot predict the ultimate resolution of these matters, including the class action litigation and the Grupo-related proceedings, at this time, and there can be no assurance that any such matters will not have a material adverse impact on TECO Energy's financial condition or results of operations.

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 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 the ultimate resolution of pending matters will have a material adverse effect on the company's results of operations or financial condition.

See also the discussions of the outcome of the coal transportation contract hearing before the FPSC in the **Regulation – Coal Transportation Contract** Section of **MD&A, Note 3** to the TECO Energy **Consolidated Financial Statements** and **Notes 3** and **10** to the Tampa Electric Company **Consolidated Financial Statements,** and also the discussion of environmental matters in **Note 12** to the TECO Energy **Consolidated Financial Statements** and **Note 9** to the Tampa Electric Company **Consolidated Financial Statements.**

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

No matter was submitted during the fourth quarter of 2005 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	63	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 R. Black	54	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	53	President, Peoples Gas System, April 2000 to date; President, Tampa Electric Company, September 2003 to October 2004.
Clinton E. Childress	57	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	46	Executive Vice President and Chief Financial Officer, TECO Energy, Inc., July 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, April 2001 to date; and prior thereto, Vice President-Finance and Chief Financial Officer, TECO Energy, Inc. and Tampa Electric Company.
Sal Litrico	50	President, TECO Transport Corporation, July 2004 to date; and prior thereto, Vice President of TECO Ocean Shipping, Inc.
Sheila M. McDevitt	59	Senior Vice President-General Counsel and Chief Legal Officer, TECO Energy, Inc., April 2001 to date; Vice President-General Counsel, TECO Energy, Inc., January 1999 to April 2001; General Counsel, Tampa Electric Company, January 1999 to date.
John B. Ramil	50	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	59	President of TECO Coal Corporation, since prior to 2001.

There is no family relationship between any of the persons named above. 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. 26, 2006, and until such officer's successor is elected and qualified.

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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*
2005					
	High	$ 16.50	$ 19.05	$ 19.30	$ 18.25
	Low	$ 14.87	$ 15.30	$ 17.15	$ 15.72
	Close	$ 15.68	$ 18.91	$ 18.00	$ 17.18
	Dividend	$ 0.19	$ 0.19	$ 0.19	$ 0.19
2004					
	High	$ 15.38	$ 14.60	$ 13.57	$ 15.49
	Low	$ 13.86	$ 11.30	$ 11.87	$ 13.40
	Close	$ 14.63	$ 11.99	$ 13.53	$ 15.35
	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. 28, 2006 was 19,305.

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.

In addition, TECO Diversified, Inc., a wholly-owned subsidiary of TECO Energy and the holding company for TECO Transport, TECO Coal and TECO Solutions, 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.

TECO Energy holds the right to defer payments on its subordinated notes issued in connection with the issuances of trust preferred securities by TECO Capital Trust I or TECO Capital Trust II. Should the company exercise this right, it would be prohibited from paying cash dividends on its common stock until the unpaid distributions on the subordinated notes are made. TECO Energy did not exercise that right during 2005, 2004 or 2003.

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 $173.4 million in 2005, $163.2 million in 2004, and $151.4 million in 2003. See the **Restrictions on Dividend Payments and Transfer of Assets** section in Note 1 to the TECO Energy **Consolidated Financial Statements** for Tampa Electric Company 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, 2005 – Oct. 31, 2005	348	$16.78	—	—
Nov. 1, 2005 – Nov. 30, 2005	7,524	$17.16	—	—
Dec. 1, 2005 – Dec. 31, 2005	2,438	$17.15	—	—
Total 4th Quarter 2005	10,310	$17.15	—	—

(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, restricted shares that were deferred upon vesting pursuant to the TECO Energy Group Deferred Compensation Plan and shares purchased by the TECO Energy Group Retirement Savings Plan pursuant to directions from plan participants or dividend reinvestment.

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

(millions, except per share amounts) *Years ended Dec. 31,*	*2005*	*2004*	*2003*	*2002*	*2001*
Revenues [1]	$ 3,010.1	$ 2,639.4	$ 2,562.9	$ 2,487.3	$ 2,330.5
Net income (loss) from continuing operations [1]	$ 211.0	$ (355.5)	$ 100.7	$ 265.4	$ 255.3
Net income (loss) from discontinued operations [1][2]	63.5	(196.5)	(1,005.8)	64.7	48.4
Cumulative effect of change in accounting principle, net	—	—	(4.3)	—	—
Net income (loss)	$ 274.5	$ (552.0)	$ (909.4)	$ 330.1	$ 303.7
Total assets	$ 7,170.1	$ 8,972.4	$ 9,964.3	$ 8,738.2	$ 6,934.2
Long-term debt	$ 3,709.2	$ 3,880.0	$ 4,392.6	$ 3,324.3	$ 1,842.5
Earnings per share (EPS) – basic;					
From continuing operations [1]	$ 1.02	$ (1.85)	$ 0.56	$ 1.73	$ 1.90
From discontinued operations [1]	0.31	(1.02)	(5.59)	0.42	0.36
From cumulative effect of change in accounting principle	—	—	(0.02)	—	—
EPS basic	$ 1.33	$ (2.87)	$ (5.05)	$ 2.15	$ 2.26
Earnings per share (EPS) – diluted;					
From continuing operations [1]	$ 1.00	$ (1.85)	$ 0.56	$ 1.73	$ 1.88
From discontinued operations [1]	0.31	(1.02)	(5.58)	0.42	0.36
From cumulative effect of change in accounting principle	—	—	(0.02)	—	—
EPS diluted	$ 1.31	$ (2.87)	$ (5.04)	$ 2.15	$ 2.24
Dividends paid per common share	$ 0.76	$ 0.76	$ 0.925	$ 1.41	$ 1.37

(1) Amounts shown include reclassifications to reflect discontinued operations as discussed in **Note 21** to the TECO Energy **Consolidated Financial Statements.**

(2) 2004 and 2003 include impairment charges of $558.6 million and $100.1 million, respectively. See **Notes 17** and **18** to the TECO Energy **Consolidated Financial Statements.**

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

This Management's Discussion and Analysis contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. Actual results may differ materially from those forecasted. Such statements are based on our current expectations, and we do not undertake to update or revise such forward looking statements. These forward-looking statements include references to our anticipated capital investments, liquidity and financing requirements, projected operating results, future transactions 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 a diversified energy-related holding company with five core businesses, consisting of regulated electric and gas utility operations in Florida and other operating companies engaged in coal mining and synthetic fuel production, waterborne transportation services and unregulated electric generation with long-term contracts and regulated electricity distribution in Guatemala.

For many years, prior to investing in merchant power generating facilities and smaller unregulated energy service providers, TECO Energy provided consistent earnings growth from its mix of high-growth, regulated Florida utilities and diversified energy-related companies. In 2000 and 2001, we announced a series of major investments in unregulated domestic power generation facilities outside of Florida, which were made in the 2000 through 2003 period. In the same period, we also invested in other smaller unregulated energy service providers within Florida. These investments were made in anticipation of a movement toward competitive energy markets in Florida and other states in which we were investing in new power plants. The wholesale power markets evolved in a manner that was much different than expected when we decided to invest in these projects, and the independent power business changed dramatically, reducing the prospects for the profitability of the investments in our unregulated domestic independent power generation facilities for several years to come (see the **TWG Merchant** section).

In 2003, we announced our revised business strategy, which was to focus on our Florida utilities and other profitable operating companies and to reduce the risk to cash flow and earnings from our involvement in the merchant power sector. Since that announcement, we have taken a number of steps that have eliminated our merchant power risk and improved our financial results. As a result of the aggressive execution of our plans to exit the merchant power business, our business risk profile was reduced, and all three of the debt rating agencies moved their outlook on TECO Energy's and Tampa Electric's debt ratings from "negative" to "stable" in 2005. One of our goals, over time, is to return to an investment-grade credit rating through our actions to improve our cash flows, reduce debt and reduce business risk.

Our regulated utility companies, Tampa Electric and Peoples Gas (PGS) operate in the high-growth Florida market. Tampa Electric serves more than 645,000 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 4,423 megawatts. PGS, Florida's largest regulated gas distribution utility, serves more than 320,000 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 1.1 billion therms in 2005. The PGS system consists of 10,000 miles of mains and 6,000 miles of service lines.

Our other energy-related operating companies are: TECO Coal, TECO Transport and TECO Guatemala. TECO Coal, through its subsidiaries, operates 11 surface and 29 underground mines and related coal processing facilities in eastern Kentucky, Tennessee and southwestern Virginia producing metallurgical-grade and high-quality steam coals. Sales in 2005 were 9.7 million tons, of which 6.4 million tons were sold as synthetic fuel. TECO Transport, our waterborne transportation company, through its subsidiaries, operates a fleet of inland river barges and towboats on the Ohio, Mississippi and Illinois rivers and their tributaries; a fleet of eight oceangoing tug-barge combination units and three ships that operate in the Gulf of Mexico and world wide; and a dry-bulk storage and transfer terminal located on the Mississippi River southeast of New Orleans. TECO Guatemala, through its subsidiaries, owns a coal-fired generating facility and has a 96% 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.

2005

Our results in 2005 reflected the continued execution of our strategy to focus on our five core energy-related businesses. We recorded significantly improved financial results in 2005 as a result of strong markets for TECO Coal and TECO Transport and continued growth at the Florida utilities (see the individual operating company results).

In 2005, we eliminated our merchant power exposure. This was accomplished through the completion of the sale and transfer of the Union and Gila River power stations to the non-recourse bank lending group (lenders) for these projects, closing the sales of the Commonwealth Chesapeake and Dell power stations and announcing the decision to terminate the uncompleted McAdams Power Station project and transfer the combustion turbines to Tampa Electric to meet that company's peaking power needs. The transfer of these combustion turbines to Tampa Electric was completed in January 2006. The merchant power generating assets were part of the TECO Wholesale Generation (TWG) subsidiary.

With no major construction programs underway in 2004 or 2005, we were able to build stronger liquidity for normal operations and to accumulate the cash that, together with the proceeds from a notes offering, allowed us to retire $380 million of 10.5% notes due in 2007 and to retire the first $100 million of 8.5% trust preferred securities (TruPS) due in 2041 in 2005 (see the **Financing Activity** section), and to accumulate cash to be used for the retirement of TECO Energy's $357 million of debt maturing in 2007.

In 2005, Tampa Electric experienced no direct impacts from the unprecedented Atlantic hurricane season; however, it did experience the spike in natural gas costs following the storms, which increased its fuel cost under-recovery. Peoples Gas experienced damage to some of its office facilities, primarily in South Florida as a result of Hurricane Wilma, with minimal financial impact. TECO Transport suffered significant damage to its terminal in Louisiana from Hurricanes Katrina and Rita, and business interruptions to its river barge operations and oceangoing operations as a result of those storms. The majority of the river barge equipment was returned to service within a matter of weeks, and the terminal resumed major operations in mid-October, six weeks after Hurricane Katrina. The direct costs of restoration incurred at the terminal in 2005 were more than offset by an insurance settlement (see the **TECO Transport** section).

OUTLOOK

Focus on our five core businesses

In 2005, the execution of our strategy, to focus on our five core energy-related businesses, which was first announced in April 2003, allowed us to return to our focus on our long-standing, profitable businesses and to set a new baseline against which to measure TECO Energy's future financial performance.

We substantially improved our cash and liquidity positions in the last two years and expect to continue to accumulate cash (see the **Liquidity, Capital Resources** section). Our priorities for the use of this cash, in order, are to improve our financial profile through debt reductions at the TECO Energy parent; to invest in our regulated businesses; and to invest in incremental growth at our other operating companies. Our debt reduction efforts are focused on the retirement, without refinancing, of the 2007 debt maturities.

We currently estimate our 2006 per share results from continuing operations to be in a range of $1.25 to $1.35. This estimated range assumes no reduction in proceeds from the sale of synthetic fuel ownership interests, which would occur if the average calendar-year 2006 oil prices are at or above the estimated $60 per barrel threshold level that would reduce the value of the synthetic fuel tax credits, and excludes the direct costs associated with Hurricane Katrina restoration and any insurance recoveries that might occur to offset these direct costs expected for TECO Transport in 2006, which are not expected to be significant. These forecasted results are based on our current assumptions for the year, including those described in each operating company discussion, which are subject to risks and uncertainties (see the **Synthetic Fuel** discussion below and the **Risk Factors** section).

After several years of limiting capital expenditures to maintenance levels, we now forecast capital expenditures at levels higher than those required to meet normal customer growth and normal generation plant maintenance, reflecting increased spending for distribution system improvements to provide higher reliability, enhanced customer services and combustion turbine additions to meet growing demand at Tampa Electric, modest distribution system expansion at Peoples Gas, and incremental production capacity increases at TECO Coal (see the **Liquidity, Capital Resources** section).

With the expiration of the synthetic fuel tax credits at the end of 2007, we expect to partially mitigate the corresponding reduction in earnings and cash flow that will result by increasing production and optimizing our coal operations, improving results from all of the operating companies, and reducing interest expense at the parent. We expect that interest expense will be lower in 2008 as a result of our planned retirement of all the remaining TECO Energy parent debt maturing in 2007, as well as the retirements and refinancings accomplished in 2005 and that we plan in 2006.

Synthetic Fuel

A major source of the earnings and cash that we expect to generate through 2007 comes from TECO Coal's previously completed sales of ownership interests in its synthetic fuel production facilities and the synthetic fuel tax credits generated for the third-party owners. In 2006 and 2007, the synthetic fuel tax credits could be reduced if oil prices exceed a certain threshold level and completely phased out if oil prices exceed the top of a range, which we estimate to be a range of $60 to $74 per barrel as measured on a NYMEX basis. Our base earnings and cash flow forecasts assume no reduction in the benefits from the synthetic fuel tax credits; however, the forecast is subject to significant variability due to the potential impact of high oil prices on the benefits from synthetic fuel production as shown in the table that follows. The amounts shown in the table below assume continued synthetic fuel production, except for the last line, which assumes no synthetic fuel is produced in 2006.

Potential Oil Price Impact on TECO Energy Earnings and Cash

(all amounts in millions except EPS)			
NYMEX Oil Price	EPS Impact	Cash from operations impact	Parent and consolidated cash flow impact
$ 60	$ –	$ –	$ –
62	(0.08)	–	(24)
67	(0.27)	5[1]	(92)
74	(0.54)	20[1]	(185)
74 with no production	(0.35)	85[2]	(120)

(1) Benefits of oil price hedges.
(2) $20 million benefit of oil price hedges and $65 million avoided annual cost of synthetic fuel production.

In December 2005, we announced that TECO Coal had amended the agreements with the investors in its synthetic fuel production facilities to provide TECO Coal with flexibility to cease producing synthetic fuel under certain conditions. If the calendar-year average oil price, on the basis of actual plus futures prices, exceeds $62 per barrel on a NYMEX basis, TECO Coal has the right to cease or reduce production and the third-party investors have the right to not participate in the production (see the **TECO Coal** section).

The tax credit program will expire on Dec. 31, 2007, and, while we cannot predict if the period for the tax credit program will be extended or renewed in the current form, we are assume that there will be no change in the current legislation. Based on the assumption that the program expires as scheduled, both net income and cash flow at TECO Coal are expected to decline in 2008 due to the loss of the benefits from the sale of the third-party ownership interests.

In 2008, TECO Coal expects to no longer produce synthetic fuel, but it expects to produce conventional coal with a production goal of 10.5 to 11 million tons per year. When production of synthetic fuel ends in 2008, TECO Coal will stop mining the high-cost coals currently being mined for use in the production of synthetic fuel and will stop operating the synthetic fuel production equipment, which are expected to reduce production costs. At that time, the earnings and cash flow from TECO Coal will be dependent on the selling price of coal, and its ability to manage production costs.

RESULTS SUMMARY

Our results in 2005 were driven by stronger markets for TECO Coal and TECO Transport, continued customer and energy sales growth at Tampa Electric and Peoples Gas, and lower TECO Energy parent-level interest expense. In 2005, net income and earnings per share were $274.5 million and $1.33, respectively, compared to a loss of $552.0 million and a per share loss of $2.87 in 2004. Results in 2005 included the $45.0 million after-tax debt-extinguishment charge associated with the June 2005 redemption of $380 million of 10.5% notes and a $76.5 million after-tax gain recorded in discontinued operations upon the final sale and transfer of the Union and Gila River power stations to the lenders in May. The gain represented the reversal of the accumulated unfunded operating losses recorded against equity for the period from Dec. 31, 2003, the date we decided to exit the projects, through the effective date of the transfer to the lenders group. Also included in results are smaller charges and gains, which are detailed in the table that reconciles 2005 net income, calculated under Generally Accepted Accounting Principles (GAAP) to non-GAAP results below. Results from discontinued operations in 2005 include the operating results for the Union, Gila River and Commonwealth Chesapeake power stations until the time of the transfers to the respective buyers, including the gain on the transfer discussed above, and true-up amounts from previously divested assets.

In 2005, net income and earnings per share from continuing operations were $211.0 million and $1.02, respectively, compared to a loss of $355.5 million and a per share loss of $1.85 for 2004. Non-GAAP results, which are adjusted for certain items included in GAAP net income from continuing operations excluding the charges and gains detailed in the 2005 GAAP to non-GAAP reconciliation table were $254.7 million in 2005, compared to $153.1 million in 2004. In 2005, results from continuing operations reflected improved results from the business segments, particularly the unregulated businesses. TECO Coal's net income was significantly higher driven by higher prices for coal and the sale of an additional 8% ownership interest in its synthetic fuel production facilities. TECO Transport's increased earnings reflected higher river barge rates due to better balance in supply and demand, and the qualification of two vessels for the positive benefit of tax law changes under the Jobs Creation Act. TECO Guatemala reported strong results from continued good operation of the power generating plants, customer and energy sales growth at the distribution utility and favorable tax rates due to the Jobs Creation Act. Tampa Electric and Peoples Gas both experienced continued customer and energy sales growth.

The net loss in 2004 was $552.0 million, primarily due to $508.6 million of charges and gains detailed in the 2004 GAAP to non-GAAP reconciliation table below. The net loss from continuing operations in 2004 was $355.5 million, compared with net income from continuing operations of $100.7 million in 2003. Non-GAAP results from continuing operations excluding the charges and gains detailed in the 2004 GAAP to non-GAAP reconciliation table were $153.1 million in 2004, compared with $172.3 million in 2003. Results from discontinued operations in 2004 reflect primarily the operating results from the Frontera, Union and Gila River power stations, BCH Mechanical and the 2004 write-offs and charges associated with these businesses.

The sale of our interests in our merchant generating assets in Texas, the sale of the Commonwealth Chesapeake Power Station in Virginia, and the adjustment of the value of the unfinished Dell and McAdams power stations to reflect the then current fair market values resulted in $562.5 million of after-tax write-offs in 2004, comprised of $431.3 million in continuing operations and $131.2 million in discontinued operations.

Results from continuing operations in 2004 were lower than 2003, primarily due to the write-offs associated with the merchant power plants and other charges detailed in the 2004 GAAP to non-GAAP reconciliation table. Excluding these charges and gains, results from continuing operations in 2004 were lower than 2003 due to the sale of an additional 40.5% ownership interest in TECO Coal's synthetic fuel production facilities, much lower equity Allowance for Funds Used During Construction income (AFUDC, which represents allowed equity cost capitalized to construction costs) at Tampa Electric, and lower results at TECO Transport. The sale of the portion of the synthetic fuel production facilities continued to generate significant cash in 2004, but earnings were at a lower level than 2003 due to our continued role in operating the synthetic fuel production facilities at a time when TECO Energy could not utilize the synfuel tax credits. The net loss on a per share basis was $2.87 in 2004, compared with net loss of $5.05 in 2003. The loss from continuing operations on a per share basis was $1.85 in 2004, compared with earnings per share from continuing operations of $0.56 in 2003. The number of average shares outstanding at Dec. 31, 2004 was 7% higher than at Dec. 31, 2003, primarily due to the shares issued in the early settlement offer for our equity security units completed in August 2004.

Results in 2003 were driven primarily by the significant charges associated with the impairment of some of our merchant power assets and other charges detailed in the 2003 GAAP to non-GAAP reconciliation table.

2005 Earnings Summary

(millions) Except per-share amounts	*2005*	*2004*	*2003*
Consolidated revenues	$ 3,010.1	$ 2,639.4	$ 2,562.9
Earnings (loss) per share – basic			
Earnings (loss) per share	$ 1.33	$ (2.87)	$ (5.05)
Discontinued operations	0.31	(1.02)	(5.59)
Earnings (loss) from continuing operations before cumulative effect of change in accounting principle	1.02	(1.85)	0.54
Cumulative effect of change in accounting principle	–	-	(0.02)
Earnings (loss) from continuing operations	$ 1.02	$ (1.85)	$ 0.56
Earnings (loss) per share – diluted			
Earnings (loss) per share	$ 1.31	$ (2.87)	$ (5.04)
Discontinued operations	0.31	(1.02)	(5.58)
Earnings (loss) from continuing operations before cumulative effect of change in accounting principle	1.00	(1.85)	0.54
Cumulative effect of change in accounting principle	–	-	(0.02)
Earnings (loss) from continuing operations	$ 1.00	$ (1.85)	$ 0.56
Net income (loss)	$ 274.5	$ (552.0)	$ (909.4)
Net income (loss) from discontinued operations	63.5	(196.5)	(1,005.8)
(Charges) and gains from continuing operations(1)	(43.7)	(508.6)	(71.6)
Cumulative effect of change in accounting principle	–	-	(4.3)
Non-GAAP results from continuing operations (2)	$ 254.7	$ 153.1	$ 172.3
Average common shares outstanding			
Basic	206.3(5)	192.6(4)	179.9(3)
Diluted	208.2(5)	192.6(4)	180.2(3)

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

(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 2003 include the issuance of 11 million shares in September.

(4) Average shares outstanding for 2004 include the issuance of 10.2 million shares in September in conjunction with the early settlement of the 9.5% adjustable conversion-rate equity security units.

(5) 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.

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 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 (gains)	–	–	–	(1.1)	–	(1.9)	46.7	43.7
Non-GAAP results from continuing operations	$ 147.1	$ 29.6	$ 115.4	$ 19.1	$ 40.4	$ (16.5)	$ (80.4)	$ 254.7

2004 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 from continuing operations	$ 146.0	$ 27.7	$ 61.3	$ 10.2	$ 5.7	$ (534.1)	$ (72.3)	$ (355.5)
Merchant power valuations	–	–	–	–	–	480.7	–	$ 480.7
Steam turbine valuations	–	–	–	–	12.8	–	–	12.8
Debt extinguishment	–	–	–	–	6.7	–	(0.5)	6.2
Taxes on cash repatriation	–	–	–	–	17.4	–	–	17.4
Asset impairment	–	–	–	0.6	–	–	–	0.6
Restructuring charges	–	0.4	–	1.1	–	–	5.0	6.5
Valuation adjustment	–	–	–	–	–	–	3.4	3.4
Tax credit reversals	–	–	(7.0)	–	–	–	–	(7.0)
Gain on sale of propane business	–	–	–	–	–	–	(12.0)	(12.0)
Total charges (gains)	–	0.4	(7.0)	1.7	36.9	480.7	(4.1)	508.6
Non-GAAP results from continuing operations	$ 146.0	$ 28.1	$ 54.3	$ 11.9	$ 42.6	$ (53.4)	$ (76.4)	$ 153.1

2003 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 from continuing operations	$ 98.9	$ 24.5	$ 77.1	$ 15.3	$ 22.0	$ (60.8)	$ (76.3)	$ 100.7
Turbine valuations	48.9	–	–	–	28.5	–	–	$ 77.4
Restructuring charges	6.1	2.6	–	1.0	–	0.3	5.2	15.2
Project cancellations	–	–	–	–	9.0	–	–	9.0
Valuation adjustment	–	–	–	–	–	–	3.2	3.2
Unutilized tax credits	–	–	7.0	–	2.7	–	–	9.7
Hardee Power Partners Gain on sale and operations	–	–	–	–	(42.9)	–	–	(42.9)
Total charges (gains)	55.0	2.6	7.0	1.0	(2.7)	0.3	8.4	71.6
Non-GAAP results from continuing operations	$ 153.9	$ 27.1	$ 84.1	$ 16.3	$ 19.3	$ (60.5)	$ (67.9)	$ 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 net income 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 true-ups to charges related to merchant power facilities 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. Substantially all of the items included in charges and gains for the periods detailed in the tables above are associated with our exit from the merchant power business and our return to our focus on our five core businesses.

OPERATING RESULTS

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, 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		2005	2004	2003
Segment Revenues [(1)]				
Regulated companies	Tampa Electric	$ 1,746.8	$ 1,687.4	$ 1,586.1
	Peoples Gas	549.5	417.2	408.4
Total regulated		2,296.3	2,104.6	1,994.5
Unregulated companies	TECO Coal	505.1	327.6	296.3
	TECO Transport	278.2	249.6	260.6
	TECO Guatemala[(2)]	7.7	11.5	158.4
	TWG – Merchant	0.4	7.6	(2.5)
Total unregulated		$ 791.4	$ 596.3	$ 712.8
Net Income (loss) [(3)]				
Regulated companies	Tampa Electric	$ 147.1	$ 146.0	$ 98.9
	Peoples Gas	29.6	27.7	24.5
Total regulated		176.7	173.7	123.4
Unregulated companies	TECO Coal	115.4	61.3	77.1
	TECO Transport	20.2	10.2	15.3
	TECO Guatemala	40.4	5.7	22.0
	TWG – Merchant	(14.6)	(534.1)	(60.8)
Total unregulated		161.4	(456.9)	53.6
Parent/Other		(127.1)	(72.3)	(76.3)
Net income (loss) from continuing operations		211.0	(355.5)	100.7
Discontinued operations		63.5	(196.5)	(1,005.8)
Net income (loss) before cumulative effect of change in accounting principle		274.5	(552.0)	(905.1)
Cumulative effect of a change in accounting principle		–	–	(4.3)
Net income (loss)		$ 274.5	$ (552.0)	$ (909.4)
Earnings per Share - Basic [(3)]				
Regulated companies	Tampa Electric	$ 0.71	$ 0.76	$ 0.55
	Peoples Gas	0.14	0.14	0.14
Total regulated		0.85	0.90	0.69
Unregulated companies	TECO Coal	0.56	0.32	0.43
	TECO Transport	0.10	0.05	0.08
	TECO Guatemala	0.20	0.03	0.12
	TWG – Merchant	(0.07)	(2.77)	(0.34)
Total unregulated		0.79	(2.37)	0.29
Parent/Other		(0.62)	(0.38)	(0.42)
Earnings (loss) per share from continuing operations		1.02	(1.85)	0.56
Discontinued operations		0.31	(1.02)	(5.59)
Earnings (loss) per share before cumulative effect of change in accounting principle		1.33	(2.87)	(5.03)
Cumulative effect of a change in accounting principle		–	–	(0.02)
EPS Total		$ 1.33	$ (2.87)	$ (5.05)

(1) Revenues for all periods have been adjusted to reflect the presentation of energy marketing-related revenues on a net basis and the reclassification of the results from those businesses that have been sold to discontinued operations (see the **Discontinued Operations** section). Segment revenues include intercompany transactions that are eliminated in the preparation of TECO Energy's consolidated financial statements.

(2) TECO Guatemala was deconsolidated under FIN 46 effective Jan. 1, 2004. Actual revenues in 2005 and 2004, which are not included in this table due to the effects of deconsolidation, were $104.0 million and $102.1 million, respectively. **Footnote 14** to the **TECO Energy Consolidated Financial Statements** provides additional information and the condensed financial information for the Guatemalan operations.

(3) Segment net income and earnings are reported on a basis that includes internally allocated financing costs to the unregulated companies. Internally allocated finance costs for 2005, 2004 and 2003 were at a pretax rate of 8%, based on the average investment in each unregulated subsidiary.

TAMPA ELECTRIC

Electric Operations Results

Tampa Electric's 2005 net income was $147.1 million, compared to $146.0 million in 2004. These results were driven by continued strong customer growth and higher energy sales partially offset by weather patterns that resulted in 5% lower total degree-days than normal and 1% lower total-degree days than 2004, when total degree-days were 3% below normal, and higher non-fuel operating expenses, which include higher depreciation expense from normal plant additions. Results also include an $8.6 million after-tax disallowance by the Florida Public Service Commission (FPSC) for the recovery of a portion of the waterborne transportation costs for the delivery of solid fuel (see the **Regulation** section).

Tampa Electric's 2004 net income was $146.0 million, compared to $98.9 million in 2003. Non-GAAP results in 2003, which excluded turbine purchase cancellations and restructuring charges, were $153.9 million. Results in 2004 were driven by lower non-fuel operating expenses, continued strong customer growth and higher energy sales offset by lower AFUDC equity, an $8.2 million after-tax disallowance by the FPSC related to waterborne transportation costs for delivery of solid fuel, and weather patterns that resulted in 3% lower total-degree days than normal and almost 7% lower total degree-days than 2003, when total degree-days were more than 4% above normal. The equity component of AFUDC from the Gannon to Bayside repowering project decreased to $0.7 million, compared to $19.8 million in 2003.

Summary of Operating Results

(millions)	*2005*	*% Change*	*2004*	*% Change*	*2003*
Revenues	$ 1,746.8	3.5	$ 1,687.4	6.4	$ 1,586.1
Other operating expenses	200.8	5.4	190.5	-6.1	202.8
Maintenance	88.1	1.0	87.2	-4.0	90.8
Depreciation	187.1	3.4	180.9	-14.0	210.3
Taxes, other than income	125.8	4.1	120.8	7.3	112.6
Non-fuel operating expenses	601.8	3.9	579.4	-6.0	616.5
Fuel	546.8	-10.8	612.9	38.3	443.3
Purchased power	269.7	56.5	172.3	-26.6	234.9
Total fuel expense	816.5	4.0	785.2	15.8	678.2
Turbine valuation adjustment	–	–	–	–	79.6
Total operating expenses	1,418.3	3.9	1,364.6	-0.7	1,374.3
Operating income	$ 328.5	1.8	$ 322.8	52.4	$ 211.8
AFUDC equity	$ –	–	$ 0.7	-96.5	$ 19.8
Net income	$ 147.1	0.8	$ 146.0	47.6	$ 98.9
Turbine cancellation charges, after-tax	–	–	–	–	48.9
Restructuring charges, after-tax	–	–	–	–	6.1
Non-GAAP results	$ 147.1	0.8	$ 146.0	-5.1	$ 153.9

Megawatt-Hour Sales (thousands)					
Residential	8,558	3.2	8,293	0.3	8,265
Commercial	6,234	4.1	5,988	2.2	5,860
Industrial	2,478	-3.1	2,556	-0.9	2,579
Other	1,642	2.6	1,600	4.0	1,538
Total retail	18,912	2.6	18,437	1.1	18,242
Sales for resale	773	16.4	664	-3.9	691
Total energy sold	19,685	3.1	19,101	0.9	18,933
Retail customers-thousands (average)	635.7	2.6	619.5	2.4	604.9

Tampa Electric Operating Revenues

Retail megawatt-hour sales rose 2.6% in 2005 despite the effects of mild weather, primarily from increased residential and commercial sales driven by customer growth. Electricity sales to the lower margin industrial customers in the phosphate industry decreased 6.5% in 2005 after a 3.7% decrease in 2004. The 2005 decline in sales to phosphate customers was driven by natural reserve depletion and migration of mining operations out of Tampa Electric's service area. Base revenues from phosphate sales represented less than 3% of base revenues in 2005 and 2004. Non-phosphate industrial sales increased in 2005 and 2004, primarily reflecting continued economic growth in the area.

Base rates for all customers were unchanged in 2005. Fuel-related revenues increased in 2005 and 2004 under the FPSC-approved fuel cost recovery clause, due to the recovery of previous under-recoveries of fuel expense in 2004 and 2003 and higher gas prices. Customers' rates under the fuel clause increased in 2006 in accordance with the rates approved by the FPSC in November 2005, to reflect the significantly higher cost of natural gas, which was exacerbated in 2005 by the unprecedented hurricane season. The customer fuel-adjustment increase was, however, partially offset by approximately $100 million of projected sales of unneeded SO_2 emissions allowances, 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 in 2005 due to a planned increase in the energy sold under a long-term contract. Sales to other utilities for resale declined in 2004, primarily as a result of lower capacity being available from coal-fired generating units due to the conversion of the coal-fired Gannon Station to natural gas. Incremental generation among the utilities in Florida is primarily natural gas-fired; therefore, the Bayside units compete with all other units burning the same fuel in the state. Energy sales to other utilities are expected to remain stable in 2006.

Based on projected growth from continued population increases and business expansion, Tampa Electric expects weather-normalized average retail energy sales growth of more than 2.5% annually over the next five years, with combined energy sales growth in the residential and commercial sectors of more than 3% annually. Tampa Electric's forecasts indicate that summer retail peak demand growth is expected to average more than 135 megawatts per year for the next five years. These growth projections assume continued local area economic growth, normal weather, and a continuation of the current energy market structure (see the **Risk Factors** section).

The economy in Tampa Electric's service area continued to grow in 2005, aided by the region's relatively low labor rates, attractive cost of living and relatively affordable housing. The Tampa metropolitan area's non-farm employment grew 2.5% in 2005 due to the strong local economy. Employment grew 2.1% in 2004 in spite of the U.S. economic slowdown in the first half of the year. The local Tampa area unemployment rate fell to 2.9% at year-end 2005, compared with 4.6% in December 2004, and 5.2% in December 2003. These rates are lower than the year-end 3.3% unemployment rate for the State of Florida and 4.9% for the nation.

Tampa Electric Operating Expenses

Total operating expenses increased in 2005 due to higher purchased power expenses as a result of lower coal-fired unit availability and the higher cost of natural gas for all utilities in Florida that is reflected in the cost of purchased power. Non-fuel operating and maintenance expenses increased as a result of higher power distribution expenses in 2005 due to more normal work activities following the 2004 hurricane restoration efforts. Other non-fuel operations and maintenance expenses increased due to increased employee-related expenses for items such as pensions, disability and medical reserves, and higher customer expenses, which included higher levels of uncollectible accounts.

Total operating expense decreased slightly in 2004 as higher fuel costs due to increased use of natural gas largely offset lower non-fuel operating and maintenance expenses and lower purchased power costs. Non-fuel operating and maintenance expenses decreased from the lower manpower requirements and lower maintenance requirements of the natural gas-fired repowered Bayside Station compared to the coal-fired Gannon Station. Operating expenses were also reduced by the restructuring activities in 2002 and 2003, which reduced the number of employees 12% during the two-year period.

Depreciation expense increased in 2005 due to normal plant additions to serve the growing customer base. Depreciation expense decreased in 2004 due to the end of the accelerated depreciation in 2003 related to the retirement of the Gannon Station coal-fired assets, which more than offset the additional depreciation from the addition of Bayside Unit 2 (see the **Environmental Compliance** section). Accelerated depreciation of the Gannon Station coal-fired assets was $36.6 million pretax in 2003. Depreciation expense is projected to increase in 2006, due to normal plant additions to serve Tampa Electric's growing customer base and maintain system reliability.

Non-fuel operations and maintenance expenses are expected to increase more than 10% in 2006 due to increased spending for customer service enhancements; higher spending for distribution system reliability to reduce the impacts of trees, animals and lightning on the system especially in the most vulnerable areas; increased spending on coal-fired generating unit maintenance to improve reliability and availability during periods of high natural gas prices; employee additions to support the programs described above; and higher employee-related costs, such as costs associated with medical, pension plans, and stock option expense.

Under regulatory accounting, the cost of fuel on the income statement represents the amounts authorized by the FPSC for recovery through the fuel adjustment clause, but the actual cost of fuel purchased may differ from those amounts. The difference between actual fuel cost and the amount authorized for recovery is deferred on the balance sheet as either under- or over-recovered fuel cost, and therefore does not impact net income.

Included in Tampa Electric's fuel adjustment filing for rates effective in 2006 was $147 million of 2005 under-recovered fuel cost. In November 2005, the FPSC authorized the recovery of this amount and the full projected 2006 fuel expense (see the **Regulation** section). Due to the upward spike in natural gas prices in the fourth quarter of 2005 following Tampa Electric's fuel adjustment filing, the actual under-recovery of fuel expenses in 2005 was $107 million above the amount authorized for recovery in 2006. This under-recovered fuel cost may remain under-recovered until 2007 or, if actual fuel prices for 2006 are below the prices authorized for recovery in 2006, the 2005 under-recovered fuel cost may be recovered through the approved rates in 2006.

Prices for all fuel types increased dramatically in 2005, especially for natural gas. The delivered cost of natural gas has increased since 2003, when the average price for the year was $6.45 per million Btu compared to the 2005 average price of $9.37 per million Btu. Coal prices have also increased during that period from a delivered cost of $2.02 per million Btu in 2003 to $2.25 per million Btu in 2005.

Natural gas prices have been extremely volatile during the 2003 through 2005 period as a result of supply constraints due to damage to production and transportation infrastructure from hurricanes and increased demand nationwide due to the higher percentage of electricity now being generated from natural gas-fired generation particularly during peak-load periods. Natural gas price volatility is expected to continue due to the tight balance in supply and demand. Coal prices, while less volatile, are expected to stay near the current levels due to the current world supply and demand situation, general economic conditions and the current high price of oil.

Tampa Electric's fuel costs increased 38.3% in 2004 after a 4.5% increase in 2003, primarily due to increased use of natural gas at the Bayside Power Station and higher natural gas prices. Natural gas consumption increased again in 2005 due to lower coal-fired unit availability. On a Btu basis, natural gas consumption increased 13.3% in 2005 while coal usage decreased 8.4%, which is in line with the increased generation from natural gas and decreased generation from coal as a result of the Bayside repowering.

On a retail energy supply basis, Tampa Electric generation accounted for 91.8%, 94.9% and 88.2% of the total retail energy sales in 2005, 2004 and 2003, respectively, with the remainder of the energy supplied by purchased power. The amount of power purchased by Tampa Electric to serve its customers increased in 2005 following a decrease in 2004, primarily due to lower coal-fired unit availability. Purchased power is expected to decrease in 2006 due to higher coal-fired unit availability.

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 Bayside. Nevertheless, coal is expected to continue to be more than half of Tampa Electric's fuel mix due to the base load units at Big Bend and the coal gasification unit, Polk Unit One. Beginning in 2007 and through 2010, one of the Big Bend coal-fired units will undergo an extensive outage each year to complete the construction of the nitrogen oxide (NO_x) control equipment (see the **Environmental Compliance** section), which is expected to reduce the generation from coal in those years.

2004 and 2005 Hurricanes

In 2005, Tampa Electric experienced no direct impacts from the major hurricanes that affected other areas of Florida; however, there was a significant indirect effect of the hurricanes in the form of the spike in natural gas costs, which increased the company's fuel under-recovery, discussed above. In 2004, Tampa Electric's service area was impacted by hurricanes Charley, Frances and Jeanne. These storms caused more than 600,000 customer outages and damaged the transmission and distribution systems and other facilities. The restoration costs were $74.5 million, which exceeded Tampa Electric's $44 million year-end unfunded storm damage reserve balance. Although rate base, operations and maintenance expense and capital expenditures were not affected by hurricane restoration costs in 2004, as costs were charged to the storm damage reserve, Tampa Electric paid an estimated $54 million of cash for hurricane restoration in 2004 with the remaining $20.5 million paid in 2005.

In June 2005, the FPSC approved a stipulation entered into by Tampa Electric, the Office of Public Counsel (OPC) and the Florida Industrial Power Users Group (FIPUG) regarding the treatment of Tampa Electric's 2004 hurricane costs. Under the stipulation, Tampa Electric agreed to reclassify approximately $39 million of the 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, which had a $30 million deficit balance, had a positive balance of about $11 million at the start of the 2005 hurricane season and a $13 million balance at Dec. 31, 2005 (see the **Regulation** section).

PEOPLES GAS

Summary of Operating Results

Peoples Gas (PGS) had 2005 net income of $29.6 million, compared with $27.7 million for the same period in 2004, including the 2004 restructuring charge. Customer growth of 3.6%, increased sales to residential and commercial customers and increased off-system sales were partially offset by higher operations and maintenance expenses in 2005. Results in 2005 reflect strong sales to commercial customers as a result of growth in the Florida economy and high levels of tourism, which enhanced commercial sales to hotels and restaurants, while sales of low-margin transportation service for interruptible customers declined.

PGS net income was $27.7 million in 2004, compared to $24.5 million in 2003. Non-GAAP results in 2004 were $28.1 million, excluding a $0.4 million after-tax restructuring charge, compared to non-GAAP results of $27.1 million in 2003, which exclude a $2.6 million after-tax restructuring charge. Results in 2004 reflect 5.3% customer growth partially offset by higher operating expenses.

Historically, the natural gas market in Florida has been underserved with the lowest market penetration in the southeastern U.S. In 2003, the most recent year that data is available, natural gas had a market penetration rate of 9% compared to the next lowest state in the southeast, North Carolina, with 29%. PGS has targeted residential customer growth through agreements with developers of new residential communities throughout Florida, which have significantly higher expected average annual usage per-household than the current average.

In 2005, residential and commercial therm sales increased through customer growth and increased usage per customer. Increased residential usage reflects increased sales to customers with multiple uses for gas as a result of marketing to high-end residential developers. The increased commercial usage reflects the continued strong Florida economy and the strong 2005 tourist business at hotels, restaurants and theme parks served by PGS.

In 2004, usage per customer decreased compared to 2003 due to milder winter weather. Volumes transported for power generation customers declined again in 2004 after declining in 2003. The high gas prices first experienced in 2003 have persisted throughout 2004 and 2005, spiking to record levels in the late summer of 2005 following hurricanes Katrina and Rita. While the higher cost of gas has had a negative impact on sales to larger interruptible and power generation customers, especially in the second half of 2003 and into the first half of 2004, most of those who could switch fuels had already done so by mid-year 2004. Many of these customers have the ability to switch to alternative fuels or to alter consumption patterns in response to rising natural gas prices. Because these are lower-margin sales, the decrease has not significantly affected PGS results.

The actual cost of gas and upstream transportation purchased and resold to end-use customers is recovered through a Purchased Gas Adjustment (PGA). The PGA rate, which is approved by the FPSC annually, is a band and can vary monthly due to changes in actual fuel costs and normally results in lower under- or over-recovered gas cost variances at PGS than at Tampa Electric.

Summary of Operating Results

(millions)	*2005*	*% Change*	*2004*	*% Change*	*2003*
Revenues	$ 549.5	31.7	$ 417.2	2.1	$ 408.4
Cost of gas sold	350.2	54.8	226.2	1.0	224.0
Operating expenses	136.2	3.9	131.1	0.8	130.0
Operating income	63.1	5.3	59.9	10.1	54.4
Net income	29.6	6.9	27.7	13.1	24.5
Restructuring charges	–	–	0.4	–	2.6
Non-GAAP results	$ 29.6	5.3	$ 28.1	3.7	$ 27.1
Therms sold - by customer segment					
Residential	70.7	7.4	65.8	2.5	64.2
Commercial	380.3	3.3	368.1	3.7	354.8
Industrial	394.6	-1.2	399.5	-1.7	406.3
Power generation	291.7	–	291.6	-19.8	363.7
Total	1,137.3	1.1	1,125.0	-5.4	1,189.0
Therms sold - by sales type					
System supply	337.1	3.3	326.4	-3.2	337.3
Transportation	800.2	0.2	798.6	-6.2	851.7
Total	1,137.3	1.1	1,125.0	-5.4	1,189.0
Customers (thousands) – average	318.4	3.6	307.4	5.3	291.9

In Florida, natural gas service is unbundled for any non-residential customers that elect this option, affording these customers the opportunity to purchase gas from any provider. The net result of this 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 these customers through its "NaturalChoice" program. At year end 2005, approximately 41% of PGS' non-residential customers had elected to take service under this program.

Operations and maintenance expense increased in 2005 primarily due to higher customer charges for uncollectible accounts, which have risen due to the high gas prices and higher personnel-related expenses for pay and benefits. Operations and maintenance expenses decreased in 2004, compared to higher than normal operations and maintenance expenses in 2003 that included higher employee-related costs, including restructuring costs, but depreciation expense increased in both years, in line with the capital expenditures made over the past several years to expand the system.

Operations and maintenance expenses are expected to increase almost 5% in 2006 primarily due to increased personnel related expenses for payroll and benefits such as pension plans and medical, stock option expense and added employees. Depreciation is expected to increase in 2006 from normal plant additions.

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 high-growth Ft. Myers and Naples areas and the northeast coast in the Jacksonville area. PGS' expansion strategy for the past several years was to take advantage of the significant capital investments in main pipeline expansions made over the past five years and to connect customers to that existing infrastructure. In 2006, PGS expects to increases its capital spending by almost $10 million for 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).

TECO COAL

TECO Coal's 2005 net income was $115.4 million, driven by higher selling prices and margins, on total sales of 9.7 million tons, compared to $61.3 million for the same period in 2004, which included the $7.0 million benefit from a tax credit true-up, on sales of 9.1 million tons. Full-year tonnage includes 6.4 million tons of synthetic fuel sales in 2005, compared to 6.3 million tons in the 2004 period. Results reflect an average net selling price per ton, which excludes transportation allowances, almost 48% higher than in 2004; average cash cost of sales, excluding synthetic fuel costs, almost 20% higher than in 2004; and increased third-party ownership in the synthetic fuel production facilities. The cash cost of sales was driven by higher prices for diesel fuel, labor and steel products. Results in 2005 also included a $1.6 million after-tax benefit from the 2004 synthetic fuel tax credit rate, which was $1.13 per million Btu on an actual basis versus the $1.12 per million Btu estimated in 2004, and a $2.4 million negative adjustment to deferred tax assets due to a reduction in the Kentucky state income tax rate.

TECO Coal's 2004 net income was $61.3 million, compared to $77.1 million in 2003. Non-GAAP results in 2004 were $54.3 million, excluding a $7.0 million benefit to income taxes from a true-up of synthetic fuel tax credits, compared to $84.1 million in 2003, which excluded a $7.0 million negative adjustment due to unrecognizable synthetic fuel tax credits, discussed below. Sales in 2004 were 9.1 million tons, compared to 9.2 million tons in 2003. These lower results reflect an increase of third-party ownership of the synthetic fuel production facilities to more than 90% and 17% higher production costs. The increased production costs were primarily due to increased diesel fuel prices, higher prices for steel products and higher contract miner costs. The higher production costs were partially offset by average prices for coal sales which were more than 12% higher than 2003.

In 2005, synthetic fuel production and sales were 6.4 million tons, compared to 6.3 million tons and 5.8 million tons in 2004 and 2003, respectively. TECO Synfuel Holdings, LLC had sold 90% of its ownership interest to two third parties by the end of 2004, along with associated percentage rights to benefits in the business that adjust from time to time. Allocation of the benefits varied in 2004 such that more than 90% of the benefits were to third parties. 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 is paid to provide feedstock, operate the synthetic fuel production facilities and sell the output; TECO Coal also recognizes a gain on the sale of the ownership interests in the facilities for each ton of synthetic fuel sold. The purchasers have the risks and rewards of ownership and are allocated 98% of the tax credits and operating costs. The 2005 net cash benefit to TECO Coal from the investors for the production of synthetic fuel was $158.3 million.

In December 2005, TECO Coal amended the agreements with the investors in its synthetic fuel production facilities to provide TECO Coal with flexibility to cease producing synthetic fuel. These amendments were entered into in order to provide the parties additional flexibility in the event that high oil prices impact the level of the tax credits. Under the amendments, TECO Coal and the investors will review actual and forecasted oil prices monthly to determine if and at what level synthetic fuel production should continue. If the calendar-year average oil price, on the basis of actual plus futures prices exceed $62 per barrel on the NYMEX basis, TECO Coal has the right to cease or reduce production and the third-party investors have the right to not participate in the production. If, later in the year, oil prices moderate, full production can resume. TECO Coal produced synthetic fuel through the first two months of 2006 and the investors participated during that period.

TECO Coal recorded no synthetic fuel tax credits in earnings for 2005 or 2004 production associated with its remaining synthetic fuel ownership interest because of TECO Energy's actual 2004 and anticipated 2005 tax positions, which were driven by tax losses incurred upon the disposition of merchant power plants. In 2004, a $7.0 million positive true-up to income taxes was related to synthetic fuel tax credits that, due to projected limitations on taxable income, were reserved for in 2003 but were found to be recognizable in 2004 upon finalizing the 2003 tax return.

TECO Coal expects 2006 total sales of conventional coal and synthetic fuel to be in a range of 9.5 to 10 million tons and per ton net selling prices in the mid $50 range compared to about $49 in 2005. The cash cost of production is expected to increase 3% to 5% over the approximately $40 per ton level in 2005 driven by higher contract miner costs, higher royalty and severance fees that are a function of coal prices, and higher transportation costs. TECO Coal's 2006 forecast assumes that it will continue to benefit from strong earnings and cash flow from the sale of 98% of the ownership of its synthetic fuel facilities to third parties. These estimates assume no reduction in synthetic fuel tax credits due to limitations that could result from oil prices exceeding the average reference price for the full year. The company estimates that oil prices, as quoted on NYMEX, would have to average more than $60 per barrel for the 2006 calendar year to begin to phase out the benefits from synthetic fuel (see the **Synthetic Fuel** discussion in the **Outlook** section). In early 2006, the average NYMEX futures price for oil for calendar year 2006 was approximately $67 per barrel on several occasions. If oil prices were to remain at these levels for the full year, the benefits from the sale of the synthetic fuel ownership interests would be reduced by approximately $0.27 per share in earnings and $92 million in cash proceeds.

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 current year. In 2004, it did not realize the high reported spot prices for the majority of its production because of the timing of its contract renewals. Due to this contracting strategy, TECO Coal is less affected by the rapid price changes, both upward and downward, than those companies that sell a higher percentage in the spot markets. In 2005, TECO Coal was successful in signing several three-year contracts for steam coal at the then current market prices.

Higher prices for competing fuels, increased demand for metallurgical coal worldwide, better balance in supply and demand, lower producer and consumer inventories and consolidation in the mining industry have contributed to higher prices recently. In addition, changes that have occurred over the past several years, including industry consolidation, longer environmental permitting time for new mines, fewer skilled coal miners, gradual depletion of high-quality Central Appalachian reserves, low inventory levels at coal-consuming utilities, and increased international demand for U.S. coal, have allowed producers to contract production for 2006 at average prices above 2005 average levels. Current indications within the domestic coal industry are that prices are expected to remain at current levels into 2007, but may decline slightly after that.

The economics of the sale of the ownership interests in the synthetic fuel production facilities are reasonably constant as they are determined by the level of the tax credits and not the price received from the sale of output. The synthetic fuel tax credit is determined annually and is estimated to be $1.15 per million Btu for 2005, and was $1.13 per million Btu in 2004 and $1.10 per million Btu in 2003. This rate escalates with inflation but could be limited by domestic oil prices. If the oil price limitation is reached, the level of the tax credits start to decline. In 2005, average annual domestic oil prices, as measured by a U.S. Department of Energy (DOE) index, would have had to exceed $53 per barrel for this limitation to have been effective, and it was estimated that the tax credit would have been eliminated at an average oil price of $66 per barrel. The DOE index is based on the "Domestic First Purchase Price" not the NYMEX quoted oil futures prices, which in 2005 averaged about $6.00 per barrel less than the NYMEX price. The synthetic fuel tax credit phase out range for 2006 based on the DOE oil prices is expected to be $54 to $68 per barrel, which is the approximate equivalent of $60 to $74 per barrel on NYMEX. In 2005, TECO Coal hedged approximately $20 million of its 2006 exposure to higher oil prices on its expected synthetic fuel production with instruments that strike at NYMEX prices of $65 per barrel (see the **Synthetic Fuel** discussion in the **Outlook** section).

Following the expiration of the synthetic fuel tax credit program on Dec. 31, 2007, we expect both net income and cash flow at TECO Coal to decline due to the loss of the benefits from the sale of the third-party ownership interests. In 2008, TECO Coal expects to no longer produce synthetic fuel, and it expects to produce only conventional coal with a production goal of 10.5 to 11 million tons per year. When production of synthetic fuel ends, TECO Coal will stop mining the high-cost coals currently being mined for use in the production of synthetic fuel and will stop operating the synthetic fuel production equipment, which are expected to reduce production costs. At that time, the earnings and cash flow from TECO Coal will be dependent on the selling price of coal in 2008, and its ability to manage production costs.

TECO Coal has received private letter rulings (PLRs) from the Internal Revenue Service (IRS) regarding the qualification of synthetic fuel production from its facilities. The PLRs confirm that the facilities are located appropriately and produce a qualified fuel eligible for synthetic fuel tax credits, which are available for the production of such non-conventional fuels through 2007. In the course of conducting its audit of TECO Energy's consolidated year 2000 tax return, the first year that TECO Coal produced synthetic fuel, the IRS reviewed the company's compliance with the requirements for synthetic fuel tax credits and completed the audit with no adjustments required. The return closed by statute in September 2004.

The significant factors that could influence TECO Coal's results in 2006 are the higher expected costs of production and the level of domestic oil prices. Longer-term factors that could influence results include weather, general economic conditions, the level of domestic oil prices, commodity price changes, and the ability to use synthetic fuel tax credits, and could be impacted earlier by administrative actions of the IRS, the U.S. Treasury or changes in laws, regulations or administration (see the **Risk Factors** section).

TECO TRANSPORT

TECO Transport's 2005 net income was $20.2 million, compared to $10.2 million in the same period in 2004. Non-GAAP results in 2005 were $19.1 million, which excluded direct hurricane costs and insurance recovery, compared to $11.9 million in 2004, which excluded management restructuring costs and valuation adjustments on oceangoing equipment. Non-GAAP results in 2005 excluded the $12.6 million after-tax direct costs associated with the restoration and recovery efforts for Hurricane Katrina and the $13.7 million after-tax benefit for insurance recovery related to the hurricane restoration costs at TECO Bulk Terminal (see the 2005 GAAP to non-GAAP reconciliation table). Results in 2005 were positively affected by the qualification of two oceangoing vessels for the benefits of tax law changes under the Jobs Creation Act, which reduces taxes on income earned by U.S. flag vessels engaged in full-time international trade. Results in 2005 were also affected by improved operating efficiencies at TECO Barge Line, higher river barge rates and increased northbound river shipments as well as increased movements of export coal, petroleum coke and other products through TECO Bulk Terminal early in 2005. Higher fuel costs were partially offset by a $3.0 million after-tax benefit from fuel hedges. In 2005, TECO Transport's net income was reduced by an estimated $4.9 million due to the ongoing business interruptions associated with operations at TECO Bulk

Terminal as a result of Hurricane Katrina.

TECO Bulk Terminal, which is located about 55 miles below New Orleans on the Mississippi River in Davant, Louisiana, received an almost direct hit from Hurricane Katrina and side effects from Hurricane Rita. Following Hurricane Katrina, the terminal was flooded and without power. There was no damage to the oceangoing fleet and manageable impacts to the river fleet. The more lightly utilized of two cranes that unload in-bound oceangoing vessels was destroyed by the storm. The majority of the river fleet was returned to service by mid-October, and the terminal also resumed major operations in mid-October. Repairs at the terminal have continued with near normal river barge unloading achieved in early January 2006. Near normal oceangoing vessel loading operations are expected to resume in early 2006. TECO Transport expects to incur additional repair and restoration costs and recognize insurance recovery in 2006 related to the effects of the hurricane.

TECO Transport's 2004 net income was $10.2 million, compared to $15.3 million in 2003. Non-GAAP results in 2004 were $11.9 million excluding a $1.1 million after-tax restructuring charge and a $0.6 million after-tax valuation adjustment on oceangoing equipment, compared to non-GAAP results of $16.3 million in 2003, which excluded a $1.0 million after-tax restructuring charge (see the 2004 GAAP to non-GAAP reconciliation table). These results were driven by lower tonnage transported for Tampa Electric due to the repowering of the formerly coal-fired Gannon Station to the natural gas-fired Bayside Station, weak market conditions in the first half of 2004 for the river and terminal business segments, higher fuel costs and unusual operating conditions, including a five-day closing of the Mississippi River, and the impact on operations from the four hurricanes. Hurricanes in August and September of 2004 disrupted river and ocean movements and caused the terminal in Louisiana to halt operations. Estimated lost revenues and direct costs due to the hurricanes reduced TECO Transport's 2004 pretax results by $3.8 million.

TECO Transport's operating companies were impacted by lower tonnage transported for Tampa Electric in 2004 and 2003 when coal shipments were reduced approximately 1 million tons annually in each of these years. Total annual tonnage handled for Tampa Electric is expected to average about 5 million tons annually, compared to more than 7 million tons annually prior to the completion of the repowering of Bayside. TECO Transport replaced a portion of this tonnage with increased third-party business and is continuing to seek other new replacement business.

The river barge industry is now experiencing a better balance in supply and demand for river barge services due to improvements in the U.S. economy, increased international movements and the scrapping of a large number of obsolete river barges by operators throughout the country. A number of river barges which were built in the 1980s, driven mainly by tax incentives, are now at the end of their useful lives and are being scrapped. The increased rate of barge retirements and the high cost of steel, which has increased the cost of construction of replacement barges, have reduced the supply of barges at a time of increasing demand. The improved U.S. economy and the reduced supply of barges is expected to maintain the improved pricing for river barge services in 2006. TECO Transport expects to receive 50 new river barges starting in mid-2006 to replace older barges that it retired in 2005 and expects to retire in 2006. The addition of these new barges is expected to be treated as an operating lease.

The demand for non-U.S. flag oceangoing vessels to meet the demand for shipments to China caused rates for these vessels, as measured by the Baltic Dry Index, to climb to a record high in November 2004. As a U.S. flag carrier, TECO Transport does not benefit directly from these increased rates since it does not compete against non-U.S. flag vessels in these markets. However, the high international shipping rates create additional opportunities for spot cargo shipments for TECO Transport's oceangoing vessels. Although prices as measured by the Baltic Dry Index have dropped significantly since the 2004 peak, the rates are above average historic levels and the trend is expected to continue.

TECO Transport expects improved results in 2006 from continued robust river market pricing as a result of favorable balance in supply and demand for river barges throughout the industry. The company also expects its oceangoing operations to benefit from fewer shipyard days for the fleet than in 2005, and for three vessels to benefit from the tax law changes that reduce taxes on income earned by U.S. flag vessels in international trade, compared to two vessels benefiting in 2005. It forecasts continued good operating efficiencies for both the oceangoing and river barge operations, but expects TECO Bulk Terminal to continue to operate at reduced volumes through early 2006 until the major repairs for damage from Hurricane Katrina are completed.

Future growth at TECO Transport is dependent upon improved pricing, higher asset utilization, and potential asset additions at both the river and oceangoing businesses. Significant factors that could influence results include weather, bulk commodity prices, fuel prices, domestic and international economic conditions, and import and export patterns (see the **Risk Factors** section).

TECO GUATEMALA

TECO Guatemala consists of two non-merchant power plants operating in Guatemala and an ownership interest in Guatemala's largest distribution utility, EEGSA. The San José and Alborada power stations in Guatemala both have long-term power purchase contracts.

Net income for TECO Guatemala in 2005 was $40.4 million, compared to $5.7 million in 2004, which included a $6.7 million after-tax charge related to debt extinguishment, $17.4 million of taxes on repatriated cash, and a $12.8 million after-tax write-off of unused steam turbines. Although it is included in the TECO Guatemala segment for accounting purposes due to the redefining of our segments, the 2004 steam turbine write-off was not directly related to the Guatemalan operation; it related to turbines purchased in anticipation of a non-merchant project for TWG that was terminated. The 2005 results reflect higher operations and maintenance expenses early in the year and somewhat higher tax rates, partially offset by energy sales and customer growth at EEGSA and higher non-fuel revenues for the power plants.

Net income in 2004 was $5.7 million compared to $22.0 million in 2003. Non-GAAP results in 2004 were $42.6 million, excluding the $36.9 million of after-tax charges shown in the 2004 GAAP to non-GAAP reconciliation table. These results were driven by continued good operating performance at the Guatemalan generating facilities, higher energy sales at EEGSA and a $5.6 million benefit from reducing previously deferred income taxes due to a change in Guatemalan tax law. In addition, an electric rate increase, approved in late 2003, contributed to significantly improved results at EEGSA in 2004.

Net income from TECO Guatemala is expected to be affected negatively by $6 to $8 million in 2006 due to the one-time, one-year favorable tax treatment on dividends under the Jobs Creation Act in 2005 that is not expected to be repeated in 2006. In addition, a change in the method of calculating the energy payments from EEGSA to the San José Power Station is expected to reduce net income in 2006 about $1 million.

TWG MERCHANT

In 2003, we announced that our strategy going forward was to focus on our Florida utilities and our profitable unregulated businesses and to reduce our exposure to the merchant power markets. In 2005, we completed our exit from the merchant power business (see the **Overview** section).

Our major investments in merchant power began in 1999, when we announced that a component of our strategy was to expand our presence in the domestic independent energy industry. Our decision to invest in this industry was based on the outlook at that time for the energy markets beyond 2001, and the expectation that there would be wide-spread deregulation of these markets. Starting in late 2001 and early 2002, after we had committed to the major investments in unregulated power, conditions in energy markets changed. Wholesale power prices declined significantly in markets across the country for many reasons, including a general slowing, or in some states a reversal, of the movement towards wholesale electric competition and the large amount of new generating capacity which came online in 2002 and 2003 that contributed to significant excess generating capacity in many areas of the country.

These changed market conditions caused us to delay some projects and sell others. In the face of these changed merchant-energy market conditions, in October 2003, we announced that we would invest little, if any, additional cash in the existing merchant generating plants.

Since our announced strategy change in 2003, we have taken a number of steps to implement that strategy. In 2004 and 2005, we completed the sale and transfer of the ownership of the Union and Gila River projects back to the lenders; we sold our interests in the following projects: (1) Texas Independent Energy (TIE), the partnership that owned the Odessa and Guadalupe plants in Texas: (2) Frontera Generation Limited Partnership owner of a power plant located in Texas; (3) the Commonwealth Chesapeake Power Station in Virginia; and (4) the uncompleted Dell Power Station in Arkansas. We announced our decision to terminate the uncompleted McAdams Power Station and to transfer combustion turbines from that project to Tampa Electric in 2006 to meet its peaking generation needs. The operating results and valuation adjustments for the Union, Gila River, Frontera, and Commonwealth Chesapeake projects are reported in discontinued operations. The operating results and valuation adjustments for TIE, Dell, and McAdams projects remain in results from continuing operations. These sales and transfers effectively completed our exit from the merchant power business.

In 2005, TWG Merchant recorded a loss of $14.6 million, compared to a loss of $534.1 million in 2004. The 2005 results included only the results for the uncompleted McAdams Power Station, the Dell Power Station through the closing of its sale in August 2005, and the costs associated with the TWG Merchant parent. Excluding charges and gains, the improvement in 2005 is primarily the result of the discontinuation of interest allocation to the McAdams Power Station. The 2005 non-GAAP results for TWG Merchant, which excluded the $1.9 million net benefit from the sale of the Dell Power Station and the recognition of additional liabilities relating to both the Dell and McAdams power stations, was a $16.5 million loss. Results in 2004 included the asset write-off and the operating losses from the ownership interest in the TIE projects, which was sold in July 2004, as well as the Dell and McAdams valuation adjustments.

TWG Merchant reported a loss in 2004 of $534.1 million, compared to a loss of $60.8 million in 2003. On a non-GAAP basis, the loss in 2004 was $53.4 million, compared to a non-GAAP loss of $60.5 million in 2003. The non-GAAP results in 2004 exclude after-tax charges for the $381.7 million valuation adjustment for Dell and McAdams, and the $99.0 million valuation adjustment related to the 2004 sale of the indirect interest in the TIE projects. The 2003 non-GAAP results exclude a $0.3 million charge for corporate restructuring.

Union and Gila River Power Stations

In October 2003, we announced that we would put little, if any, additional cash into the merchant generation portfolio, and in February 2004, we announced our decision to exit from our ownership of the Union and Gila River projects and to cease further funding of these plants after having negotiated the conceptual terms of a sale of the projects to the lenders.

The negotiated arrangements included (1) the terms of the proposed sale and transfer; (2) the treatment of $66 million of letters of credit posted by us under the construction undertakings related to the projects, with $35 million drawn in February 2004 for the benefit of the project companies and the remaining $31 million cancelled and returned to us; and (3) our payment of $30 million to the lenders upon completion of the transfer of the plants in exchange for full releases by the lenders and project entities of TECO Energy and its related entities of all previous financial obligations (except for warranty items identified prior to the expiration of the original warranty period).

Because two members of the lending group did not vote in favor of the sale and transfer, the sale and transfer was effected through a pre-negotiated Chapter 11 reorganization, which was confirmed by the Bankruptcy Court on Apr. 19, 2005. In order to facilitate the speed of the sale and transfer, we agreed to pay $1.8 million for the attorneys' fees for the two non-consenting lenders. The sale and transfer was consummated and the releases became effective in May 2005.

LIQUIDITY, CAPITAL RESOURCES

Our consolidated cash and cash equivalents, excluding all restricted cash, totaled $345.7 million at Dec. 31, 2005. Restricted cash of $37.6 million includes $30.3 million held in escrow until the end of 2007 related to the sale of a 49.5% interest in the synthetic coal production facilities. Cash at Dec. 31, 2005 excluded the unrestricted cash balances of $15.7 million and restricted cash of $8.3 million related to the San José and Alborada power stations, as these project companies were deconsolidated due to the adoption of FIN 46R, *Consolidation of Variable Interest Entities,* effective Jan. 1, 2004.

In addition, at Dec. 31, 2005, aggregate availability under bank credit facilities was $445.7 million, net of letters of credit of $14.3 million outstanding under these facilities and $215 million drawn on Tampa Electric Company's bank and accounts receivable credit facilities. At the end of the year, total liquidity, including cash plus credit facilities, was $791.4 million, which included $277.4 million at Tampa Electric Company, consisting of $260.0 million of undrawn credit facilities and $17.4 million of cash.

TECO Energy parent had total liquidity of $500.0 million at Dec. 31, 2005, consisting of $314.3 million of cash and availability of $185.7 million under its credit facilities.

In 2005, we met our cash needs from a mix of internal sources, asset sales and short-term borrowings under Tampa Electric Company's credit facilities. Cash from operations was $174 million in 2005. Other sources of cash in 2005 included $206 million of proceeds from third-party investors for ownership interests in TECO Coal's synthetic fuel production facilities, $180 million from the final settlement of the 9.5% adjustable conversion-rate equity security units, $300 million from the issuance of long-term debt, and $165 million from the sale of the Commonwealth Chesapeake and Dell power stations. We utilized the proceeds from the long-term debt issuance in combination with cash on hand to retire prior to maturity $480 million of our highest-cost debt. We paid dividends in 2005 of $158 million on TECO Energy common stock. Our capital expenditures for the year were $295 million, and we paid $32 million to the lenders upon the final transfer of the Union and Gila River power stations.

In 2004, we met our cash needs largely from internal sources and asset sales. Cash from operations was $140 million. Other sources of cash included $161 million of proceeds from the sale of a 90% ownership interest in TECO Coal's synthetic fuel production facilities to third-party owners net of escrowed cash and $230 million of proceeds from the sales of interests in various businesses, including the Frontera Power Station, the Hamakua Power Station, the propane business, and Prior Energy. Cash used in financing activities included payment of common dividends of $145 million and the repayment of long-term debt of $225 million, including $75 million of first mortgage bonds at Tampa Electric and $123 million of TECO Capital Trust II trust preferred securities. Capital expenditures in 2004 were $273 million.

Cash from Operations

In 2005, our consolidated cash flow from operations of $174 million was affected by a number of factors, including Tampa Electric's net under-recovery of costs recovered under regulatory clauses, the cash premium paid in the early retirement of our 10.5% notes, and the accounting for the sale of interests in the synthetic fuel production facilities at TECO Coal, the costs of which are included in cash from operations while the benefits of which are recorded in financing and investing activities, as described more fully below. Tampa Electric's under-recovery of fuel costs in 2005, largely caused by gas price increases in the second half of the year as a result of the impacts of hurricanes Dennis, Katrina and Rita on Gulf of Mexico gas production facilities, was offset in part by $79 million of proceeds from the sale of accumulated sulfur dioxide (SO_2) emissions credits. Cash operating losses from the Union and Gila River power stations affected consolidated cash from operations through the date the plants were transferred to the lenders, but did not affect consolidated cash since investing activities included an offsetting source of restricted cash at the project companies.

Following the combined sale of 90.0% ownership interests in 2003 and 2004, TECO Coal sold an additional 8% ownership interest in its synthetic fuel production facilities in 2005, bringing the total third-party ownership interest sold to 98%. Cash flow from operations includes the operating losses of approximately $11.00 per ton (pretax) associated with the production of synthetic fuel, while the cash benefits from the sale of the synthetic fuel production facilities of approximately $33 per ton (pretax) are included in the investing and financing activities on the Consolidated Statement of Cash Flows. Investing activity includes cash from the gain on the sale of the synthetic fuel facilities. The cash paid by the owner for its portion of the operating loss from the production of synthetic fuel is included in financing activities as a minority interest.

We expect cash from operations to increase substantially in 2006 from improved operating results, collection by Tampa Electric of a portion of its under-recovered fuel expense from 2005, and lower interest expense due to the retirement of $480 million of high-cost debt in 2005 (see the **Cash and Liquidity Outlook** section).

Before 2004, we had not made a contribution to our defined benefit pension plan since the 1995 plan year because investment returns had been more than sufficient to cover liability growth. In 2005, we made a $17 million contribution to the plan following a $14 million contribution in 2004. Our minimum required contribution in 2006 is $6 million. We estimate that our minimum required contribution in 2007 will be $25 million and will average about $10 million annually in 2008 through 2010 (see **Note 5** to the TECO Energy **Consolidated Financial Statements**).

Cash from Investing Activities

Cash from investing activities of $37 million in 2005 included, among other items, capital investments totaling $295 million and net asset sale proceeds of $310 million. Asset sales included $90 million from the sale of the Commonwealth Chesapeake Power Station, $75 million from the sale of the Dell Power Station, $123 million from the sale of the 98% ownership interests in TECO Coal's synthetic fuel facilities and $22 million from the sale of smaller, non-core assets. Cash from the release of previously restricted cash included the release of $20 million of previously restricted cash associated with the initial sale of a 49.5% ownership interest in TECO Coal's synthetic fuel production facilities and $28 million of cash related to the Union and Gila River power stations.

Capital spending in 2005 was essentially at the maintenance levels required to support customer growth, system safety and reliability at Tampa Electric and Peoples Gas and maintenance levels at TECO Coal and TECO Transport for normal equipment replacements and capitalized maintenance expenditures. In addition, capital spending included expenditures for environmental compliance required under Tampa Electric's consent decree (see the **Environmental Compliance** section).

We expect capital spending for the next several years to be higher than previously forecast primarily as a result of capital spending for Tampa Electric's generation capacity additions, as well as customer service enhancements, improvements in reliability and capacity factors of its coal-fired units to mitigate the impact of high natural gas prices, and increased spending on distribution system reliability, based on lessons learned in recent hurricane seasons. Expectations of higher capital spending also include, to a lesser extent, capital to incrementally expand TECO Coal's production (see the **Capital Investments** section).

Cash from Financing Activities

Our financing activities in 2005 resulted in net cash generation of $38 million. This included the early retirement of $480 million of high-cost TECO Energy debt, scheduled principal payments of Peoples Gas debt, and $158 million in common stock dividends. As described in the **Financing Activity** section, we received $300 million of proceeds from the issuance of TECO Energy notes and $180 million of proceeds from the final conversion of the 9.5% adjustable conversion-rate equity security units. In addition, Tampa Electric Company drew an additional $100 million under its credit facilities, and we received $83 million for reimbursement of the operating losses of TECO Coal's synthetic fuel production facilities in the form of minority interest payments from the third-party owners.

We have no significant corporate debt maturities until 2007; however, consistent with our stated goal to improve our financial position, we used a combination of the proceeds from the notes issued and cash on hand to retire in full the $380 million 10.5% notes due in 2007 and to retire $100 million of our $200 million 8.5% TruPS due in 2041. In 2006, our plans include the retirement of the remaining $100 million of 8.5%TruPS (see the **Financing Activity** section) and a $50 million equity contribution to Tampa Electric; however, we will monitor any impact from oil prices on the cash expected from the synthetic fuel production facilities prior to committing to retiring this debt or contributing this equity. In 2006, Tampa Electric Company expects to issue long-term notes to reduce short-term borrowings under its credit facilities and support its capital spending program, which includes the NO_x control projects and generation capacity additions.

Cash and Liquidity Outlook

In general, we target consolidated liquidity (unrestricted cash on hand plus undrawn credit facilities) of approximately $500 million, comprised of $300 million for Tampa Electric Company and $200 million for TECO Energy. However, because we are accumulating cash for the planned retirement of $100 million of 8.5% TruPS in 2006 and $357 million of maturing TECO Energy notes in 2007, we are building cash in excess of our general targets through 2006. At Dec. 31, 2005 our consolidated liquidity was $791 million. Of this total, Tampa Electric had total liquidity of $277 million, TECO Energy parent had total liquidity of $500 million, and there was $14 million of cash at the unregulated operating companies.

We currently forecast our 2006 consolidated cash flow from operations in a range from $500 to $550 million and consolidated net cash generation in a range of $135 to $175 million after dividends. This forecast includes recovery in 2006 of approximately $70 million of 2005 net fuel and other clause under-recovery at Tampa Electric. Cash flow from operations includes the projected $65 million cost of producing synthetic fuel for the full year, but excludes the projected $205 million of synthetic fuel investor proceeds, as it is reported in cash from investing and financing activities. This forecast assumes no reduction in proceeds that would occur if oil prices exceed the threshold level at which the synthetic fuel tax credits would begin to be reduced (see the **Synthetic Fuel** discussion in the **Outlook** section). The forecast of consolidated net cash generation assumes estimated capital expenditures of approximately $450 million, net Tampa Electric Company borrowing of approximately $110 million, and the retirement of the remaining $100 million of 8.5% TruPS. As discussed above, we will monitor any impact from oil prices on the cash expected from the synthetic fuel production facilities prior to committing to retiring this debt.

We expect 2006 net cash generation at TECO Energy parent to be in a range from $130 to $170 million. This forecast is based on the assumptions described above and also assumes that we make a $50 million equity contribution to Tampa Electric and pay common stock dividends at current levels.

We plan to maintain liquidity in excess of our targeted level, and to accumulate additional cash to extinguish all of the TECO Energy parent 2007 debt maturities without raising external capital beyond Tampa Electric's incremental borrowing requirements to support its capital spending program. It is possible, however, that unforeseen cash requirements and/or shortfalls, particularly from the impact of high oil prices on the expected proceeds from synthetic fuel production, or higher capital spending requirements could cause us to fall short of our liquidity target or to require external capital to meet the 2007 TECO Energy parent debt maturities (see the **Risk Factors** section).

Credit Facilities

At Dec. 31, 2005, TECO Energy had a bank credit facility in place of $200 million with a maturity date of October 2010, and Tampa Electric Company had a bank credit facility totaling $325 million, also maturing in October 2010. In addition, Tampa Electric Company had a $150 million accounts receivable securitized borrowing facility. The TECO Energy and Tampa Electric Company bank credit facilities include sub-limits for letters of credit of $100 million and $50 million, respectively. The TECO Energy facility was undrawn at Dec. 31, 2005, except for $14.3 million of outstanding letters of credit. At Dec. 31, 2005, $215 million was drawn on the Tampa Electric Company credit facilities.

Our $200 million credit facility, which was amended and extended to its current maturity in October 2005, is secured by the stock of TECO Transport Corporation, which is to be released upon our achieving an investment grade credit rating at both Standard & Poor's (S&P) and Moody's. The facility has two financial covenants, earnings before interest, taxes, depreciation, and amortization (EBITDA)-to-interest and debt-to-EBITDA, but no debt-to-total capital covenant (see the **Covenants in Financing Agreements** section).

At current ratings, TECO Energy's and Tampa Electric Company's bank credit facilities require commitment fees of 37.5 basis points and 12.5 basis points, respectively, and drawn amounts are charged interest at LIBOR plus 125 – 150 basis points and 52.5 – 65 basis points, respectively.

In January 2005, Tampa Electric Company and TEC Receivables Corp. (TRC), a wholly-owned subsidiary of Tampa Electric, entered into a $150 million accounts receivable securitized 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 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'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) for the 12-months ending each quarter-end, the ratio of Tampa Electric Company's EBITDA-to-interest, as defined in the agreement, must be equal to or exceed 2.0 times; (2) at each quarter-end, Tampa Electric Company's debt-to-capital ratio, as defined in the agreement, must not exceed 60%; and (3) certain dilution and delinquency ratios with respect to the receivables.

At TECO Energy, we have not had access to the commercial paper market since the September 2002 downgrade by S&P of our commercial paper program to A3. Tampa Electric Company continued to have access to the commercial paper market until the S&P downgrade of its commercial paper program to A3 in June 2003. The lack of access to the commercial paper market has caused TECO Energy and Tampa Electric Company to utilize the above-described credit facilities for short-term borrowing needs.

Covenants in Financing Agreements

In order to utilize their respective bank credit facilities, TECO Energy and Tampa Electric Company must meet certain financial tests as defined in the applicable agreements (see **Credit Facilities** above). In addition, TECO Energy, Tampa Electric Company, and other operating companies have certain restrictive covenants in specific agreements and debt instruments. TECO Energy, Tampa Electric Company, and the other operating companies are 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, 2005. 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, 2005*
Tampa Electric Company			
PGS senior notes	EBIT/interest [2]	Minimum of 2.0 times	3.5 times
	Restricted payments	Shareholder equity at least $500	$1,666
	Funded debt/capital	Cannot exceed 65%	50.0%
	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 60%	51.0%
	EBITDA/interest [2]	Minimum of 2.0 times	5.6 times
6.25% senior notes	Debt/capital	Cannot exceed 60%	51.0%
	Limit on liens[4]	Cannot exceed $787	$287 liens outstanding
TECO Energy			
Credit facility [3]	Debt/EBITDA [2]	Cannot exceed 5.25 times	3.8 times
	EBITDA/interest [2]	Minimum of 2.60 times	3.6 times
	Limit on additional indebtedness	Cannot exceed $102	$ 0
	Dividend restriction[4]	Cannot exceed $50 per quarter	$40
$300 million note indenture	Limit on liens[5]	Cannot exceed 5% of tangible assets	$274 unrestricted
$100 million and $200 million note indentures	Restrictions on secured debt[5]	(6)	(6)
TECO Diversified			
Coal supply agreement guarantee	Dividend restriction	Net worth not less than $403 (40% of tangible net assets)	$597

(1) As defined in each applicable instrument.

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

(3) See description of credit facilities in **Note 6** to 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/Senior Unsecured Debt at Dec. 31, 2005

	Standard & Poor's	*Moody's*	*Fitch*
Tampa Electric Company	BBB-	Baa2	BBB+
TECO Energy / TECO Finance	BB	Ba2	BB+

In 2005, we achieved a stable outlook with all three of the major credit rating agencies when Moody's revised its outlook to stable in May. This action follows outlook revisions to stable by S&P and Fitch Ratings (Fitch) in 2004. In 2005, S&P reaffirmed our ratings and stable outlook and the ratings and stable outlook of Tampa Electric in July and November, and Fitch affirmed our ratings and stable outlook and Tampa Electric's ratings and stable outlook in January 2006.

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 to repay debt, lease payments and unconditional commitments related to capital expenditures. This table does not include contingent obligations, which are discussed in a subsequent table.

Contractual Cash Obligations at Dec. 31, 2005

		Payments Due by Period				
(millions)	*Total*	*2006*	*2007*	*2008*	*2009-2010*	*After 2010*
Long-term debt(1):						
Recourse	$ 3,528.2	$ 5.9	$ 566.7	$ 5.7	$ 409.2	$ 2,540.7
Non-recourse	13.0	1.3	1.3	1.4	2.8	6.2
Junior subordinated notes	177.6	–	71.4	–	–	106.2
Operating leases/rentals (2)	188.4	27.9	25.3	17.5	32.7	85.0
Net purchase obligations/commitments (2) (3)	188.5	75.1	35.4	24.6	53.4	–
Interest payment obligations(4)	1,963.3	243.0	230.1	205.7	395.3	889.2
Total contractual obligations (5)	$ 6,059.0	$ 353.2	$ 930.2	$ 254.9	$ 893.4	$ 3,627.3

(1) Includes debt at TECO Energy, 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) Excludes the TECO Transport $21 million purchase agreement for 54 river barges that is expected to be converted to an operating lease in early 2006.

(3) Reflects those contractual obligations and commitments considered material to the respective operating companies, individually. At the end of 2005, these commitments include Tampa Electric's outstanding commitments of about $198 million primarily for long-term capitalized maintenance agreements for its combustion turbines, and a $20 million purchase obligation for the two combustion turbines from TPS McAdams. Total purchase obligations are reduced by the $20 million payment to TPS Mc Adams.

(4) Includes variable rate notes at interest rates as of Dec. 31, 2005.

(5) The total excludes a $6.3 million contribution to the qualified pension plan and a $12.7 million contribution to the other postretirement employee benefits plans in 2006. No future contributions are included as 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**). The total also exludes specific pension plan obligations, the estimates for which are expected to vary over time (see **Note 5** to the **TECO Energy Consolidated Financial Statements**).

Summary of Contingent Obligations

The following table summarizes the letters of credit and guarantees outstanding that are not included in the Summary of Contractual Obligations table above and not otherwise included in our Consolidated Financial Statements.

Contingent Obligations at Dec. 31, 2005

			Commitment Expiration			
(millions)		*Total(2)*	*2006*	*2007*	*2008-2010*	*After 2010*
Letters of credit (1)		$ 16.3	$ 4.8	$ –	$ –	$ 11.5
Guarantees:	Fuel purchase/energy management	96.9	74.2	–	–	22.7 (3)
	Other	11.4	10.0	–	–	1.4
Total contingent obligations		$ 124.6	$ 89.0	$ –	$ –	$ 35.6

(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 INVESTMENTS

Capital Investments

(millions)	Actual 2005	Forecast 2006	2007	2008-2010	2006-2010 Total
Tampa Electric					
Transmission	$ 7	$ 19	$ 13	$ 84	$ 116
Distribution	84	99	100	302	501
Generation	58	87	104	209	400
Generation expansion	–	74	17	37	128
Other	19	17	22	50	89
NO_x control projects	25	78	75	135	288
Other environmental	10	10	39	46	95
Tampa Electric total	203	384	370	863	1,617
Peoples Gas	43	51	50	128	229
TECO Coal	24	30	35	76	141
TECO Transport	18	11	25	69	105
TECO Guatemala	–	–	–	1	1
Other	7	(20)	–	–	(20)
Total	$ 295	$ 456	$ 480	$ 1,137	$ 2,073

TECO Energy's 2005 capital investments of $295 million (without reduction for asset and business sale proceeds) included $203 million for Tampa Electric and $43 million for PGS. Tampa Electric's capital investments in 2005 were primarily for equipment and facilities to meet its growing customer base and generating equipment maintenance and capital expenditures required for environmental compliance including $25 million for NO_x control projects (see the **Environmental Compliance** section). Capital expenditures for PGS were approximately $28 million for system expansion and approximately $15 million for maintenance of the existing system. TECO Coal's capital expenditures included $24 million primarily for normal mining equipment replacement, but also included new high-wall mining equipment and equipment to improve recoveries of coal from a coal-preparation plant. TECO Transport invested $18 million in 2005 primarily for capitalized maintenance of oceangoing vessels.

TECO Energy estimates capital spending for ongoing operations to be $456 million for 2006 and $1,617 million during the 2007 – 2010 period.

For 2006, Tampa Electric expects to spend $384 million, consisting of about $190 million to support system growth and generation reliability, approximately $12 million for distribution system reliability improvements and enhancements to customer-service systems, $20 million for coal-fired generation capacity factor and availability improvements, $74 million for the addition of two combustion turbines at the Polk Power Station to meet its peaking generation capacity needs, $78 million for the addition of selective catalytic reduction (SCR) equipment at the Big Bend Station for NO_x control, and $10 million for other environmental compliance programs. At the end of 2005, Tampa Electric had outstanding commitments of about $198 million, primarily for long-term capitalized maintenance agreements for its combustion turbines and a $20 million purchase obligation for the two combustion turbines from TPS McAdams.

Tampa Electric's total capital expenditures over the 2007 – 2010 period are projected to be $1,233 million, including $54 million for generation expansion projects, which includes $37 million for summer peak capacity improvements to existing combustion turbines, $20 million for coal-fired unit performance improvements, $29 million for distribution system reliability and customer-service enhancements, $210 million for compliance with the Environmental Consent Decree for the SCR equipment and $85 million for other required environmental capital expenditures. 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 $51 million in 2006 and $178 million during the 2007 – 2010 period. Included in these amounts is an average of approximately $29 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 and TECO Transport expect to invest a combined $41 million in 2006 and $205 million during the 2007 – 2010 period. Included in these amounts are expansion projects to add approximately 1.5 million tons per year to TECO Coal's production. Also included is normal renewal and replacement capital, including coal mining equipment and capitalized maintenance on oceangoing vessels and inland river transportation equipment. TECO Coal had outstanding commitments of approximately $11 million, primarily for replacement of coal mining equipment at Dec. 31, 2005. Capital expenditures for TECO Transport do not include the $21 million contract for the construction of replacements river barges, which is expected to be treated as an operating lease (see the footnotes to the **Contractual Cash Obligation** table).

Included in Other is the $20 million cash offset in 2006, related to the sale of two combustion turbines by TPS McAdams to Tampa Electric. The corresponding capital expenditure has been included in the Tampa Electric Generation Expansion line in 2006 and the outstanding commitments at Dec. 31, 2005.

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 at Tampa Electric and PGS; the new programs for system reliability, customer service enhancements, and coal-fired generating unit performance improvements detailed above; peaking capacity additions, but no new base load capacity additions at Tampa Electric; 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 2005 year-end capital structure, excluding the effect of unearned compensation, was 68.0% senior debt, 3.2% junior subordinated debt, and 28.8% common equity. The debt-to-total-capital ratio decreased from last year, primarily due to the net reduction of $180 million of TECO Energy parent debt in 2005.

In 2005, as part of our overall efforts to manage our debt and reduce interest expense, we accessed the debt markets for new capital on two occasions for $200 million of fixed rate notes and $100 million of floating-rate notes. The proceeds from the fixed-rate notes, together with cash on hand, were used to retire in full the $380 million aggregate principal amount outstanding of our 10.5% notes due 2007. The floating-rate notes were issued to provide us the increased financial flexibility to call and retire $100 million, or 50%, of our 8.5% TruPS of TECO Capital Trust I. They also provide us increased future financial flexibility as additional cash becomes available during 2006 to call and retire the remaining $100 million of 8.5% TruPS; as indicated previously, we will monitor any impact from oil prices on the cash expected from the synthetic fuel production facilities prior to committing to retiring this debt (see the **Synthetic Fuel** discussion in the **Outlook** section). In addition, Tampa Electric used short-term borrowings under its credit facilities for working capital needs, which included temporarily under-recovered fuel costs, and to support its environmental capital spending program. We also raised a small, recurring amount of equity through our dividend reinvestment plan.

In 2004, we did not access the debt capital markets except for short-term borrowings under Tampa Electric's credit facilities and the small, recurring amount of equity raised through our dividend reinvestment plan.

In 2004, we completed an early settlement offer on our 9.5% adjustable conversion-rate equity security units (units). Under the terms of the offer, each unit holder received 0.9509 shares of TECO Energy common stock for each unit held and $1.39 per unit in cash, which included the future quarterly distributions through the normal settlement date and a $0.20 per unit incentive. Under the early settlement offer, 10.8 million units were exchanged for 10.2 million shares of our common stock, and we paid $14.9 million of cash for future distributions and incentives. The effect of the exchange was that we retired $269 million, or about 60%, of the associated trust preferred securities and increased the common shares outstanding three months earlier than would have otherwise occurred.

In 2004, we remarketed the remaining $163 million of outstanding trust preferred securities associated with the units within TECO Capital Trust II, as required. We purchased and subsequently retired $123 million of the securities offered in this transaction. Our purchase was funded through a $124 million bridge loan with Merrill Lynch and JP Morgan, which we repaid in December 2004. Trust preferred securities totaling $71 million of this series remain outstanding, including the 3% ($14 million) held by TECO Capital Trust II, and have a coupon rate of 5.93% which was set in the remarketing. The proceeds from the remarketing were used by the trustee to purchase a portfolio of U.S. Treasury securities with a January 2005 maturity. Upon final settlement of the units in January 2005, we issued 6.85 million shares of TECO Energy common stock and received $180 million of cash proceeds from the matured U.S. Treasury securities.

The following table provides details of the financing activities beginning in 2003.

Date	*Security*	*Company*	*Net Proceeds/ facility size (millions)*	*Coupon*	*Use*
Oct. 2005	Credit facility	TECO Energy	$ 200		5-year facility
Oct. 2005	Credit facility	Tampa Electric Company	$325		5-year facility
Jun. 2005	5-year notes	TECO Energy	$ 100	Floating rate	Initiate debt redemption program
May 2005	10-year notes	TECO Energy	$ 200	6.75%	Initiate debt redemption program
Jan. 2005	Common equity (1)	TECO Energy	$ 180	–	Final settlement of equity units
Jan. 2005	Credit facility	Tampa Electric Company	$ 150	–	Accounts receivable facility
Oct. 2004	Trust preferred securities (2)	TECO Energy	$ 0	5.93%	Required TECO Capital Trust II remarketing
Oct. 2004	Credit facility	Tampa Electric Company	$ 150	–	3-year facility
Aug. 2004	Common equity (3)	TECO Energy	$ 0	–	Early settlement of equity units
Jul. 2004	Credit facility	TECO Energy	$ 200	–	3-year facility
Nov. 2003	Credit facility	Tampa Electric Company	$ 125 $ 125	– –	364-day facility 3-year facility
Sep. 2003	Common equity	TECO Energy	$ 129	–	Repay short-term debt, and general corporate purposes
Jun. 2003	7-year notes	TECO Energy	$ 293	7.5%	Repay short-term debt, and general corporate purposes
Apr. 2003	13-year notes	Tampa Electric Company	$ 250	6.25%	Repay maturing short-term debt, and general corporate purposes

(1) 6.8 million shares issued in the final settlement of the 9.5% convertible equity units
(2) No increase in outstanding debt, interest rate reset
(3) 10.2 million shares issued in an early settlement offer on the 9.5% convertible equity units

OFF-BALANCE SHEET FINANCING

Unconsolidated affiliates have project debt balances as follows at Dec. 31, 2005. The two power plant financings are non-recourse project loans and the debt associated with EEGSA is general corporate debt at EEGSA; all 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 those projects are not operated successfully.

Off-Balance Sheet Debt at Dec. 31, 2005

(millions)	*Long-term Debt*	*TECO Guatemala's Ownership Interest*
San José Power Station	$ 98.2	100%
Alborada Power Station	$ 17.4	96%
Empresa Eléctrica de Guatemala S.A.(EEGSA)	$ 219.1	24%

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. (This and other effects of implementing FIN 46R are described in **Note 2** to the TECO Energy **Consolidated Financial Statements.**)

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Long-Lived Assets

In accordance with Financial Accounting Standard (FAS) 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. Also, we annually test the long-lived assets in the last quarter of each year to ensure that gradual change over the year and the seasonality of the markets are considered in the 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.

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**).

During the fourth quarter of 2004, as a part of its annual impairment review, management conducted a review of the prospects for long-term power prices, as well as opportunities for actual sales of assets. As a result of this review, we sold the Frontera project and determined it was appropriate to reduce the probability that the Dell, McAdams, and Commonwealth Chesapeake projects would be held for use for the overall economic life of those projects. The first step in the impairment testing was weighted more toward an ultimate recovery of the investment. In each case, the testing resulted in a determination that the carrying value of each project was not recoverable. This recoverability test is conducted by comparing the probability weighted undiscounted cash flows for the asset to its carrying value. If the test is not passed, a second step is required. Each of the projects listed above required the second step, in which the difference between the fair market value of the projects and the carrying value was estimated in order to determine and record appropriate impairment charges. Critical estimates are also inherent in determining the fair market value. We based the fair market values on probability weighted values. To the extent actual fair market value should vary from the probability weighted average values, future impairment charges or gains on disposition could occur (see **Note 18** to the TECO Energy **Consolidated Financial Statements**). There were no material adjustments to these estimates in 2005.

When specific criteria are met, a disposal group, comprised of assets and liabilities expected to be transferred in a sale within one year, is classified in assets and liabilities held for sale. Furthermore, the results of operations associated with a disposal group may, if additional criteria are met, be presented as discontinued operations in the statement of income. The Union and Gila projects, Frontera, Prior Energy, TECO BGA, TECO BCH, TECO AGC, TECO Thermal, and TECO Coalbed Methane were classified as assets and liabilities held for sale, and the results associated with these investments were presented as discontinued operations (see **Notes 1, 18** and **21** to the TECO Energy **Consolidated Financial Statements**).

Goodwill and Other Intangible Assets

In accordance with FAS 142, *Goodwill and Other Intangible Assets*, we review goodwill and intangibles for each reporting unit at least annually for impairment. The goodwill impairment test is a two-step process, which requires management to make judgments in determining what assumptions to use in the calculation. The first step of the process consists of estimating the fair value of each reporting unit based on a discounted cash flow model using revenue and profit forecasts and comparing those estimated fair values with the carrying values, which include the goodwill. If the estimated fair value is less than the carrying value, a second step is performed to compute the amount of the impairment by determining an implied fair value of goodwill. Estimating the reporting unit's implied fair value of goodwill requires us to allocate the estimated fair value of the reporting unit to the assets and liabilities of the reporting unit. Any unallocated fair value represents the implied fair value of goodwill, which is compared to its corresponding carrying value. During the fourth quarter of 2004, as a result of conditions in the energy services market, we were required to recognize an impairment charge for the goodwill related to the BCH reporting unit. This $11.8 million pretax impairment charge completely eliminated the goodwill associated with that investment. This impairment charge was reflected in discontinued operations, as we subsequently sold this unit.

We had $59.4 million of goodwill remaining on our balance sheet at Dec. 31, 2005, which was related to its Guatemalan reporting unit. Assuming an 8.3% discount rate, which management believes is appropriate since these projects have long-term power purchase agreements; the goodwill was not impaired at Dec. 31, 2005. Assuming a 1 to 3% increase in the discount rate would not reduce the implied fair value of the goodwill to an extent that an impairment charge would be necessary. However, increasing the discount rate 3.9%, to 12.2%, to calculate the implied fair value of the goodwill would have resulted in an approximate $1 million pretax impairment charge (see **Note 17** to the TECO Energy **Consolidated Financial Statements**).

Equity Investments

In accordance with APB No. 18, *The Equity Method of Accounting for Investments in Common Stock*, we only record an impairment of an equity investment when a decline in the fair value below the carrying value of the investment is determined to be other than temporary. The accounting estimate of impairment of equity investments is critical, since management must assess other than temporary impairments based on: (1) the magnitude of the difference of the fair value below the carrying value; (2) the period of time in which the decline in the fair value is less than the carrying value; and (3) other reasonably available qualitative or quantitative information that provides evidence to indicate that a decline in fair value is temporary. During 2005, there were no triggering events that would have necessitated an impairment analysis. During the year ended Dec. 31, 2004, the company recorded an impairment of an equity investment in TIE. This impairment charge was driven by management's decision to not make additional investments in this project, which materially impacted the impairment assessment (see **Notes 16** and **18** to the TECO Energy **Consolidated Financial Statements**).

Deferred Income Taxes

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

At Dec. 31, 2005, we had net deferred income tax assets of $735.7 million, attributable primarily to losses or expected losses on asset dispositions, property related items, alternative minimum tax credit carryover of synthetic fuel non-conventional fuel tax credits, 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, 2005 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**).

Accounting for Contingencies

In accordance with FAS 5, *Accounting for Contingencies*, we make estimates at the end of each reporting period to record the probable loss related to contingent liabilities. Examples of such expected losses and respective contingent liabilities would include environmental and legal contingencies and incurred but unreported medical and general liability claims. We consider these estimates of liabilities to be critical since the company must first determine the likelihood that the known claims or legal events will result in a future loss to the company. Then we must determine if the future amount of expected loss can be reasonably estimated.

For a known claim, if the company determines that it is probable that future events will result in a loss and that loss can be reasonably estimated, the expected loss and respective liability are recorded. If we determine that the likelihood is remote that those future events will develop in a manner that will result in a loss to the company, no loss or liability is recorded. If there is more than a remote possibility but it is less than likely that future events will result in a loss to the company, we disclose the specific claim or situation if it is material.

For medical and general liability claims that have been incurred but not reported, we rely on a third-party actuary to advise us as to probable liabilities that will become known in the future but were incurred in the current reporting period, and we record the expected loss and liability accordingly.

Many of the material claims that have been made or could be made against the company in the future are covered by insurance. Accounting for the expected loss and liability under FAS 5 has different recognition criteria than expected insurance recoveries such that it is possible that the company could have to report a loss and respective liabilities in accounting periods before the offsetting gain from the insurance recovery could be reported.

While the company carefully evaluates all known claims and cases to record the most probable outcome, future events could develop in an unexpected manner that could have a material impact on future financial statements. See **Note 12** to the TECO Energy **Consolidated Financial Statements** for a complete discussion of certain legal contingencies that existed at Dec. 31, 2005.

Employee Postretirement Benefits

We sponsor a defined benefit pension plan (the 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, discount rates, and health care cost trend rates. These factors are determined by us within certain guidelines, with the help of external experts. 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 and this assumption 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, 2005 net periodic expense by approximately $4.3 million. Likewise, a 0.75% increase or a 0.85% decrease in the discount rate assumption would result in an approximately $3 million change in the 2005 net periodic pension expense.

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 FAS 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 Jan. 1, 2006 by $1.8 million and net periodic cost for 2005 by $0.7 million. In 2005, we filed and received approval for our part D subsidy application and are continuing to analyze what, if any, plan design changes should be made with respect to our retiree medical program in response to the Act.

The assumed health care cost trend rate for medical costs was 9.5% in 2005 and decreases to 5.0% in 2013 and thereafter. A 1% increase in the health care trend rates would produce a 5% ($0.8 million) increase in the aggregate service and interest cost for 2005 and a 3% ($6.4 million) increase in the accumulated postretirement benefit obligation as of Sep. 30, 2005, the measurement date.

A 1% decrease in the health care trend rates would produce a 3% ($0.6 million) decrease in the aggregate service and interest cost for 2005 and a 3% ($5.3 million) decrease in the accumulated postretirement benefit obligation as of Sep. 30, 2005, 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.

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 FAS 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. During 2005, current regulatory assets increased significantly as a result of high fuel costs.

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**).

Revenue Recognition

Except as discussed below, we recognize revenues on a gross basis when the risks and rewards of ownership have transferred to the buyer and the products are physically delivered or services provided. Revenues for any financial or hedge transactions that do not result in physical delivery are reported on a net basis.

The determination of the physical delivery of energy sales to individual customers is based on the reading of meters, which occurs on a regular basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading may be estimated, and the corresponding unbilled revenue is estimated. Unbilled revenue is estimated each month primarily based on historical experience, customer-specific factors, customer rates, and daily generation volumes, as applicable. These revenues are subsequently adjusted to reflect actual results. Revenues for regulated activities at Tampa Electric and PGS are subject to the actions of regulatory agencies.

The percentage-of-completion method is used to recognize revenues for certain transportation services at TECO Transport. The percentage-of-completion method requires management to make estimates regarding the distance traveled and/or time elapsed. Revenue is recognized by comparing the estimated current total distance traveled with the total distance required. Each month revenue recognition and realized profit are adjusted to reflect only the percentage of distance traveled.

We estimate certain amounts related to revenues on a variety of factors, as described above. Actual results may be different from these estimates (see **Note 1** to the TECO Energy **Consolidated Financial Statements**).

RECENTLY ISSUED ACCOUNTING STANDARDS

In accordance with recently issued accounting pronouncements, we are required to comply with certain changes in accounting rules and regulations (see **Note 2** to the TECO Energy **Consolidated Financial Statements**).

FASB Statement No. 123 (revised 2004), *Share-Based Payment*, became effective Jan. 1, 2006. The revision to FAS 123 requires financial statement cost recognition for certain share-based payment transactions that are made after the effective date. Additionally, the revision requires financial statement cost recognition for certain share-based payment transactions that have been made prior to the effective date, but for which the requisite service is provided after the effective date (see **Note 9** to the TECO Energy **Consolidated Financial Statements**). The impact of implementing FAS 123R is not expected to be materially different from the proforma amount disclosed in **Note 1** to the TECO Energy **Consolidated Financial Statements.**

FASB Interpretation No. 47 (FIN 47), *Accounting for Conditional Asset Retirement Obligation, an Interpretation of FASB Statement No. 143*, was issued in March 2005 and became effective as of Dec. 31, 2005. FIN 47 clarifies the term

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"conditional asset retirement obligation" as a legal obligation to perform an asset retirement activity in which the timing and the method of settlement are conditional on a future event that may or may not be within the control of the entity, and clarifies when and entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation. We implemented FIN 47 in the fourth quarter of 2005. At that time, Tampa Electric recorded an increase to net property, plant and equipment of $3.6 million (net of accumulated depreciation of $0.4 million), an increase to regulatory assets of $2.7 million and an increase to asset retirement obligations of $18.3 million (including $12.1 million reclassified from a regulatory liability). There was no impact on the income statement as a result of the implementation of FIN 47. See **Note 15** to the TECO Energy **Consolidated Financial Statements** for a discussion of the effects of this implementation.

In October 2004, the EITF issued EITF Issue No. 04-10, *Determining Whether to Aggregate Operating Segments That Do Not Meet Qualitative Thresholds* (EITF 04-10). EITF 04-10 states that operating segments that do not meet the quantitative thresholds can be aggregated only if aggregation is consistent with the objective and basic principles of FAS 131, *Disclosures about Segments of an Enterprise and Related Information* (FAS 131), the segments have similar economic characteristics, and the segments share a majority of the aggregation criteria outlined in FAS 131. The adoption of this additional guidance in EITF 04-10 reinforced the company's decision to revise segment reporting and separately disclose TECO Guatemala as a separate segment (see **Notes 1** and **14** to the **TECO Energy Consolidated Financial Statements**).

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 merchant power plants, 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 Transport.

The TECO Energy group of companies uses 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 optimize the value of physical assets, primarily generation capacity and natural gas delivery.

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, 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 adopted 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. The Credit Guidelines are administered and monitored within the Middle Office, independent of the Front Office.

Credit exposures are calculated, compared to limits and reported to management on a daily basis. 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.

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, 2005, a hypothetical 10% increase in the consolidated group's weighted average interest rate on its variable rate debt during 2006, as compared to 2005, would not result in a material impact on pretax earnings. Comparatively, as of Dec. 31, 2004, a hypothetical 10% increase in the consolidated group's weighted average interest rate on its variable rate debt during 2005, as compared to 2004, would not have resulted in a material impact on pretax earnings. This is driven by the very low amounts of variable rate debt at either TECO Energy or Tampa Electric.

These amounts were determined based on the variable rate obligations existing on the indicated dates at TECO Energy and its subsidiaries. A hypothetical 10% decrease in interest rates would increase the fair market value of our long-term debt by approximately 2.8% and 2.1% at Dec. 31, 2005 and 2004, 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 risk.

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. 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 PGS and Tampa Electric 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, 2005 and 2004, a change in commodity prices would not have a material impact on earnings for Tampa Electric or PGS, but could have an impact on the timing of the cash recovery of the cost of fuel (see the **Tampa Electric** and **Regulation** sections).

Unregulated Operating Companies

Most of the unregulated subsidiaries at TECO Energy are subject to significant commodity risk. These include TECO Coal, TECO Transport and TECO Guatemala. The unregulated 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. Based on the uncontracted tons subject to market price variation at Dec. 31, 2005 and 2004, a hypothetical 10% increase in the average annual market price of coal for each year would have resulted in an increase in pretax earnings of approximately $1 million in both years.

TECO Coal is also indirectly exposed to changes in the price of crude oil. Under the rules governing synthetic fuel tax credits, those credits can be phased out in the event that the price of crude oil reaches a certain threshold. The synthetic fuel tax credit is determined annually and is estimated to be $1.15 per million Btu for 2005, and was $1.13 per million Btu in 2004 and $1.10 per million Btu in 2003. This rate escalates with inflation but could be limited by domestic oil prices. If the oil price limitation is reached, the level of the tax credits starts to decline. In 2005, average annual domestic oil prices, as measured by the DOE index, would have had to exceed $53 per barrel for this limitation to have been effective, and it was estimated that the tax credit would have been eliminated at an average oil price of $66 per barrel. The DOE index is based on the "Domestic First Purchase Price" not the NYMEX-quoted oil futures prices, which in 2005 averaged about $6.00 per barrel less than the NYMEX price. The synthetic fuel tax credit phase-out range for 2006 based on the DOE oil prices is expected to be $54 to $68 per barrel, which would be the equivalent of a NYMEX price of approximately $60 to $74 per barrel (see the **Synthetic Fuel** discussion in the **Outlook** section).

Commodity price risk exists at TECO Transport as a result of periodic purchases of fuel oil. Haulage and freight agreements often include fuel price adjustments to transfer the risk of market fuel price movements to the customer. TECO Transport also utilizes derivative instruments to reduce the risk of price variability for anticipated fuel purchases in excess of purchases subject to fuel adjustment clauses. As of Dec. 31, 2005, substantially all of the projected fuel price risk for 2006 was removed via price adjustment clauses and derivative instruments. As a result, a hypothetical 10% increase in the price of fuel would not result in a material impact on pretax earnings as of Dec. 31, 2005.

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 energy derivative assets (liabilities) for the year ended Dec. 31, 2005:

Changes in Fair Value of Energy Derivatives (millions)	
Net fair value of energy derivatives as of Dec. 31, 2004	$ (8.8)
Net change in unrealized fair value of derivatives	149.8
Changes in valuation techniques and assumptions	–
Realized net settlement of derivatives	(72.4)
Net fair value of energy derivatives as of Dec. 31, 2005	$ 68.6

Roll-Forward of Energy Derivative Net Assets (Liabilities) (millions)	
Total energy derivative net assets (liabilities) as of Dec. 31, 2004	$ (8.8)
Change in fair value of net derivative assets (liabilities):	
Recorded in OCI	77.1
Recorded in earnings	(8.4)
Net option premium payments	2.9
Net purchase (sale) of existing contracts	5.8
Net fair value of energy derivatives as of Dec. 31, 2005	$ 68.6

When available, the company uses quoted market prices to record the fair value of energy derivative contracts. However, many energy 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 energy derivative contracts, the valuation is an estimate based on the best available information. Actual cash flows could be materially different from the estimated value upon maturity.

The following is a summary table of sources of fair value, by maturity period, for energy derivative contracts at Dec. 31, 2005.

Maturity and Source of Energy Derivative Contracts Net Assets (Liabilities) at Dec. 31, 2005

(millions)	*Current*	*Non-current*	*Total Fair Value*
Source of fair value			
Actively quoted prices	$ 58.1	$ 4.9	$ 63.0
Model prices [(1)]	5.6	–	5.6
Total	$ 63.7	$ 4.9	$ 68.6

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

OTHER ITEMS IMPACTING NET INCOME

2005 Items

In 2005, our results from continuing operations included $43.7 million of charges and gains related to debt extinguishment and hurricane restoration costs which were partially offset by insurance recoveries (see the **Results Summary** section).

2004 Items

In 2004, our results from continuing operations included $508.6 million of charges and gains related primarily to valuation adjustments on merchant power assets, refinancing costs and the associated taxes on the cash repatriated from the San José Power Station in Guatemala, the gain on the sale of our interest in our propane business, corporate restructuring charges, and tax credit true-ups (see the **Results Summary** section).

2003 Items

In 2003, our results from continuing operations included $71.6 million of charges and gains related to valuation adjustments, project cancellation costs, turbine valuation adjustments, tax credit reversals, and corporate restructuring at the various operating companies and $42.9 million related to the sale of HPP and its operating net income through the date of the sale (see the **Results Summary** section). In addition, we recognized $1.1 million in after-tax charges related to a change in accounting principle for the implementation of FAS 143, *Accounting for Asset Retirement Obligations*, and a $3.2 million after-tax charge for the implementation FAS 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity.*

OTHER INCOME (EXPENSE)

In 2005, Other Income (expense) of $160.5 million reflected the installment sale of the 98% interest in the synthetic fuel production facilities at TECO Coal, income from the Guatemalan operations, which are on equity investment accounting, and gains on the smaller assets sold in 2005 partially offset by the debt extinguishment charges associated with our 2005 debt retirement program.

In 2004, Other Income (expense) of $23.1 million reflected the income related to the gain on the sale of the Hamakua Power Station, the sale of our interest in the propane business and the installment sale of the 90% interest in the synthetic fuel production facilities at TECO Coal, and income from the deconsolidated Guatemalan operations largely offset by a $152.3 million pretax impairment charge related to our investment in the TIE projects.

AFUDC equity at Tampa Electric, which is included in Other Income (expense), was $0.7 million in 2004 and $19.8 million in 2003. AFUDC is expected to increase in 2006 due to the installation of NO_x control at the Big Bend Station at Tampa Electric and the addition of two combustion turbines for peaking capacity at the Polk Power Station (see the **Environmental Compliance** and **Liquidity, Capital Resources** sections).

In 2005, earnings from equity investments (which is included in Other Income) included a $57.9 million pretax benefit from TECO Guatemala.

INTEREST EXPENSE

Total interest expense was $291.4 million in 2005 compared to $322.9 million in 2004 and $316.5 million in 2003. Interest expense was reduced by the retirement of $391.6 million of trust preferred securities in late 2004, and the repayment in June 2005 of $380 million of 10.5% notes. Interest expense also reflected interest associated with $200 million of fixed-rate notes issued in May 2005 and $100 million of floating-rate notes issued in June 2005 (see the **Financing Activity** section), and higher short-term borrowings under credit facilities at Tampa Electric.

Interest expense is expected to decrease in 2006 due to the full year benefits from the June 2005 debt retirement, the retirement of $100 million of 8.5% TruPS in December 2005 and the planned retirement of the remaining $100 million of TruPS, partially offset by Tampa Electric's increased borrowings to support its capital spending program (see the **Liquidity, Capital Resources** section).

INCOME TAXES

The provision for income taxes increased in 2005 as a result of more-normal operations and fewer write-offs of merchant generating assets. The provision for income taxes decreased in 2004 as we incurred net operating losses primarily as a result of losses on the disposition of merchant power generating assets. Income tax expense as a percentage of income from continuing operations before taxes was 32.6% in 2005, 40.8% in 2004 and (207.0%) in 2003. For 2006, 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 related to prior years' audits was $27.4 million, $22.4 million and $58.8 million in 2005, 2004 and 2003, respectively. The 2005 cash payments included approximately $15 million of audit true-up amounts primarily related to the closing of the 2001 and 2002 income tax return audits.

Due to the generation of deferred income tax assets related to the net operating loss (NOL) carry-forward from disposition of the merchant generating assets, we expect future cash tax payments for income taxes to be limited to approximately 10% of the AMT rate and various state taxes. We currently expect to utilize these NOL through 2011. Beyond 2011, we expect to use more than $190 million of AMT carry-forward to limit future cash tax payments for federal income taxes to the level of AMT. Our current projection of cash income tax payments in 2006 is about $12 million, including amounts for refunds of foreign tax credits carried back to prior years. For the 2007-2010 period, we estimate tax payments to be approximately $10 million annually.

Total income tax expense in years prior to 2004 was reduced by the federal tax credits related to the production of non-conventional fuels. We recognized no tax credits in 2004 and $73.0 million in 2003. These tax credits are generated annually on qualified production at TECO Coal through December 31, 2007, subject to changes in the law, regulation or administration that could impact the qualification for non-conventional fuel tax credits. We were unable to utilize any of these tax credits in both 2005 and 2004 due to our net tax loss position for the years. Under the Energy Policy Act of 2005 that was signed into law on Aug. 8, 2005, effective Jan. 1, 2006 tax credits from the production of synthetic fuels generated in 2006 and 2007 that could not be utilized in those years will be carried forward for 20 years.

The synthetic fuel tax credit is determined annually and is estimated to be $1.15 per million Btu for 2005, and was $1.13 per million Btu in 2004 and $1.10 per million Btu in 2003. This rate escalates with inflation but could be limited by domestic oil prices. If the oil price limitation is reached, the level of the tax credits starts to decline. In 2005, average annual domestic oil prices, as measured by the DOE index, would have had to exceed $53 per barrel for this limitation to have been effective, and it was estimated that the tax credit would have been eliminated at an average oil price of $66 per barrel. The DOE index is based on the "Domestic First Purchase Price" not the NYMEX quoted oil futures prices, which in 2005 averaged about $6.00 per barrel less than the NYMEX price. The synthetic fuel tax credit phase-out range for 2006 based on the DOE oil prices is expected to be $54 to $68 per barrel, which would be the equivalent of a NYMEX price of approximately $60 to $74 per barrel (see the **Synthetic Fuel** discussion in the **Outlook** section).

In 2005, 2004, and 2003, 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 $9.4 million, $10.5 million, and $12.3 million for 2005, 2004, and 2003, 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)	*2005*	*2004*	*2003*
Loss on operations	$ (13.0)	$ (96.0)	$ (61.9)
Gain on disposition of Union and Gila River	76.5		
Union and Gila River write-off	–	–	(762.0)
Union and Gila River joint venture termination	–	–	(94.7)
Frontera goodwill write-off	–	–	(44.9)
Frontera write-off	–	(25.6)	–
Frontera operations	–	(5.8)	(3.0)
Commonwealth Chesapeake operations		2.5	(22.7)
Commonwealth Chesapeake write-off		(51.3)	(16.3)
TECO Solutions / other	–	(20.3)	(23.1)
TECO Coalbed Methane	–	–	22.8
Total discontinued operations	$ 63.5	$ (196.5)	$ (1,005.8)

In 2005, net income from discontinued operations was $63.5 million, compared to a loss of $196.5 million in 2004. These results include the operating results from the Union and Gila River power stations 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 true-up amounts from previously divested assets.

The net loss from discontinued operations for 2004 was $196.5 million. Discontinued operations in 2004 reflect the operating losses for the Union and Gila River power stations, the write-off and losses from operations at the Commonwealth Chesapeake and Frontera power stations, and the write-offs and losses from operations associated with certain TECO Solutions companies.

INFLATION

The effects of inflation on our results have not been significant for the past several years. The annual rate of inflation, as measured by the Consumer Price Index (CPI), all items, all urban consumers as reported by the U.S. Department of Labor, was 3.4%, 2.7% and 2.3% in 2005, 2004 and 2003, respectively. Published forecasts by economists and by several agencies of the U.S. government indicate that inflation is expected to be relatively modest again in 2006, with a 2.8% increase expected.

Prices for certain products and services used by TECO Energy's operating companies increased at rates above the CPI in 2005, including prices for steel products and petroleum-based products used extensively in all of our operating companies, and for subcontracted mining services used by TECO Coal. These prices are expected to continue to rise in 2006, but at a rate slower than in 2005. In the case of TECO Transport, a portion of the increased cost of petroleum products is passed through to its contract customers through fuel adjustment clauses while other costs are covered by inflation adjustment clauses, and 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

Our commitment to environmental compliance is an important element of our culture. Each of our operating companies has an environmental compliance plan tailored to its industry and location. These plans are part of our overall corporate compliance plan, known as Standards of Integrity.

Among our companies, Tampa Electric has the most significant number of stationary sources with air emissions impacts 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 selections, a responsible fuel mix taking into account price and availability impacts to its customers, and a significant capital expenditure program to add emissions controls.

Air Quality Control

IGCC Technology – Polk Power Station

In 1996, Tampa Electric began commercial operation of the Polk Power Station, originally a 260-megawatt Integrated Gasification Combined Cycle (IGCC) power plant, which was the first of its kind commercially available IGCC plant in operation. Since that time, 360 megawatts of peaking capacity was added at Polk. The IGCC unit was constructed in cooperation with the U.S. Department of Energy (DOE) as a part of its "Clean Coal Program." DOE contributed approximately $140 million to assist in the commercialization of this technology to enable the clean burning of coal, the most abundant fossil fuel in the United States. This technology converts coal into a synthesis gas and removes 95% of the SO_2 from the gas prior to combustion and coupled with efficient combined-cycle technology uses approximately 10% less fuel for the same level of power output.

Polk Power Station remains the best example of IGCC technology in the United States. Tampa Electric is the leader in operations and maintenance experience and enhancement techniques for clean-coal burning technology. The most recent evaluation of coal-burning plants, by the Energy Probe Research Foundation, an independent environmental research firm, ranked the Polk Power Station as the cleanest coal-burning generating plant in the United States.

Consent Decree

Tampa Electric, through voluntary negotiations with the Environmental Protection Agency (EPA) and the U.S. Department of Justice and the Florida Department of Environmental Protections (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 efficient, natural gas-fueled, combined-cycle electric generation, which uses 10% less fuel for the same amount of power output.

In 2004, Tampa Electric made its NO_x reduction technology selection and decided to install selective catalytic reduction (SCR) for NO_x control on Big Bend Unit 4, with an expected in-service date by Jun. 1, 2007. Tampa Electric has also decided to install SCRs 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 system are currently in progress. Tampa Electric's capital investment forecast includes amounts in the 2006 through 2010 period for compliance with the NO_x, SO_2 and particulate matter (PM) reduction requirements (see the **Capital Investments** 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) is scheduled to enter service by Jun. 1, 2007 and cost recovery for the capital investment, which is dependent on filings related to the prudence of actual expenditures to be made in 2007, is expected to start in 2008.

Emission Reductions

Projects committed to under the Consent Decree and Consent Final Judgment will result in significant reductions in emissions. Since 1998, Tampa Electric has reduced annual SO_2, NO_x and PM from its facilities by 161,600 tons, 39,500 tons, and 4,300 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 has resulted in a significant reduction in emissions of all pollutant types. Tampa Electric's actions to install additional NO_x emissions controls on all Big Bend units will result in the further reduction of emissions. By 2010, the SCR projects will result in a total phased reduction of NO_x by 60,000 tons per year from 1998 levels. In total, Tampa Electric's emission reduction initiatives will result in the reduction of SO_2, NO_x and PM emissions by 89%, 89%, and 72%, respectively, below 1998 levels. With these improvements in place, Tampa Electric's facilities will meet the same standards required of new power generating facilities and help to significantly enhance the quality of the air in the community. 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 would lead to a mercury removal efficiency of approximately 70%.

Tampa Electric has supported voluntary efforts to reduce carbon emissions and has taken significant steps to reduce its overall emissions at its facilities. Since 1998, Tampa Electric has reduced its system-wide emissions of CO_2 by approximately 24%, bringing emissions to below 1990 levels, emissions of CO_2 should remain near 1990 levels until the addition of the next base load unit which is expected after 2012. It is estimated that in 2005, the repowering resulted in a decrease in CO_2 emissions of approximately 4.0 million tons below 1998 levels. During this same timeframe, the numbers of retail customers and retail energy sales have risen by approximately 40%.

As a result of all its already completed emission reduction actions, and upon completion of the SCR projects, Tampa Electric will have achieved emission reduction levels called for in the Clean Air Interstate Rule (CAIR) and Clean Air Act proposals including the Bush Administration's "Clear Skies" proposal.

The EPA has recently proposed modifications to the 24-hour course and fine particulate matter 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 expenditure by Tampa Electric.

Carbon Reductions

As previously noted, we support voluntary efforts to reduce CO_2 that will allow us to be sensitive to price effects on our customers as a result of high fuel costs and unusually high capital costs. Technology advances may make future reductions easier, but as a result of Tampa Electric's already dramatic reductions in emissions it is well-positioned to engage in the carbon reduction debate. There have been a variety of approaches discussed, including a cap and trade program and a carbon tax in some form. Neither of these approaches have been fully explored, nor have reasonable alternatives been identified.

Water Quality

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. Big Bend units 3 and 4 use proprietary fine-mesh screens, the best available technology, to further reduce impacts to acquatic organisms. Water recycling and beneficial reuse programs are widely employed on the fresh water systems at both plants. Numerous methods are used to prevent storm water, and other water discharges protecting ground water and the waters of Tampa Bay.

Renewable Energy

Tampa Electric's renewable energy program uses energy from several sources to support customer demand for its Renewable Program. The majority of renewable energy comes from sources that include:

- 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. More than 60 tons of bahia grass, grown on the 4,300 acre plant site, were ground and mixed with the pulverized coal slurry used in the plant's gasifier.
- A 30-kilowatt micro-turbine uses methane gas from a local landfill. This unique technology produces enough electricity to power over 13 homes, using a fuel source that would otherwise be released into the atmosphere.
- Photovoltaic panels have been installed on a school and the Museum of Science and Industry to harness energy from the sun.

Through the end of 2005, the environmental impacts of customer's participation in the program have been significant:

- More than 2 million kwhs of renewable energy have been produced to support participating customer requirements;
- Approximately 1,400 tons of coal have been offset with energy from renewable resources;
- CO_2 reductions from using renewable resources are the equivalent of planting more than 5,800 acres of trees or removing almost 1,700 cars from the streets.

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, 2005, Tampa Electric Company has estimated its ultimate financial liability to be approximately $14.3 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 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 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

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 expects to continue earning within its allowed ROE range even though it has not sought a base rate increase since 1992 despite the addition of the generating assets at Polk Power Station, the repowering of the Bayside Power Station and the addition of infrastructure to support customer growth that has averaged 2.5% for the past 10 years.

Cost Recovery Clauses – Tampa Electric

In September 2005, 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 2006. In late October 2005, Tampa Electric filed updated fuel and purchased power rates which included significantly higher actual costs than were projected for the third quarter of 2005 due to the rapid increase in natural gas prices as a result of hurricanes Katrina and Rita. In November 2005, the FPSC approved Tampa Electric's requested rates. The rates include the impacts of increased natural gas and coal prices expected in 2006, the collection of approximately $153 million for underestimated 2005 fuel and purchased power expenses, and the operations and maintenance expense associated with the Big Bend Units 1– 3 pre-SCR projects required by the EPA Consent Decree and FDEP Consent Final Judgment (see the **Environmental Compliance** section). The rates were partially offset by proceeds from the projected sale of approximately $100 million excess SO_2 emissions allowances. Accordingly, Tampa Electric's residential customer rate per 1,000 kilowatt-hours increased $11.54 from $98.07 in 2005 to $109.61 in 2006.

In October 2004 and May 2005, 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, respectively, for NO_x control in compliance with the environmental consent decree. The SCR for Big Bend Unit 4 is scheduled to enter service by Jun. 1, 2007 and cost recovery, which is dependent on filings to be made in 2007, is expected to start in 2008. 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 2009, 2010 and 2011, respectively.

Coal Transportation Contract

Tampa Electric's 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 Request for Proposal (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. The prudence of the RFP process and final contract were originally scheduled to be reviewed by the FPSC in November 2003, but the hearing was deferred due to protests from other parties seeking more time to evaluate the contract information.

Following hearings in May and June of 2004, 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. The order neither required Tampa Electric to rebid nor prohibited Tampa Electric from rebidding the contract, which expires Dec. 31, 2008.

In October 2004, Tampa Electric filed a motion for clarification and reconsideration of the order contending that the FPSC had failed to take into account information that was available that could have changed the outcome. Tampa Electric also asked the FPSC for clarification on the ruling specifically regarding the bidding guidelines provided in the order and the FPSC process associated with the rebidding.

In 2005, the FPSC heard oral arguments on the motion and denied Tampa Electric's request for reconsideration and clarification. In 2005, Tampa Electric decided that it would not rebid the contract, at least in the near term, but that it would look for other means to offset the reduction in the fuel transportation recovery costs.

Storm Damage Cost Recovery

Following Hurricane Andrew in 1992, Florida's investor owned utilities (IOUs) were unable to obtain transmission and distribution insurance coverage for hurricanes, tornados or other damage due to destructive acts of nature. Tampa Electric and other IOUs were permitted to implement a self-insurance program effective Jan. 1, 1994 for such costs of restoration, and the FPSC authorized Tampa Electric to accrue $4 million annually to grow its unfunded storm damage reserve. Tampa Electric had never utilized its reserve before the 2004 hurricane season. The final costs for restoration associated with hurricanes Charley, Frances and Jeanne in 2004 were approximately $74 million. These costs were charged against the storm damage reserve and therefore did not reduce earnings but did reduce cash flow from operations. Tampa Electric filed for and received approval from the FPSC to defer prudently incurred storm damage restoration costs to the reserve until alternative accounting treatment is sought.

In June 2005, the FPSC approved a stipulation entered into by Tampa Electric, the OPC and FIPUG regarding the treatment of Tampa Electric's 2004 hurricane costs. Under the stipulation, Tampa Electric agreed to reclassify approximately $39 million of the 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, which had a $30 million deficit balance, had a positive balance of about $11 million at the June start of the 2005 hurricane season and a $13 million balance at Dec. 31, 2005.

In the 2005 legislative session, the Florida Legislature passed a bill that would allow IOUs in Florida to "securitize" storm damage costs. Under this bill, IOUs would have the opportunity to recover hurricane restoration costs and establish a higher storm reserve fund through the sale of bonds that would be repaid by an FPSC approved surcharge on customer bills. Tampa Electric elected to forego securitizing its 2004 hurricane costs following the approval of the stipulation discussed above. However, Tampa Electric continues to evaluate securitization as a possible means of funding for future storms.

Hardening of Transmission and Distribution Facilities

Due to extensive storm damage to utility facilities during the last two hurricane seasons and the resulting outages utility customers experienced throughout the state, the FPSC has 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

February 2006 FPSC workshop to review 2004 and 2005 hurricane damage, restoration practices and activities, and plans for the 2006 hurricane season, the FPSC issued an order that will require utilities to inspect wooden utility poles every eight years. For many years, Tampa Electric has routinely inspected its wooden poles and will adjust its inspection schedule to comply with the FPSC's order. In addition to the activities underway at the FPSC, certain legislation has been introduced in the Florida Legislature to address hurricane related issues similar to those described above.

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. The new rules became effective prospectively for requests-for-proposal for applicable capacity additions.

FERC Market Power Test

In November 2004, Tampa Electric and the other market-based rate authorized entities within TECO Energy filed a triennial market power study update. In March 2005, after a review of that filing and supporting information, the FERC determined that Tampa Electric had failed certain tests for market power within two regions of peninsular Florida, primarily comprised of Tampa Electric's own service territory. Tampa Electric currently only sells wholesale power within its own service territory at cost-based rates that were previously approved by FERC. FERC instituted an investigation of Tampa Electric's potential market power in the two regions and ordered Tampa Electric to make a compliance filing to provide documentation demonstrating that Tampa Electric does not have market power in any other region of the state.

Tampa Electric submitted compliance filings after which FERC staff requested additional information to rebut the presumption that Tampa Electric has generation market power, which Tampa Electric submitted in September 2005. In November 2005, FERC found that Tampa Electric did have generation market power in its own control and within the area served by Reedy Creek (Walt Disney World).

Rather than continuing to contest FERC's conclusion, Tampa Electric has agreed to limit itself to only conducting wholesale cost-based transactions in these two parts of Florida. Tampa Electric can continue to make wholesale transactions at market-based rates everywhere else in Florida and throughout the country.

Regional Transmission Organization (RTO)

In December 1999, the FERC issued Order No. 2000, dealing with its continuing effort to effect open access to transmission facilities in large regional markets. In response, the peninsular Florida IOUs (Florida Power & Light, Progress Energy Florida and Tampa Electric) agreed to form an RTO to be known as GridFlorida LLC, which would independently control the transmission assets of the filing utilities, as well as other utilities in the region that chose to join. In March 2001, the FERC conditionally approved GridFlorida.

Following challenges to the proposed structure by the FPSC in 2001 and subsequent modification of the plans by the three filing utilities, the FPSC voted to approve many of the compliance changes submitted in August 2002. The process was again delayed in 2002 when the OPC filed an appeal with the Florida Supreme Court asserting that the FPSC could not relinquish its jurisdictional responsibility to regulate the IOUs and, by approving GridFlorida, they were doing just that. The Florida Supreme Court dismissed the OPC appeal in May 2003, citing that it was premature because certain portions of the FPSC GridFlorida order were not final.

Following a September 2003 FERC and FPSC joint meeting to discuss the wholesale market, RTO issues related to GridFlorida, and, in particular, federal and state interactions, deliberations by the FPSC were put on hold in 2004 to allow a consulting firm, engaged by the GridFlorida applicants, to conduct a cost/benefit study of the GridFlorida RTO. As a result, the

FPSC held a series of collaborative meetings with all interested parties to facilitate the development of the study methodology, as well as participate in the submission of data required to complete the study.

The final results of the study were submitted to the FPSC in late 2005. The results of the study indicate significant benefits and savings that could accrue from the RTO design, but even larger costs for implementation. Therefore, the GridFlorida participants are exploring alternative designs in an effort to retain many of the benefits shown in the study while reducing the costs for implementation. In the meantime, the GridFlorida applicants filed a request to close the docket with the FPSC. The ultimate results of the process remain uncertain, but no final resolution is expected before late 2006.

Peoples Gas 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 were effective after Jan. 16, 2003. PGS' authorized rates provide an allowed ROE range from 10.25% to 12.25% with an 11.25% midpoint, and a capital structure with 57.43% equity.

Peoples Gas Cost Recovery Clauses

In September 2005, PGS filed a request with the FPSC for a mid-course correction to its 2005 Purchased Gas Adjustment (PGA) clause. The PGA rate can vary monthly due to changes in actual fuel costs but is not expected to exceed the FPSC approved annual cap. The request was initiated due to the drastic increase in the price of natural gas following hurricanes Katrina and Rita. The FPSC approved the request, and the higher PGA factor became effective in October 2005.

In November 2005, the FPSC approved rates under Peoples' Gas PGA for the period January 2006 through December 2006 for the recovery of the costs of natural gas purchased for its distribution customers. The PGA approved for 2006 is at the same rate as the PGA approved for the mid-course correction in October 2005.

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 November 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 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

In the last several years, the U.S. Congress, the U.S. Securities and Exchange Commission (SEC), the New York Stock Exchange (NYSE), and other interested groups have focused extensively on improving corporate accountability and corporate governance in an effort to restore investor confidence. The rules passed by the SEC and the listing standards adopted by the NYSE require, among other things, independence by the Board of Directors and various Board committees, a statement of governance guidelines and detailed committee charters, an internal audit function, a code of ethics for the CEO, senior financial officers and directors, adequate internal controls to detect fraud, increased oversight of financial disclosure by the Audit Committee, and certification by the CEO and CFO of the fair presentation of the financial results.

The corporate culture of TECO Energy is based on integrity and sound business ethics. We have longstanding policies and practices that are designed to provide the framework for the ethical operation of the company, protect the shareholders' interests, and ensure compliance with the law and requirements of the NYSE. For many years, the vast majority of our Board of Directors has been independent, and the required independent Board committees have been in place. In addition, we have had a rigorous internal audit and compliance function, including an anonymous reporting system which includes the reporting of matters required to be disclosed to the Audit Committee and the non-management directors, and a code of ethics for all employees, officers and directors, called the Standards of Integrity. In addition, to ensure that our vendors are aware of our expectation that they conduct their business in an ethical and professional manner, we require that they comply, as we do, with the Principles and Standards of Ethical Supply Management Conduct published by the Institute for Supply Management.

At TECO Energy, we are committed to integrity and transparency in our financial reporting. Our existing controls and procedures for full and complete financial reporting and disclosure have been formalized into a comprehensive system of checks and balances that are reviewed quarterly for effectiveness. The CEO and CFO have filed with the SEC, as required by law, sworn statements certifying without exception the accuracy of the financial statements each quarter, and the annual certification is filed as an exhibit to our Annual Report on Form 10-K. Additionally, the CEO has signed and filed with the NYSE the required annual certifications as to compliance with the NYSE's corporate governance listing standards.

The Board of Directors operates under a set of guidelines that clearly establish the Board's responsibilities, and each committee has a charter that defines its purpose, duties and responsibilities. The Corporate Governance Guidelines and the committee charters are reviewed regularly to ensure that they comply with all of the relevant regulations and meet the needs of the Board. More information about the members of the Board of Directors, as well as copies of the Corporate Governance Guidelines, the various committee charters, and the Standards of Integrity, can be found in the corporate governance section of the Investor Relations page on our website, **www.tecoenergy.com**.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Compliance with Section 404 of the Sarbanes-Oxley Act of 2002 (SOX 404) and related rules of the Securities and Exchange Commission require management of public companies to assess the effectiveness of the company's internal control over financial reporting as of the end of each fiscal year. This includes disclosure of any material weaknesses in the company's internal control over financial reporting that have been identified by management. In addition, SOX 404 requires the company's independent auditor to attest to and report on management's annual assessment of the company's internal control over financial reporting. We have documented, tested and assessed our system of internal control over financial reporting, as required under SOX 404 using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in the Internal Control - Integrated Framework, and Public Company Accounting Oversight Board Auditing Standard No. 2, An Audit of Internal Control Over Financial Reporting Performed in Conjunction With An Audit of Financial Statements (Standard No. 2). This has provided the basis for management's report and our independent auditor's attestation on the effectiveness of our internal control over financial reporting as of Dec. 31, 2005. The scope of our assessment of our internal control over financial reporting included all of our consolidated entities. We have completed the assessment of the effectiveness on our internal control over financial reporting as of Dec. 31, 2005, and have concluded that our controls are operating effectively (see the **Management's Report on Internal Control Over Financial Reporting** and the **Report of Independent Registered Certified Public Accounting Firm** sections).

We estimate our external SOX 404 compliance costs in 2005 were approximately $1.9 million.

TRANSACTIONS WITH RELATED AND CERTAIN OTHER PARTIES

We have interests in unconsolidated affiliates, which are discussed in the **TECO Guatemala** and **Off-Balance Sheet Financing** sections.

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 our internal control over financial reporting as of Dec. 31, 2005 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 our internal control over financial reporting was effective as of Dec. 31, 2005.

PricewaterhouseCoopers LLP, an independent registered certified public accounting firm, has audited management's assessment of the effectiveness of the Company's internal control over financial reporting as of Dec. 31, 2005 as stated in their report below.

REPORT OF INDEPENDENT REGISTERED CERTIFIED PUBLIC ACCOUNTING FIRM

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

We have completed an integrated audit of TECO Energy, Inc.'s 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of Dec. 31, 2005 and audits of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated financial statements listed in the index appearing herein under Item 8 present fairly, in all material respects, the financial position of TECO Energy, Inc. and its subsidiaries at Dec. 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended Dec. 31, 2005 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules information listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in the **Notes 2** and **15** to the Financial Statements, the Company adopted the provisions of Financial Accounting Standards Board Interpretation No. 46-R, "*Consolidation of Variable Interest Entities*," on Jan. 1, 2004 and Financial Accounting Standards 143, "*Accounting of Asset Retirement Obligations*" on Jan. 1, 2003.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing herein under Item 8, that the Company maintained effective internal control over financial reporting as of Dec. 31, 2005 based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of Dec. 31, 2005, based on criteria established in Internal Control - Integrated Framework issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Tampa, Florida
February 22, 2006

TECO ENERGY, INC.
Consolidated Balance Sheets

Assets *(millions) Dec. 31,*	*2005*	*2004*
Current assets		
Cash and cash equivalents	$ 345.7	$ 96.7
Restricted cash	37.6	57.1
Receivables, less allowance for uncollectibles of $6.9 and $8.0 at Dec. 31, 2005 and 2004, respectively	323.3	286.8
Inventories, at average cost		
Fuel	84.9	46.2
Materials and supplies	68.9	74.6
Current regulatory assets	296.3	63.9
Current derivative assets	64.0	3.8
Prepayments and other current assets	51.5	26.8
Assets held for sale	—	128.8
Total current assets	1,272.2	784.7
Property, plant and equipment		
Utility plant in service		
Electric	4,892.3	4,857.9
Gas	839.5	810.8
Construction work in progress	200.0	207.1
Other property	822.7	847.6
Property, plant and equipment, at original cost	6,754.5	6,723.4
Accumulated depreciation	(2,187.6)	(2,065.5)
Total property, plant and equipment (net)	4,566.9	4,657.9
Other assets		
Deferred income taxes	735.7	875.0
Other investments	8.0	8.0
Long-term regulatory assets	101.1	137.1
Long-term derivative assets	4.9	—
Investment in unconsolidated affiliates	297.1	263.0
Goodwill	59.4	59.4
Deferred charges and other assets	116.8	128.2
Assets held for sale	8.0	2,059.1
Total other assets	1,331.0	3,529.8
Total assets	$ 7,170.1	$ 8,972.4

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

TECO ENERGY, INC.
Consolidated Balance Sheets – continued

Liabilities and capital (millions, except per share amounts) Dec. 31,	*2005*	*2004*
Current liabilities		
Long-term debt due within one year		
Recourse	$ 5.9	$ 5.5
Non-recourse	1.3	8.1
Notes payable	215.0	115.0
Accounts payable	354.7	257.8
Customer deposits	115.2	105.8
Current regulatory liabilities	146.8	22.5
Current derivative liabilities	0.3	11.5
Interest accrued	50.0	50.6
Taxes accrued	34.9	36.3
Liabilities associated with assets held for sale	1.8	1,631.8
Total current liabilities	925.9	2,244.9
Other liabilities		
Investment tax credits	17.3	20.0
Long-term regulatory liabilities	543.1	516.5
Long-term derivative liability	—	0.5
Deferred credits and other liabilities	382.9	354.4
Liabilities associated with assets held for sale	—	672.2
Long-term debt, less amount due within one year		
Recourse	3,519.8	3,588.9
Non-recourse	11.7	13.4
Junior subordinated	177.7	277.7
Total other liabilities	4,652.5	5,443.6
Commitments and contingencies (see Note 12)		
Capital		
Common equity (400 million shares authorized; par value $1; 208.2 million shares and 199.7 million shares issued and outstanding at Dec. 31, 2005 and 2004, respectively)	208.2	199.7
Additional paid in capital	1,527.0	1,489.4
Retained deficit	(83.1)	(357.6)
Accumulated other comprehensive loss	(51.1)	(43.8)
Common equity	1,601.0	1,287.7
Unearned compensation	(9.3)	(3.8)
Total capital	1,591.7	1,283.9
Total liabilities and capital	$ 7,170.1	$ 8,972.4

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,*	*2005*	*2004*	*2003*
Revenues			
Regulated electric and gas (includes franchise fees and gross receipts taxes of $87.2 million in 2005, $83.8 million in 2004 and $77.7 million in 2003)	$ 2,293.8	$ 2,101.0	$ 1,991.1
Unregulated	716.3	538.4	571.8
Total revenues	3,010.1	2,639.4	2,562.9
Expenses			
Regulated operations			
Fuel	461.1	536.7	344.9
Purchased power	269.7	172.3	184.7
Cost of natural gas sold	350.2	226.2	224.0
Other	270.3	258.2	258.4
Other operations	653.6	590.5	595.7
Maintenance	168.4	137.4	144.8
Depreciation	282.2	275.9	313.4
Asset impairment	3.2	632.2	132.9
Goodwill and intangible asset impairment	—	4.8	6.7
Restructuring charges	—	1.2	24.6
Taxes, other than income	194.7	184.3	171.6
Total expenses	2,653.4	3,019.7	2,401.7
Income (loss) from operations	356.7	(380.3)	161.2
Other (expense) income			
Allowance for other funds used during construction	—	0.7	19.8
Gain on sale of assets and other income	171.6	143.0	119.9
Loss on debt extinguishment	(74.2)	(4.4)	—
Impairment on TIE investment	—	(152.3)	—
Income (loss) from equity investments	60.4	36.1	(0.4)
Total other income	157.8	23.1	139.3
Interest charges			
Interest expense	288.7	323.2	284.1
Distribution on preferred securities of subsidiary	—	—	40.0
Allowance for borrowed funds used during construction	—	(0.3)	(7.6)
Total interest charges	288.7	322.9	316.5
Income (loss) from continuing operations before provision for income taxes	225.8	(680.1)	(16.0)
Provision (benefit) for income taxes	101.9	(245.1)	(67.9)
Income (loss) from continuing operations before minority interests	123.9	(435.0)	51.9
Minority interest	87.1	79.5	48.8
Income (loss) from continuing operations	211.0	(355.5)	100.7
Discontinued operations			
Income (loss) from discontinued operations	88.2	(294.0)	(1,577.3)
Income tax provision (benefit)	24.7	(97.5)	(571.5)
Total discontinued operations	63.5	(196.5)	(1,005.8)
Cumulative effect of change in accounting principle, net of tax	—	—	(4.3)
Net income (loss)	$ 274.5	$ (552.0)	$ (909.4)
Average common shares outstanding – Basic	206.3	192.6	179.9
– Diluted	208.2	192.6	180.2
Earnings (loss) per share from continuing operations – Basic	$ 1.02	$ (1.85)	$ 0.56
– Diluted	$ 1.00	$ (1.85)	$ 0.56
Earnings (loss) per share – Basic	$ 1.33	$ (2.87)	$ (5.05)
– Diluted	$ 1.31	$ (2.87)	$ (5.04)
Dividends paid per common share outstanding	$ 0.76	$ 0.76	$ 0.925

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,*	*2005*	*2004*	*2003*
Net income (loss)	$ 274.5	$ (552.0)	$ (909.4)
Other comprehensive income (loss), net of tax			
Foreign currency translation adjustments	—	—	1.2
Net unrealized (losses) gains on cash flow hedges	(0.1)	4.8	28.1
Minimum pension liability adjustments	(7.2)	7.2	(43.9)
Other comprehensive income (loss), net of tax	(7.3)	12.0	(14.6)
Comprehensive income (loss)	$ 267.2	$ (540.0)	$ (924.0)

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,*	*2005*	*2004*	*2003*
Cash flows from operating activities			
Net income (loss)	$ 274.5	$ (552.0)	$ (909.4)
Adjustments to reconcile net income (loss) to net cash from operating activities:			
Depreciation	282.2	289.6	382.0
Deferred income taxes	110.8	(355.3)	(709.4)
Investment tax credits, net	(2.7)	(2.9)	(4.7)
Allowance for funds used during construction	—	(1.0)	(27.4)
Amortization of unearned compensation	5.5	13.6	18.3
Cumulative effect of change in accounting principle, pretax	—	—	7.1
Gain on sales of business/assets, pretax	(261.6)	(92.9)	(147.5)
Equity in earnings of unconsolidated affiliates, net of cash distributions on earnings	(35.9)	(34.3)	13.8
Minority interest	(87.1)	(79.5)	(48.8)
Debt extinguishment	19.8	—	—
Asset impairment, pretax	3.2	876.7	1,330.7
Goodwill and intangible asset impairment, pretax	—	16.6	122.7
TMDP arbitration (recovery) reserve, pretax	—	(5.6)	32.0
Loss on joint venture termination, pretax	—	—	153.9
Deferred recovery clause	(154.3)	25.1	(27.3)
Receivables, less allowance for uncollectibles	(56.7)	32.1	96.4
Inventories	(38.1)	41.8	7.0
Prepayments and other deposits	(11.3)	3.6	(13.3)
Taxes accrued	(17.4)	(82.0)	34.5
Interest accrued	17.5	76.7	(60.7)
Accounts payable	119.0	(69.2)	(17.5)
Other	6.5	38.5	78.9
Cash flows from operating activities	173.9	139.6	311.3
Cash flows from investing activities			
Capital expenditures	(295.3)	(273.2)	(590.6)
Allowance for funds used during construction	—	1.0	27.4
Net proceeds from sales of business/assets	278.3	349.5	296.5
Net cash reduction from deconsolidation	—	(22.7)	—
Restricted cash	47.6	(34.3)	(46.2)
Distributions from (investment in) unconsolidated affiliates	2.8	45.4	(30.6)
Other non-current investments	4.1	24.7	(32.4)
Cash flows from investing activities	37.5	90.4	(375.9)
Cash flows from financing activities			
Dividends	(157.7)	(145.2)	(165.2)
Common stock	16.2	10.2	136.6
Proceeds from long-term debt	311.9	—	655.1
Repayment of long-term debt	(494.1)	(225.0)	(526.5)
Minority interest	83.1	76.1	44.4
Restricted cash	—	—	(5.9)
Exchange of equity units	180.2	(17.7)	—
Settlement of joint venture termination obligation	—	—	(33.5)
Net increase (decrease) in short-term debt	100.0	77.5	(323.0)
Equity contract adjustment payments	(2.0)	(17.4)	(20.3)
Cash flows from financing activities	37.6	(241.5)	(238.3)
Net (decrease) increase in cash and cash equivalents	249.0	(11.5)	(302.9)
Cash and cash equivalents at beginning of the year	96.7	108.2	411.1
Cash and cash equivalents at end of the year	$ 345.7	$ 96.7	$ 108.2
Supplemental disclosure of cash flow information			
Cash paid during the year for:			
Interest (net of amounts capitalized) [1]	$ 288.9	$ 372.1	$ 493.1
Income taxes	$ 27.4	$ 22.4	$ 58.8

(1) Included in interest paid during the year is interest paid on debt obligation for discontinued operations of $12.0 million, $51.5 million and $166.6 million for 2005, 2004 and 2003, respectively.

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, 2002	175.8	$ 175.8	$ 1,094.5	$1,413.7	$ (41.2)	$ (31.1)	$2,611.7
Net loss				(909.4)			(909.4)
Other comprehensive loss, after tax					(14.6)		(14.6)
Common stock issued	12.0	12.0	125.0			(0.4)	136.6
Cash dividends declared				(165.2)			(165.2)
Amortization of unearned compensation						18.3	18.3
Tax benefits — ESOP dividends and stock options			1.3	0.4			1.7
Performance shares						(1.4)	(1.4)
Balance, Dec. 31, 2003	187.8	$ 187.8	$ 1,220.8	$ 339.5	$ (55.8)	$ (14.6)	$1,677.7
Net loss				(552.0)			(552.0)
Other comprehensive income, after tax					12.0		12.0
Common stock issued	0.9	0.9	7.8			1.5	10.2
Cash dividends declared				(145.2)			(145.2)
Early exchange of equity security units	10.2	10.2	251.6				261.8
Settlement of claim	0.8	0.8	9.2				10.0
Amortization of unearned compensation						13.6	13.6
Tax benefits — ESOP dividends				0.1			0.1
Performance shares						(4.3)	(4.3)
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

(1) TECO Energy had a maximum of 400 million shares of $1 par value common stock authorized as of Dec. 31, 2005, 2004 and 2003.

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.

TECO Energy adopted the provisions of Financial Accounting Standards Board (FASB) Interpretation No. 46 (FIN 46), *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51*, as of Oct. 1, 2003 with no material impact. Effective Jan. 1, 2004, the company adopted FASB Interpretation No. 46R, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51* (FIN 46R), which impacted the consolidation principles applied to certain entities. 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. FIN 46R impacted the consolidation policy for the subsidiaries that hold interests in San José and Alborada power stations in Guatemala, the funding companies involved in the issuance of the trust preferred securities, TECO AGC, Ltd., and Hernando Oaks, LLC (see **Note 2**).

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.

Revised Segment Reporting

In 2003, the company, as part of its renewed focus on core utility and profitable unregulated operations, revised internal reporting information used for decision making purposes. With this change, management focused on the results and performance of TECO Wholesale Generation, Inc. (formerly TECO Power Services Corporation), or TWG Merchant, as a segment comprised of all merchant operations, from which the Commonwealth Chesapeake Company, Frontera, Union, and Gila River projects' operations have been reclassified to discontinued operations. TWG Merchant includes the results of operations for the Dell and McAdams power plants, as well as the equity investment in the Texas Independent Energy (TIE) projects up to the date of sale (see **Note 16** for details), held through PLC Development Holdings, LLC (PLC), and TECO EnergySource (TES), the energy marketing operation for the merchant plants.

In the first quarter of 2005, the company further revised internal reporting information used for decision making purposes by viewing the results and performance of TECO Guatemala, Inc. (TECO Guatemala) (formerly TWG Non-Merchant, Inc.) as a separate segment comprised of all Guatemalan operations. TECO Guatemala includes the equity investments in the San José and Alborada power plants, the equity investment in the Guatemalan distribution company, Empresa Eléctrica de Guatemala, S.A. (EEGSA), and the TECO Guatemala parent company. Results for TECO Guatemala were previously reported in the Other Unregulated segment. Following the sales of the larger energy services businesses, which were previously reported in the Other Unregulated segment, the remaining small operations of TECO Solutions, Inc. (TECO Solutions) are now reported within "Other & Eliminations". Prior period segment results have been restated to reflect the revised segment structure (**see Note 14**).

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, 2005 and 2004 includes $30.3 million and $50.0 million, respectively, of cash held in escrow related to the 2003 sale of TECO Coal Corporation's (TECO Coal) indirectly owned synthetic fuel production facilities (to provide credit support for the company's current credit rating). The $30.3 million of cash from the synthetic fuel facility sale will be retained in escrow to support the company's obligation under the sale agreement, until the expiration of the agreement or TECO Energy achieves an investment-grade credit rating. Restricted cash at Dec. 31, 2005 and 2004 also includes $7.3 million and $7.1 million, respectively, of cash held in escrow related to the 2003 sale of Hardee Power Partners (HPP) (see

Note 16). The $7.3 million will be released from escrow in 2012, upon maturity of debt financing currently held by the purchaser of HPP.

Cost Capitalization

Development costs – TECO Energy capitalizes the external costs of construction-related development activities after achieving certain project-related milestones that indicate that completion of a project is probable. Such costs include direct incremental amounts incurred for professional services (primarily legal, engineering and consulting services), permits, options and deposits on land and equipment purchase commitments, capitalized interest and other related costs. In accordance with Statement of Position (SOP) 98-5, *Reporting on the Costs of Start-up Activities*, start-up costs and organization costs are expensed as incurred.

Debt issuance costs – The company capitalizes the external costs of obtaining debt financing and amortizes such costs over the life of the related debt. These costs are included in "Deferred Charges and Other Assets" on TECO Energy's Consolidated Balance Sheet.

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, $0.7 million and $17.3 million of interest costs in 2005, 2004 and 2003, respectively.

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 implicit 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 computes 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. Unregulated electric generating, pipeline and transmission facilities are depreciated over the expected useful lives of the related equipment, a period of up to 40 years. Total depreciation expense for the years ended Dec. 31, 2005, 2004, and 2003 was $267.6, $257.6 and $296.3, respectively. Total plant acquisition adjustments were $10.0 million and $10.3 million as of Dec. 31, 2005 and 2004, respectively. The provision for total regulated and unregulated utility plant in service, expressed as a percentage of the original cost of depreciable property, was 4.0% for 2005, 3.9% for 2004 and 4.5% for 2003. For the year ended Dec. 31, 2003, Tampa Electric recognized depreciation expense of $36.6 million related to accelerated depreciation of certain Gannon power station coal-fired assets, in accordance with a regulatory order issued by the FPSC. Construction work-in-progress is not depreciated until the asset is completed or placed in service.

The implementation of FAS 143 in 2003 and FIN 47 in 2005 resulted in increases in the carrying amount of long-lived assets and the reclassification of the accumulated reserve for cost of removal as "Regulatory liabilities". The adjusted capitalized amount is depreciated over the remaining useful life of the asset. (See **Note 15**).

Allowance for Funds Used During Construction (AFUDC)

AFUDC is a non-cash credit to income with a corresponding charge to utility plant which represents the cost of borrowed funds and a reasonable return on other funds used for construction. The rate used to calculate AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. The rate was 7.79% for 2004 and 2003. Total AFUDC for 2004 and 2003 was $1.0 million and $27.4 million, respectively. No projects qualified for AFUDC in 2005. The base on which AFUDC is calculated excludes construction work-in-progress which has been included in rate base.

Investments in Unconsolidated Affiliates

Investments in unconsolidated affiliates are accounted for using the equity method of accounting. The percentage ownership interest for each investment at Dec. 31, 2005 and 2004 is presented in the following table:

TECO Energy's Percent Ownership in Unconsolidated Affiliates		
Dec. 31,	*2005*	*2004*
TECO Transport		
Ocean Dry Bulk, LLC	50%	50%
TECO Guatemala		
Empresa Eléctrica de Guatemala, S.A. (EEGSA)	24%	24%
Central Generadora Electrica San José, Limitada (San José or CGESJ)(1)	100%	100%
Tampa Centro Americana de Electricidad, Limitada (Alborada or TCAE)(1)	96%	96%
Other		
Litestream Technologies, LLC(2)	36%	36%
Walden Woods Business Center, Ltd.	50%	50%
TECO Capital Funding LLC I(3)	100%	100%
TECO Capital Funding LLC II(3)	100%	100%

(1) As of Jan. 1, 2004, in accordance with the interpretation and application of the consolidation guidance established in FIN 46R to long-term power purchase agreements, TECO Energy can no longer consolidate CGESJ or TCAE, the project companies for the San José and Alborada power plants, respectively, in Guatemala. See **Notes 2** and **14** for additional details.

(2) In 2004, the assets of Litestream Technologies, LLC were sold in bankruptcy. The company still indirectly owned a 36% interest in Litestream Technologies, LLC as of Dec. 31, 2005 and 2004.

(3) As of Jan. 1, 2004, in accordance with the interpretation and application of the consolidation guidance established in FIN 46R, TECO Energy can no longer consolidate Capital Funding I & II. See **Notes 2 and 7** for additional details.

Regulatory Assets and Liabilities

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

Deferred Income Taxes

TECO Energy utilizes the liability method in the measurement of deferred income taxes. Under the liability method, the temporary differences between the financial statement and tax bases of assets and liabilities are reported as deferred taxes measured at current tax rates. Tampa Electric and PGS are regulated, and their books and records reflect approved regulatory treatment, including certain adjustments to accumulated deferred income taxes and the establishment of a corresponding regulatory tax liability reflecting the amount payable to customers through future rates.

Investment Tax Credits

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

Revenue Recognition

TECO Energy recognizes revenues consistent with the Securities and Exchange Commission's (SEC's) Staff Accounting Bulletin (SAB) 104, *Revenue Recognition in Financial Statements*. The interpretive criteria outlined in SEC's SAB 104 are that 1) there is persuasive evidence that an arrangement exists; 2) delivery has occurred or services have been rendered; 3) the fee is fixed and determinable; and 4) collectibility is reasonably assured. 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 certain transportation services at TECO Transport are recognized using the percentage of completion method, which includes 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, 2005 and 2004 were $3.8 million and $3.9 million, respectively. Costs netted against revenues for the year ended Dec. 31, 2003 are reflected in discontinued operations (see **Note 21**).

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Other Income and Minority Interest

TECO Energy earns a significant portion of its income indirectly through the synthetic fuel operations at TECO Coal. At the end of 2005, 2004 and 2003, TECO Coal had sold ownership interests in the synthetic fuel facilities to unrelated third-party investors equal to 98%, 90% and 49.5%, respectively. These investors pay for the purchase of the ownership interests as synthetic fuel is produced with the payments being based both on the amount of production and sales of synthetic fuel and the related, underlying value of the tax credit, which is subject to limitation based on the price of domestic crude oil prices. These payments are recorded in "Other Income" in TECO Energy's Consolidated Income Statement and comprise the majority of that line item.

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

Revenues and Fuel Costs

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-recovery 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, 2005 and 2004, unbilled revenues of $52.3 million and $46.3 million, respectively, are included in the "Receivables" line item on TECO Energy's Consolidated Balance Sheet.

Purchased Power

Tampa Electric purchases power on a regular basis primarily to meet the needs of its retail customers. As a result of the sale of HPP in October 2003 (see **Note 16**), power purchases from HPP, subsequent to the sale, are reflected as non-affiliate purchases by Tampa Electric. Tampa Electric's long-term power purchase agreement from HPP was not affected by the sale of HPP. Under the existing power purchase agreement, which has been approved by the FERC and the FPSC, Tampa Electric has full entitlement to the output of the CT2B unit at all times and full entitlement to the output of the remaining units at the Hardee power station at all times except when Seminole Electric Cooperative has entitlement due to outages and/or durations on a specified portion of its generating units. Tampa Electric purchased power from non-TECO Energy affiliates, including purchases from HPP, at a cost of $269.7 million, $172.3 million and $234.9 million, respectively, for the years ended Dec. 31, 2005, 2004 and 2003. The associated revenue at HPP from power sold to Tampa Electric of $50.1 million for 2003 is offset against "Regulated operations — Purchased power" in TECO Energy's Consolidated Income Statement. The prudently incurred purchased power costs at Tampa Electric are recoverable 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 $87.2 million, $83.8 million and $77.7 million for the years ended Dec. 31, 2005, 2004 and 2003, 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, 2005, 2004 and 2003, these totaled $87.0 million, $83.6 million and $77.5 million, respectively.

Asset Impairments

TECO Energy and its subsidiaries apply the provisions of FAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* 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 offering costs associated with various debt offerings that are being amortized over the related obligation period as in increase in interest expense.

Deferred Credits and Other Liabilities

Other deferred credits primarily include the accrued post-retirement benefit liability, the pension liability, incurred but not reported medical and general liability claims, and deferred gains on sale-lease back transactions involving marine assets.

Stock-Based Compensation

TECO Energy has adopted the disclosure-only provisions of FAS 123, *Accounting for Stock-Based Compensation*, but applies Accounting Principles Board Opinion No. (APB) 25, *Accounting for Stock Issued to Employees*, and related interpretations in accounting for its stock-based compensation plans. Effective Jan. 1, 2003, the company adopted FAS 148, *Accounting for Stock-Based Compensation-Transition and Disclosure, an amendment of FASB Statement No. 123*. This standard amends FAS 123 to provide for stock-based employee compensation. It also requires prominent disclosure about the effects on reported net income of the company's accounting policy decisions with respect to stock-based employee compensation in both annual and interim financial statements.

The types of awards granted under the Equity Plans and Director Equity Plans include stock options, stock grants, time-vested restricted stock and performance-based restricted stock (see **Note 9** for a description of the plans). Stock options are granted with an option price greater than or equal to the fair value on the grant date; therefore, no compensation expense has been reflected in net income. Under FAS 123, the pro forma expense for the stock options was determined using the Black-Scholes valuation model with weighted average assumptions shown in the following table. Stock grants and time-vested restricted stock are granted at a price equal to the fair value on the grant date, with expense spread over the vesting period, which is normally 3 years. Under FAS 123, the pro forma expense for stock grants and time-vested restricted stock is equivalent to what has been reflected in net income. Performance-based restricted stock is granted at a price equal to the fair value on the grant date, with shares vesting in 3 years at 0% to 200% of the original grant, based on the total return of TECO Energy common stock compared to a peer group of utility stocks. The expense reflected in net income for performance-based restricted stock is based on the actual awards vested under the performance measurement. Under FAS 123, the pro forma expense for performance-based restricted stock was determined using the Monte-Carlo valuation model with weighted average assumptions shown in the following table. If the company had elected to recognize compensation expense for stock options based on the fair value at grant date, consistent with the method prescribed by FAS 123, net income and earnings would have been reduced to the pro forma amounts as follows.

Pro Forma Stock-Based Compensation Expense

(millions, except per share amounts) *For the years ended Dec. 31,*		*2005*	*2004*	*2003*
Net income (loss) from continuing operations	As reported	$ 211.0	$ (355.5)	100.7
	Add: Unearned compensation expense[1]	3.4	3.2	1.0
	Less: Pro forma expense[2]	6.8	8.8	8.0
	Pro forma	$ 207.6	$ (361.1)	$ 93.7
Net income (loss)	As reported	$ 274.5	$ (552.0)	$ (909.4)
	Add: Unearned compensation expense[1]	3.4	3.2	1.0
	Less: Pro forma expense[2]	6.8	8.8	8.0
	Pro forma	$ 271.1	$ (557.6)	$ (916.4)
Net income (loss) from continuing operations — EPS, basic	As reported	$ 1.02	$ (1.85)	$ 0.56
	Pro forma	$ 1.01	$ (1.87)	$ 0.52
Net income (loss) from continuing operations — EPS, diluted	As reported	$ 1.00	$ (1.85)	$ 0.56
	Pro forma	$ 0.99	$ (1.87)	$ 0.52
Net income (loss) — EPS, basic	As reported	$ 1.33	$ (2.87)	$ (5.05)
	Pro forma	$ 1.31	$ (2.89)	$ (5.10)
Net income (loss) — EPS, diluted	As reported	$ 1.31	$ (2.87)	$ (5.04)
	Pro forma	$ 1.29	$ (2.89)	$ (5.09)
Assumptions applicable to stock options				
Risk-free interest rate		4.02%	4.04%	3.52%
Expected lives (in years)		7	7	7
Expected stock volatility		34.12%	34.09%	32.68%
Dividend yield		4.66%	5.67%	6.87%
Assumptions applicable to performance-based restricted stock				
Risk-free interest rate		3.74%	2.78%	2.14%
Expected lives (in years)		3	3	3
Expected stock volatility		45.31%	45.85%	45.35%
Dividend yield		4.49%	5.79%	6.72%

(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 market value at date of grant, after tax.

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. In March 2004, Tampa Electric repaid $75 million of 7.75% first mortgage bonds issued under an indenture that included a limitation on dividends covenant. This covenant is no longer operative since there are no bonds outstanding under the indenture. Certain long-term debt at PGS contains restrictions that limit the payment of dividends and distributions on the common stock of Tampa Electric.

In addition, TECO Diversified, Inc., a wholly-owned subsidiary of TECO Energy and the holding company for TECO Transport, TECO Coal and TECO Solutions, 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.

TECO Energy holds the right to defer payments on its subordinated notes issued in connection with the issuance of trust preferred securities by TECO Capital Trust I and TECO Capital Trust II. Should the company exercise this right, it would be prohibited from paying cash dividends on its common stock until the unpaid distributions on the subordinated notes are made. TECO Energy did not exercise that right during 2005, 2004 or 2003.

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 2005, 2004 and 2003 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.

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Reclassifications

Certain prior year amounts were reclassified to conform to the current year presentation. Results for all prior periods have been reclassified from continuing operations to discontinued operations as appropriate for each of the entities as discussed in **Note 21**.

2. New Accounting Pronouncements

Consolidation of Variable Interest Entities

The equity method of accounting is generally used to account for significant investments in arrangements in which we or our subsidiary companies do not have a majority ownership interest or exercise control. A new approach for determining if a reporting entity should consolidate certain legal entities, including partnerships, limited liability companies, or trusts, among others, collectively defined as variable interest entities (VIEs) was developed and later revised under FIN 46 (FIN 46R), *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51.*

A legal entity is considered a VIE, with some exemptions if specific criteria are met, if it does not have sufficient equity at risk to finance its own activities without relying on financial support from other parties. Additional criteria must be applied to determine if this condition is met or if the equity holders, as a group, lack any one of three stipulated characteristics of a controlling financial interest. If the legal entity is a VIE, then the reporting entity determined to be the primary beneficiary of the VIE must consolidate it. Even if a reporting entity is not obligated to consolidate a VIE, then certain disclosures must be made about the VIE if the reporting entity has a significant variable interest.

TECO Energy adopted the provisions of FIN 46 in 2003 with no material impact. As of Jan. 1, 2004, FIN 46R was adopted for the remaining VIEs as described below.

Prior to the adoption of FIN 46, 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 (loss) from Equity Investments" in 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 $118.5 million in these entities. (See **Note 14** for additional financial information related to these projects).

TECO Funding I, LLC and TECO Funding II, LLC are limited liability, wholly-owned subsidiaries of TECO Energy. These funding companies sold preferred securities to Capital Trust I and Capital Trust II (see **Note 7** for additional details of the activities of the trusts). The funding companies used those proceeds to purchase junior subordinated notes from TECO Energy. The funding companies are considered VIEs in accordance with FIN 46R. Since management does not believe the company has any material exposure to losses as a result of its involvement with TECO Funding I and II, these entities were deconsolidated as of Jan. 1, 2004 reflecting that the company is not the primary beneficiary of the funding companies. The funding companies are presented as equity investments in the TECO Energy's Consolidated Balance Sheet. The impact of the deconsolidation was an increase in liabilities of $20.2 million and a corresponding increase in assets.

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 is its investment of approximately $8.2 million, the company could lose potential earnings and could incur losses related to the production costs for the future production of synthetic fuel, in the event that such production creates 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 believes that the company is the primary beneficiary of this VIE and continues to consolidate the entity under the guidance of FIN 46R.

TECO Transport entered into two separate sale leaseback transactions for certain vessels which were recognized as sales in December 2001 and December 2002, and are currently recognized as operating leases for use of the assets. The sale leaseback transactions were entered into with separate third parties that the company believes meet the definition of a VIE. TECO Transport currently leases two ocean going tugboats, four ocean going barges, five river towboats and 49 river barges through these two trusts. The estimated maximum loss exposure faced by TECO Transport is the incremental cost of obtaining suitable replacement equipment to meet the company's contractual shipping obligations. In accordance with the guidance of FIN 46R, management has concluded that the company is not the primary beneficiary of the lessor trusts and continues to report only the impacts of the operating leases and any other required cash contributions.

In 1992, a subsidiary of the company, Hardee Power Partners, Ltd. (HPP) 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 and have no obligation to do so. 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. For a description and measure of the purchases of electricity under the HPP PPA, see **Note 1 – Purchased Power.**

TECO Properties formed a limited liability company (Hernando Oaks, LLC) with a project developer to buy and develop land in Hernando County, Florida into a residential golf community. Hernando Oaks, LLC met the definition of a VIE, due to subordinated financial support in the form of a guarantee by the company on behalf of Hernando Oaks, LLC. The company consolidated Hernando Oaks, LLC as of Jan. 1, 2004, resulting in an increase in assets of $18.5 million and a corresponding increase in liabilities. Hernando Oaks, LLC was sold during 2005.

A subsidiary of TECO Solutions formed a partnership to construct, own and operate a water cooling plant to produce and distribute chilled water to customers via a local distribution loop primarily for use in air conditioning systems. The partnership, TECO AGC, Ltd., met the definition of a VIE due to subordinated financing of $3.3 million provided to the partnership as of Dec. 31, 2003, in addition to the company's equity investment. The company consolidated TECO AGC, Ltd. as of Jan. 1, 2004 with no material increase in assets or liabilities. TECO AGC, Ltd was sold in 2004.

Amendment to Derivatives Accounting

In April 2003, the FASB issued FAS 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*, which clarifies the definition of a derivative and modifies, as necessary, FAS 133 to reflect certain decisions made by the FASB as part of the Derivatives Implementation Group (DIG) process. The majority of the guidance was already effective and previously applied by the company in the course of the adoption of FAS 133.

In particular, FAS 149 incorporates the conclusions previously reached in 2001 under DIG Issue C10, *Can Option Contracts and Forward Contracts with Optionality Features Qualify for the Normal Purchases and Normal Sales Exception?,* and DIG Issue C15, *Normal Purchases and Normal Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity*. In limited circumstances when the criteria are met and documented, TECO Energy designates option-type and forward contracts in electricity as a normal purchase or normal sale (NPNS) exception to FAS 133. A contract designated and documented as qualifying for the NPNS exception is not subject to the measurement and recognition requirements of FAS 133. The incorporation of the conclusions reached under DIG Issues C10 and C15 into the standard did not have a material impact on the consolidated financial statements of TECO Energy.

FAS 149 establishes multiple effective dates based on the source of the guidance. For all DIG Issues previously cleared by the FASB and not modified under FAS 149, the effective date of the issue remains the same. For all other aspects of the standard, the guidance is effective for all contracts entered into or modified after Jun. 30, 2003. The adoption of the additional guidance in FAS 149 did not have a material impact on the consolidated financial statements.

Financial Instruments with Characteristics of both Liabilities and Equity

In May 2003, the FASB issued FAS 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*, which requires that an issuer classify certain financial instruments as a liability or an asset. Previously, many financial instruments with characteristics of both liabilities and equity were classified as equity. Financial instruments subject to FAS 150 include financial instruments with any of the following features:

- An unconditional redemption obligation at a specified or determinable date, or upon an event that is certain to occur;
- An obligation to repurchase shares, or indexed to such an obligation, and may require physical share or net cash settlement;
- An unconditional, or for new issuances conditional, obligation that may be settled by issuing a variable number of equity shares if either (a) a fixed monetary amount is known at inception, (b) the variability is indexed to something other than the fair value of the issuer's equity shares, or (c) the variability moves inversely to changes in the fair value of the issuer's shares.

The standard requires that all such instruments be classified as a liability, or an asset in certain circumstances, and initially measured at fair value. Forward contracts that require a fixed physical share settlement and mandatorily redeemable financial instruments must be subsequently re-measured at fair value on each reporting date.

This standard was effective for all financial instruments entered into or modified after May 31, 2003, and for all other financial instruments, at the beginning of the first interim period beginning after Jun. 15, 2003. The adoption of FAS 150 had no material impact on the company.

Aggregate Operating Segments

In October 2004, the EITF issued EITF Issue No. 04-10, *Determining Whether to Aggregate Operating Segments That Do Not Meet Qualitative Thresholds* (EITF 04-10). EITF 04-10 states that operating segments that do not meet the quantitative thresholds can be aggregated only if aggregation is consistent with the objective and basic principles of FAS 131, *Disclosures about Segments of an Enterprise and Related Information* (FAS 131), the segments have similar economic characteristics, and the segments share a majority of the aggregation criteria outlined in FAS 131. The adoption of this additional guidance in EITF 04-10 reinforced the company's decision to revise segment reporting and separately disclose TECO Guatemala as a separate segment (see **Notes 1** and **14**).

Reporting Discontinued Operations

In November 2004, the Emerging Issues Task Force (EITF) issued EITF *Issue No. 03-13, Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations.* The company adopted the guidance provided by the EITF in 2004 as related to assessing the actual or projected direct and indirect cash flows of a disposal component to assess the extent or lack of continuing involvement. See **Note 21** for discussion of discontinued operations and assets held for sale.

Stock-Based Compensation

FASB Statement No. 123 (revised 2004) *Share-Based Payment* (FAS 123R), which is effective Jan. 1, 2006, changes the accounting for stock-based compensation. Through the end of 2005, the company accounted for its share-based payment transactions under the provisions of APB 25, where certain stock-based compensation information was presented as disclosure information only (see **Note 1**). FAS 123R requires that compensation cost related to share-based payments be recognized in the financial statements as an expense. All of the types of stock-based awards provided by TECO Energy fall within the scope of FAS 123R and include stock options, time-vested restricted stock and performance-based restricted stock. TECO Energy will adopt FAS 123R on Jan. 1, 2006 using the modified-prospective transition method. Under this transition method, compensation cost recognized beginning in January 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 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 value estimated in accordance with the provisions of FAS 123R). Prior period results will not be restated. The impact of implementing FAS 123R is not expected to be materially different from the pro forma amounts disclosed in **Note 1**.

Under APB 25, the company recognized expenses for retirement-eligible employees over the nominal vesting period. Under FAS 123R, any new awards made to retirement-eligible employees must be recognized immediately or over the period from the grant date to the date of retirement eligibility (non-substantive approach). The impact on both reported and pro forma net income for 2005, 2004 and 2003 of applying the nominal vesting period approach versus the non-substantive vesting period approach for retirement-eligible employees would not have been material.

Inventory Costs

FASB Statement No. 151, *Inventory Costs, an amendment to ARB No. 43, Chapter 4,* sets forth certain costs related to inventory that must be included as current period costs. This Statement became effective as of Jul. 1, 2005 and did not materially impact the company's financial position, results of operations or cash flow.

Nonmonetary Assets

FASB Statement No. 153, *Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29,* became effective as of Jul. 1, 2005 and did not materially impact the company's financial position, results of operations or cash flow.

Asset Retirement Obligations

FASB Interpretation No. 47 (FIN 47), *Accounting for Conditional Asset Retirement Obligation, an Interpretation of FASB Statement No. 143,* was issued in March 2005 and became effective as of Dec. 31, 2005. FIN 47 clarifies the term "conditional asset retirement obligation" as a legal obligation to perform an asset retirement activity in which the timing and method of settlement are conditional on a future event that may or may not be within the control of the entity, and clarifies when an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation. The company implemented FIN 47 during the fourth quarter of 2005. See **Note 15** for discussion of the effects of this implementation.

3. Regulatory

As discussed in **Note 1**, Tampa Electric's and PGS' retail business are regulated by the FPSC.

Base Rate – 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 as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties. Tampa Electric expects to continue maintaining earnings within its allowed ROE range for the foreseeable future.

Tampa Electric has not sought a base rate increase to recover significant plant investment since 1992, including the Bayside Power Station, which entered service in 2003 and 2004.

Cost Recovery – Tampa Electric

In September 2005, Tampa Electric filed with the FPSC for approval of fuel and purchased power, capacity, environmental and conservation cost recovery rates for the period January 2006 through December 2006. In late October 2005, Tampa Electric filed updated fuel and purchased power rates which included significantly higher actual than projected costs for the third quarter of 2005 due to the rapid increase in natural gas prices as a result of hurricanes Dennis, Katrina and Rita. In November, the FPSC approved Tampa Electric's requested changes. The rates include the impacts of increased natural gas and coal prices expected in 2006, the collection of some of the underestimated 2005 fuel expenses, the proceeds from the sale of sulfur dioxide (SO_2) emissions allowances and the O&M costs associated with the Environmental Protection Agency (EPA) Consent Decree and Florida Department of Environmental Protection (FDEP) Consent Final Judgment required Big Bend Units 1 - 3 Pre-SCR projects (see **Note 12** for additional details regarding projected environmental expenditures). 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 **Note 13**). 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 Rate – PGS

As a result of a base rate proceeding, effective Jan. 16, 2003, PGS' allowable ROE range is 10.25% to 12.25% with an 11.25% midpoint. PGS expects to continue earning within its allowed ROE range for the foreseeable future.

Cost Recovery – PGS

In September 2005, PGS filed a request with the FPSC for a mid-course correction to its 2005 Purchased Gas Adjustment (PGA) clause. The PGA rate can vary monthly due to changes in actual fuel costs but is not expected to exceed the FPSC approved annual cap. The request was initiated due to the rapid increase in the price of natural gas following hurricanes Dennis, Katrina and Rita. The FPSC approved the request and the higher PGA factor was effective in October 2005. In November 2005, the FPSC approved the annual rates under PGS' PGA for the period January 2006 through December 2006.

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 commodities. Once allocated, allowances may be bought, sold, traded or banked for use in future years. 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 over 95% of which accrues to 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 needs and allowances available. The SO_2 allowances unneeded and sold in 2005 resulted from lower emissions at Tampa Electric brought about by environmental actions taken by the company under the Clean Air Act. Tampa Electric currently receives 84,635 allowances annually to cover its emissions. This allocation will continue through 2009. The allocation amount will change beginning in 2010 in accordance with the EPA's SO_2 allowance program.

In 2005, Tampa Electric sold approximately 100,000 unneeded allowances, resulting in a gain of approximately $79.7 million ($49.0 million after tax).

Other Items

Regional Transmission Organization (RTO)

In October 2002, the RTO process involving the proposed formation of GridFlorida, LLC, as initiated in response to the FERC's continuing efforts to affect open access to transmission facilities in large regional markets, was delayed when the Office of Public Counsel (OPC) filed an appeal with the Florida Supreme Court. Oral arguments occurred in May 2003, and the Florida Supreme Court dismissed the appeal citing that it was premature because certain portions of the FPSC GridFlorida order were not final.

In September 2003, a joint meeting of the FERC and FPSC took place to discuss wholesale markets, RTO issues related to GridFlorida and, in particular, federal and state interactions. During 2004, deliberations by the FPSC were put on hold to allow a consulting firm, engaged by the GridFlorida applicants, to conduct a cost/benefit study of the GridFlorida RTO.

As a result, the FPSC held a series of collaborative meetings during the year with all interested parties to facilitate development of the study methodology as well as participate in the submission of data required to complete the study. Preliminary results of the study were submitted to the FPSC in late 2005 and they indicated that the estimated costs of a GridFlorida RTO structure exceeded the expected benefits. As a result, the GridFlorida participants are exploring alternative designs in an effort to retain many of the benefits shown in the study while reducing the costs for implementation. In January 2006, the applicants filed a request with the FPSC to close the docket. The ultimate results of the process remain uncertain, but there may be a final resolution in 2006.

Storm Damage Cost Recovery

Following Hurricane Andrew in 1992, Florida's investor owned utilities (IOUs) were unable to obtain transmission and distribution insurance coverage in the event of hurricanes, tornados or other damage due to destructive acts of nature. Tampa Electric and other IOUs were permitted to implement a self-insurance program effective Jan. 1, 1994 for such costs of restoration, and the FPSC authorized Tampa Electric to accrue $4 million annually to grow its unfunded storm damage reserve.

The costs for restoration associated with hurricanes Charley, Frances and Jeanne were approximately $74 million, which exceeded the storm damage reserve by $30 million. These excess costs over the reserve amounts were charged against the reserve and were reflected as a regulatory asset. The storm costs did not reduce earnings but did reduce cash flow from operations. Tampa Electric filed for and received approval from the FPSC to defer prudently incurred storm damage restoration costs to the reserve until alternative accounting treatment is sought.

In June 2005, the FPSC approved a stipulation entered into by Tampa Electric, the OPC and the Florida Industrial Power Users group regarding the treatment of Tampa Electric's 2004 hurricane costs. Under the stipulation, Tampa Electric agreed to reclassify approximately $39 million of the 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, which had about a $30 million deficit balance, had a positive balance of approximately $11 million at the start of the 2005 hurricane season and a $13 million balance at Dec. 31, 2005.

Coal Transportation Contract

In September 2004, the FPSC voted to disallow certain costs that Tampa Electric can recover from its customers for waterborne fuel transportation services under a contract with TECO Transport.

Regulatory Assets and Liabilities

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

Tampa Electric and PGS apply the accounting treatment permitted by FAS 71. Areas of applicability include deferral of revenues under approved regulatory agreements; revenue recognition resulting from cost recovery clauses that provide for monthly billing charges to reflect increases or decreases in fuel; purchased power, conservation and environmental costs; and deferral of costs as regulatory assets, when cost recovery is ordered over a period longer than a fiscal year, to the period that the regulatory agency recognizes them. Details of the regulatory assets and liabilities as of Dec. 31, 2005 and 2004 are presented in the following table:

Regulatory Assets and Liabilities

(millions) Dec. 31,	*2005*	*2004*
Regulatory assets:		
Regulatory tax asset[1]	$ 79.5	$ 57.6
Other:		
Cost recovery clauses	264.1	48.2
Deferred bond refinancing costs[2]	28.8	32.5
Environmental remediation	14.2	16.9
Competitive rate adjustment	5.6	6.1
Transmission and distribution storm reserve	—	28.0
Other	5.2	11.7
	317.9	143.4
Total regulatory assets	397.4	201.0
Less current portion	296.3	63.9
Long-term regulatory assets	$ 101.1	$ 137.1
Regulatory liabilities:		
Regulatory tax liability[1]	$ 23.4	$ 29.5
Other:		
Deferred allowance auction credits	1.3	2.3
Recovery clause related	136.9	8.7
Environmental remediation	14.2	16.9
Transmission and distribution storm reserve	12.5	—
Deferred gain on property sales	7.7	1.7
Accumulated reserve – cost of removal	493.8	479.9
Other	0.1	—
	666.5	509.5
Total regulatory liabilities	689.9	539.0
Less current portion	146.8	22.5
Long-term regulatory liabilities	$ 543.1	$ 516.5

(1) Related to plant life. Includes $13.1 million and $14.6 million of excess deferred taxes as of Dec. 31, 2005 and Dec. 31, 2004, respectively.

(2) Amortized over the term of the related debt instrument.

4. Income Tax Expense

Income tax expense consists of the following components:

Income Tax Expense (Benefit) (millions)	Federal	Foreign	State	Total
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
2004				
Continuing operations				
Current payable	$ (7.6)	$ (1.1)	$ 10.6	$ 1.9
Deferred	(193.2)	0.3	(51.2)	(244.1)
Amortization of investment tax credits	(2.9)	—	-	(2.9)
Income tax benefit from continuing operations	(203.7)	(0.8)	(40.6)	(245.1)
Discontinued operations				
Current payable	8.3	—	5.6	13.9
Deferred	(110.6)	—	(0.8)	(111.4)
Income tax (benefit) expense from discontinued operations	(102.3)	—	4.8	(97.5)
Total income tax benefit	$ (306.0)	$ (0.8)	$ (35.8)	$ (342.6)
2003				
Continuing operations				
Current payable	$ 59.6	$ 2.2	$ 7.3	$ 69.1
Deferred	(123.2)	5.3	(14.4)	(132.3)
Amortization of investment tax credits	(4.7)	—	—	(4.7)
Income tax (benefit) expense from continuing operations	(68.3)	7.5	(7.1)	(67.9)
Discontinued operations				
Current payable	(1.6)	—	7.0	5.4
Deferred	(539.5)	—	(37.4)	(576.9)
Income tax benefit from discontinued operations	(541.1)	—	(30.4)	(571.5)
Total income tax (benefit) expense	$ (609.4)	$ 7.5	$ (37.5)	$ (639.4)

TECO Energy uses the liability method to determine deferred income taxes. Under the 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.

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, 2005 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,	*2005*	*2004*
Deferred income tax assets [1]		
Property related	$ 254.2	$ 780.3
Alternative minimum tax credit forward	192.4	208.5
Investment in partnership	65.1	80.8
Goodwill write-down	—	16.0
Net operating loss carryforward	757.4	158.8
Other	74.1	134.7
Total deferred income tax assets	1,343.2	1,379.1
Deferred income tax liabilities [1]		
Property related	(572.9)	(557.6)
Deferred fuel	(103.6)	(12.7)
Other	69.0	66.2
Total deferred income tax liabilities	(607.5)	(504.1)
Net deferred tax assets	$ 735.7	$ 875.0

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

Included in the "Property related" component of the deferred tax asset is the impact of the asset impairments discussed in Notes 18 and 21.

At Dec. 31, 2005, the company has unused federal net operating losses of approximately $1,980.0 million and state (Florida) net operating losses of approximately $1,171.1 million, which expire in 2024 and 2025. In addition, the company has available alternative minimum tax credit carryforwards for tax purposes of approximately $192 million which may be used indefinitely to reduce federal income taxes.

Effective Income Tax Rate

(millions) *For the years ended Dec. 31,*	*2005*	*2004*	*2003*
Net income (loss) from continuing operations before minority interest	$ 123.9	$ (435.0)	$ 51.9
Plus: minority interest	87.1	79.5	48.8
Net income (loss) from continuing operations	211.0	(355.5)	100.7
Total income tax provision (benefit)	101.9	(245.1)	(67.9)
Income (loss) from continuing operations before income taxes	312.9	(600.6)	32.8
Income taxes on above at federal statutory rate of 35%	109.5	(210.2)	11.5
Increase (decrease) due to			
State income tax, net of federal income tax	18.1	(26.3)	(4.6)
Foreign income taxes	6.6	(0.8)	7.5
Amortization of investment tax credits	(2.7)	(2.9)	(4.7)
Permanent reinvestment – foreign income	(9.4)	(10.5)	(12.3)
Non-conventional fuels tax credit	—	—	(66.0)
AFUDC equity	—	(0.3)	(6.9)
Dividend income	1.6	14.6	—
Depletion	(8.4)	(2.0)	(1.0)
Other	(13.4)	(6.7)	8.6
Total income tax provision from continuing operations	$ 101.9	$ (245.1)	$ (67.9)
Provision for income taxes as a percent of income from continuing operations, before income taxes	32.6%	40.8%	(207.0%)[1]

(1) This calculation is not necessarily meaningful as a result of the interaction between tax losses and tax credits for the period.

During the twelve months ended Dec. 31, 2005 and Dec. 31, 2004, 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 Accounting Principles Board Opinion No. 23, *Accounting for Taxes – Special Areas* (APB 23), adjustment of deferred tax assets for the effect of an enacted change in state rates, repatriation of foreign source income to the United States, and reduction of income tax expense under the new "tonnage tax" regime.

At Dec. 31, 2005, the portion of cumulative undistributed earnings from our investments in EEGSA was approximately $53.3 million. With the exception of the earnings repatriated in 2005, which resulted in additional tax expense of $0.1 million, these earnings have been and are intended to be indefinitely invested in foreign operations. Therefore, no expense has been recorded for U.S. taxes or foreign withholding taxes that may be applicable upon actual or deemed repatriation.

On Oct. 22, 2004, the President 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 Reconciliation.

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 2005.

The consolidated entity recorded a net state benefit in 2005 and 2004 to reflect state deferred balances at the expected realizable rate which is lower than in prior years and to record estimated state benefits from impairments. The total effective income tax rate differs from the federal statutory rate due to state income tax, net of federal income tax, the non-conventional fuels tax credit, and other miscellaneous items. The actual cash paid for income taxes as required for the alternative minimum tax, state income taxes, and prior year audit in 2005, 2004 and 2003 was $27.4 million, $22.4 million and $58.8 million, respectively.

5. Employee Postretirement Benefits

Pension Benefits

TECO Energy has a non-contributory defined benefit retirement plan that covers substantially all employees. Benefits are based on employees' age, years of service and final average earnings. The company's policy is to fund the plan based on the amount determined by the company's actuaries within the guidelines set by ERISA for the minimum annual contribution. In 2005, the company made a contribution of $17.3 million to the plan. In 2006, the company's minimum contribution is $6.3 million and the company expects to contribute at least that amount.

Amounts disclosed for pension benefits also include the unfunded obligations for the supplemental executive retirement plans. These are non-qualified, non-contributory defined benefit retirement plans available to certain members of senior management. In 2005, the company made a contribution of $4.6 million to these plans. In 2006, the company expects to make a contribution of about $1.6 million to these plans.

TECO Energy reported other comprehensive losses of $7.2 million in 2005 and $43.9 million in 2003 and other comprehensive income of $7.2 million in 2004, related to adjustments to the minimum pension liability associated with these pension plans (see **Note 10**).

The asset allocation for the company's pension plan as of Sep. 30, 2005 and 2004, the measurement dates for the company's post-retirement benefit plans, and the target allocation for 2006, by asset category, is as follows:

Asset Allocation

Asset category	*Target Allocation for 2006*	*Percentage of Plan Assets at Sep. 30, 2005*	*2004*
Equities	55% – 60%	64%	60%
Fixed income	40% – 45%	36%	40%
Total		100%	100%

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.

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

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expenses paid. 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. 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.

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 2006, the company expects to make a contribution of about $12.7 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 adds 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 will at least be "actuarially equivalent" to the standard drug benefits to be offered under Medicare Part D.

On May 19, 2004, the FASB issued FSP 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* (FSP 106-2). The guidance in FSP 106-2 requires (a) that the effects of the federal subsidy be considered an actuarial gain and recognized in the same manner as other actuarial gains and losses and (b) certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits. TECO Energy adopted FSP 106-2 retroactive for the second quarter of 2004. The expected subsidy reduced the net amount recognized at Dec. 31, 2005 by $1.8 million, and net periodic cost for 2005 by $0.7 million.

In 2005, the company filed and received approval for its Part D subsidy application with the Centers for Medicare and Medicaid Services (CMS) and is continuing to analyze what, if any, plan design changes should be made with respect to the company's retiree medical program in response to the MMA.

The following charts summarize the income statement and balance sheet impact, as well as the benefit obligations, assets, funded status and rate assumptions associated with the pension and other postretirement benefits.

Benefit Expense

(millions)	*Pension Benefits*			*Other Postretirement Benefits*		
For the years ended Dec. 31,	*2005*	*2004*	*2003*	*2005*	*2004*	*2003*
Components of net periodic benefit expense						
Service cost (benefits earned during the period)	$ 16.2	$ 17.0	$ 14.3	$ 6.5	$ 4.3	$ 4.2
Interest cost on projected benefit obligations	32.7	33.0	30.8	11.2	10.8	12.5
Expected return on assets	(37.2)	(39.1)	(42.1)	—	—	—
Amortization of:						
Transition (asset) obligation	(0.2)	(1.1)	(1.1)	2.7	2.7	2.7
Prior service (benefit) cost	(0.5)	(0.5)	(0.5)	3.0	1.8	1.8
Actuarial loss	4.3	2.7	1.4	—	0.7	1.5
Pension expense	15.3	12.0	2.8	23.4	20.3	22.7
Settlement	1.4	6.6	—	—	—	—
Additional amounts recognized	—	0.4	—	—	—	0.1
Net pension expense recognized in the Consolidated Statements of Income	$ 16.7	$ 19.0	$ 2.8	$ 23.4	$ 20.3	$ 22.8
Assumptions used to determine net cost						
Discount rate	6.00%	6.00%	6.75%	6.00%	6.00%	6.75%
Rate of compensation increase	4.25%	4.25%	4.82%	4.25%	4.25%	4.82%
Expected return on plan assets	8.75%	8.75%	9.00%	N/A	N/A	N/A

The following table shows the funded status of the qualified and non-qualified pension plans for which the projected obligation exceeds the fair value of the plan assets:

Pension Plans – Projected Obligation Exceeds Plan Assets

(millions) Sep. 30,	*2005*	*2004*
Projected benefit obligation	$ 562.1	$ 545.4
Fair value of plan assets	434.7	407.6
Projected obligation in excess of plan assets	$ 127.4	$ 137.8

As of Sep. 30, 2005 and 2004, for the qualified and non-qualified pension plans, the accumulated obligation exceeded the fair value of the plan assets. The table below shows the funded status for the respective plans:

Pension Plans – Accumulated Obligation Exceeds Plan Assets

(millions) Sep. 30,	*2005*	*2004*
Accumulated benefit obligation	$ 509.7	$ 476.2
Fair value of plan assets	434.7	407.6
Accumulated obligation in excess of plan assets	$ 75.0	$ 68.6

The accumulated postretirement benefit obligation exceeds plan assets for the postretirement health and welfare benefits plan.

Employee Postretirement Benefits

(millions)	Pension Benefits 2005	Pension Benefits 2004	Other Postretirement Benefits 2005	Other Postretirement Benefits 2004
Change in benefit obligation				
Net benefit obligation at prior measurement date	$ 545.4	$ 554.5	$ 185.7	$ 198.7
Service cost	16.2	17.0	6.4	4.3
Interest cost	32.6	33.0	11.3	10.8
Plan participants' contributions	—	—	2.7	3.5
Actuarial loss	7.1	(0.9)	14.2	(34.3)
Plan amendments	—	1.5	—	17.0
Curtailment	—	(2.2)	—	—
Settlement	(3.1)	—	—	—
Gross benefits paid	(36.1)	(57.5)	(14.1)	(14.3)
Net benefit obligation at measurement date	$ 562.1	$ 545.4	$ 206.2	$ 185.7
Change in plan assets				
Fair value of plan assets at prior measurement date	$ 407.6	$ 391.8	$ —	$ —
Actual return on plan assets	44.4	43.0	—	—
Employer contributions	21.9	30.3	11.4	10.8
Plan participants' contributions	—	—	2.7	3.5
Settlement	(3.1)	—	—	—
Gross benefits paid	(36.1)	(57.5)	(14.1)	(14.3)
Fair value of plan assets at measurement date	$ 434.7	$ 407.6	$ —	$ —
Funded status				
Fair value of plan assets	$ 434.7	$ 407.6	$ —	$ —
Benefit obligation	562.1	545.4	206.2	185.7
Funded status at measurement date	(127.4)	(137.8)	(206.2)	(185.7)
Net contributions after measurement date	0.3	0.4	2.6	2.8
Unrecognized net actuarial loss	143.3	149.2	26.6	12.4
Unrecognized prior service (benefit) cost	(4.9)	(5.4)	32.7	35.6
Unrecognized net transition (asset) obligation	—	(0.2)	19.2	22.0
Accrued liability at end of year	$ 11.3	$ 6.2	$ (125.1)	$ (112.9)
Amounts recognized in the statement of financial position				
Prepaid benefit cost	$ 28.6	$ 23.6	$ —	$ —
Accrued benefit cost	(17.2)	(17.4)	(125.1)	(112.9)
Additional minimum liability	(86.0)	(74.4)	—	—
Intangible asset	1.9	2.2	—	—
Accumulated other comprehensive income	84.0	72.2	—	—
Net amount recognized at end of year	$ 11.3	$ 6.2	$ (125.1)	$ (112.9)
Assumptions used in determining benefit obligations, end of year				
Discount rate to determine projected benefit obligation	5.50%	6.00%	5.50%	6.00%
Rate of increase in compensation levels	3.75%	4.25%	3.75%	4.25%

Employer contributions and benefits paid in the above table include those amounts contributed directly to, and paid directly from plan assets, and paid directly to plan participants. The assumed health care cost trend rate for medical costs was 9.5% and 10.5% in 2005 and 2004, respectively, and decreases to 5.0% in 2013 and thereafter.

A 1% increase in the medical trend rates would produce a 5% ($0.8 million) increase in the aggregate service and interest cost for 2005 and a 3% ($6.4 million) increase in the accumulated postretirement benefit obligation as of Sep. 30, 2005, the measurement date.

A 1% decrease in the medical trend rates would produce a 3% ($0.6 million) decrease in the aggregate service and interest cost for 2005 and a 3% ($5.3 million) decrease in the accumulated postretirement benefit obligation as of Sep. 30, 2005, the measurement date.

Information about expected benefit payments for the pension and postretirement benefit plans follows:

Expected Benefit Payments (including projected service and net of employee contributions)

(millions) For the years ended Dec. 31,	Pension Benefits	Other Benefits (exclusive of subsidy payments under MMA)	Employer Value of Expected Payments MMA	Other Benefits net of Expected Payments under MMA
2006	$ 41.4	$ 12.7	$ (0.8)	$ 11.9
2007	$ 42.2	$ 13.7	$ (0.9)	$ 12.8
2008	$ 43.9	$ 14.8	$ (1.0)	$ 13.8
2009	$ 45.1	$ 15.6	$ (1.1)	$ 14.5
2010	$ 46.1	$ 16.5	$ (1.2)	$ 15.3
2011-2015	$ 243.8	$ 89.7	$ (8.2)	$ 81.5

6. Short-Term Debt

At Dec. 31, 2005 and 2004, the following credit facilities and related borrowings existed:

Credit Facilities	*Dec. 31, 2005*			*Dec. 31, 2004*		
(millions)	*Credit Facilities*	*Borrowings Outstanding*[1]	*Letters of Credit Outstanding*	*Credit Facilities*	*Borrowings Outstanding*[1]	*Letters of Credit Outstanding*
Tampa Electric:						
5-year facility[2]	$ 325.0	$ 120.0	$ —	$ 150.0	$ 115.0	$ —
3-year facility	—	—	—	125.0	—	—
1-year accounts receivable facility	150.0	95.0	—	—	—	—
TECO Energy:						
5-year facility	200.0	—	14.3	200.0	—	27.4
Total	$ 675.0	$ 215.0	$ 14.3	$ 475.0	$ 115.0	$ 27.4

(1) Borrowings outstanding are reported as notes payable.
(2) A 3-year facility as of Dec. 31, 2004 (as discussed below).

These credit facilities require commitment fees ranging from 12.5 to 37.5 basis points. The weighted average interest rate on outstanding notes payable at Dec. 31, 2005 and 2004 was 4.45% and 3.32%, respectively.

TECO Energy Credit Facility

On Oct. 11, 2005, TECO Energy amended its $200 million bank credit facility, extending the maturity to Oct. 11, 2010 with optional extensions of up to two additional years with lenders' consent. The amended facility also allows TECO Energy to increase the facility size by up to $50 million with lenders' consent. The facility is secured by the stock of TECO Transport, which security will be released if TECO Energy achieves investment-grade ratings and stable outlooks from both Moody's and Standard & Poor's. This facility includes a $100 million sub-limit for letters of credit. 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 5.25 times through Mar. 31, 2007, 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 2.25 times through Dec. 30, 2005 and 2.60 times thereafter. 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, to issue additional indebtedness in excess of a calculated level (initially $100 million), unless the indebtedness refinances currently outstanding indebtedness or meets certain other conditions. The new facility also provides that, in the event the aggregate quarterly dividend payments on TECO Energy common stock were to equal or exceed $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 Credit Facility

On Oct. 11, 2005, Tampa Electric amended its $150 million bank credit facility, increasing the facility size to $325 million and extending the maturity to Oct. 11, 2010 with optional extensions of up to two additional years with lenders' consent. Tampa Electric terminated its $125 million 3-year bank credit facility. The amended facility also allows Tampa Electric to increase the facility size by up to $50 million with lenders' consent; and includes a $50 million sub-limit for letters of credit. The financial covenants were also amended to eliminate the requirement that Tampa Electric maintain a specified ratio of EBITDA to interest, as defined in the agreement, and increase the permissible quarter-end debt to capital, as defined in the agreement, to 65%.

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 securitized 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. See **Note 23** for a subsequent event involving this facility.

7. Long-Term Debt

At Dec. 31, 2005, total long-term debt, excluding amounts currently due, had a carrying amount of $3,709.2 million and an estimated fair market value of $3,865.9 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, and certain pollution control equipment is pledged to secure certain installment contracts payable. 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 2006 through 2010 and thereafter are as follows:

Long-Term Debt Maturities For Continuing Operations

Dec. 31, 2005 (millions)	*2006*	*2007*	*2008*	*2009*	*2010*	*Thereafter*	*Total Long-term Debt*
TECO Energy							
Debt securities	$ –	$ 300.0	$ —	$ –	$ 400.0	$ 1,200.0	$ 1,900.0
Junior subordinated notes	–	71.4	—	–	–	106.2	177.6
Tampa Electric	–	125.0	—	–	–	1,223.9	1,348.9
Peoples Gas	5.9	31.1	5.7	5.5	3.7	116.8	168.7
TECO Transport	–	110.6	—	–	–	–	110.6
TECO Guatemala	1.3	1.3	1.4	1.4	1.4	6.2	13.0
Total long-term debt maturities	$ 7.2	$ 639.4	$ 7.1	$ 6.9	$ 405.1	2,653.1	$ 3,718.8

Debt Securities

TECO Energy – $100 million Senior Unsecured Floating Rate Notes

On Jun. 7, 2005, TECO Energy issued $100 million of senior unsecured Floating Rate Notes due 2010 through an institutional private placement. Net proceeds of $99.3 million were used to implement TECO Energy's debt redemption, refinancing, and hedging strategy. On Oct. 14, 2005, TECO Energy completed an exchange offer related to the Floating Rate Notes, thereby satisfying its obligations under a registration rights agreement.

TECO Energy – $200 million Senior Unsecured 6.75% Notes

On May 26, 2005, TECO Energy issued $200 million of senior unsecured 6.75% Notes due 2015. Net proceeds of $198.5 million were used in TECO Energy's debt redemption and refinancing plan. On Oct. 14, 2005, TECO Energy completed an exchange offer related to the 6.75% Notes, thereby satisfying its obligations under a registration rights agreement.

TECO Energy – $300 million 7.5% Senior Unsecured Notes

On Jun. 13, 2003, TECO Energy issued $300 million of 7.5% Senior Unsecured Notes due in 2010. Net proceeds of $293.0 million were used to repay short-term debt and for general corporate purposes.

Tampa Electric – $250 million 6.25% Senior Notes

In April 2003, Tampa Electric issued $250 million of 6.25% Senior Notes due 2014-2016, in a private placement. Net proceeds of $250.0 million were used to repay short-term indebtedness and for general corporate purposes at Tampa Electric.

Junior Subordinated Notes

Based on the provisions of FAS 150, the preferred securities issued by the company were reclassified and presented as long-term debt for external financial reporting purposes. The cumulative effect of the adoption of FAS 150 was an after-tax loss of $3.2 million ($5.3 million pretax) in 2003, reflecting an adjustment to recognize interest expense ratably over the life of the instruments in accordance with the new guidance.

Effective Jan. 1, 2004, TECO Energy adopted FIN 46R. As a result, the company's preferred securities were no longer recognized as a result of the deconsolidation of the funding companies established to issue the securities purchases by the trusts described below. As described below, the company issued junior subordinated notes to the funding companies in connection with the issuance of the trust preferred securities. The company has reflected the junior subordinated notes and the equity investment in the funding companies on the balance sheet. See **Note 2** for additional discussion of the impact of FIN 46R.

Capital Trust I

In December 2000, TECO Capital Trust I, a trust established for the sole purpose of issuing Trust Preferred Securities (TRuPS) and purchasing company preferred securities, issued 8 million shares of $25 par, 8.5% TRuPS, due 2041, with an aggregate liquidation value of $200 million. Each TRuPS represents an undivided beneficial interest in the assets of the Trust. The TRuPS represent an indirect interest in a corresponding amount of the TECO Energy 8.5% junior subordinated notes due 2041. Distributions are payable quarterly in arrears on Jan. 31, Apr. 30, Jul. 31, and Oct. 31 of each year. Distributions were $18.2 million in 2005, and $17.0 million per year in 2004 and 2003. For 2004 and 2005, these distributions were reflected in interest expense.

On Dec. 20, 2005, TECO Energy completed the early redemption of $100 million aggregate liquidation amount of the 8.5% TRuPS of TECO Capital Trust I. The remaining 4 million shares of $25 par, 8.5% TRuPS, due 2041, have an aggregate liquidation value of $100 million.

The remaining junior subordinated notes may be redeemed at the option of TECO Energy at any time on or after Dec. 20, 2005 at 100% of their principal amount plus accrued interest through the redemption date. Upon any liquidation of the company preferred securities, holders of the TRuPS would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends through the date of redemption.

Capital Trust II

In January 2002, TECO Energy sold 17.965 million mandatorily convertible equity security units in the form of 9.5% equity units at $25 per unit resulting in $436 million of net proceeds. Each equity unit consisted of $25 in principal amount of a trust preferred security of TECO Capital Trust II, a Delaware business trust formed for the purpose of issuing these securities, with a stated liquidation amount of $25 and a contract to purchase shares of common stock of TECO Energy in January 2005 at a price per share of between $26.29 and $30.10 based on the market price at that time. The equity units represented an indirect interest in a corresponding amount of the TECO Energy 5.11% junior subordinated notes. The holders of these contracts were entitled to quarterly contract adjustment payments at the annualized rate of 4.39% of the stated amount of $25 per year through and including Jan. 15, 2005.

In August 2004, the company exchanged approximately 10.227 million common shares and $14.9 million in cash for 10.756 million units through an early settlement offer (see **Note 9**). After the acceptance of the early settlement offer, approximately 7.209 million units remained outstanding.

In October 2004, $162.7 million of TECO Capital Trust II trust preferred securities out of a total $180.2 million aggregate stated liquidation amount of such trust preferred securities outstanding were remarketed. The distribution rate on the trust preferred securities was reset to a coupon rate of 5.934% per annum, payable quarterly, effective on and after Oct. 16, 2004.

At the closing of the remarketing on Oct. 15, 2004, the company purchased approximately $122.7 million of the trust preferred securities that were remarketed and retired the trust preferred securities it purchased. The company funded its participation by borrowing $124.1 million under an unsecured bridge loan facility with JP Morgan Chase Bank and Merrill

Lynch Bank USA. The company received the proceeds of this loan on Oct. 15, 2004 and repaid the loan on Dec. 23, 2004 with the proceeds from the sale of Frontera Generation Limited Partnership (see **Note 16**).

On Jan. 14, 2005, the final settlement rate was set for TECO Energy's remaining outstanding 7.209 million equity security units that were not tendered in the early settlement offer completed in August 2004. On Jan. 18, 2005, each holder of the TECO Energy units purchased from TECO Energy 0.9509 shares of TECO Energy common stock per unit for $25 per share. The cash for the unit holders' purchase obligation was satisfied from the proceeds received upon the maturity of a portfolio of U.S. Treasury securities acquired in connection with the October 2004 remarketing of the trust preferred securities of TECO Capital Trust II. As a result, TECO Energy issued 6.85 million shares of common stock on Jan. 18, 2005 and received approximately $180 million of proceeds from the settlement.

At Dec. 31, 2005 and 2004, TECO Energy had the following long-term debt outstanding:

Long-term Debt *(millions) Dec. 31,*		*Due*	*2005*	*2004*
TECO Energy	Notes: 7.2% (effective rate of 7.38%) (1)	2011	$ 600.0	$ 600.0
	6.125% (effective rate of 6.32%) (1)	2007	300.0	300.0
	7% (effective rate of 7.09%) (1)	2012	400.0	400.0
	10.5% (effective rate of 12.37% for 2004) (1)(14)	2007	—	380.0
	7.5% (effective rate of 7.85%) (1)(2)	2010	300.0	300.0
	6.75% (effective rate of 6.85%)(1)(2)	2015	200.0	—
	Floating rate 6.25% (effective rate of 6.46%)(1)(2)(9)	2010	100.0	—
	Junior subordinated notes: 8.50% (3)	2041	106.2	206.2
	5.93% (4)	2007	71.4	71.4
			2,077.6	2,257.6
Tampa Electric	Installment contracts payable: (5)			
	6.25% Refunding bonds (effective rate of 6.81%) (6)(13)	2034	86.0	86.0
	5.85% Refunding bonds (effective rate of 5.88%)(15)	2030	75.0	75.0
	5.1% Refunding bonds (effective rate of 5.73%) (7)	2013	60.7	60.7
	5.5% Refunding bonds (effective rate of 6.31%) (7)	2023	86.4	86.4
	4% (effective rate of 4.19%) (8)(15)	2025	51.6	51.6
	4% (effective rate of 4.17%) (8)(15)	2018	54.2	54.2
	4.25% (effective rate of 4.44%) (8)(15)	2020	20.0	20.0
	Notes: 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
	5.375% (effective rate of 5.59%) (1)	2007	125.0	125.0
	6.25% (effective rate of 6.31%) (1)(2)	2014-2016	250.0	250.0
			1,348.9	1,348.9
Peoples Gas System	Senior Notes: (1)(2) 10.35%	2006-2007	1.8	2.6
	10.33%	2006-2008	3.0	4.0
	10.3%	2006-2009	4.8	5.6
	9.93%	2006-2010	5.0	5.8
	8%	2006-2012	19.1	21.2
	Notes: 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
	5.375% (effective rate of 5.59%) (1)	2007	25.0	25.0
			168.7	174.2
TECO Guatemala	Non-recourse secured facility notes, variable rate:			
	6.63% for 2004(9)	2005-2009	—	4.4
	Note: 3% Fixed rate	2006-2014	13.0	—
			13.0	4.4

Long-term Debt *(millions) Dec. 31,*		*Due*	*2005*	*2004*
TWG Merchant	Non-recourse secured facility notes, variable rate: 8.13% for 2004 (9)(10)	2004	—	1,395.0
	Non-recourse financing facility — Union County: 7.5% (5)(10)	2005-2021	—	676.1
			—	2,071.1
Other Unregulated	Dock and wharf bonds, 5% (5)	2007	110.6	110.6
	Non-recourse mortgage notes, variable rate:			
	5.43% for 2004 (9)(11)	2005	—	4.1
	4.78% (effective rate of 5.09% for 2004) (12)	2005-2006	—	13.0
			110.6	127.7
Unamortized debt discount, net			(2.4)	(19.2)
			3,716.4	5,964.7
Less amount due within one year			7.2	13.6
Less long-term liabilities held for sale (10)			—	2,071.1
Total long-term debt			$ 3,709.2	$ 3,880.0

(1) These securities are subject to redemption in whole or in part, at any time, at the option of the company.
(2) These long-term debt agreements contain various restrictive financial covenants.
(3) These securities may be redeemed in whole or in part, at par by action of the company on or after Dec. 20, 2005.
(4) The rate on these securities was reset from 5.11% (effective rate of 5.85%) to 5.93% on Oct. 15, 2004.
(5) Tax-exempt securities.
(6) Proceeds of these bonds were used to refund bonds with an interest rate of 9.9% in February 1995. For accounting purposes, interest expense has been recorded using a blended rate of 6.52% on the original and refunding bonds, consistent with regulatory treatment.
(7) Proceeds of these bonds were used to refund bonds with interest rates of 5.75%-8%.
(8) The interest rate on these bonds was fixed for a five-year term on Aug. 5, 2002.
(9) Composite year-end interest rate.
(10) This obligation was transferred in the disposition of the Union and Gila River power plants. The liability was classified as "Liabilities associated with assets held for sale" at Dec. 31, 2004. These notes were in default as of Dec. 31, 2004. See Note 21 for additional details.
(11) These notes represented 100% of the debt for BT-One, LLC, an 80% owned consolidated affiliate. In total, the company had a $1.0 million guarantee on these notes.
(12) These notes represented 100% of the debt for Hernando Oaks, LLC, a 50% owned consolidated affiliate. In total, the company had a $9.2 million guarantee on these notes.
(13) See Note 23 for subsequent event regarding these bonds.
(14) The June 2005 redemption of these notes resulted in a $46.7 million after tax debt extinguishment charge.
(15) Certain pollution control equipment is pledged to secure these bonds.

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

In April 2004, the 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. The rights of the holders of the outstanding options under the 1996 Plan were not affected. The purpose of the 2004 Plan is to attract and retain key employees and consultants of the company, to provide an incentive for them to achieve long-range performance goals and to enable them to participate in the long-term growth of the company. The 2004 Plan amended the 1996 Plan to increase the number of shares of common stock subject to grants by 10 million shares, place various limitations on the types of awards available to be granted, specify a ten-year term for the 2004 Plan and any grants made thereunder and allow awards to consultants of the company. Under the 2004 Plan, the Compensation Committee of the Board of Directors may award 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"), 0.9 million, 2.4 million and 2.8 million stock options were granted to employees in 2005, 2004 and 2003, respectively, each with a maximum term of 10 years. The weighted average fair value per share of stock options granted to employees under the Equity Plans in 2005, 2004 and 2003, respectively, was $3.93, $2.80 and $1.79, using the Black-Scholes option pricing model with assumptions as described in **Note 1**. In addition, 0.4 million, 0.3 million and 0.6 million shares of restricted stock were awarded in 2005, 2004, and 2003, respectively, with weighted average fair values of $21.57, $14.80 and $13.59, respectively. These include both time-vested restricted stock (fair value based on the stock price on date of grant) and performance-based restricted stock (fair value determined using the Monte Carlo valuation model, with assumptions as described in **Note 1**).

Compensation expense recognized for stock grants awarded under the 2004 Plan and the 1996 Plan was $5.5 million, $5.2 million and $1.6 million in 2005, 2004 and 2003, respectively. Approximately 70% of the stock grants awarded in 2005 and half of the stock grants awarded in 2004 and 2003 are performance shares, restricted subject to meeting specified total shareholder return goals, vesting in three years with final payout ranging from zero to 200% of the original grant. Adjustments are made to reflect contingent shares which could be issuable based on current period results. The consolidated balance sheets at Dec. 31, 2005 and 2004 reflected a $5.4 million and a $(0.5) million liability, respectively, classified as other deferred credits, for these contingent shares. The remaining stock grants are generally restricted subject to continued employment, with the majority of the 2005, 2004 and 2003 stock grants vesting in three years, and the 1997 and 1996 stock grants vesting at normal retirement age.

Stock option transactions during the last three years under the Equity Plans are summarized as follows:

Stock Options – Equity Plans

	Option Shares (thousands)	*Weighted Avg. Option Price*
Balance at Dec. 31, 2002	6,416	$ 25.94
Granted	2,829	$ 11.10
Exercised	(14)	$ 11.09
Cancelled	(306)	$ 23.35
Balance at Dec. 31, 2003	8,925	$ 21.35
Granted	2,388	$ 13.44
Exercised	(512)	$ 11.17
Cancelled	(489)	$ 22.87
Balance at Dec. 31, 2004	10,312	$ 19.95
Granted	917	$ 16.29
Exercised	(986)	$ 11.60
Cancelled	(549)	$ 22.16
Balance at Dec. 31, 2005	9,694	$ 20.33
Exercisable at Dec. 31, 2005	1,652	$ 12.09
Available for future grant at Dec. 31, 2005	8,713	

As of Dec. 31, 2005, the 9.7 million options outstanding under the Equity Plans are summarized below.

Stock Options Outstanding at Dec. 31, 2005

Option Shares (thousands)	*Range of Option Prices*	*Weighted Avg. Option Price*	*Weighted Avg. Remaining Contractual Life*
3,541	$11.09 — $13.50	$12.50	8 Years
899	$16.21 — $18.87	$16.29	9 Years
1,593	$21.25 — $22.48	$21.35	4 Years
487	$23.55 — $25.97	$24.09	1 Year
3,174	$27.56 — $31.58	$29.11	5 Years
9,694	$11.09 — $31.58	$20.33	6 Years

In April 1997, the 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 rights of the holders of outstanding options under the 1991 Plan will not be affected. 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 is administered by the Board of Directors. The 1997 Plan amended the 1991 Plan to increase the number of shares of common stock subject to grants by 250,000 shares, expanded the types of awards available to be granted and replaced the fixed formula grant by giving the Board discretionary authority to determine the amount and timing of awards under the plan.

Under the 1997 Plan, 5,000, 5,000 and 6,000 stock grants were awarded to directors in 2005, 2004 and 2003, respectively, with weighted average fair values of $16.21, $13.56 and $11.09, respectively. In addition, 35,000, 35,000 and 40,000 stock options were granted to directors in 2005, 2004 and 2003, respectively, each with a maximum term of 10 years. The weighted average fair value per share of stock options granted to directors under the 1997 Plan in 2005, 2004 and 2003, respectively, was $3.95, $2.90 and $1.49, using the Black-Scholes option pricing model with assumptions as described in **Note 1**. Stock option transactions during the last three years under the 1997 Plan are summarized as follows:

Stock Options — Director Equity Plans

	Option Shares (thousands)	*Weighted Avg. Option Price*
Balance at Dec. 31, 2002	206	$ 25.31
Granted	40	$ 11.72
Exercised	–	$ –
Cancelled	(10)	$ 23.41
Balance at Dec. 31, 2003	236	$ 23.08
Granted	35	$ 14.03
Exercised	–	$ –
Cancelled	(8)	$ 19.81
Balance at Dec. 31, 2004	263	$ 21.97
Granted	35	$ 17.01
Exercised	(5)	$ 11.09
Cancelled	(40)	$ 25.66
Balance at Dec. 31, 2005	253	$ 20.93
Exercisable at Dec. 31, 2005	95	$ 13.79
Available for future grant at Dec. 31, 2005	196	

As of Dec. 31, 2005, the 253,000 options outstanding under the 1997 Plan with option prices of $11.09 – $31.58, had a weighted average option price of $20.93 and a weighted average remaining contractual life of six years.

Dividend Reinvestment Plan

In 1992, TECO Energy implemented a Dividend Reinvestment and Common Stock Purchase Plan. TECO Energy raised $4.9 million, $5.1 million and $8.0 million of common equity from this plan in 2005, 2004 and 2003, 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 outstanding under the TECO Capital Trust II securities, receiving approximately $180 million of proceeds from the settlement (see **Note 7**).

On Aug. 25, 2004, the company completed an early settlement exchange offer of its TECO Capital Trust II Equity Security Units for 10.2 million shares of common stock (see **Note 7**).

In September 2003, TECO Energy sold 11 million shares of common stock to funds managed by Franklin Advisers, Inc. at a price of $11.76 per share. Net proceeds of approximately $129 million were used to repay short-term indebtedness and for general corporate purposes.

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.

Employee Stock Ownership Plan

Effective Jan. 1, 1990, TECO Energy amended the TECO Energy Group Retirement Savings Plan, a tax-qualified benefit plan available to substantially all employees, to include an employee stock ownership plan (ESOP). During 1990, the ESOP purchased 7 million shares of TECO Energy common stock on the open market for $100 million. The share purchase was financed through a loan from TECO Energy to the ESOP. This loan was at a fixed interest rate of 9.3% and was repaid from dividends on ESOP shares and from TECO Energy's contributions to the ESOP. Shares were released to provide employees with the company match in accordance with the terms of the TECO Energy Group Retirement Savings Plan and in lieu of dividends on allocated ESOP shares. At Dec. 31, 2004, the ESOP had no shares remaining to be allocated.

TECO Energy's contributions to the ESOP were $2.1 million and $21.1 million in 2004 and 2003, respectively. TECO Energy's annual contribution equals the interest accrued on the loan during the year plus additional principal payments needed to meet the matching allocation requirements under the plan, less dividends received on the ESOP shares. The components of net ESOP expense recognized for the prior years are as follows:

ESOP Expense

(millions) *For the years ended Dec. 31,*	*2004*	*2003*
Interest expense	$ 0.3	$ 2.6
Compensation expense	8.4	16.0
Dividends	(4.0)	(5.3)
Net ESOP expense	$ 4.7	$ 13.3

Compensation expense was determined by the shares allocated method.

For financial statement purposes, the unallocated shares of TECO Energy stock were reflected as a reduction of common equity, classified as unearned compensation. Dividends on all ESOP shares were recorded as a reduction of retained earnings, as are dividends on all TECO Energy common stock. The dividends received by the ESOP were used to pay debt service on the loan between TECO Energy and the ESOP.

The tax benefit related to dividends paid to the ESOP for allocated shares is a reduction of income tax expense and was $1.5 million and $1.6 million for 2004 and 2003, respectively. The tax benefit related to dividends paid to the ESOP for unallocated shares is an increase in retained earnings and was $0.1 million and $0.4 million in 2004 and 2003, respectively. All ESOP shares were considered outstanding for earnings per share computations.

10. Other Comprehensive Income

TECO Energy reported the following other comprehensive income (loss) (OCI) for the years ended Dec. 31, 2005, 2004 and 2003, related to changes in the fair value of cash flow hedges, foreign currency adjustments and adjustments to the minimum pension liability associated with the company's pension plans:

Comprehensive Income (Loss) *(millions)*	*Gross*	*Tax*	*Net*
2005			
Unrealized gain on cash flow hedges	$ 7.3	$ 3.7	$ 3.6
Less: Gain reclassified to net income [1]	(5.7)	(2.0)	(3.7)
Gain (loss) on cash flow hedges	1.6	1.7	(0.1)
Pension adjustments [2]	(11.8)	(4.6)	(7.2)
Total other comprehensive loss	$ (10.2)	$ (2.9)	$ (7.3)
2004			
Unrealized loss on cash flow hedges	$ (14.6)	$ (4.9)	$ (9.7)
Less: Loss reclassified to net income [1]	22.8	8.3	14.5
Gain on cash flow hedges	8.2	3.4	4.8
Pension adjustments [2]	9.5	2.3	7.2
Total other comprehensive income	$ 17.7	$ 5.7	$ 12.0
2003			
Unrealized loss on cash flow hedges [1]	$ (31.8)	$ (10.6)	$ (21.2)
Less: Loss reclassified to net income [1]	76.4	27.1	49.3
Gain on cash flow hedges	44.6	16.5	28.1
Foreign currency adjustments	1.2	—	1.2
Pension adjustments[2]	(69.3)	(25.4)	(43.9)
Total other comprehensive loss	$ (23.5)	$ (8.9)	$ (14.6)

(1) Amounts include interest rate swaps designated as cash flow hedges at TPGC, which was consolidated effective Apr. 1, 2003 as a result of the termination of the partnership. Prior to Apr. 1, 2003, only the company's proportionate share of its equity investee's comprehensive loss was included. See Notes 20 and 21 for additional details regarding the OCI balances for cash flow hedges.

(2) See Note 5 for additional details regarding pension adjustments.

Accumulated Other Comprehensive Income *(millions) Dec. 31,*	*2005*	*2004*
Minimum pension liability adjustment (1)	$ (51.5)	$ (44.3)
Net unrealized gains from cash flow hedges (2)	0.4	0.5
Total accumulated other comprehensive income	$ (51.1)	$ (43.8)

(1) Net of tax benefit of $32.5 million and $27.9 million as of Dec. 31, 2005 and 2004, respectively.

(2) Net of tax (expense) benefit of $(0.4) million and $1.3 million as of Dec. 31, 2005 and 2004, respectively.

11. Earnings Per Share

For the years ended Dec. 31, 2005, 2004 and 2003, stock options for 5.4 million shares, 10.6 million shares and 6.3 million shares, respectively, were excluded from the computation of diluted earnings per share due to their antidilutive effect. Additionally, 1.9 million and 14.9 million common shares issuable under the purchase contract associated with the mandatorily convertible equity units were also excluded from the computation of diluted earnings per share for the years ended Dec. 31, 2004 and 2003, respectively, due to their antidilutive effect.

Earnings per Share *(millions, except per share amounts)* *For the years ended Dec. 31,*		*2005*	*2004*	*2003*
Numerator				
Net income (loss) from continuing operations, basic		$ 211.0	$ (355.5)	$ 100.7
Effect of contingent performance shares, net of tax		(2.0)	—	—
Net income (loss) from continuing operations, diluted		209.0	(355.5)	100.7
Cumulative effect of a change in accounting principle, net of tax		—	—	(4.3)
Discontinued operations, net of tax		63.5	(196.5)	(1,005.8)
Net income (loss), diluted		$ 272.5	$ (552.0)	$ (909.4)
Denominator				
Average number of shares outstanding – basic		206.3	192.6	179.9
Plus: Incremental shares for unvested restricted stock and assumed conversions: Stock options at end of period, unvested unrestricted stock and contingent performance shares		5.4	—	2.8
Less: Treasury shares which could be purchased		(3.5)	—	(2.5)
Average number of shares outstanding – diluted		208.2	192.6	180.2
Earnings per share from continuing operations	Basic	$ 1.02	$ (1.85)	$ 0.56
	Diluted	$ 1.00	$ (1.85)	$ 0.56
Earnings per share from discontinued operations, net	Basic	$ 0.31	$ (1.02)	$ (5.59)
	Diluted	$ 0.31	$ (1.02)	$ (5.58)
Earnings per share from cumulative effect of change in accounting principle, net	Basic	$ —	$ —	$ (0.02)
	Diluted	$ —	$ —	$ (0.02)
Earnings per share	Basic	$ 1.33	$ (2.87)	$ (5.05)
	Diluted	$ 1.31	$ (2.87)	$ (5.04)

12. Commitments and Contingencies

Capital Investments

TECO Energy has made certain commitments in connection with its continuing capital expenditure program. These estimated capital investments total approximately $456 million for 2006.

For 2006, Tampa Electric expects to spend $384 million, consisting of about $190 million to support system growth and generation reliability, approximately $12 million for distribution system reliability improvements and enhancements to customer-service systems, $20 million for coal-fired generation capacity factor and availability improvements, $74 million for the addition of two combustion turbines at the Polk Power Station to meet its peaking generation capacity needs, $78 million for the addition of selective catalytic reduction (SCR) equipment at the Big Bend Station for NO_x control and $10 million for other environmental compliance programs. At the end of 2005, Tampa Electric had outstanding commitments of about $198 million primarily for long-term capitalized maintenance agreements for its combustion turbines. The Environmental Consent Decree compliance expenditures are eligible for recovery of depreciation and a return on investment through the Environmental Cost Recovery Clause (see **Note 1**).

Capital expenditures for PGS are expected to be about $51 million in 2006. Included in this amount is approximately $29 million for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing renewal, replacement and system safety.

TECO Coal and TECO Transport expect to invest a combined $41 million in 2006. Included in this amount are expansion projects to add approximately 1.5 million tons to TECO Coal's production. Also included is normal renewal and replacement capital, including coal mining equipment and capitalized maintenance on ocean-going vessels and inland river transportation equipment. TECO Coal had outstanding commitments at Dec. 31, 2005 of approximately $11 million, primarily for replacement of coal mining equipment. Capital expenditures for TECO Transport do not include the $21 million contract for the construction of replacement river barges, which is expected to be treated as an operating lease.

Included in other capital expenditures is a cash offset of $20 million in 2006, related to the sale of two combustion turbines by TPS McAdams to Tampa Electric. The corresponding capital expenditure has been included in Tampa Electric's generation expansion for 2006 and also in their outstanding commitments as of Dec. 31, 2005.

Legal Contingencies

Tampa Electric Transmission Litigation

Four lawsuits were filed in the Circuit Court in Hillsborough County against Tampa Electric in connection with the location of transmission structures and upgrades to a substation in certain residential areas by residents in the areas surrounding the structures and substation. The resident plaintiffs are seeking to remove the poles or to receive monetary damages. The plaintiffs were seeking class action status, which status was denied. Three cases (two, Jorrison and Acosta were consolidated) are pending before two separate judges. Tampa Electric's motion to dismiss the claim for injunctive relief (non-monetary relief) was granted in the Alvarez case (substation case). Tampa Electric has filed new motions for partial summary judgment in both the Shaw and Acosta cases with respect to property owners not located adjacent to or in close proximity to the poles ("Remote Plaintiffs'). Two of the three motions in the Shaw case were granted on Jan. 13, 2006 and the third was denied on Jan. 20, 2006. This is expected to result in a number of plaintiffs dropping out of the case unless the summary judgements are overturned on appeal. The Shaw case has been transferred to the Trial Division (cases expected to have trials lasting two weeks or more), and the parties have stipulated to a trial date of Sep. 11, 2006. The motion for summary judgment in the Acosta case was argued Feb. 21, 2006 and the court took it under advisement. At that time, plaintiffs' counsel in the Acosta case dropped 65 plaintiffs.

McAdams Letter of Credit Litigation

Relating to the NEPCO default under the McAdams construction contract, in early 2002 TPS McAdams drew on a letter of credit in the amount of $19.95 million issued by West LB. In February 2003 West LB sued TPS McAdams SNC Lavalin and certain officers of NEPCO in federal district court in New York alleging that at the time of the TPS McAdams draw NEPCO had not yet failed to perform, but that performance was brought into question by Enron's bankruptcy. TPS McAdams has had a motion to dismiss pending since April 2003. In October, the case was referred to the bankruptcy court to be considered with the remains of the Enron bankruptcy. At a case status conference on Feb. 9, 2006, the bankruptcy judge scheduled a hearing on TPS McAdams' motion to dismiss for Mar. 23, 2006.

Grupo Litigation

In March 2001, TECO Wholesale Generation, Inc. (TWG) (under its former name of TECO Power Services Corporation) was served with a lawsuit in the Circuit Court for Hillsborough County by a Tampa-based firm named Grupo Interamerica, LLC (Grupo) seeking damages in connection with a potential investment in a power project in Colombia in 1996. Grupo alleged, among other things, that TWG breached an oral contract with Grupo. The trial court granted TWG's motion for summary judgment in the Grupo case in Hillsborough County Circuit Court in October 2004, and the plaintiffs appealed. The appellate court ruled in TWG's and TPSI's favor in September 2005; the appellants' motion for rehearing was denied, and the decision became final in late December 2005.

On Aug. 30, 2004, a Colombian trade union, Sindicato de Trabajadores de la Electricidad de Colombia (the "Union"), which was to be the owner/lessor of the power plant if the transaction had been consummated, filed a demand for arbitration in Colombia pursuant to provisions of a confidentiality and exclusivity agreement (the confidentiality agreement) between the trade union and an indirect subsidiary of TWG, TPS International Power, Inc. (TPSI), alleging breach of contract and seeking damages of approximately $50 million. The hearings before the Arbitration Tribunal (Tribunal) began in September 2005. The testimony phase of the proceeding has closed. The Tribunal has appointed experts on the subject of damages including the useful life of the facility and valuation of the project. The valuation report was due on Feb. 16, 2006. TPSI has also engaged its own expert. After receipt of the expert's report, both parties will have approximately four weeks to seek and obtain clarifications, if required. Liability is a matter of law to be determined by the Tribunal. Two U.S. based witnesses (one called by both parties and one called by TPSI) testified on Feb. 3, 2006. From the receipt of the clarifications to the expert's report, the parties have about four to six weeks to prepare and present written and oral closing arguments (May 2, 2006). After closing arguments, the Tribunal, although it has no deadlines, will likely take six to eight weeks to render its decision. These dates are tentative based on the best judgment of TPSI's Colombian Counsel and can be modified by order of the Tribunal.

Securities Class Action Lawsuits & Related SEC Inquiry

A number of securities class action lawsuits were filed in August, September and October 2004 against the company and certain current and former officers (the defendants) by purchasers of TECO Energy securities. These suits, which were filed in the U.S. District Court for the Middle District of Florida, allege disclosure violations under the Securities Exchange Act of 1934. These actions, which seek unspecified damages, were consolidated, and, on Feb. 1, 2005, the Court entered its order appointing (i) the "TECO Lead Plaintiff Group," comprised of NECA-IBEW Pension Fund (The Decatur Plan), Monroe County Employees Retirement System, John Marder and Charles Korpak, as the Lead Plaintiff for the Class and (ii) the law firm of Lerach Coughlin Stoia Geller Rudman & Robbins LLP as Lead Counsel. The plaintiffs filed their Consolidated Class Action Complaint for Securities Fraud on May 3, 2005. The consolidated complaint maintains the same class period, Oct. 30, 2001 to Feb. 4, 2003, and the same parties as those contained in the original complaint. The nature of the claims, which relate to the adequacy of the company's disclosures and financial reporting, also remains the same. The defendants filed their motion to dismiss on Jul. 25, 2005, and the plaintiffs filed their response on Dec. 2, 2005. The company filed a reply on Jan. 13, 2006 and the plaintiffs filed their response on Jan. 25, 2006. The company continues to defend the litigation vigorously. In addition, in connection with the previously disclosed SEC informal inquiry resulting from a letter from the non-equity member in CCC raising issues related to the arbitration proceeding involving that project, the SEC has requested additional information primarily relating to the allegations made in these securities class action lawsuits focusing on various merchant plant investments and related matters. The company is cooperating and continues to provide information on an agreed schedule and pursuant to an agreed process. A derivative case has been filed against several officers and directors in state court in connection with their alleged actions during the same period as the subject of the class action suit. This action was filed after a statutory demand which was being investigated by a special committee of the board. Motions to dismiss on behalf of all defendants have been filed.

Other Issues

The company cannot predict the ultimate resolution of these matters, including the class action litigation and the Grupo-related proceedings, at this time, and there can be no assurance that any such matters will not have a material adverse impact on TECO Energy's financial condition or results of operations.

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 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 the ultimate resolution of pending matters 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, 2005, Tampa Electric Company has estimated its ultimate financial liability to be approximately $14.3 million, with the majority attributable to the Peoples Gas division, 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 may be recoverable through customer rates established in future base rate proceedings.

TECO Transport Storm Damage

In August and September 2005, TECO Transport subsidiaries sustained flood and wind damage, as well as business interruptions as a result of hurricanes Katrina and Rita. The company has incurred $20.2 million pretax ($12.6 million after tax) of direct costs associated with these storms, including property damage, salvage, and cleanup expenses. The company carried wind and flood insurance for a majority of the property damaged. TECO Transport settled its claim for damages to its terminal and is in the process of filing claims with its insurance carrier for marine damage. The company has received $22 million pretax ($13.7 million after tax) in insurance recoveries. The company anticipates receiving additional recoveries during the first quarter of 2006. It is anticipated that these recoveries will not be as great as the costs incurred.

Long Term Commitments

TECO Energy has commitments under long-term operating leases, primarily for building space, office equipment and heavy equipment, and marine assets at TECO Transport. On Dec. 30, 2002, TECO Transport completed a sale-leaseback transaction to be accounted for as an operating lease covering one ocean-going tug and barge, five river towboats and 49 river barges. On Dec. 21, 2001, TECO Transport sold three ocean-going barges and one ocean-going tug boat in a sale-leaseback transaction to be accounted for as an operating lease. Both lease terms are 12 years with early buyout options after 5 years.

Total rental expense for these operating leases, included in the Consolidated Statements of Income for the years ended Dec. 31, 2005, 2004 and 2003 was $28.3 million, $32.3 million and $28.9 million, respectively.

The following is a schedule of future minimum lease payments at Dec. 31, 2005 for all operating leases with noncancelable lease terms in excess of one year:

Future Minimum Lease Payments of Operating Leases

Year ended Dec. 31:	*Amount (millions)*
2006	$ 27.9
2007	25.3
2008	17.5
2009	16.5
2010	16.2
Thereafter	85.0
Total minimum lease payments	$ 188.4

In 1994, Tampa Electric bought out a long-term coal supply contract which would have expired in 2004 for a lump sum payment of $25.5 million. In February 1995, the FPSC authorized the recovery of this buy-out amount plus carrying costs through the Fuel and Purchased Power Cost Recovery Clause over the 10-year period beginning Apr. 1, 1995. In each of the years 2004 and 2003, $2.7 million of buy-out costs were amortized to expense. It was fully amortized by the end of 2004.

Guarantees and Letters of Credit

On Jan. 1, 2003, TECO Energy adopted the prospective initial measurement provisions for certain types of guarantees, in accordance with FASB Interpretation No. (FIN) 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others (an interpretation of FASB Statements No. 5, 57 and 107 and rescission of FASB Interpretation No. 34).* Upon issuance or modification of a guarantee after Jan. 1, 2003, the company must determine if the obligation is subject to either or both of the following:

- Initial recognition and initial measurement of a liability; and/or
- Disclosure of specific details of the guarantee.

Generally, guarantees of the performance of a third party or guarantees that are based on an underlying (where such a guarantee is not a derivative subject to FAS 133) are likely to be subject to the recognition and measurement, as well as the disclosure provisions, of FIN 45. Such guarantees must initially be recorded at fair value, as determined in accordance with the interpretation.

Alternatively, guarantees between and on behalf of entities under common control or that are similar to product warranties are subject only to the disclosure provisions of the interpretation. The company must disclose information as to the term of the guarantee and the maximum potential amount of future gross payments (undiscounted) under the guarantee, even if the likelihood of a claim is remote.

A summary of the face amount or maximum theoretical obligation under TECO Energy's letters of credit and guarantees as of Dec. 31, 2005 are as follows:

Letters of Credit and Guarantees

(millions)	*Maturing*					
Letters of Credit and Guarantees for the Benefit of:	*2006*	*2007*	*2008-2010*	*After 2010*	*Total*	*Liabilities Recognized at Dec. 31, 2005*
Tampa Electric						
Letters of credit	$ –	$ –	$ –	$ 2.4	$ 2.4	$ –
Guarantees:						
Fuel purchase/energy management [1][2]	–	–	–	20.0	20.0	–
	–	–	–	22.4	22.4	–
TWG Merchant						
Guarantees:						
Risk management related[2][3]	74.2	–	–	–	74.2	–
	74.2	–	–	–	74.2	–
TECO Transport						
Letters of credit	–	–	–	2.4	2.4	–
TECO Coal						
Letters of credit	–	–	–	6.7	6.7	–
Guarantees: Other [2]	10.0	–	–	1.4 [1]	11.4	1.4
	10.0	–	–	8.1	18.1	1.4
TECO Guatemala						
Letters of credit	4.8	–	–	–	4.8	–
Other unregulated						
Guarantees:						
Fuel purchase/energy management [1][2]	–	–	–	2.7	2.7	–
Total	$ 89.0	$ –	$ –	$ 35.6	$124.6	$ 1.4

(1) These guarantees renew annually and are shown on the basis that they will continue to renew beyond 2010.
(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, 2005. The obligations under these letters of credit and guarantees include net accounts payable and net derivative liabilities.
(3) These represent guarantees of agreements between TECO Energy Source and various counterparties, primarily financial institutions, to enable the execution of transactions for hedging activities on behalf of TECO Energy, TECO Transport and TECO Coal.

Financial Covenants

In order to utilize their respective bank facilities, TECO Energy and Tampa Electric must meet certain financial tests as defined in the applicable agreements. In addition, TECO Energy, Tampa Electric and other operating companies have certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2005, TECO Energy, Tampa Electric and the other operating companies were in compliance with all required financial covenants.

13. Related Parties

In February 2002, Tampa Electric and TECO-PANDA Generating Company II (TPGC II) entered into an assignment and assumption agreement under which Tampa Electric obtained TPGC II's rights and interests to four combustion turbines being purchased from General Electric, and assumed the corresponding liabilities and obligations for such equipment. In accordance with the terms of the assignment and assumption agreement, Tampa Electric paid $62.5 million to TPGC II as reimbursement for amounts already paid to General Electric by TPGC II for such equipment. No gain or loss was incurred on the transfer. In the first quarter of 2003, Tampa Electric recorded a $48.9 million after-tax charge related to the cancellation of these turbine purchase commitments (see **Note 18**).

On Jan. 3, 2003, the $137.0 million loan receivable from PLC Development Holding LLC (PLC), a wholly-owned subsidiary of Panda Energy, converted to a 50% ownership interest in PLC, leading to a joint venture with Panda Energy. This joint venture held a 50% ownership interest in Texas Independent Energy, L.P. (TIE). The TIE partnership indirectly owns and operates the Odessa and Guadalupe power stations in Texas. In September 2003, a subsidiary of TWG Merchant completed foreclosure proceedings against two subsidiaries of Panda Energy receiving their ownership interest in PLC as a result of payment defaults of a $23.0 million note receivable. Consequently, in 2003, PLC was fully consolidated by TECO Energy and the $23.0 million note receivable was converted to an equity interest. The investment in PLC was sold in 2004. See **Note 16** for additional information regarding PLC.

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, $1.4 million and $1.2 million for the years ended Dec. 31, 2005, 2004 and 2003, 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, 2005, 2004 and 2003. No material balances were payable as of Dec. 31, 2005 or 2004.

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.

As more fully described in **Note 1**, 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.

The information presented in the following table excludes all discontinued operations. See **Note 21** 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	Eliminations & Other	Total TECO Energy
2005								
Revenues — outsiders	$1,744.3	$549.5	$ 505.1	$ 192.5	$ 7.7[9]	$ 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
Equity earnings of unconsolidated affiliates	–	–	–	(0.3)	57.9	–	2.8	60.4
Depreciation	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	133.2	291.4
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)[4]	$ 211.0
Goodwill, net	–	–	–	–	59.3	–	–	59.3
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[8]	322.4	408.4	233.0	545.2	7,170.1
Capital expenditures	203.5	42.5	24.1	18.1	0.2	6.9	–	295.3
2004								
Revenues — outsiders	$1,683.8	$417.2	$ 327.6	$ 173.4	$ 11.5[9]	$ 7.6	$ 18.3	$2,639.4
Sales to affiliates	3.6	–	–	76.2	–	–	(79.8)	–
Total revenues	$1,687.4	$417.2	$ 327.6	$ 249.6	$ 11.5	$ 7.6	$ (61.5)	$2,639.4
Equity earnings of unconsolidated affiliates	–	–	–	0.2	45.7	(9.2)	(0.6)	36.1
Depreciation	180.9	34.1	36.3	21.9	0.8	1.0	0.9	275.9
Restructuring costs [3]	–	0.7	–	–	–	0.5	–	1.2
Total interest charges [2]	95.8	15.2	11.2	4.7	14.7	50.7	130.6	322.9
Internally allocated interest [2]	–	–	11.1	(1.0)	14.3	50.7	(76.8)	(1.7)
Provision (benefit) for taxes	83.9	17.3	22.8	4.6	8.1	(314.0)	(67.8)	(245.1)
Net income (loss) from continuing operations [2]	$ 146.0	$ 27.7	$ 61.3	$ 10.2	$ 5.7[5]	$ (534.1)	$ (72.3)[4]	$ (355.5)
Goodwill, net	–	–	–	–	59.4	–	–	59.4
Investment in unconsolidated affiliates	–	–	–	3.3	239.2	–	20.5	263.0
Other non-current investments	–	–	–	–	–	–	8.0	8.0
Total assets	4,167.3	671.1	413.9[8]	315.4	363.6	2,736.8	304.3	8,972.4
Capital expenditures	181.2	38.7	22.9	20.2	0.4	0.2	0.1	263.7
2003								
Revenues — outsiders	$1,582.7	$408.4	$ 296.3	$ 162.2	$ 108.2	$ (2.5)	$ 7.6	$2,562.9
Sales to affiliates	3.4	–	–	98.4	50.2	–	(152.0)	–
Total revenues	$1,586.1	$408.4	$296.3	$ 260.6	$ 158.4	$ (2.5)	$ (144.4)	$2,562.9
Equity earnings of unconsolidated affiliates	–	–	–	–	5.7	(8.2)	2.1	(0.4)
Depreciation	210.3	32.7	34.2	20.6	15.0	0.3	0.3	313.4
Restructuring costs [3]	9.9	4.1	–	1.7	4.7	0.4	3.8	24.6
Total interest charges [2]	85.0	15.6	11.0	4.9	23.0	55.7	121.3	316.5
Internally allocated interest [2]	–	–	11.0	(2.0)	13.2	67.8	(93.7)	(3.7)
Provision (benefit) for taxes	48.3	15.7	(64.4)	9.7	9.2	(36.6)[7]	(49.8)	(67.9)
Net income (loss) from continuing operations [2]	$ 98.9[6]	$ 24.5	$ 77.1	$ 15.3	$ 22.0[5]	$ (60.8)	$ (76.3)	$ 100.7
Goodwill, net	–	–	–	–	59.4	–	11.8	71.2
Investment in unconsolidated affiliates	–	–	–	–	140.8	158.9	43.8	343.5
Other non-current investments	–	–	–	–	8.1	–	8.4	16.5
Total assets	4,178.6	651.5	340.8[8]	315.8	549.8	3,504.4	921.4	10,462.3
Capital expenditures	289.1	42.6	20.6	19.6	19.2	(1.5)	2.1	391.7

(1) From continuing operations. All periods have been adjusted to reflect the reclassification of results from operations to discontinued operations for CCC and Frontera Generation Limited Partnership (Frontera) (formerly included in the TWG Merchant segment) and BCH Mechanical, Inc. (BCH) and other Energy Services operations (formerly included in the Eliminations & Other segment).

(2) Segment net income is reported on a basis that includes internally allocated financing costs. Internally allocated costs for 2005, 2004 and 2003 were at pretax rates of 8%, 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) See **Note 19** for a discussion of restructuring charges in 2004 and 2003.

(4) Net income for the year ended Dec. 31, 2005 includes $46.7 million after tax of debt extinguishment charges at TECO Energy parent (including a $19.8 million non-cash charge). Net income for 2004 includes an after tax gain of $12.0 million on the sale of TECO Energy's interest in its propane business, partially offset by a non-cash $3.4 million after-tax asset impairment charge at TECO Solutions.

(5) Net income for 2004 includes a non-cash $12.8 million after-tax asset impairment charge related to certain steam turbines (see **Note 18**), $6.7 million after-tax charge related to the refinancing of the debt associated with the San José power station in Guatemala, and $17.4 million in after-tax charges associated with income taxes due to repatriation of cash from Guatemala following the refinancing. Net income for 2003 includes $34.6 million of after-tax gains on the sale of HPP (see **Note 17**).

(6) Net income for 2003 includes a non-cash $48.9 million after tax asset impairment charge related to turbine purchase cancellations (see **Note 18**).

(7) Taxes have been allocated, for segment reporting purposes, to TWG Merchant based on the weighted-average tax rates of the TWG Merchant components.

(8) The carrying value of mineral rights as of Dec. 31, 2005, 2004, and 2003 was $22.5 million, $25.0 million and $27.5 million, respectively.

(9) Revenues for 2005 and 2004 are exclusive of entities deconsolidated as a result of FIN 46R and include only revenues for the Guatemalan entities not affected by FIN 46R.

Tampa Electric Company, through its Tampa Electric division, provides retail electric utility services to more than 645,000 customers in West Central Florida. Its Peoples Gas System division is engaged in the purchase and distribution of natural gas for more than 321,000 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 nonconventional 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, transports, stores and transfers coal and other dry bulk commodities for third parties and Tampa Electric. TECO Transport's subsidiaries operate on the Mississippi, Ohio and Illinois rivers, in the Gulf of Mexico and worldwide.

TECO Guatemala includes the equity investments in the San José and Alborada power plants, TEMSA, the equity investment in the Guatemalan distribution company, EEGSA, and the TECO Guatemala parent company. See below for further information on the deconsolidated Guatemala investments.

TWG Merchant has subsidiaries that have an interest in an independent power project in Mississippi.

Foreign Operations

TECO Guatemala, through its subsidiaries, owns independent power operations and electric related other investments in Guatemala. TECO Energy, through its equity investments, has a 100% ownership interest in the 120-megawatt San José power station and in transmission facilities in Guatemala. The plant provides capacity and energy under a U.S. dollar-denominated power sales agreement to EEGSA. TECO Energy, through its equity investments, also has a 96% ownership interest and operates the 78-megawatt Alborada power station that supplies capacity and energy to EEGSA, under a U.S. dollar-denominated power sales agreement. Prior to 2004, the subsidiaries that hold interests in the San José and Alborada power stations in Guatemala were consolidated entities. As of Jan. 1, 2004, in accordance with the interpretation and application of the consolidation guidance established in FIN 46R to long-term power purchase agreements, TECO Energy can no longer consolidate these project companies and they are considered equity investments (see **Notes 1** and **2** for additional details).

TECO Energy, through its subsidiaries, owns a 30% interest in a three member consortium that also includes Iberdrola, an electric utility in Spain, and Electricidad de Portugal, an electric utility in Portugal. The consortium, called Distribuidora Electrica Centroamericana Dos owns an 80.9% interest in both EEGSA and Inversiones Electricas Centroamericanas, S.A., the holding company for Guatemalan-based electric transmission,services and unregulated distribution companies, a 55% interest in Navega.com, a telecommunications and data transmission carrier, and a 99.7% interest in Almacenaje y Manejo de Materiales Eléctricos, S.A., a company that manages, controls and sells electrical supplies and inventory materials.

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The information presented in the following table provides select condensed financial information for the unconsolidated operations of the San José and Alborada power stations and the DECA II/EEGSA project.

TECO Guatemala Selected Financial Data

(millions)		*San José*		*Alborada*		*DECA II/EEGSA*
2005						
Condensed income statement information						
Revenues	$	75.4	$	21.0	$	580.8[1]
Net income	$	27.0	$	12.8	$	67.7[1]
TECO's equity in net income [3]	$	27.0	$	12.3	$	18.6[1]
Condensed balance sheet information						
Total assets	$	201.1	$	49.5	$	[2]
Total liabilities	$	99.1	$	19.5	$	[2]
TECO's equity and advances	$	100.3	$	30.1	$	155.5[1]
2004						
Condensed income statement information						
Revenues	$	70.1	$	20.5	$	639.6
Net income	$	17.6	$	11.8	$	42.5
TECO's equity in net income	$	17.6	$	11.4	$	16.2
Condensed balance sheet information						
Total assets	$	200.5	$	55.8	$	926.4
Total liabilities	$	114.1	$	28.0	$	432.2
TECO's equity and advances	$	84.2	$	24.4	$	138.2

(1) 2005 income statement information is based on management's estimates, derived from information provided by EEGSA and its related affiliates. Final 2005 income statement information for the DECA II/EEGSA project will be received during the first quarter of 2006 and true-up adjustments will be made at that time. These adjustments are not expected to be material.

(2) EEGSA and its related affiliates had not provided balance sheet information prior to the company's filing date.

(3) Total net income from the entire Guatemalan segment was $40.4 million in 2005 and $5.7 million in 2004. The above selected income information includes only the project level information as stated above and does not include certain parent-based oversight costs and U.S. taxes.

15. Asset Retirement Obligations

On Jan. 1, 2003, TECO Energy adopted FAS 143, *Accounting for Asset Retirement Obligations*. The company recognized liabilities for retirement obligations associated with certain long-lived assets, in accordance with the relevant accounting guidance. 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 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.

In accordance with FAS 143, in 2003 TECO Energy recorded an increase to net property, plant and equipment of $7.8 million (net of accumulated depreciation of $6.6 million) and an increase to asset retirement obligations of $22.1 million, partially offset by previously recognized accrued reclamation obligations associated with coal mining activities of $12.3 million. A pretax charge of $1.8 million, net of a $0.2 million offset due to a regulatory asset at Tampa Electric, ($1.1 million after tax) was recognized as a change in accounting principle.

In accordance with FIN 47 in the fourth quarter of 2005, Tampa Electric recorded an increase to net property, plant and equipment of $3.6 million (net of accumulated depreciation of $0.4 million), an increase to regulatory assets of $2.7 million and an increase to asset retirement obligations of $18.3 million (including $12.1 million reclassified from a regulatory liability). If FIN 47 had been applied for all periods presented, the pro forma asset retirement obligation would have been $18.3 million and $18.5 million as of Jan. 1, 2004 and Dec. 31, 2004, respectively.

For the years ended Dec. 31, 2005, 2004 and 2003, TECO Energy recognized $1.6 million, $2.0 million, and $1.2 million of accretion expense, respectively, associated with asset retirement obligations. During 2005, no significant revisions to estimated cash flows used in determining the recognized asset retirement obligations were necessary. 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.

Upon adoption of FAS 143 at Jan. 1, 2003, the estimated accumulated cost of removal and dismantlement included in net accumulated depreciation as of Dec. 31, 2003 of $462.2 million was reclassified to a regulatory liability (see also **Note 3**). 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

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 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 (the Plan). 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. See **Note 20** for additional details.

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 21**).

PLC/TIE

At Dec. 31, 2002, TWG Merchant had a loan receivable of $137 million from PLC, a subsidiary of Panda Energy. On Jan. 3, 2003, this loan was converted to a partnership interest in PLC. See **Note 13** for additional details regarding the conversion of this loan to an equity interest in PLC. Furthermore, in September 2003, the company consummated the foreclosure on Panda Energy's interest in PLC resulting from a payment default on a $23 million note receivable leading to TWG Merchant's 100% indirect ownership in PLC which owns 50% of TIE (see **Notes 13 and 20**). As of Sep. 30, 2003, TWG Merchant consolidated PLC, resulting in a net increase in investment in unconsolidated affiliates of approximately $18 million. On Aug. 30, 2004, a TWG Merchant subsidiary completed the sale of its 50% indirect interest in TIE to PSEG Americas Inc., for $0.5 million. The company recorded a $152.3 million pretax impairment ($99.0 million after tax) to write off the value of the investment as a result of the sale.

Summary financial information for TIE is included in the table below.

(millions) Dec. 31,	2004 [(1)]	2003
Revenues	$ 319.7	$ 453.1
Operating income	$ 4.8	$ 25.5
Net (loss) available for allocation to partners	$ (18.3)	$ (14.4)

(1) 2004 only reflects results through Jul. 31, 2004, the effective date of the sale. The amounts for July 2004 represent estimates based on information received from the management of TIE.

Frontera

On Dec. 22, 2004, subsidiaries of TWG Merchant completed the sale of their respective interests in Frontera Generation Limited Partnership (Frontera), the owner of the Frontera Power Station in Texas, to a subsidiary of Centrica plc for $133.7 million, consisting of $128.5 million of cash and assumption of $5.2 million of liabilities. As a result of the sale, a pretax loss of $42.1 million ($27.0 million after tax) was recorded. The sale was subject to certain ordinary and customary post-closing adjustments to working capital items which were completed as expected with no material adjustments. See **Note 21** for additional details related to this transaction.

Commonwealth Chesapeake

In August 2004, the company entered into an agreement with NCP of Virginia, LLC (NCP), the non-equity member in Commonwealth Chesapeake Company (CCC), under which TECO Energy and a subsidiary agreed to purchase NCP's interest in CCC for $30 million in cash plus shares of TECO Energy common stock having a value of $10 million, and NCP released all claims against the company and its subsidiaries. The funds and shares were released from escrow upon receipt of FERC approval on Sep. 30, 2004 (see **Note 12** for additional details of this transaction).

On Apr. 19, 2005, an indirect subsidiary of TECO Energy completed the sale of its membership interests in CCC, the owner of the Commonwealth Chesapeake Power Station in Virginia, to an affiliate of Tenaska Power Fund, L.P. Net proceeds from the sale were $90.2 million after consideration for the value of working capital less transaction-related expenses. As a result of asset impairments recorded in the fourth quarter 2004, the sale transaction resulted in a pretax gain of $0.9 million ($0.6 million after-tax) upon close. The transaction terms provided for certain ordinary and customary post-closing adjustments to working capital items, which were completed as expected with no material adjustments in the third quarter of 2005. CCC's results are reflected in discontinued operations for all periods presented (see **Note 21**).

TECO Propane Ventures

In the first quarter of 2004, US Propane, LLC sold a majority of its assets, consisting of direct and indirect equity investments in Heritage Propane Partners, L.P., and the remaining indirect investment was sold in the second quarter of 2004. The sales resulted in cash proceeds of $53 million and after-tax gains totaling $12.0 million.

Hamakua Power Station

On Jul. 15, 2004, TECO Wholesale Generation's 50% indirect interest in the Hamakua Power Station in Hawaii was sold to an affiliate of Black River Energy, an affiliate of Energy Investors Funds' US Power Fund, L.P. Via its ownership of Black River Energy, which already owns 50% of the plant, Energy Investors Funds is now the sole owner of Hamakua. Cash proceeds from the sale were approximately $12 million, and resulted in an immaterial gain. As a result of the transaction, TECO Energy was also relieved of certain financial guarantees related to the facility.

Prior Energy

Effective Feb. 1, 2004, a subsidiary of TECO Energy completed the sale of Prior Energy for net proceeds of approximately $30 million. This sale did not result in a material gain or loss to the company. See the Other transactions section of **Note 21** for additional details relating to this disposition.

BGA

Effective Jan. 1, 2004, the company completed the sale of TECO BGA, Inc. (formerly a component of TECO Energy Services) to an entity owned by an employee group for a loss on disposal of $12.2 million ($7.5 million after tax). This loss was recorded as part of the asset impairment charge reported in the income statement for the year ended Dec. 31, 2003.

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. No significant gain or loss was recognized at the time of the sale. The company, through its various affiliates, provides feedstock supply, and operating, sales and management services to PLS through 2007, the current expiry date for the related synthetic fuel credit for which the production qualifies. Because the transaction was structured on a deferred payment basis typical of similar transactions in the industry, TECO Coal received no significant cash at the time of sale. The sale required receipt of a positive response to a Private Letter Ruling (PLR) request, and the proceeds from this transaction were held in escrow pending resolution of this contingency. On Oct. 31, 2003, TECO Coal received a PLR from the IRS that resolved any uncertainty related to the previous sale of the 49.5% interest in its synthetic fuel facilities; triggered the release of certain cash escrows related to this sale; and confirmed that synthetic fuel produced by TECO Coal is eligible for synthetic fuel credits and that its testing procedures are in compliance with the requirements of the IRS. On Nov. 5, 2003, $8.9 million of $58.9 million restricted cash that had been held in escrow was released following receipt of the PLR. 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 TECO 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 has 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 is 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 subsidiaries will continue to supply the feedstock and operate the facilities.

TECO Coalbed Methane

TECO Coalbed Methane, a subsidiary of TECO Energy, produced natural gas from coal seams in Alabama's Black Warrior Basin. In September 2002, the company announced its intent to sell the TECO Coalbed Methane gas assets. On Dec. 20, 2002, substantially all of TECO Coalbed Methane's assets in Alabama were sold to the Municipal Gas Authority of Georgia. Proceeds from the sale were $140 million, $42 million paid in cash at closing, and a $98 million note receivable which was paid in January 2003. Net income for the year ended Dec. 31, 2003 included a $23.5 million after-tax gain for the final cash installment from the sale of these assets. TECO Coalbed Methane's results are included in discontinued operations for all periods presented (see **Note 21**).

Hardee Power Partners

In 2003, Hardee Power Partners, Ltd. (HPP), which holds a 370-MW gas-fired generation facility located in central Florida, was sold to an affiliate of Invenergy LLC and GTCR Golder Rauner LLC. Under the terms of the sale, subsidiaries of the company would continue to provide service to HPP under the existing operation and maintenance agreement. Under the terms of the agreement, these services ceased in September 2004. Additionally, Tampa Electric's long-term power purchase obligation to receive electricity from HPP remains in effect with no changes as a result of the transaction (see **Note 1**). The sale proceeds of approximately $107 million exceeded the net book value of $51.5 million (including assets of $149.1 million and liabilities of $97.6 million) resulting in a pretax gain of $56.3 million.

Due to the anticipated power purchases by Tampa Electric from HPP under the pre-existing long-term power purchase agreement (see the **Purchased Power** section of **Note 1**) resulting in cash outflows, the results from operations are precluded from being presented as discontinued operations.

17. Goodwill and Other Intangible Assets

FAS 141 *Business Combinations*, requires all business combinations be accounted for using the purchase method of accounting. Under FAS 142 *Goodwill and Other Intangible Assets*, goodwill is not subject to amortization. Rather, goodwill and intangible assets, with an indefinite life, are subject to an annual 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, 2005, 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.

In December 2004, the company recognized an $11.8 million pretax charge ($8.4 million after tax) to write off the value of the remaining goodwill associated with BCH Mechanical. In 2003, the company recorded pretax goodwill impairments of $17.7 million ($10.9 million after tax) and $1.7 million ($1.1 million after tax), respectively, for BCH Mechanical and TECO BGA. These charges are reflected in discontinued operations. See **Note 21** for additional details.

In December 2004, as a result of its annual impairment assessment, the company recognized a pretax impairment charge of $4.8 million ($3.1 million after tax) to write off the value of an intangible asset associated with the acquisition of the Commonwealth Chesapeake power station (see **Note 18** for additional details). In 2003, the company also recognized pretax impairment charges of $6.7 million ($4.1 million after tax) to write-off technology licenses at TWG Merchant. Included in discontinued operations in 2003 is a pretax impairment charge of $1.5 million ($0.8 million after tax) to write off a long-term customer arrangement at BGA. For the years ended Dec. 31, 2004 and 2003, the company recognized amortization expense of $0.2 million and $4.7 million, respectively.

Further, the company recognized a pretax impairment charge in June 2003 of $95.2 million ($61.2 million after tax) to write off all of the goodwill previously recorded at TWG Merchant based on the implied fair value of its goodwill, in accordance with FAS 142. This goodwill arose from the previous acquisitions of the Commonwealth Chesapeake power station in Virginia and the Frontera power station in Texas. These charges are reflected in discontinued operations as a result of the company's sale of its interest in Frontera in December 2004 and CCC in April 2005 (see **Note 16** for additional details).

18. Asset Impairments

Following major investments in merchant power, during 2001 and 2002, conditions in merchant energy markets changed dramatically, reducing prospects for profitability and leading to cessation of new merchant development activities in 2003. During 2003, the company announced that it would re-focus on its regulated utilities and its profitable unregulated businesses, and reduce its exposure to the merchant power sector. This led to the decision in 2003 to exit the Union and Gila River power stations (see **Note 21** for additional details). During 2004, wholesale power prices remained weak and prospects for price recovery for the next several years remained poor. While management monitored these events throughout 2004, there were no specific triggering events prior to the fourth quarter that warranted a SFAS 142 or 144 impairment analysis. In the fourth quarter of 2004, management conducted a review of prospects for long-term price recovery as well as opportunities for sales of the assets. This review led to the sale of the company's investment in the Frontera power station in December 2004 (see **Note 16**). Also as a result of this review, management determined as of Dec. 31, 2004 a lower probability that the remaining merchant investments would be held for the long term, resulting in impairments to the Dell, McAdams, and Commonwealth Chesapeake power stations described below. During 2005, an additional impairment was made to McAdams, also discussed below.

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.

In December 2004, a pretax impairment charge of $609.5 million ($390.7 million after tax) was recognized related to the company's investments in the Dell and McAdams power stations. Under a probability analysis weighted toward short-term recovery, the investments failed the recoverability test of FAS 144. As a result, the assets were written down to fair market value based on a probability weighting of potential sales of the assets and salvage value, which represented the best estimate of fair market value.

In December 2004, the company recognized a pretax impairment charge of $81.3 million ($52.1 million after tax) related to its investment in the Commonwealth Chesapeake power station. Under a probability analysis weighted toward short-term recovery, the investments failed the recoverability test of FAS 144. As a result, the assets were written down to fair market value based on a probability weighting of potential sales of the assets, which represented the best estimate of fair market value. Of the $81.3 million charge, $4.8 million ($3.1 million after tax) was recorded as an impairment of an intangible asset related to the acquisition of the membership interest in the project and is included in "goodwill and intangible asset impairment" on TECO Energy's Consolidated Income Statement.

On Aug. 30, 2004, a TWG Merchant subsidiary completed the sale of its 50% indirect interest in TIE. In the second quarter of 2004 the company recorded a $151.9 million pretax impairment ($98.7 million after tax) to record the estimated write-off of the investment reflecting the anticipated sale. This estimate was finalized resulting in an additional $0.4 million pretax impairment ($0.3 million after tax) being recorded in the third quarter of 2004. See **Note 16** for additional details.

In December 2004, a pretax impairment charge of $8.2 million ($5.9 million after tax) was recognized related to the company's interests in BCH Mechanical. The impairment charge and results of operations are reflected in discontinued operations (see **Note 21**).

In December 2004, as part of its annual impairment review, pretax impairment charges of $21.1 million ($12.8 million after tax) were recognized to write off the remaining value of steam turbines originally planned for use in a cogeneration project. Based on management's review of the market for steam turbines and its refocus on its core businesses, it was determined that the turbines should be written down to fair market value. In December 2003, pretax asset impairment charges of $27.8 million ($17.4 million after tax) were recognized primarily related to the steam turbines and licenses that were also planned for use in a cogeneration project. Although the steam turbine impairment charges were not directly related to TECO Guatemala, they are reflected in the TECO Guatemala segment for accounting purposes, due to the redefining of TECO Energy segment reporting.

In the first quarter of 2004, Litestream Technologies, LLC, an entity in which TECO Fiber, a subsidiary of TECO Solutions, holds an equity investment, was placed into bankruptcy by creditors. As a result of the bankruptcy, the company recognized a pretax loss of $5.5 million ($3.4 million after tax). The loss on the equity investment in Litestream was determined using the estimated fair value of the company's claims to net assets. The charge is reflected in the Eliminations and Other segment.

Additional impairment charges recognized in 2004 included a $2.4 million pretax ($1.5 million after tax) valuation adjustment at TECO Solutions related to a district cooling plant, which is reflected in discontinued operations, and a pretax impairment of $0.9 million ($0.6 million after tax) on ocean-going barges at TECO Transport.

As of Dec. 31, 2003, based on the negotiations with potential buyers, including the project lenders, a change in management's expectations regarding an exit strategy in the near term and management's designation of the Union and Gila River project companies as held for sale, a pretax asset impairment charge of $1,185.7 million ($770.7 million after tax) was recognized and reflected in discontinued operations, in accordance with FAS 144 (see **Note 21** for additional details).

In 2003, TECO Energy recognized a pretax asset impairment charge of $104.1 million ($64.2 million after tax) relating to installment payments made and capitalized under turbine purchase commitments in prior periods. Certain turbine rights had been transferred from TPGC II to Tampa Electric in 2002 for use in Tampa Electric's generation expansion activities (see **Note 13**). These cancellations, made in April 2003, fully terminate all turbine purchase obligations for these entities.

19. Restructuring Costs

In 2004, as part of the company's continued focus to exit merchant operations and to grow the core utility operations to provide for centralized oversight along functional lines, certain restructuring activities were implemented. These actions involved seven employees, including officers and other personnel from operations and support services. In 2003, TECO Energy announced a corporate reorganization to restructure the company along functional lines, consistent with its objectives to grow the core utility operations, maintain liquidity, generate cash and maximize the value in the existing assets. The 2003 actions included the involuntary termination or retirement of 337 employees, including officers and other personnel from operations and support services. The total costs associated with this program included severance, salary continuation and other termination and retirement benefits.

The company recognized a pretax expense of $1.2 million and $24.6 million for accrued benefits and other termination and retirement benefits for the years ended Dec. 31, 2004 and 2003, respectively. There were no restructuring costs recognized for the year ended Dec. 31, 2005.

Restructuring Charges

(millions) *For the years ended Dec. 31,*	*2004*	*2003*
Tampa Electric	$ –	$ 9.9
Peoples Gas	0.7	4.1
TWG Merchant	0.5	0.4
TECO Transport	–	1.7
TECO Guatemala	–	4.6
Eliminations and other (1)	–	3.9
Total TECO Energy	$ 1.2	$ 24.6

(1) This amount primarily relates to charges at TECO Energy parent.

Accrued Liability for Restructuring Costs

(millions)	*2005*	*2004*	*2003*
Beginning balance	$ 0.5	$ 15.8	$ 6.0
Charged to income (pretax)	–	1.2	24.6
Payments and settlements	0.5	16.5	14.8
Ending balance	$ –	$ 0.5	$ 15.8

20. TPGC Joint Venture Termination

In January 2002, TWG Merchant subsidiaries agreed to purchase the interests of Panda Energy in the TPGC projects in 2007 for $60 million, and TECO Energy guaranteed payment of this obligation. Panda Energy obtained bank financing using the purchase obligation and assigned TECO Energy's guarantee as collateral. Under certain circumstances, the purchase obligation could have been accelerated for a reduced price based on the timing of the acceleration. In connection with this purchase obligation, Panda Energy retained a cancellation right, exercisable in 2007 for $20 million by the holder, with early exercise permitted for a reduced price ranging from $16 million to $8 million, depending on the cancellation date.

On Apr. 9, 2003, the TWG subsidiaries and Panda Energy amended the agreements related to the purchase obligation. The modified terms accelerated the purchase obligation to occur on or before Jul. 1, 2003, and added the Panda Energy interests in PLC for an overall purchase obligation to $58 million. The purchase obligation of $58 million included $35 million for Panda Energy's interest in TPGC, and a short-term receivable from Panda, collateralized by Panda's remaining interests in PLC (see **Note 13** for additional details on TECO Energy's indirect ownership interest in PLC). Both modifications to the purchase obligation were subject to the condition, which TECO Energy could waive, that bank financing be obtained by TECO Energy. Panda Energy's cancellation right was accelerated to expire on Jun. 16, 2003. TECO Energy's guarantee of the TWG subsidiaries' obligation was modified to reflect the amendments to the purchase obligation. In April 2003, TECO Energy recognized the fair value of the guarantee as a pretax loss of $35.0 million ($21.4 million after tax), included in discontinued operations, as a result of the expected disposition of the project companies (see **Note 21**). From April 2003 through June 2003, TECO Energy made and accrued certain principal payments under the guarantee commitment.

As a result of the amendments to these agreements in early April 2003, management believed the exercise of the modified guarantee and the related purchase obligation became highly probable. The likelihood of the exercise of the purchase obligation created a presumption of effective control. When combined with TECO Energy's exposure to the majority of risk of loss under the previously disclosed letters of credit and contractor undertakings, management believed that consolidation of TPGC was appropriate as of the date of the modifications to the agreements. Prior to Apr. 1, 2003, TWG recognized assets of $839.1 million, liabilities of $48.9 million and an unrealized loss in OCI of $69.0 million, to reflect the equity method of accounting for its investment in TPGC. As a result of the consolidation on Apr. 1, 2003, the company recognized additional assets of $2,446.9 million, primarily relating to utility plant and construction work in progress, additional liabilities of $1,976.8 million (including non-recourse debt), and an additional unrealized loss in OCI of $69.0 million for interest rate swaps designated as hedges. For the year ended Dec. 31, 2003, TWG recorded total pretax charges of $249.1 million ($155.9 million after tax) as a direct result of the consolidation of TPGC. See **Note 21** for a discussion of the subsequent designation of the TPGC projects as assets and liabilities held for sale.

In June 2003, TECO Energy satisfied the bank financing condition resulting in the acceleration of TECO Energy's guaranteed purchase obligation and executed a final agreement with Panda to effect the termination of Panda's involvement in the partnership. Proceeds from the bank financing obtained in June 2003 were used to fund the net termination payment to Panda. Upon acceleration of the guaranteed purchase obligation and the resulting partnership termination, TWG received the 50% outstanding partnership interests in TPGC. As previously discussed, under the amended agreements, $35.0 million, pretax, had been recognized in April 2003 as the fair value of the guaranteed purchase obligation. The remaining amount was recorded as due from Panda and collateralized by Panda's remaining interests in PLC. Foreclosure proceedings were consummated on Panda's remaining interests in PLC in September 2003. As of Dec. 31, 2004, substantially all of the assets and liabilities associated with the TPGC projects (Union and Gila River) were classified as held for sale. All results of operations for these two projects have been reclassified to discontinued operations for all periods presented.

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 release of liability and $1.8 million as reimbursement of legal fees for two non-consenting lenders in the Chapter 11 proceeding.

21. Discontinued Operations and Assets Held for Sale

Union and Gila River Project Companies (TPGC)

On Jun. 1, 2005, the company completed the sale and transfer of the Projects (see **Note 16**). 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. As of December 2003, the date the company decided to exit the Projects, an impairment charge was recorded to reduce the property, plant and equipment associated with the Projects to fair value. Subsequent to the impairment charge, and 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, as of Dec. 31, 2004, were reclassified in 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,*	*2005*	*2004*	*2003*
Revenues	$ 109.1	$ 510.7	$ 319.4
Asset impairment [(1)]	$ –	$ –	$ (1,185.7)
Loss from operations	$ (23.0)	$ (33.5)	$ (1,239.8)
Loss on joint venture termination	$ –	$ –	$ (153.9)
Gain on sale before tax	$ 117.7	$ –	$ –
Income (loss) before provision for income taxes	$ 90.0	$ (144.9)	$ (1,441.4)
Provision (benefit) for income taxes	24.9	(48.9)	(522.7)
Net income (loss) from discontinued operations	$ 65.1	$ (96.0)	$ (918.7)

(1) Includes charges recognized in accordance with FAS 133.

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.

Asset impairment charges

The pretax asset impairment charge of $1,185.7 million ($762.0 million after tax) recorded in 2003 is comprised of an impairment in long-lived assets and a related charge to reflect the impacts of hedge accounting. The asset impairment charge was recognized in accordance with FAS 144. The recognition of the asset impairment effectively accelerated the recognition of previously capitalized interest. As a result, in accordance with cash flow hedge accounting under FAS 133, a reversal from OCI of $22.6 million of pretax losses on the interest rate swaps was required to give effect in the income statement to the previously hedged interest which was capitalized during construction.

In addition, as of Dec. 31, 2003 the change in future expectations regarding the probability of the company retaining the long-term, non-recourse debt resulted in the reversal of an additional $63.8 million pretax losses which were previously deferred in OCI and related to the future recognition of capitalized interest amortization and future interest expense on the non-recourse debt, anticipated to be recognized in periods subsequent to 2004.

Loss on joint venture termination

As discussed in greater detail in **Note 20**, the consolidation of TPGC on Apr. 1, 2003 resulted in the recognition of a pretax charge of $153.9 million ($94.7 million after tax) which was recorded in discontinued operations. This pretax charge included: $35.0 million ($21.4 million after tax) related to the partnership termination under the guarantee; and $118.9 million ($73.3 million after tax) related to the consolidation of TPGC to reflect the impact of Panda Energy's portion of TPGC's partnership deficit and the elimination of certain related-party liabilities (see **Note 13**).

The following table provides a summary of the carrying amounts of the significant assets and liabilities reported in the combined current and non-current "Assets held for sale" and "Liabilities associated with assets held for sale" line items:

Assets held for sale – Union and Gila River Project Companies

(millions) Dec. 31,	*2004*
Current assets	$ 128.8
Net property, plant and equipment	1,369.0
Other investments	658.5
Other non-current assets	22.4
Total assets held for sale	$ 2,178.7

Liabilities associated with assets held for sale – Union and Gila River Project Companies

(millions) Dec. 31,	*2004*
Current portion of long-term debt, non-recourse – Secured Facility Note	$ 1,395.0
Other current liabilities	233.8
Long-term debt, non-recourse Financing Facility Note	658.5
Other non-current liabilities	13.7
Total liabilities associated with assets held for sale	$ 2,301.0

Current and non-current assets

Current assets included $47.9 million of restricted cash as of Dec. 31, 2004. Also included in current assets was $17.6 million, as of Dec. 31, 2004, representing the current portion of the investment in Union County bonds, described in Other investments below.

Net property, plant and equipment

Net property, plant and equipment has been reduced by accumulated depreciation of $49.4 million and a valuation adjustment of $1,099.3 million as of Dec. 31, 2004. In accordance with FAS 144, no depreciation was recognized on TPGC's assets in 2005 or 2004 as a result of being classified as held for sale. Had TPGC's assets not been classified as held for sale, depreciation expense of $31.3 million and $84.7 million would have been recognized in 2005 and 2004, respectively. This impairment charge arose as a result of changes in management's expectations, including its long-term strategic outlook, and is more fully described in **Note 18.** The decline of the fair value of the disposal group (comprised of the assets and liabilities expected to be transferred upon disposition) below the carrying value is principally attributable to the decline in future wholesale power price expectations as a result of the repercussions of the failure of deregulation in California and the Enron bankruptcy; less than economic dispatch in some areas of the country; the U.S. economic slowdown; uncertainty with respect to long-term price recovery; and the significant excess generating capacity in many areas of the country. The primary triggering event for the recognition of the charge by the company was the significant change in management's expectations regarding the company's long-term future involvement in the Union and Gila River project companies and the decision, during the fourth quarter of 2003, to sell the project companies.

Other investments

Other investments represent industrial revenue bonds from Union County, Arkansas, which were acquired by Union Power Partners, L.P. (UPP), a subsidiary of TPGC, with financing obtained by borrowings from Union County (the County). As of Dec. 31, 2004, UPP's investment in the bonds from the County (excluding the current position) totaled $658.5 million, which equals the non-recourse financing facility from the County. The County's debt service payments on the bonds equal UPP's debt service obligations to the County. This agreement provides an incentive to and a means through which the company can invest in the County.

Interest income on the investment and interest expense on the related long-term, non-recourse financing had no net impact on the company's results of discontinued operations. The obligation to pay cash under the long-term debt was fully offset by the right to receive cash from the bond issuer. The interest rate and maturity date on both the bonds and the related long-term debt was 7.5% per year and June 2021.

Current and non-current liabilities

Included in current liabilities is the current portion of the financing facility due to the County, described in Other investments above, of $17.6 million as of Dec. 31, 2004. Also included is $68.1 million as of Dec. 31, 2004, for interest rate swaps entered into by the Union and Gila River projects in connection with the non-recourse collateralized borrowings.

The purpose of the interest rate swap agreement was to effectively convert a portion of the floating-rate debt to a fixed rate. The interest rate swap agreements had terms ranging from 2 to 5 years with the majority maturing in June 2006. As more fully described in **Note 22,** the designation of the secured facility note as a liability associated with assets held for sale resulted in the prospective loss of hedge accounting for the periods beyond the expected effective date of the sale.

Non-recourse, secured facility note

In 2001, the Union and Gila River project companies obtained construction financing of $1,395.0 million in the form of floating rate, non-recourse senior secured credit facilities from a bank group. The Union and Gila River project companies each jointly and severally guaranteed and cross-collateralized the loans and debts of the other. The loans were non-recourse to TECO Energy, TWG and its subsidiaries that owned the project entities.

Credit Facilities

The Union and Gila River project companies, as part of the non-recourse project financing, had credit facilities for commercial letters of credit to facilitate gas purchases and power sales. These facilities were recourse only to the project companies, and not to TECO Energy or its other subsidiaries. At Dec. 31, 2004, the credit facilities totaled $265.0 million, and aggregate letters of credit outstanding under the facilities totaled $181.4 million. The project companies also had an $80 million debt reserve facility, which was cancelled in 2004. The Union and Gila River project companies' non-recourse credit facilities had maturity dates of June 2006.

Other transactions

Components of income from discontinued operations include CCC (sold in 2005), BCH Mechanical (sold in 2005), Frontera (sold in 2004), Prior Energy (sold in 2004), TECO BGA (sold in 2004), TECO AGC (sold in 2004) and TECO Coalbed Methane (sold in 2002). See **Note 16** for additional details related to these sales. Results for 2004 include a $2.4 million pretax ($1.5 million after-tax) asset impairment charge at TECO Solutions related to a district cooling plant.

At Dec. 31, 2005, assets and liabilities held for sale includes TECO Thermal, an investment of TECO Solutions. 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 (TPGC) transaction:

Components of income from discontinued operations – Other

(millions) *For the years ended Dec. 31,*	*2005*	*2004*	*2003*
Revenues	$ 10.6	$ 141.7	$ 198.5
Loss from operations	$ (0.3)	$ (110.1)	$ (132.0)
(Loss) gain on sale	$ (2.1)	$ (43.4)	$ 39.7
Loss before provision for income taxes [1]	$ (1.8)	$ (149.1)	$(135.9)
Benefit for income taxes	(0.2)	(48.6)	(48.8)
Net loss from discontinued operations [1]	$ (1.6)	$ (100.5)	$ (87.1)

(1) Results for BCH, TECO Thermal, TECO BGA and Prior Energy include internal financing costs, allocated prior to discontinued operations designation. Internally allocated costs for 2004 and 2003 were at a pretax rate of 8%, based on the average investment in each subsidiary. There was no internally allocated financing costs to discontinued operations in 2005.

Revenues

Discontinued operations include revenues for energy marketing operations at Prior Energy and TECO Gas Services (for 2003 only), which 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, 2005, 2004 and 2003 were ($0.1) million, $128.0 million and $853.4 million, respectively.

(Loss) Gain on sale

As a result of the sale of Frontera in December 2004, the company recognized a pretax loss of $42.1 million ($27.0 million after tax). The sales of Prior Energy and TECO AGC, Ltd. in 2004 did not result in a material gain or loss to the company.

As a result of the sale of TECO Coalbed Methane in December 2002, the company recognized a pretax gain of $39.7 million for the year ended Dec. 31, 2003.

Assets and Liabilities

The following table provides a summary of the carrying amounts of the significant assets and liabilities reported in the combined current and non-current "Assets held for sale" and "Liabilities associated with assets held for sale" line items for all other transactions described above:

Assets held for sale

(millions) Dec. 31,	*2005*	*2004*
Net property, plant and equipment	$ 6.4	$ 7.7
Other non-current assets	1.6	1.5
Total assets held for sale	$ 8.0	$ 9.2

Liabilities associated with assets held for sale

(millions) Dec. 31,	*2005*	*2004*
Current liabilities	$ 1.8	$ 3.0
Total liabilities associated with assets held for sale	$ 1.8	$ 3.0

22. 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 electricity, natural gas and fuel oil price fluctuations related to the operations of natural gas-fired and fuel oil-fired power plants at TWG Merchant, prior to the transfer of the Union & Gila power plants in June 2005;
- To limit the exposure to price fluctuations for physical purchases of fuel at TECO Transport; 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 FAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by FAS 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activity* and FAS 149, *Amendment on Statement 133 on Derivative Instruments and Hedging Activities*. These standards require companies to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as either components of 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 the loss on the related hedging instrument must be reclassified from OCI to earnings based on its value at the time of its reclassification. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the amount paid or received on the underlying physical transaction.

At Dec. 31, 2005 and 2004, respectively, TECO Energy and its affiliates had derivative assets (current and non-current) totaling $68.9 million and $3.8 million, and liabilities (current and non-current) totaling $0.3 million and $12.0 million. At Dec. 31, 2005 and 2004, accumulated other comprehensive income (AOCI) included $0.4 million and $0.5 million, respectively, of unrealized after-tax gains, representing the fair value of cash flow hedges whose transactions will occur in the future. Included in AOCI at Dec. 31, 2003 was an unrealized after-tax loss of $14.6 million on interest rate swaps designated as cash flow hedges, reflecting the remaining amount included in AOCI related to cash flow hedges for the period preceding the disposition of TPGC (see **Note 21**). Amounts recorded in AOCI reflect the estimated fair value of derivative instruments designated as hedges, based on market prices as of the balance sheet date. 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.

For the years ended Dec. 31, 2005, 2004 and 2003, TECO Energy and its affiliates reclassified amounts from OCI (excluding certain reclassifications for interest rate swaps described below) and recognized net pretax gains (losses) of $5.7 million, $1.2 million and ($12.6) million, respectively. Amounts reclassified from OCI were primarily related to cash flow hedges of physical purchases of natural gas, fuel oil and physical sales of electricity. For these types of hedge relationships, the loss on the derivative, reclassified from OCI to earnings, is offset by the reduced expense arising from lower prices paid or received for spot purchases of natural gas or decreased revenue from sales of electricity. Conversely, reclassification of a gain from OCI to earnings is offset by the increased cost of spot purchases of natural gas or sales of electricity.

As a result of 1) the suspension of construction on the Dell and McAdams power plants at TWG in 2003 and 2) the maintenance activity on the Frontera Power Station at TWG in early 2003, the company discontinued hedge accounting for purchases of natural gas and sales of electricity which were no longer anticipated to take place within two months of the originally designated time period for delivery. The discontinuation of hedge accounting resulted in a reclassification of a pretax gain of $0.2 million from OCI to earnings, reflecting the fair value of the related derivatives as of the discontinuation date. In addition, as a result of the designation of TPGC as an asset held for sale in 2003, the company concluded that the hedged interest expense for periods beyond the expected disposition date were no longer probable. As a result, the company reclassified pretax losses of $24.0 million ($15.6 million after tax) and $63.8 million ($41.5 million after tax) from OCI to income from discontinued operations in 2004 and 2003, respectively (see **Note 21**). Gains and losses on these derivative instruments, subsequent to the discontinuation of hedge accounting treatment, were recorded in earnings.

Based on the fair value of cash flow hedges at Dec. 31, 2005, pretax gains of $0.2 million are expected to be reversed from OCI to the Consolidated Statements of Income within the next twelve months. However, these losses and other future reclassifications from OCI will fluctuate with movements in the underlying market price of the derivative instruments. The company does not currently have any cash flow hedges for transactions forecasted to take place in periods subsequent to 2007.

During the year ended Dec. 31, 2003, Prior Energy, a subsidiary of TECO Energy, recognized pretax losses of $1.3 million for transactions that were in place to hedge gas storage inventory that qualified for fair value hedge accounting treatment under FAS 133. These gains and losses are included in discontinued operations as a result of the sale of Prior Energy (see **Notes 16** and **21**).

At Dec. 31, 2005, TECO Energy subsidiaries had derivative assets totaling $5.6 million for transactions that were not designated as either a cash flow or fair value hedge. These derivatives are marked-to-market with fair value gains and losses recognized through earnings. For the years ended Dec. 31, 2005, 2004 and 2003, the company recognized gains (losses) on marked-to-market derivatives of $0.5 million, $0.8 million and ($6.5) million, respectively.

23. Subsequent Events

Issuance of Series 2006 Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project)

On Jan. 19, 2006, the Hillsborough County Industrial Development Authority (HCIDA) issued $85.95 million of HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2006 (Series 2006 Bonds) for the benefit of Tampa Electric. Tampa Electric is responsible for payment of the interest and principal associated with the Series 2006 Bonds. The proceeds of this issuance, together with available cash, were used to call and retire in February 2006 $85.95 million of the existing HCIDA Pollution Control Revenue Bonds Series 1994 (the Series 1994 Bonds), which had a maturity date of Dec. 1, 2034. Costs of the issuance were paid from available funds of Tampa Electric. Tampa Electric entered into a Loan and Trust Agreement with the HCIDA, as issuer, and The Bank of New York, as trustee, in connection with the issuance of the Series 2006 Bonds.

The Series 2006 Bonds mature on Dec. 1, 2034 and bear interest at an auction rate, which was initially set at 2.80% and will be reset pursuant to an auction procedure at the end of every auction period, which was initially set at seven days. In connection with the issuance of the Series 2006 Bonds, Tampa Electric entered into an insurance agreement with Ambac Assurance Corporation pursuant to which Ambac Assurance Corporation issued a financial guaranty insurance policy, providing insurance for Tampa Electric's obligation for payment on the Series 2006 Bonds and allowing the Series 2006 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's ability to incur certain liens, subject to a number of exceptions, without equally and ratably securing these notes.

During any auction period Tampa Electric may redeem all or any part of the Series 2006 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 2006 Bonds to be redeemed, plus 100% of the principal amount of the Series 2006 Bonds to be redeemed. The Series 2006 Bonds are also subject to special mandatory redemption in the event that interest payable on any Series 2006 Bonds has become subject to federal income tax in accordance with the Loan and Trust Agreement.

Redemption of Series 1994 Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project)

On Feb. 24, 2006, pursuant to the terms of the indenture governing $85.95 million of Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 1994 and at Tampa Electric's and the HCIDA's direction, the trustee redeemed the Series 1994 Bonds. The redemption price was equal to 101% of par plus accumulated but unpaid distributions to Feb. 24, 2006.

Extension of Maturity of Tampa Electric's Accounts Receivable Securitized Borrowing Facility

On Jan. 5, 2006, Tampa Electric and TEC Receivables Corp (TRC), a wholly-owned subsidiary of Tampa Electric, extended the maturity of Tampa Electric's $150 million accounts receivable securitized borrowing facility from Jan. 5, 2006 to Jan. 4, 2007. See Note 6 for a more detailed description of the facility.

24. Quarterly Data (unaudited)

Financial data by quarter is as follows:

(millions, except per share amounts) *Quarter ended*	*Dec. 31*	*Sep. 30*	*Jun. 30*(5)	*Mar. 31*
2005				
Revenues	$ 770.0	$ 836.4	$ 719.0	$ 684.7
Income from operations	$ 83.5	$ 100.6	$ 92.7	$ 79.9
Net income				
Net income from continuing operations (3)	$ 52.6	$ 94.5	$ 12.4	$ 51.5
Net income (3)	$ 52.0	$ 94.6	$ 95.2	$ 32.7
Earnings per share (EPS) — basic				
EPS from continuing operations	$ 0.25	$ 0.46	$ 0.06	$ 0.25
EPS	$ 0.25	$ 0.46	$ 0.46	$ 0.16
Earnings per share (EPS) — diluted				
EPS from continuing operations	$ 0.24	$ 0.45	$ 0.04	$ 0.25
EPS	$ 0.24	$ 0.45	$ 0.44	$ 0.16
Dividends paid per common share	$ 0.19	$ 0.19	$ 0.19	$ 0.19
Stock price per common share (2)				
High	$ 18.25	$ 19.30	$ 19.05	$ 16.50
Low	$ 15.72	$ 17.15	$ 15.30	$ 14.87
Close	$ 17.18	$ 18.00	$ 18.91	$ 15.68

Quarter ended	*Dec. 31*(1)	*Sep. 30*(1)	*Jun. 30*(1)	*Mar. 31*(1)
2004				
Revenues	$ 656.4	$ 698.1	$ 668.9	$ 616.0
(Loss) income from operations	$ (590.2)	$ 76.4	$ 81.7	$ 51.8
Net (loss) income				
Net (loss) income from continuing operations (4)	$ (351.1)	$ 45.8	$ (81.9)	$ 31.7
Net (loss) income (4)	$ (487.6)	$ 41.3	$ (108.2)	$ 2.5
Earnings per share (EPS) — basic				
EPS from continuing operations	$ (1.76)	$ 0.23	$ (0.43)	$ 0.17
EPS	$ (2.44)	$ 0.21	$ (0.57)	$ 0.01
Earnings per share (EPS) — diluted				
EPS from continuing operations	$ (1.76)	$ 0.23	$ (0.43)	$ 0.17
EPS	$ (2.44)	$ 0.21	$ (0.57)	$ 0.01
Dividends paid per common share	$ 0.19	$ 0.19	$ 0.19	$ 0.19
Stock price per common share (2)				
High	$ 15.49	$ 13.57	$ 14.60	$ 15.38
Low	$ 13.40	$ 11.87	$ 11.30	$ 13.86
Close	$ 15.35	$ 13.53	$ 11.99	$ 14.63

(1) Amounts shown include reclassifications to reflect discontinued operations as discussed in **Note 21.**
(2) Trading prices for common shares.
(3) Fourth quarter results include an impairment charge as described in **Note 18.**
(4) Second and fourth quarter results include impairment charges as described in **Note 17** and **Note 18.**
(5) Second quarter results include a debt extinguishment charge.

TAMPA ELECTRIC COMPANY
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

REPORT OF INDEPENDENT REGISTERED CERTIFIED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Tampa Electric Company:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Tampa Electric Company and its subsidiaries at Dec. 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended Dec. 31, 2005 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a) (2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Tampa, Florida
February 22, 2006

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TAMPA ELECTRIC COMPANY
Consolidated Balance Sheets

Assets (*millions*) *Dec. 31,*	*2005*	*2004*
Property, plant and equipment		
Utility plant in service		
Electric	$ 4,889.0	$ 4,776.2
Gas	839.6	810.8
Construction work in progress	164.0	129.8
Property, plant and equipment, at original costs	5,892.6	5,716.8
Accumulated depreciation	(1,658.7)	(1,563.4)
	4,233.9	4,153.4
Other property	7.4	3.6
Total property, plant and equipment	4,241.3	4,157.0
Current assets		
Cash and cash equivalents	17.4	1.3
Receivables, less allowance for uncollectibles of $1.3 million and $1.0 million at Dec. 31, 2005 and 2004, respectively	232.5	197.6
Inventories		
Fuel, at average cost	68.3	34.6
Materials and supplies	45.5	47.2
Current regulatory assets	296.3	63.9
Current derivative assets	58.2	—
Current deferred income taxes	—	3.3
Taxes receivable	35.1	33.4
Prepayments and other current assets	7.9	10.9
Total current assets	761.2	392.2
Deferred debits		
Non-current deferred income taxes	—	—
Unamortized debt expense	17.4	19.9
Long-term regulatory assets	101.1	137.1
Long-term derivative assets	4.9	—
Other	30.3	19.7
Total deferred debits	153.7	176.7
Total assets	$5,156.2	$ 4,725.9

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

TAMPA ELECTRIC COMPANY
Consolidated Balance Sheets (continued)

Liabilities and capital *(millions) Dec. 31,*	*2005*	*2004*
Commitments and Contingencies (see Note 9)		
Capital		
Common stock	$ 1,376.8	$ 1,376.8
Retained earnings	288.7	285.4
Total capital	1,665.5	1,662.2
Long-term debt, less amount due within one year	1,508.5	1,513.9
Total capitalization	3,174.0	3,176.1
Current liabilities		
Long-term debt due within one year	5.9	5.5
Notes payable	215.0	115.0
Accounts payable	231.2	161.1
Customer deposits	115.2	105.8
Current regulatory liabilities	146.8	22.5
Current derivative liabilities	0.3	11.2
Interest accrued	25.5	25.2
Current deferred income taxes	116.8	—
Taxes accrued	15.2	13.5
Total current liabilities	871.9	459.8
Deferred credits		
Non-current deferred income taxes	372.9	392.8
Investment tax credits	17.1	19.8
Long-term regulatory liabilities	543.1	516.5
Long-term derivative liability	—	0.5
Other	177.2	160.4
Total deferred credits	1,110.3	1,090.0
Total liabilities and capital	$ 5,156.2	$ 4,725.9

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

TAMPA ELECTRIC COMPANY
Consolidated Statements Of Income

(millions) *For the years ended Dec. 31,*	*2005*	*2004*	*2003*
Revenues			
Electric (includes franchise fees and gross receipts taxes of $70.6 million in 2005, $69.6 million in 2004, and $64.4 million in 2003)	$ 1,746.2	$ 1,686.7	$ 1,585.4
Gas (includes franchise fees and gross receipts taxes of $16.6 million in 2005, $14.2 million in 2004, and $13.3 million in 2003)	549.5	417.2	408.4
Total revenues	2,295.7	2,103.9	1,993.8
Expenses			
Operations			
Fuel	546.8	613.0	443.3
Purchased power	269.7	172.3	234.9
Cost of natural gas sold	350.2	226.2	224.0
Other	269.7	257.5	257.7
Maintenance	91.8	90.5	94.3
Depreciation	222.1	214.9	243.0
Restructuring charges	—	0.7	14.0
Taxes, federal and state income	107.8	100.3	94.0
Taxes, other than income	153.8	146.0	136.7
Total expenses	2,011.9	1,821.4	1,741.9
Income from operations	283.8	282.5	251.9
Other (expense) income			
Allowance for other funds used during construction	—	0.7	19.8
Other income, net	6.3	1.5	1.2
Asset impairment (net of income tax benefit of $30.7 million)	—	—	(48.9)
Total other (expense) income	6.3	2.2	(27.9)
Interest charges			
Interest on long-term debt	98.3	100.7	102.7
Other interest	15.1	10.6	5.5
Allowance for borrowed funds used during construction	—	(0.3)	(7.6)
Total interest charges	113.4	111.0	100.6
Net income	$ 176.7	$ 173.7	$ 123.4

Consolidated Statements Of Comprehensive Income

(millions) *For the years ended Dec. 31,*	*2005*	*2004*	*2003*
Net income	$ 176.7	$ 173.7	$ 123.4
Other comprehensive (loss) income, net of tax			
Net unrealized gain (loss) on cash flow hedges	—	—	—
Other comprehensive income (loss), net of tax	—	—	—
Comprehensive income	$ 176.7	$ 173.7	$ 123.4

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

TAMPA ELECTRIC COMPANY
Consolidated Statements Of Cash Flows

(millions) *For the years ended Dec. 31,*	*2005*	*2004*	*2003*
Cash flows from operating activities			
Net income	$ 176.7	$ 173.7	$ 123.4
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation	222.1	214.9	243.0
Deferred income taxes	72.2	54.9	(23.9)
Investment tax credits, net	(2.6)	(2.7)	(4.6)
Allowance for funds used during construction	—	(1.0)	(27.4)
Loss on sales of assets, pretax	—	—	0.8
Asset impairment, pretax	—	—	79.6
Deferred recovery clause	(154.3)	25.2	(27.3)
Receivables, less allowance for uncollectibles	(32.4)	(11.6)	0.5
Inventories	(32.0)	33.3	12.2
Prepayments and other deposits	3.0	(5.3)	0.1
Taxes accrued	0.1	(102.8)	36.0
Interest accrued	0.3	(1.5)	8.4
Accounts payable	67.5	(6.8)	(10.8)
Other regulatory assets and liabilities	1.6	(68.0)	4.0
Other	13.5	12.0	63.2
Cash flows from operating activities	335.7	314.3	477.2
Cash flows from investing activities			
Capital expenditures	(246.0)	(219.9)	(331.7)
Allowance for funds used during construction	—	1.0	27.4
Net proceeds from sales of assets	5.3	0.8	4.3
Cash flows from investing activities	(240.7)	(218.1)	(300.0)
Cash flows from financing activities			
Return of contributed capital to parent	—	—	(158.3)
Proceeds from long-term debt	—	—	250.0
Repayment of long-term debt	(5.5)	(80.3)	(80.3)
Net (decrease) increase in short-term debt	100.0	115.0	(10.5)
Payment of dividends	(173.4)	(163.2)	(151.4)
Cash flows from financing activities	(78.9)	(128.5)	(150.5)
Net (decrease) increase in cash and cash equivalents	16.1	(32.3)	26.7
Cash and cash equivalents at beginning of year	1.3	33.6	6.9
Cash and cash equivalents at end of year	$ 17.4	$ 1.3	$ 33.6
Supplemental disclosure of cash flow information			
Cash paid during the year for:			
Interest	$ 100.7	$ 103.9	$ 109.4
Income taxes	$ 30.3	$ 103.9	$ 61.9

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

TAMPA ELECTRIC COMPANY
Consolidated Statements Of Retained Earnings

(millions) *For the years ended Dec. 31,*	*2005*	*2004*	*2003*
Balance, beginning of year	$ 285.4	$ 274.9	$ 302.9
Add: Net income	176.7	173.7	123.4
	462.1	448.6	426.3
Deduct: Cash dividends on capital stock			
Common	173.4	163.2	151.4
	173.4	163.2	151.4
Balance, end of year	$ 288.7	$ 285.4	$ 274.9

Consolidated Statements Of Capitalization

		Capital Stock Outstanding Dec. 31,		*Cash dividends paid* [1]	
(millions, except share amounts)	*Current Redemption Price*	*Shares*	*Amount*	*Per Share*	*Amount*
Common stock — without par value					
25 million shares authorized					
2005	N/A	10	$ 1,376.8	[2]	$ 173.4
2004	N/A	10	$ 1,376.8	[2]	$ 163.2
Preferred stock — $100 par value					
1.5 million shares authorized, none outstanding.					
Preferred stock – no par					
2.5 million shares authorized, none outstanding.					
Preference stock – no par					
2.5 million shares authorized, none outstanding.					

(1) Quarterly dividends paid on Feb. 15, May 15, Aug. 15 and Nov. 15.
(2) Not meaningful

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

TAMPA ELECTRIC COMPANY
Consolidated Statements Of Capitalization (continued)

Long-Term Debt (millions) Dec. 31,	*Due*	*2005*	*2004*
Tampa Electric			
Installment contracts payable [1]:			
6.25% Refunding bonds (effective rate of 6.81%) [2][5][7]	2034	$ 86.0	$ 86.0
5.85% Refunding bonds (effective rate of 5.88%)[8]	2030	75.0	75.0
5.1% Refunding bonds (effective rate of 5.75%) [3]	2013	60.7	60.7
5.5% Refunding bonds (effective rate of 6.32%) [3]	2023	86.4	86.4
4% (effective rate of 4.19%) [4][8]	2025	51.6	51.6
4% (effective rate of 4.16%) [4][8]	2018	54.2	54.2
4.25% (effective rate of 4.44%) [4][8]	2020	20.0	20.0
Notes: 6.875% (effective rate of 6.98%) [5]	2012	210.0	210.0
6.375% (effective rate of 7.35%) [5]	2012	330.0	330.0
5.375% (effective rate of 5.59%) [5]	2007	125.0	125.0
6.25% (effective rate of 6.31%) [5][6]	2014 – 2016	250.0	250.0
		1,348.9	1,348.9
Peoples Gas System			
Senior Notes: [5][6] 10.35%	2006 – 2007	1.8	2.6
10.33%	2006 – 2008	3.0	4.0
10.3%	2006 – 2009	4.8	5.6
9.93%	2006 – 2010	5.0	5.8
8.0%	2006 – 2012	19.1	21.2
Notes: 6.875% (effective rate of 6.98%) [5]	2012	40.0	40.0
6.375% (effective rate of 7.35%) [5]	2012	70.0	70.0
5.375% (effective rate of 5.59%) [5]	2007	25.0	25.0
		168.7	174.2
		1,517.6	1,523.1
Unamortized debt premium (discount), net		(3.2)	(3.7)
		1,514.4	1,519.4
Less amount due within one year		5.9	5.5
Total long-term debt		$ 1,508.5	$ 1,513.9

(1) Tax-exempt securities.
(2) Proceeds of these bonds were used to refund bonds with an interest rate of 9.9% in February 1995. For accounting purposes, interest expense has been recorded using a blended rate of 6.52% on the original and refunding bonds, consistent with regulatory treatment.
(3) Proceeds on these bonds were used to refund bonds with interest rates of 5.75% to 8%.
(4) The interest rate on these bonds was fixed for a five-year term on Aug. 5, 2002.
(5) These securities are subject to redemption in whole or in part, at any time, at the option of the company.
(6) This long-term debt agreement contains various restrictive covenants
(7) See **Note 16** for a subsequent event regarding these bonds.
(8) Certain pollution control equipment is pledged to secure these bonds.

At Dec. 31, 2005, total long-term debt, excluding amounts currently due, had a carrying amount of $1,508.5 million and an estimated fair market value of $1,575.8 million. The estimated fair market value of long-term debt was based on quoted market prices for the same or similar issues, on the current rates offered for debt of the same remaining maturities, or for long-term debt issues with variable rates that approximate market rates, at carrying amounts. The carrying amount of long-term debt due within one year approximated fair market value because of the short maturity of these instruments.

A substantial part of the tangible assets of Tampa Electric is pledged as collateral to secure first mortgage bonds issued under Tampa Electric's first mortgage bond indentures, and certain pollution control equipment is pledged to secure installment contracts payable. There are currently no bonds outstanding under Tampa Electric's first mortgage bond indenture, and Tampa Electric could cause the lien associated with this indenture to be released at any time. If the lien under the first mortgage bond indenture were released, the terms of the liens on the pollution control equipment would permit Tampa Electric to cause these liens to be discharged, as well. Maturities and annual sinking fund requirements of long-term debt for the years 2006 through 2010 and thereafter are as follows:

Long-Term Debt Maturities

Dec. 31, 2005 (millions)	*2006*	*2007*	*2008*	*2009*	*2010*	*Thereafter*	*Total Long-term Debt*
Tampa Electric	$ –	$ 125.0	$ —	$ –	$ –	$ 1,223.9	$ 1,348.9
Peoples Gas	5.9	31.1	5.7	5.5	3.7	116.8	168.7
Total long-term debt maturities	$ 5.9	$ 156.1	$ 5.7	$ 5.5	$ 3.7	$ 1,340.7	$ 1,517.6

In April 2003, Tampa Electric issued $250 million of 6.25% Senior Notes due in 2016, in a private placement. Net proceeds of approximately $250 million were used to repay short-term indebtedness and for general corporate purposes.

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

TAMPA ELECTRIC COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Significant Accounting Policies

The significant accounting policies are as follows:

Principles of Consolidation

Tampa Electric Company is a wholly-owned subsidiary of TECO Energy, Inc, and is comprised of the Electric division, generally referred to as Tampa Electric, and the Natural Gas division, generally referred to as Peoples Gas System (PGS). All significant intercompany balances and intercompany transactions have been eliminated in consolidation.

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

Planned Major Maintenance

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

Depreciation

Tampa Electric computes depreciation expense by applying composite, straight-line rates (approved by the state regulatory agency) to the investment in depreciable property. Total depreciation expense for the years ended Dec. 31, 2005, 2004 and 2003 was $215.0 million, $207.5 million and $235.7 million, respectively. Total plant acquisition adjustments were $10.0 million and $10.3 million as of Dec. 31, 2005 and 2004, respectively. The provision for total regulated and unregulated utility plant in service, expressed as a percentage of the original cost of depreciable property, was 4.0% for 2005, 3.9% for 2004 and 4.5% for 2003 as approved by the FPSC. For the year ended Dec. 31, 2003, Tampa Electric recognized depreciation expense of $36.6 million related to acclerated depreciation of certain Gannon power station coal-fired assets, in accordance with a regulatory order issued by the FPSC. Construction work-in progress is not depreciated until the asset is completed or placed in service.

The implementation of FAS 143 in 2003 and FIN 47 in 2005 resulted in increases in the carrying amount of long-lived assets and the reclassification of the accumulated reserve for cost of removal as "Regulatory liabilities" for all periods presented. The adjusted capitalized amount is depreciated over the remaining uselful life of the asset. See **Note 12**.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is a non-cash credit to income with a corresponding charge to utility plant which represents the cost of borrowed funds and a reasonable return on other funds used for construction. The rate used to calculate AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. The rate was 7.79% for 2004 and 2003. Total AFUDC for 2004 and 2003 was $1.0 million and $27.4 million, respectively. No projects qualified for AFUDC in 2005. The base on which AFUDC is calculated excludes construction work-in-progress which has been included in rate base.

Deferred Income Taxes

Tampa Electric Company utilizes the liability method in the measurement of deferred income taxes. Under the liability method, the temporary differences between the financial statement and tax bases of assets and liabilities are reported as deferred taxes measured at current tax rates. Tampa Electric and PGS are regulated, and their books and records reflect approved regulatory treatment, including certain adjustments to accumulated deferred income taxes and the establishment of a corresponding regulatory tax liability reflecting the amount payable to customers through future rates.

Investment Tax Credits

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

Revenue Recognition

Tampa Electric Company recognizes revenues consistent with the Securities and Exchange Commission's Staff Accounting Bulletin (SAB) 104, *Revenue Recognition in Financial Statements*. The interpretive criteria outlined in SAB 104 are that 1) there is persuasive evidence that an arrangement exists; 2) delivery has occurred or services have been rendered; 3) the fee is fixed and determinable; and 4) collectibility is reasonably assured. Except as discussed below, Tampa Electric Company recognizes revenues on a gross basis when earned for the physical delivery of products or services and the risks and rewards of ownership have transferred to the buyer.

The regulated utilities' (Tampa Electric and Peoples Gas System) 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 Financial Accounting Standard No. (FAS) 71, *Accounting for the Effects of Certain Types of Regulation*, to the company.

Revenues and Fuel Costs

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-recovery 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 Tampa Electric and PGS are allowed to be recovered from customers through prices approved in the regulatory process. These costs are recognized as the associated revenues are billed. Tampa Electric and PGS accrue base revenues for services rendered but unbilled to provide a closer matching of revenues and expenses. See **Note 3.**

As of Dec. 31, 2005 and 2004, unbilled revenues of $52.3 million and $46.3 million, respectively, are included in the "Receivables" line item on the balance sheet.

Purchased Power

Tampa Electric purchases power on a regular basis primarily to meet the needs of its retail customers. As a result of the sale of Hardee Power Partners, Ltd. (HPP) in October 2003 (see **Note 16** to the **TECO Energy Consolidated Financial Statements**), power purchases from HPP, subsequent to the sale, are reflected as non-affiliate purchases by Tampa Electric. Tampa Electric's long-term power purchase agreement from HPP was not affected by the sale of HPP. Under the existing agreement, which has been approved by the FERC and FPSC, Tampa Electric has full entitlement to the output of the CT2B unit at all times and full entitlement to the output of the remaining units at the Hardee power station at all times except when Seminole Electric Cooperative has entitlement due to outages and/or durations on a specified portion of its generating units. Tampa Electric purchased power from non-TECO Energy affiliates, including HPP, at a cost of $269.7 million, $172.3 million and $234.9 million, respectively, for the years ended Dec. 31, 2005, 2004 and 2003. The prudently incurred purchased power costs are recoverable through an FPSC-approved cost recovery clause.

Accounting for Excise Taxes, Franchise Fees and Gross Receipts

Tampa Electric Company is allowed to recover certain costs incurred from customers through prices approved by the FPSC. The amounts included in customers' bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Statements of Income. These amounts totaled $87.2 million, $83.8 million and $77.7 million, for the years ended Dec. 31, 2005, 2004 and 2003, 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, 2005, 2004 and 2003, these totaled $87.0 million, $83.6 million and $77.5 million, respectively.

Excise taxes paid by the regulated utilities are not material and are expensed as incurred.

Asset Impairments

Tampa Electric Company has adopted FAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which supersedes FAS 121, *Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of*. FAS 144 addresses accounting and reporting for the impairment or disposal of long-lived assets, including the disposal of a component of a business.

In accordance with FAS 144, the company assesses whether there has been impairment of its long-lived assets and certain intangibles held and used by the company when such impairment indicators exist. Indicators of impairment existed for asset groups, triggering a requirement to ascertain the recoverability of these assets using undiscounted cash flows before interest expense. See **Note 13** for specific details regarding the results of these assessments.

Restrictions on Dividend Payments and Transfer of Assets

In March 2004, Tampa Electric repaid $75 million of 7.75% first mortgage bonds issued under an indenture that included a limitation on dividends covenant. This covenant is no longer operative since there are no bonds outstanding under the indenture. Certain long-term debt at PGS contains restrictions that limit the payment of dividends and distributions on the common stock of Tampa Electric.

See **Note 9** for additional information on significant financial covenants.

Receivables and Allowance for Uncollectible Accounts

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

Reclassifications

Certain prior year amounts, primarily related to income taxes, were reclassified to conform to the current year presentation.

2. New Accounting Pronouncements

Amendment to Derivatives Accounting

In April 2003, the FASB issued FAS 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*, which clarifies the definition of a derivative and modifies, as necessary, FAS 133 to reflect certain decisions made by the FASB as part of the Derivatives Implementation Group (DIG) process. The majority of the guidance was already effective and previously applied by the company in the course of the adoption of FAS 133.

In particular, FAS 149 incorporates the conclusions previously reached in 2001 under DIG Issue C10, *Can Option Contracts and Forward Contracts with Optionality Features Qualify for the Normal Purchases and Normal Sales Exception*, and DIG Issue C15, *Normal Purchases and Normal Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity*. In limited circumstances, when the criteria are met and documented, Tampa Electric Company designates option-type and forward contracts in electricity as a normal purchase or normal sale (NPNS) exception to FAS 133. A contract designated and documented as qualifying for the NPNS exception is not subject to the measurement and recognition requirements of FAS 133. The incorporation of the conclusions reached under DIG Issues C10 and C15 into the standard will not have a material impact on the consolidated financial statements of Tampa Electric Company.

FAS 149 establishes multiple effective dates based on the source of the guidance. For all DIG Issues previously cleared by the FASB and not modified under FAS 149, the effective date of the issue remains the same. For all other aspects of the standard, the guidance is effective for all contracts entered into or modified after June 30, 2003. The adoption of the additional guidance in FAS 149 did not have a material impact on the consolidated financial statements.

Financial Instruments with Characteristics of both Liabilities and Equity

In May 2003, the FASB issued FAS 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*, which requires that an issuer classify certain financial instruments as a liability or an asset. Previously, many financial instruments with characteristics of both liabilities and equity were classified as equity. Financial instruments subject to FAS 150 include financial instruments with any of the following features:

- An unconditional redemption obligation at a specified or determinable date, or upon an event that is certain to occur;
- An obligation to repurchase shares, or indexed to such an obligation, and may require physical share or net cash settlement; or
- An unconditional, or for new issuances conditional, obligation that may be settled by issuing a variable number of equity shares if either (a) a fixed monetary amount is known at inception, (b) the variability is indexed to something other than the fair value of the issuer's equity shares, or (c) the variability moves inversely to changes in the fair value of the issuer's shares.

The standard requires that all such instruments be classified as a liability, or an asset in certain circumstances, and initially measured at fair value. Forward contracts that require a fixed physical share settlement and mandatorily redeemable financial instruments must be subsequently re-measured at fair value on each reporting date.

This standard is effective for all financial instruments entered into or modified after May 31, 2003, and for all other financial instruments, at the beginning of the first interim period beginning after Jun. 15, 2003. The adoption of FAS 150 has had no material impact on the consolidated financial statements of Tampa Electric Company.

Inventory Costs

FASB Statement No. 151, *Inventory Costs, an amendment to ARB No. 43, Chapter 4*, sets forth certain costs related to inventory that must be included as current period costs. This Statement became effective as of Jul. 1, 2005 and did not materially impact the company's financial position, results of operations or cash flow.

Nonmonetary Assets

FASB Statement No. 153, *Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29*, became effective as of Jul. 1, 2005 and did not materially impact the company's financial position, results of operations or cash flows.

Asset Retirement Obligations

FASB Interpretation No. 47 (FIN 47), *Accounting for Conditional Asset Retirement Obligation, an Interpretation of FASB Statement No. 143*, was issued in March 2005 and became effective as of Dec. 31, 2005. FIN 47 clarifies the term "conditional asset retirement obligation" as a legal obligation to perform an asset retirement activity in which the timing and method of settlement are conditional on a future event that may or may not be within the control of the entity, and clarifies when an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation. The company implemented FIN 47 during the fourth quarter of 2005. See Note 12 for discussion of the effects of this implementation.

3. Regulatory

As discussed in **Note 1**, Tampa Electric's and PGS' retail business are regulated by the FPSC.

Base Rate – 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 as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties. Tampa Electric expects to continue maintaining earnings within its allowed ROE range for the foreseeable future.

Tampa Electric has not sought a base rate increase to recover significant plant investment, including the Bayside Power Station, which entered service in 2003 and 2004.

Cost Recovery – Tampa Electric

In September 2005, Tampa Electric filed with the FPSC for approval of fuel and purchased power, capacity, environmental and conservation cost recovery rates for the period January 2006 through December 2006. In late October 2005, Tampa Electric filed updated fuel and purchased power rates which included significantly higher actual than projected costs for the third quarter of 2005 due to the rapid increase in natural gas prices as a result of hurricanes Dennis, Katrina and Rita. In November, the FPSC approved Tampa Electric's requested changes. The rates include the impacts of increased natural gas and coal prices expected in 2006, the collection of some of the underestimated 2005 fuel expenses, the proceeds from the sale of sulfure dioxide (SO_2) emissions allowances and the O&M costs associated with the Environmental Protection Agency (EPA) Consent Decree and Florida Department of Environmental Protection (FDEP) Consent Final Judgment required Big Bend Units 1 - 3 Pre-SCR projects. See **Note 9** for additional details regarding projected environmental expenditures. 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 **Note 10**). 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 Rate – PGS

As a result of a base rate proceeding, effective Jan. 16, 2003, PGS' allowable ROE range is 10.25% to 12.25% with an 11.25% midpoint. PGS expects to continue earning within its allowed ROE range for the foreseeable future.

Cost Recovery – PGS

In September 2005, PGS filed a request with the FPSC for a mid-course correction to its 2005 Purchased Gas Adjustment (PGA) clause. The PGA rate can vary monthly due to changes in actual fuel costs but is not expected to exceed the FPSC approved annual cap. The request was initiated due to the rapid increase in the price of natural gas following hurricanes Dennis, Katrina and Rita. The FPSC approved the request and the higher PGA factor was effective in October 2005. In November 2005, the FPSC approved the annual rates under PGS' PGA for the period January 2006 through December 2006.

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 commodities. Once allocated, allowances may be bought, sold, traded, or banked for use in future years. 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 over 95% of which accrues to 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 needs and allowances available. The SO_2 allowances unneeded and sold in 2005 resulted from lower emissions at Tampa Electric brought about by environmental actions taken by the company under the Clean Air Act. Tampa Electric currently receives 84,635 allowances annually to cover its emissions. This allocation will continue through 2009. The allocation amount will change beginning in 2010 in accordance with the EPA's SO_2 allowance program.

In 2005, Tampa Electric sold approximately 100,000 unneeded allowances, resulting in a gain of approximately \$79.7 million (\$49.0 million after tax).

Other Items

Regional Transmission Organization (RTO)

In October 2002, the RTO process involving the proposed formation of GridFlorida, LLC, as initiated in response to the FERC's continuing efforts to affect open access to transmission facilities in large regional markets, was delayed when the Office of Public Counsel (OPC) filed an appeal with the Florida Supreme Court. Oral arguments occurred in May 2003, and the Florida Supreme Court dismissed the appeal citing that it was premature because certain portions of the FPSC GridFlorida order were not final.

In September 2003, a joint meeting of the FERC and FPSC took place to discuss wholesale markets, RTO issues related to GridFlorida and, in particular, federal and state interactions. During 2004, deliberations by the FPSC were put on hold to allow a consulting firm, engaged by the GridFlorida applicants, to conduct a cost/benefit study of the GridFlorida RTO. As a result, the FPSC held a series of collaborative meetings during the year with all interested parties to facilitate development of the study methodology as well as participate in the submission of data required to complete the study. Preliminary results of the study were submitted to the FPSC in late 2005, and they indicated that the estimated costs of a GridFlorida RTO structure exceeded the expected benefits. As a result, the GridFlorida participants are exploring alternative designs in an effort to retain many of the benefits shown in the study while reducing the costs for implementation. In January 2006, the applicants filed a request with the FPSC to close the docket. The ultimate results of the process remain uncertain, but there may be a final resolution in 2006.

Storm Damage Cost Recovery

Following Hurricane Andrew in 1992, Florida's investor owned utilities (IOUs) were unable to obtain transmission and distribution insurance coverage in the event of hurricanes, tornados or other damage due to destructive acts of nature. Tampa Electric and other IOUs were permitted to implement a self-insurance program effective Jan. 1, 1994 for such costs of restoration, and the FPSC authorized Tampa Electric to accrue $4 million annually to grow its unfunded storm damage reserve.

The costs for restoration associated with hurricanes Charley, Frances and Jeanne were approximately $74 million, which exceeded the storm damage reserve by $30 million. These excess costs over the reserve amounts were charged against the reserve and were reflected as a regulatory asset. The storm costs did not reduce earnings but did reduce cash flow from operations. Tampa Electric filed for and received approval from the FPSC to defer prudently incurred storm damage restoration costs to the reserve until alternative accounting treatment is sought.

In June 2005, the FPSC approved a stipulation entered into by Tampa Electric, the Office of Public Counsel and the Florida Industrial Power Users group regarding the treatment of Tampa Electric's 2004 hurricane costs. Under the stipulation, Tampa Electric agreed to reclassify approximately $39 million of the 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, which had about a $30 million deficit balance, had a positive balance of approximately $11 million at the start of the 2005 hurricane season and a $13 million balance as of Dec. 31, 2005.

Coal Transportation Contract

In September 2004, the FPSC voted to disallow certain costs that Tampa Electric can recover from its customers for waterborne fuel transportation services under a contract with TECO Transport (see **Note 10** for additional details).

Regulatory Assets and Liabilities

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

Tampa Electric and PGS apply the accounting treatment permitted by FAS 71, *Accounting for the Effects of Certain Types of Regulation.* Areas of applicability include deferral of revenues under approved regulatory agreements; revenue recognition resulting from cost recovery clauses that provide for monthly billing charges to reflect increases or decreases in fuel; purchased power, conservation and environmental costs; and deferral of costs as regulatory assets, when cost recovery is ordered over a period longer than a fiscal year, to the period that the regulatory agency recognizes them. Details of the regulatory assets and liabilities as of Dec. 31, 2005 and 2004 are presented in the following table:

Regulatory Assets and Liabilities

(millions) Dec. 31,	*2005*	*2004*
Regulatory assets:		
Regulatory tax asset[1]	$ 79.5	$ 57.6
Other:		
Cost recovery clauses	264.1	48.2
Deferred bond refinancing costs[2]	28.8	32.5
Environmental remediation	14.2	16.9
Competitive rate adjustment	5.6	6.1
Transmission and distribution storm reserve	—	28.0
Other	5.2	11.7
	317.9	143.4
Total regulatory assets	397.4	201.0
Less current portion	296.3	63.9
Long-term regulatory assets	$ 101.1	$ 137.1
Regulatory liabilities:		
Regulatory tax liability[1]	$ 23.4	$ 29.5
Other:		
Deferred allowance auction credits	1.3	2.3
Recovery clause related	136.9	8.7
Environmental remediation	14.2	16.9
Transmission and distribution storm reserve	12.5	—
Deferred gain on property sales	7.7	1.7
Accumulated reserve – cost of removal	493.8	479.9
Other	0.1	—
	666.5	509.5
Total regulatory liabilities	689.9	539.0
Less current portion	146.8	22.5
Long-term regulatory liabilities	$ 543.1	$ 516.5

(1) Related primarily to plant life. Includes excess $13.1 million and $14.6 million of excess deferred taxes as of Dec. 31, 2005 and 2004, respectively.

(2) Amortized over the term of the related debt instrument.

4. Income Tax Expense

Tampa Electric Company is included in the filing of a consolidated federal income tax return with TECO Energy and its affiliates. Tampa Electric Company's income tax expense is based upon a separate return computation. Income tax expense consists of the following components:

Income Tax Expense

(millions)	*Federal*	*State*	*Total*
2005			
Currently payable	$ 33.9	$ 5.6	$ 39.5
Deferred	61.7	10.5	72.2
Amortization of investment tax credits	(2.6)	—	(2.6)
Total income tax expense	$ 93.0	$ 16.1	$ 109.1
Included in other income, net			1.3
Included in operating expenses			$ 107.8

(millions)	*Federal*	*State*	*Total*
2004			
Currently payable	$ 41.7	$ 7.3	$ 49.0
Deferred	46.8	8.1	54.9
Amortization of investment tax credits	(2.7)	—	(2.7)
Total income tax expense	$ 85.8	$ 15.4	$ 101.2
Included in other income, net			0.9
Included in operating expenses			$ 100.3
2003			
Currently payable	$ 74.9	$ 17.6	$ 92.5
Deferred	(16.0)	(7.9)	(23.9)
Amortization of investment tax credits	(4.6)	—	(4.6)
Total income tax expense	$ 54.3	$ 9.7	$ 64.0
Included in other income, net			(30.0)
Included in operating expenses			$ 94.0

Deferred taxes result from temporary differences in the recognition of certain liabilities or assets for tax and financial reporting purposes. 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,	*2005*	*2004*
Deferred income tax assets (1)		
Property related	$ 97.8	$ 91.3
Insurance reserves	15.1	14.7
Investment tax credits	10.3	11.8
Other	2.9	5.4
Total deferred income tax assets	$ 126.1	$ 123.2
Deferred income tax liabilities (1)		
Property related	$ (568.7)	$ (551.1)
Deferred fuel	(103.6)	(12.7)
Emission allowances	26.5	—
Medical benefits	38.5	35.8
Other	(8.5)	15.3
Total deferred income tax liabilities	$ (615.8)	$ (512.7)
Accumulated deferred income taxes	$ (489.7)	$ (389.5)

Deferred income tax assets and liabilities above are included in the balance sheet as follows:

(millions) Dec. 31,	*2005*	*2004*
Currently deferred tax assets	$ —	$ 3.3
Current deferred tax liabilities	(116.8)	—
Non-current deferred tax liabilities	(372.9)	(392.8)
Total	$ (489.7)	$ (389.5)

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

The total income tax provisions differ from amounts computed by applying the federal statutory tax rate to income before income taxes for the reasons presented below. The actual cash paid for income taxes in 2005, 2004 and 2003 was $30.3 million, $103.9 million and $61.9 million, respectively.

Effective Income Tax Rate

(millions)	*2005*	*2004*	*2003*
Net income	$ 176.7	$ 173.7	$ 123.4 [(1)]
Total income tax provision	109.1	101.2	64.0 [(1)]
Income before income taxes	$ 285.8	$ 274.9	$ 187.4 [(1)]
Income taxes on above at federal statutory rate of 35%	$ 100.0	$ 96.2	$ 65.6
Increase (decrease) due to			
State income tax, net of federal income tax	10.5	10.0	6.3
Amortization of investment tax credits	(2.6)	(2.7)	(4.6)
Equity portion of AFUDC	(—)	(0.3)	(7.0)
Other	1.2	(2.0)	3.7
Total income tax provision	$ 109.1	$ 101.2	$ 64.0
Provision for income taxes as a percent of income from continuing operations, before income taxes	38.2%	36.8%	34.2%

(1) Includes $48.9 million after-tax ($79.6 million pretax) charges associated with cancellation of turbine purchase commitments.

5. Employee Postretirement Benefits

Pension Benefits

Tampa Electric Company is a participant in the comprehensive retirement plans of TECO Energy (multi-employer plans), including a non-contributory defined benefit retirement plan which covers substantially all employees. Where appropriate and reasonably determinable, the portion of expenses, income, gains or losses allocable to Tampa Electric Company are presented. Otherwise, such amounts presented reflect the amount allocable to all participants of the TECO Energy retirement plans. Benefits are based on employees' age, years of service and final average earnings. The company's policy is to fund the plan based on the amount determined by the company's actuaries within the guidelines set by ERISA for the minimum annual contribution. In 2005, TECO Energy made a contribution of $17.3 million to the plan, of which Tampa Electric Company's portion was $11.4 million. In 2006, TECO Energy's minimum contribution is about $6.3 million, of which Tampa Electric Company's portion is expected to be about $4.2 million.

Amounts disclosed for pension benefits also include the unfunded obligations for the supplemental executive retirement plans. These are non-qualified, non-contributory defined benefit retirement plans available to certain members of senior management. In 2005, TECO Energy made a contribution of about $4.6 million to these plans. In 2006, TECO Energy expects to make a contribution of about $1.6 million to these plans.

TECO Energy reported other comprehensive losses of $7.2 million and $43.9 million in 2005 and 2003, respectively, and other comprehensive income of $7.2 million in 2004, related to adjustments to the minimum pension liability associated with these pension plans.

The asset allocation for the company's pension plan as of Sep. 30, 2005 and 2004, the measurement dates for TECO Energy's post retirement benefit plans, and the target allocation for 2006, by asset category, follows:

Asset Allocation

	Target Allocation for	*Percentage of Plan Assets at Sep. 30,*	
Asset category	*2006*	*2005*	*2004*
Equities	55% – 60%	64%	60%
Fixed income	40% – 45%	36%	40%
Total		100%	100%

TECO Energy'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. TECO Energy's strategy is to hire proven managers and allocate assets to reflect a mix of investment styles, emphasize preservation of principal to minimize the impact of declining markets, and stay fully invested except for cash to meet benefit payment obligations and plan expenses.

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 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. 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.

Components of net pension expense, reconciliation of the funded status and the accrued pension liability TECO Energy, Inc. are presented below.

Pension Benefit Expense – TECO Energy, Inc.

(millions)	*2005*	*2004*	*2003*
Components of net periodic benefit expense			
Service cost (benefits earned during the period)	$ 16.2	$ 17.0	$ 14.3
Interest cost on projected benefit obligations	32.7	33.0	30.8
Expected return on assets	(37.2)	(39.1)	(42.1)
Amortization of:			
Transition obligation	(0.2)	(1.1)	(1.1)
Prior service cost	(0.5)	(0.5)	(0.5)
Actuarial (gain) loss	4.3	2.7	1.4
Pension expense (benefit)	15.3	12.0	2.8
Special termination benefit charge	—	—	—
Settlement	1.4	6.6	—
Additional amounts recognized	—	0.4	—
Net pension expense (benefit) recognized in the TECO Energy Consolidated Statements of Income (1)	$ 16.7	$ 19.0	$ 2.8
Assumptions used to determine net costs			
Discount rate	6.00%	6.00%	6.75%
Rate of compensation increase	4.25%	4.25%	4.82%
Expected return on plan assets	8.75%	8.75%	9.00%

(1) Tampa Electric Company's portion was $9.7 million, $5.2 million and ($1.9) million for 2005, 2004 and 2003, respectively.

The following table shows the funded status of the qualified and non-qualified pension plans for which the projected obligation exceeds the fair value to the plan assets:

Pension Plans – Projected Obligation Exceeds Plan Assets – TECO Energy, Inc.

(millions) Sep. 30,	*2005*	*2004*
Projected benefit obligation	$ 562.1	$ 545.4
Fair value of plan assets	434.7	407.6
Projected obligation in excess of plan assets	$127.4	$ 137.8

As of Sep. 30, 2005 and 2004, for the qualified and non-qualified pension plans, the accumulated obligation exceeded the fair value of the plan assets. The table below shows the funded status for the respective plans:

Pension Plans – Accumulated Obligation Exceeds Plan Assets – TECO Energy, Inc.

(millions) Sep. 30,	*2005*	*2004*
Accumulated benefit obligation	$ 509.7	$ 476.2
Fair value of plan assets	434.7	407.6
Accumulated obligation in excess of plan assets	$ 75.0	$ 68.6

Reconciliation of the funded status of the retirement plan and the accrued pension prepayment/(liability) – TECO Energy, Inc.

(millions)	*2005*	*2004*
Change in benefit obligation		
Net benefit obligation at prior measurement date	$ 545.4	$ 554.5
Service cost	16.2	17.0
Interest cost	32.6	33.0
Actuarial loss	7.1	(0.9)
Plan amendments	—	1.5
Curtailment	—	(2.2)
Settlement	(3.1)	—
Gross benefits paid	(36.1)	(57.5)
Net benefit obligation at measurement date	$ 562.1	$ 545.4
Change in plan assets		
Fair value of plan assets at prior measurement date	$ 407.6	$ 391.8
Actual return on plan assets	44.4	43.0
Employer contributions	21.9	30.3
Settlement	(3.1)	—
Gross benefits paid (including expenses)	(36.1)	(57.5)
Fair value of plan assets at measurement date	$ 434.7	$ 407.6
Funded status		
Fair value of plan assets	$ 434.7	$ 407.6
Benefit obligation	562.1	545.4
Funded status at measurement date	(127.4)	(137.8)
Net contributions after measurement date	0.3	0.4
Unrecognized net actuarial loss	143.3	149.2
Unrecognized prior service cost (benefit)	4.9	(5.4)
Unrecognized net transition obligation (asset)	—	(0.2)
Accrued liability at end of year	$ 11.3	$ 6.2
Amounts recognized in the statement of financial position		
Prepaid benefit cost	$ 28.6	$ 23.6
Accrued benefit cost	(17.2)	(17.4)
Additional minimum liability	(86.0)	(74.4)
Intangible asset	1.9	2.2
Accumulated other comprehensive income	84.0	72.2
Net amount recognized at end of year	$ 11.3	$ 6.2
Assumptions used in determining benefit obligations, end of year		
Discount rate to determine projected benefit obligation	5.50%	6.00%
Rate of increase in compensation levels	3.75%	4.25%

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 2006, TECO Energy expects to make a contribution of about $12.7 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 adds 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. TECO Energy has determined that prescription drug benefits available to certain Medicare-eligible participants under its defined-dollar-benefit postretirement health care plan will at least be "actuarially equivalent" to the standard drug benefits to be offered under Medicare Part D.

On May 19, 2004, the FASB issued FSP 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* (FSP 106-2), The guidance in FSP 106-2 requires (a) that the effects of the federal subsidy be considered an actuarial gain and recognized in the same manner as other actuarial gains and losses and (b) certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits. TECO Energy adopted FSP 106-2 retroactive for the second quarter in 2004. The expected subsidy reduced the net amount recognized at December 31, 2005 by $1.8 million, and net periodic cost for 2005 by $0.7 million.

In 2005, TECO Energy filed and received approval for its Part D subsidy application with CMS and is continuing to analyze what, if any, plan design changes should be made with respect to the company's retiree medical program in response to the MMA.

The following charts summarize the income statement and balance sheet impact for Tampa Electric Company, as well as the benefit obligations, assets, funded status and rate assumptions associated with other postretirement benefits.

Other Postretirement Benefit Expense

(millions)	*2005*	*2004*	*2003*
Components of net periodic benefit expense			
Service cost (benefits earned during the period)	$ 2.4	$ 2.6	$ 2.6
Interest cost on projected benefit obligations	7.3	7.9	9.3
Amortization of:			
Transition obligation (asset)	2.1	2.1	2.1
Prior service cost	1.7	1.7	1.7
Actuarial loss	—	0.3	1.0
Pension expense	13.5	14.6	16.7
Additional amounts recognized	—	—	0.1
Net periodic postretirement benefit expense	$ 13.5	$ 14.6	$ 16.8

The accumulated postretirement benefit obligation exceeds plan assets for the postretirement health and welfare benefits plan.

Reconciliation of the funded status of the postretirement benefit plan and the accrued liability

(millions)	*2005*	*2004*
Change in benefit obligation		
Net benefit obligation at prior measurement date	$ 123.1	$ 146.8
Adjustment to include TECO Stevedoring	—	2.2 (1)
Net benefit obligation at prior measurement date, as adjusted	123.1	149.0
Service cost	2.5	2.6
Interest cost	7.3	7.9
Plan participants' contributions	1.8	2.6
Actuarial loss	17.0	(28.4)
Gross benefits paid	(10.1)	(10.6)
Net benefit obligation at measurement date	$ 141.6	$ 123.1
Change in plan assets		
Fair value of plan assets at prior measurement date	—	—
Employer contributions	8.3	8.0
Plan participants' contributions	1.8	2.6
Gross benefits paid	(10.1)	(10.6)
Fair value of plan assets at measurement date	$ —	$ —
Funded status		
Funded status at measurement date	$ (141.6)	$ (123.1)
Net contributions after measurement date	2.0	2.0
Unrecognized net actuarial loss	20.2	3.3
Unrecognized prior service cost	15.4	17.1
Unrecognized net transition obligation	15.0	17.0
Accrued liability at end of year	$ (89.0)	$ (83.7)
Assumptions used in determining actuarial valuations		
Discount rate to determine projected benefit obligation	5.50%	6.00%
Rate of increase in compensation levels	3.75%	4.25%

(1) Tampa Electric Company's net benefit obligation balance as of Jan. 1, 2004 reflects the transfer of amounts related to TECO Stevedoring that were combined with Tampa Electric Company.

Employer contributions and benefits paid in the above tables include both those amounts contributed directly to, and paid directly from plan assets, and paid directly to plan participants. The assumed health care cost trend rate for medical costs was 9.5% and 10.5% in 2005 and 2004, respectively, and decreases to 5.0% in 2013 and thereafter.

A 1% increase in the medical trend rates would produce a 1% ($0.1 million) increase in the aggregate service and interest cost for 2005, and a 2% ($2.6 million) increase in the accumulated postretirement benefit obligation as of Sep. 30, 2005, the measurement date.

A 1% decrease in the medical trend rates would produce a 1% ($0.1 million) decrease in the aggregate service and interest cost for 2005 and a 2% ($2.3 million) decrease in the accumulated postretirement benefit obligation as of Sep. 30, 2005, the measurement date.

Information about TECO Energy's expected benefit payments for the pension and postretirement benefit plans follows:

Expected Benefit Payments – TECO Energy
(including projected service and net of employee contributions)

(millions) *For the years ended Dec. 31,*	*Pension Benefits*	*Other Benefits (exclusive of subsidy payments under MMA)*	*Employer Value of Expected Payments MMA*	*Other Benefits net of Expected Payments under MMA*
2006	$ 41.4	$ 12.7 [1]	$ (0.8)	$ 11.9 [1]
2007	$ 42.2	$ 13.7	$ (0.9)	$ 12.8
2008	$ 43.9	$ 14.8	$ (1.0)	$ 13.8
2009	$ 45.1	$ 15.6	$ (1.1)	$ 14.5
2010	$ 46.1	$ 16.5	$ (1.2)	$ 15.3
2011-2015	$ 243.8	$ 89.7	$ (8.2)	$ 81.5

(1) Tampa Electric Company's portion of Other Postretirement Benefit payments for 2006 is expected to be about $9.7 million ($9.1 million net of expected payments under MMA).

6. Short-Term Debt

At Dec. 31, 2005 and 2004, the following credit facilities and related borrowings existed:

Credit Facilities	Dec. 31, 2005			Dec. 31, 2004		
(millions)	*Credit Facilities*	*Borrowings Outstanding[1]*	*Letters of Credit Outstanding*	*Credit Facilities*	*Borrowings Outstanding*	*Letters of Credit Outstanding*
Recourse:						
Tampa Electric Company:						
5-year facility[2]	$ 325.0	$ 120.0	$ —	$ 150.0	$ 115.0	$ —
3-year facility	—	—	—	125.0	—	—
1-year accounts receivable facility	150.0	95.0	—	—	—	—
Total	$ 475.0	$ 215.0	$ —	$ 275.0	$ 115.0	$ —

(1) Borrowings outstanding are reported as notes payable.
(2) A 3-year facility as of Dec. 31, 2004 (as discussed below).

These credit facilities require commitment fees ranging from 12.5 – 17.5 basis points. The weighted average interest rate on outstanding notes payable at Dec. 31, 2005 and 2004 was 4.45% and 3.32%, respectively.

Tampa Electric Credit Facility

On Oct. 11, 2005, Tampa Electric amended its $150 million bank credit facility, increasing the facility size to $325 million and extending the maturity to Oct. 11, 2010 with optional extensions of up to two additional years with lenders' consent. Tampa Electric terminated its $125 million 3-year bank credit facility. The amended facility also allows Tampa Electric to increase the facility size by up to $50 million with lenders' consent; and includes a $50 million sub-limit for letters of credit. The financial covenants were also amended to eliminate the requirement that Tampa Electric maintain a specified ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest, as defined in the agreement, and increase the permissible quarter-end debt to capital, as defined in the agreement, to 65%.

Tampa Electric Company Accounts Receivable Facility

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 securitized 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. See **Note 16** for a subsequent event involving this facility.

7. Common Stock

Tampa Electric Company is a wholly owned subsidiary of TECO Energy, Inc.

	Common Stock		*Issue*	
(millions, except per share amounts)	*Shares*	*Amount*	*Expense*	*Total*
Balance Dec. 31, 2005, 2004, and 2003	10	$ 1,377.5	$ (0.7)	$ 1,376.8

8. Other Comprehensive Income

Tampa Electric Company reported the following comprehensive income (loss) for the years ended Dec. 31, 2005, 2004 and 2003 related to changes in the fair value of cash flow hedges:

Comprehensive income (loss) (millions)	*Gross*	*Tax*	*Net*
2005			
Unrealized gain on cash flow hedges	$ 65.3	$ 25.2	$ 40.1
Less: Gain reclassified to net income	(65.3)	(25.2)	(40.1)
Total other comprehensive income (loss)	$ —	$ —	$ —
2004			
Unrealized gain on cash flow hedges	$ 8.8	$ 3.4	$ 5.4
Less: Gain reclassified to net income	(8.8)	(3.4)	(5.4)
Total other comprehensive income (loss)	$ —	$ —	$ —
2003			
Unrealized gain on cash flow hedges	$ 3.2	$ 1.2	$ 2.0
Less: Gain reclassified to net income	(3.2)	(1.2)	(2.0)
Total other comprehensive income (loss)	$ —	$ —	$ —

9. Commitments and Contingencies

Capital Investments

For 2006, Tampa Electric expects to spend $384 million, consisting of about $190 million to support system growth and generation reliability, approximately $12 million for distribution system reliability improvements and enhancements to customer-service systems, $20 million for coal-fired generation capacity factor and availability improvements, $74 million for the addition of two combustion turbines at the Polk Power Station to meet its peaking generation capacity needs, $78 million for the addition of selective catalytic reduction (SCR) equipment at the Big Bend Station for NO_x control, and $10 million for other environmental compliance programs. At the end of 2005, Tampa Electric had outstanding commitments of about $198 million primarily for long-term capitalized maintenance agreements for its combustion turbines.

Capital expenditures for PGS are expected to be about $51 million in 2006 and $50 million in 2007. Included in these amounts are approximately $29 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing renewal, replacement and system safety.

Legal Contingencies

From time to time Tampa Electric Company is involved in various other legal, tax and regulatory proceedings before various courts, regulatory commissions, and governmental agencies in the ordinary course of its business. Where appropriate, accruals are made in accordance with FAS 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 the ultimate resolution of pending matters will have a material adverse effect on the company's results of operations or financial condition.

Tampa Electric Transmission Litigation

Four lawsuits were filed in the Circuit Court in Hillsborough County against Tampa Electric in connection with the location of transmission structures and upgrades to a substation in certain residential areas by residents in the areas surrounding the structures and substation. The resident plaintiffs are seeking to remove the poles or to receive monetary damages. The plaintiffs were seeking class action status, which status was denied. Three cases (two, Jorrison and Acosta were consolidated) are pending before two separate judges. Tampa Electric's motion to dismiss the claim for injunctive relief (non-monetary relief) was granted in the Alvarez case (substation case). Tampa Electric has filed new motions for partial summary judgment in both the Shaw and Acosta cases with respect to property owners not located adjacent to or in close proximity to the poles ("Remote Plaintiffs'). Two of the three motions in the Shaw case were granted on Jan. 13, 2006 and the third was denied on Jan. 20, 2006. This is expected to result in a number of plaintiffs dropping out of the case unless the summary judgements are overturned on appeal. The Shaw case has been transferred to the Trial Division (cases expected to have trials lasting two weeks or more), and the parties have stipulated to a trial date of Sep. 11, 2006. The motion for summary judgment in the Acosta case was argued Feb. 21, 2006, and the court took it under advisement. At that time, plaintiffs' counsel in the Acosta case dropped 65 plaintiffs.

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, 2005, Tampa Electric Company has estimated its ultimate financial liability to be approximately $14.3 million, with the majority attributable to the Peoples Gas division, 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 may be recoverable through customer rates established in future base rate proceedings.

Long Term Commitments

Tampa Electric Company has commitments under long-term operating leases, primarily for building space, office equipment and heavy equipment. Total rental expense included in the Consolidated Statements of Income for the years ended Dec. 31, 2005, 2004 and 2003 was $2.1 million, $6.7 million and $6.2 million, respectively.

The following table is a schedule of future minimum lease payments at Dec. 31, 2005 for all operating leases with noncancelable lease terms in excess of one year:

Future Minimum Lease Payments for Operating Leases

Year ended Dec. 31:	*Amount (millions)*
2006	$ 2.1
2007	2.0
2008	1.9
2009	1.9
2010	1.9
Later Years	28.4
Total minimum lease payments	$ 38.2

In 1994, Tampa Electric bought out a long-term coal supply contract which would have expired in 2004 for a lump sum payment of $25.5 million. In February 1995, the FPSC authorized the recovery of this buy-out amount plus carrying costs through the Fuel and Purchase Power Cost Recovery Clause over the 10-year period beginning Apr. 1, 1995. In each of the years 2004 and 2003, $2.7 million of buy-out costs were amortized to expense. It was fully amortized by the end of 2004.

Guarantees and Letters of Credit

On Jan. 1, 2003, Tampa Electric Company adopted the prospective initial measurement provisions for certain types of guarantees, in accordance with FASB Interpretation No. (FIN) 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others (an interpretation of FASB Statements No. 5, 57, and 107 and rescission of FASB Interpretation No. 34).* Upon issuance or modification of a guarantee after Jan. 1, 2003, the company must determine if the obligation is subject to either or both of the following:

- Initial recognition and initial measurement of a liability; and/or
- Disclosure of specific details of the guarantee.

Generally, guarantees of the performance of a third party or guarantees that are based on an underlying (where such a guarantee is not a derivative subject to FAS 133) are likely to be subject to the recognition and measurement, as well as the disclosure provisions, of FIN 45. Such guarantees must initially be recorded at fair value, as determined in accordance with the interpretation.

Alternatively, guarantees between and on behalf of entities under common control or that are similar to product warranties are subject only to the disclosure provisions of the interpretation. The company must disclose information as to the term of the guarantee and the maximum potential amount of future gross payments (undiscounted) under the guarantee, even if the likelihood of a claim is remote.

At Dec. 31, 2005, Tampa Electric was not obligated under guarantees or letters of credit for the benefit of third parties, including entities under common control. At Dec. 31, 2005, TECO Energy had provided a fuel purchase guarantee on behalf of Tampa Electric and had outstanding letters of credit on behalf of Tampa Electric in the face amounts of $20.0 million and $2.4 million, respectively.

Financial Covenants

In order to utilize its bank credit facilities, Tampa Electric Company must meet certain financial tests as defined in the applicable agreements. In addition, Tampa Electric Company has certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2005, Tampa Electric Company was in compliance with required financial covenants.

10. Related Party Transactions

In October 2003, Tampa Electric signed a five-year contract renewal with an affiliate company, TECO Transport, for integrated waterborne fuel transportation services effective Jan. 1, 2004. The contract calls for inland river and ocean transportation along with river terminal storage and blending services for up to 5.5 million tons of coal annually through 2008. In September 2004, the FPSC voted to disallow approximately $14 to $16 million (pretax) of the costs that Tampa Electric can recover from its customers for water transportation services. The decision allows, but does not require, Tampa Electric to rebid the water transportation and terminal service contract. In October 2004, Tampa Electric filed with the FPSC a motion for clarification and reconsideration of the disallowance of recovery of costs under its waterbourne transporation contract with TECO Transport. On Mar. 1, 2005, the FPSC heard oral arguments on the motion and denied Tampa Electric's request for reconsideration and clarification. The impact of the FPSC vote was fully recognized by Tampa Electric in 2004.

In February 2002, Tampa Electric and TECO-PANDA Generating Company (TPGC II), an affiliate of TECO Wholesale Generation, entered into an assignment and assumption agreement under which Tampa Electric obtained TPGC II's rights and interests in four combustion turbines being purchased from General Electric, and assumed the corresponding liabilities and obligations for such equipment. In accordance with the terms of the assignment and assumption agreement, Tampa Electric paid $62.5 million to TPGC II as reimbursement for amounts already paid to General Electric by TPGC II for such equipment. No gain or loss was incurred on the transfer. In the first quarter of 2003, Tampa Electric recorded a $48.9

million after-tax charge related to the cancellation of these turbine purchase commitments (see **Note 13**).

In the second and third quarters of 2003, Tampa Electric returned approximately $158 million of capital to TECO Energy. TECO Energy had previously contributed capital to Tampa Electric in support of Tampa Electric's construction program in the wholesale business, which was subsequently scaled back.

A summary of activities between Tampa Electric Company and its affiliates follows:

Net transactions with affiliates:

(millions)	*2005*	*2004*	*2003*
Fuel and interchange related, net	$ 82.5	$ 70.2	$ 173.6
Administrative and general, net	$ 13.3	$ 9.1	$ 13.7

Amounts due from or to affiliates of the company at Dec. 31,

(millions)	*2005*	*2004*
Accounts receivable [1]	$ 4.9	$ 4.5
Accounts payable [1]	$ 12.2	$ 11.5

(1) Accounts receivable and accounts payable were incurred in the ordinary course of business and do not bear interest.

11. Segment Information

Tampa Electric Company is a public utility operating within the state of Florida. Through its Tampa Electric division, it is engaged in the generation, purchase, transmission, distribution and sale of electric energy to more than 645,000 customers in West Central Florida. Its Peoples Gas System division is engaged in the purchase, distribution and marketing of natural gas for more than 321,000 residential, commercial, industrial and electric power generation customers in the state of Florida.

Segment Information

(millions)	*Tampa Electric*	*Peoples Gas*	*Other & Eliminations*	*Tampa Electric Company*
2005				
Revenues – outsiders	$1,744.3	$ 549.5	$ —	$2,293.8
Sales to affiliates	2.5	—	(0.6)	1.9
Total revenues	$1,746.8	$ 549.5	$ (0.6)	$2,295.7
Depreciation	187.1	35.0	—	222.1
Total interest charges	98.3	15.1	—	113.4
Provision for taxes	90.6	18.5	—	109.1
Net income	$ 147.1	$ 29.6	$ —	$ 176.7
Total assets	4,438.2	721.5	(3.5)	5,156.2
Capital expenditures	$ 203.5	$ 42.5	$ —	$ 246.0
2004				
Revenues – outsiders	$1,683.8	$ 417.2	$ —	$2,101.0
Sales to affiliates	3.6	—	(0.7)	2.9
Total revenues	$1,687.4	$ 417.2	$ (0.7)	$2,103.9
Depreciation	180.9	34.1	(0.1)	214.9
Restructuring costs [(1)]	—	0.7	—	0.7
Total interest charges	95.8	15.2	—	111.0
Provision for taxes	83.9	17.3	—	101.2
Net income	$ 146.0	$ 27.7	$ —	$ 173.7
Total assets	4,055.9	671.1	(1.1)	4,725.9
Capital expenditures	$ 181.2	$ 38.7	$ —	$ 219.9
2003				
Revenues – outsiders	$1,582.7	$ 408.4	$ —	$1,991.1
Sales to affiliates	3.4	—	(0.7)	2.7
Total revenues	$1,586.1	$ 408.4	$ (0.7)	$1,993.8
Depreciation	210.3	32.7	—	243.0
Restructuring costs [(1)]	9.9	4.1	—	14.0
Total interest charges	85.0	15.6	—	100.6
Provision for taxes	48.3 [(2)]	15.7	—	64.0
Net income	$ 98.9 [(2)]	$ 24.5	$ —	$ 123.4
Total assets	4,178.6	651.5	9.6	4,839.7
Capital expenditures	$ 289.1	$ 42.6	$ —	$ 331.7

(1) See **Note 14** for a discussion of restructuring charges in 2004 and 2003.

(2) Net income for 2003 includes a $48.9 million after-tax charge ($79.6 million pretax) asset impairment charge related to the turbine purchase cancellations (see **Note 13**).

12. Asset Retirement Obligations

On Jan. 1, 2003, Tampa Electric Company adopted FAS 143, *Accounting for Asset Retirement Obligations*. The company recognized liabilities for retirement obligations associated with certain long-lived assets, in accordance with the relevant accounting guidance. 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 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.

As a result of the adoption of FAS 143 in 2003, Tampa Electric Company recorded an increase to net property, plant and equipment of $0.1 million (net of accumulated depreciation), an increase in regulatory assets of $0.2 million, and an increase to asset retirement obligations of $0.3 million. The after-tax charge recorded as a change in accounting principle was not material.

As a result of the adoption of FIN 47 in the fourth quarter of 2005, Tampa Electric recorded an increase to net property, plant and equipment of $3.6 million (net of accumulated depreciation of $0.4 million), an increase to regulatory assets of $2.7 million and an increase to asset retirement obligations of $18.3 million (including $12.1 million reclassified from a regulatory liability). If FIN 47 had been applied for all periods presented, the pro forma asset retirement obligation would have been $18.3 million and $18.5 million as of Jan. 1, 2004 and Dec. 31, 2004, respectively.

For years ended Dec. 31, 2005, 2004 and 2003, accretion expense associated with asset retirement obligations for Tampa Electric Company was not material. During this period, no significant revisions to estimated cash flows used in determining the recognized asset retirement obligations were necessary.

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.

Upon adoption of FAS 143 at Jan. 1, 2003, the estimated accumulated cost of removal and dismantlement included in net accumulated depreciation at Dec. 31, 2003 of $462.2 million was reclassified to a regulatory liability (see also **Note 3**). 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 are charged to accumulated depreciation and the accumulated cost of removal reserve reported as a regulatory liability, respectively.

13. Asset Impairments

In 2003, Tampa Electric Company recorded a $48.9 million after-tax charge ($79.6 million pretax) to reflect the impact of the cancellation of turbine purchase commitments. As reported previously and in **Note 10**, certain turbine rights had been transferred from Other Unregulated operations of TECO Energy to Tampa Electric in 2002 for use in Tampa Electric's generation expansion activities. These cancellations, made in April 2003, fully terminate all turbine purchase obligations.

There were no asset impairments recognized in the years ended Dec. 31, 2005 or 2004.

14. Restructuring Costs

In 2003, TECO Energy announced a corporate reorganization to restructure the company along functional lines, consistent with its objectives to grow the core utility operations, maintain liquidity, generate cash and maximize the value in the existing assets. Tampa Electric Company completed these actions mid-year 2004. As a result of these actions, TECO Energy is now aligned to provide for centralized oversight along functional lines for power plant operations, energy delivery, energy management, and human resources and technology/support services. These actions included the involuntary termination or retirement of one employee in 2004, and 232 employees in 2003 at Tampa Electric Company, including officers and other personnel from operations and support services.

Tampa Electric Company recognized pretax expense of $0.7 million and $14.0 million for accrued benefits and other termination and retirement benefits for the years ended Dec. 31, 2004 and 2003, respectively, which have all been paid or otherwise settled as of Dec. 31, 2004.

Restructuring Charges *(millions)* *For the years ended Dec. 31,*	*2005*	*2004*	*2003*
Tampa Electric	$ —	$ —	$ 9.9
Peoples Gas	—	0.7	4.1
Total Tampa Electric Company	$ —	$ 0.7	$ 14.0

Accrued Liability for Restructuring Costs *(millions)*	*2005*	*2004*	*2003*
Beginning balance	$ —	$ 10.7	$ 5.1
Charged to income (pretax)	—	0.7	14.0
Payments and settlements	—	11.4	8.4
Ending balance	$ —	$ —	$ 10.7

15. Derivatives and Hedging

From time to time, Tampa Electric Company enters 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.

The company uses derivatives only to reduce normal operating and market risks, not for speculative purposes. The company's primary objective is to reduce the impact of market price volatility on ratepayers, and uses derivative instruments primarily to optimize the value of physical assets, including generation capacity, natural gas production and natural gas delivery.

The risk management policies adopted by the company provide a framework through which management monitors various risk exposures. Daily and periodic reporting of positions and other relevant metrics are performed by a centralized risk management group which is independent of all operating companies.

The company applies the provisions of FAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by FAS 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activity* and FAS 149, *Amendment on Statement 133 on Derivative Instruments and Hedging Activities*. These standards require companies to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as either components of other comprehensive income (OCI) or in net income, depending on the designation of those instruments. The changes in fair value that are recorded in OCI are not immediately recognized in current net income. As the underlying hedged transaction matures or the physical commodity is delivered, the deferred gain or the loss on the related hedging instrument must be reclassified from OCI to earnings based on its value at the time of its reclassification. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the amount paid or received on the underlying physical transaction. Additionally, amounts deferred in OCI related to an effective designated cash flow hedge must be reclassified to current earnings if the anticipated hedged transaction is no longer probable of occurring.

At Dec. 31, 2005 and 2004, respectively, the company had net derivative assets (liabilities) of $62.8 million and ($11.7) million. As a result of applying the provision of FAS 71, the change in value of these derivatives is recorded as regulatory assets or liabilities as of Dec. 31, 2005 and 2004, respectively, to reflect the impact of the fuel recovery clause on the risks of hedging activities (see **Note 3**).

Based on the fair values of derivatives at Dec. 31, 2005, pretax gains of $57.9 million are expected to be reversed from regulatory assets or liabilities to the Consolidated Statements of Income within the next twelve months. However, these gains and other future reclassifications from regulatory assets or liabilities will fluctuate with movements in the underlying market price of the derivative instruments. The company does not currently have any cash flow hedges for transactions forecasted to take place in periods subsequent to 2007.

16. Subsequent Events

Issuance of Series 2006 Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project)

On Jan. 19, 2006, the Hillsborough County Industrial Development Authority (HCIDA) issued $85.95 million of HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2006 (Series 2006 Bonds) for the benefit of Tampa Electric. Tampa Electric is responsible for payment of the interest and principal associated with the Series 2006 Bonds. The proceeds of this issuance, together with available cash, were used to call and retire in February 2006 $85.95 million of the existing HCIDA Pollution Control Revenue Bonds Series 1994 (the Series 1994 Bonds), which had a maturity date of Dec. 1, 2034. Costs of the issuance were paid from available funds of Tampa Electric. Tampa Electric entered into a Loan and Trust Agreement with the HCIDA, as issuer, and The Bank of New York, as trustee in connection with the issuance of the Series 2006 Bonds.

The Series 2006 Bonds mature on Dec. 1, 2034 and bear interest at an auction rate, which was initially set at 2.80% and will be reset pursuant to an auction procedure at the end of every auction period, which was initially set at seven days. In connection with the issuance of the Series 2006 Bonds, Tampa Electric entered into an insurance agreement with Ambac Assurance Corporation pursuant to which Ambac Assurance Corporation issued a financial guaranty insurance policy, providing insurance for Tampa Electric's obligation for payment on the Series 2006 Bonds and allowing the Series 2006 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's ability to incur certain liens, subject to a number of exceptions, without equally and ratably securing these notes.

During any auction period Tampa Electric may redeem all or any part of the Series 2006 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 2006 Bonds to be redeemed, plus 100% of the principal amount of the Series 2006 Bonds to be redeemed. The Series 2006 Bonds are also subject to special mandatory redemption in the event that interest payable on any Series 2006 Bonds has become subject to federal income tax in accordance with the Loan and Trust Agreement.

Redemption of Series 1994 Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project)

On Feb. 24, 2006, pursuant to the terms of the indenture governing $85.95 million of Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 1994 and at Tampa Electric's and the HCIDA's direction, the trustee redeemed the Series 1994 Bonds. The redemption price was equal to 101% of par plus accumulated but unpaid distributions to Feb. 24, 2006.

Extension of Maturity of Tampa Electric's Accounts Receivable Securitized Borrowing Facility

On Jan. 5, 2006, Tampa Electric and TEC Receivables Corp (TRC), a wholly-owned subsidiary of Tampa Electric, extended the maturity of Tampa Electric's $150 million accounts receivable securitized borrowing facility from Jan. 5, 2006 to Jan. 4, 2007. See Note 6 for a more detailed description of the facility.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

During the period Jan. 1, 2004 to the date of this report, neither TECO Energy nor Tampa Electric Company has had or has filed with the Commission a report as to any changes in or disagreements with accountants on accounting principles or practices, financial statement disclosure, or auditing scope or procedure.

Item 9A. CONTROLS AND PROCEDURES

TECO Energy, Inc.

Conclusions Regarding Effectiveness of Disclosure Controls and Procedures.

TECO Energy's management, with the participation of its principal executive officer and principal financial officer, has evaluated the effectiveness of TECO Energy's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this annual report (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 and designed to ensure that the information relating to TECO Energy (including its consolidated subsidiaries) required to be included in TECO Energy's reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the requisite time periods.

Management's Report on Internal Control over Financial Reporting.

Management's Report on Internal Control Over Financial Reporting is on page 79 of this report.

Management's assessment of the effectiveness of TECO Energy, Inc.'s internal control over financial reporting as of Dec. 31, 2005 has been audited by PricewaterhouseCoopers LLP, an independent registered certified public accounting firm, as stated in their report which is on pages 78 and 79 of this report.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. A control system, no matter how well designed and operated, can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Changes in Internal Control over Financial Reporting.

There was no change in TECO Energy's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) identified in connection with the evaluation of TECO Energy's internal controls that occurred during TECO Energy's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, such controls.

Tampa Electric Company

Conclusions Regarding Effectiveness of Disclosure Controls and Procedures.

Tampa Electric Company's management, with the participation of its principal executive officer and principal financial officer, has evaluated the effectiveness of Tampa Electric Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this annual report (the "Evaluation Date"). Based on such evaluation, Tampa Electric Company's principal executive officer and principal financial officer have concluded that, as of the Evaluation Date, Tampa Electric Company's disclosure controls and procedures are effective and designed to ensure that the information relating to Tampa Electric Company (including its consolidated subsidiaries) required to be included in Tampa Electric Company's reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the requisite time periods.

Changes in Internal Control over Financial Reporting.

There was no change in Tampa Electric Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) identified in connection with the evaluation of Tampa Electric Company's internal controls that occurred during Tampa Electric Company's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, such controls.

Item 9B. OTHER INFORMATION

None.

PART III

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

(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, dated Mar. 15, 2006, for its Annual Meeting of Shareholders to be held on Apr. 26, 2006 (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 35 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 on the Investor Relations page 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 under the captions "Compensation Committee Report on Executive Compensation", "Summary Compensation Table", "Option Grants in Last Fiscal Year", "Aggregated Option Exercises in Last Fiscal Year and Fiscal Year-End Option Value", "Long Term Incentive Plans-Awards in Last Fiscal Year", "Pension Table" and "Employment, Termination and Change in Control Arrangements" 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.

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	9,694	$ 20.33	8,713
1997 Director Equity Plan	253	$ 20.93	196
	9,947	$ 20.35	8,909
Equity compensation plans/arrangements not approved by the stockholders			
None	—	—	—
Total	9,947	$ 20.35	8,909

(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.

The information required by Item 13 is included under the caption "Certain Relationships and Related Transactions" 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, Inc. is included under the caption "Independent Public Accountants" in the Proxy Statement and is incorporated herein by reference.

Tampa Electric Company incurred $1.0 million and $1.0 million in audit related fees rendered by PricewaterhouseCoopers in 2005 and 2004, respectively, including $0.4 million and $0.6 million in 2005 and 2004, respectively, related to Sarbanes-Oxley. No other specific fees were incurred at Tampa Electric Company in those years, related to PricewaterhouseCoopers.

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 77
   Tampa Electric Company Financial Statements – See index on page 133
2. Financial Statement Schedules
   Condensed Parent Company Financial Statements Schedule I – pages 166 – 169
   TECO Energy, Inc. Schedule II – page 170
   Tampa Electric Company Schedule II – page 171
3. Exhibits – See index beginning on page 175

(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

Assets *(millions)*	*Dec. 31, 2005*	*Dec. 31, 2004*
Current assets		
Cash and cash equivalents	$ 330.0	$ 70.4
Restricted cash	7.3	7.0
Advances to affiliates	400.4	3,069.6
Accounts receivable from affiliates	2.8	13.9
Other current assets	6.8	1.2
Total current assets	747.3	3,162.1
Other assets		
Investment in subsidiaries	2,533.9	568.7
Deferred income taxes	1,801.7	483.7
Other assets	24.5	35.3
Total other assets	4,360.1	1,087.7
Total assets	$ 5,107.4	$ 4,249.8

Liabilities and capital		
Current liabilities		
Notes payable	$ —	$ —
Accounts payable to affiliates	0.8	0.4
Accounts payable	24.2	8.9
Interest payable	21.7	19.6
Taxes accrued	578.8	—
Other current liabilities	(0.5)	7.1
Total current liabilities	625.0	36.0
Other liabilities		
Advances from affiliates	316.1	283.6
Deferred income taxes	399.1	318.9
Long-term debt		
Junior subordinated	177.7	277.7
Others	1,900.6	1,964.4
Other liabilities	97.2	85.3
Total other liabilities	2,890.7	2,929.9
Capital		
Common equity	208.2	199.7
Additional paid in capital	1,527.0	1,489.4
Retained earnings (deficit)	(83.1)	(357.6)
Accumulated other comprehensive income	(51.1)	(43.8)
Common equity	1,601.0	1,287.7
Unearned compensation	(9.3)	(3.8)
Total capital	1,591.7	1,283.9
Total liabilities and capital	$ 5,107.4	$ 4,249.8

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

SCHEDULE I – CONDENSED PARENT COMPANY FINANCIAL STATEMENTS

TECO ENERGY, INC.
PARENT COMPANY ONLY
Condensed Statements of Income

For the years ended Dec. 31, (millions)	*2005*	*2004*	*2003*
Revenues	$ —	$ 1.7	$ 4.4
Expenses			
Administrative and general expenses	10.1	19.4	7.2
Restructuring charges	0.1	—	2.6
Total expenses	10.2	19.4	9.8
Income from operations	(10.2)	(17.7)	(5.4)
Loss on debt extinguishment	(74.2)	(4.4)	—
Earnings (losses) from investments in subsidiaries	433.6	(470.3)	(873.2)
Interest income (expense)			
Interest income			
Affiliates	36.8	78.2	139.3
Others	9.6	—	—
Interest expense			
Affiliates	—	(29.6)	(43.0)
Others	(166.7)	(178.9)	(171.9)
Total interest expense	(120.3)	(130.3)	(75.6)
Income (loss) before income taxes	228.9	(622.7)	(954.2)
(Benefit) for income taxes	(45.6)	(70.7)	(48.0)
Net income (loss)	274.5	(552.0)	(906.2)
Cumulative effect of change in accounting principle, net of tax	—	—	(3.2)
Net income (loss)	$ 274.5	$ (552.0)	$ (909.4)

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

SCHEDULE I – CONDENSED PARENT COMPANY FINANCIAL STATEMENTS

TECO ENERGY, INC.
PARENT COMPANY ONLY
Condensed Statements of Cash Flows

For the years ended Dec. 31, (millions)	*2005*	*2004*	*2003*
Cash flows from operating activities	$ (59.9)	$ 91.7	$ 10.2
Cash flows from investing activities			
Restricted cash	(0.3)	—	—
Investment in subsidiaries	—	28.7	156.7
Dividends from subsidiaries	275.6	219.4	296.0
Net change in affiliate advances	189.7	32.9	(741.2)
Cash flows from investing activities	465.0	281.0	(288.5)
Cash flows from financing activities			
Dividends to shareholders	(157.7)	(145.2)	(165.2)
Common stock	196.4	10.2	136.6
Proceeds from long-term debt – others	297.8	—	296.8
Repayment of long-term debt – others	(480.0)	(122.7)	—
Early exchange of equity units	—	(17.7)	—
Net increase (decrease) in short-term debt	—	(37.5)	(312.5)
Equity contract adjustment payments	(2.0)	(17.4)	(20.3)
Cash flows from financing activities	(145.5)	(330.3)	(64.6)
Net (decrease) increase in cash and cash equivalents	259.6	42.4	(342.9)
Cash and cash equivalents at beginning of period	70.4	28.0	370.9
Cash and cash equivalents at end of period	$ 330.0	$ 70.4	$ 28.0

The accompanying notes are an integral part of the condensed 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.

2. Long-term Obligations

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.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

TECO ENERGY, INC.
For the Years Ended Dec. 31, 2005, 2004 and 2003
(millions)

	Balance at Beginning of Period	Additions: Charged to Income	Additions: Other Charges	Payments & Deductions [1]	Balance at End of Period
Allowance for Uncollectible Accounts:					
2005	$ 8.0	$ 8.7	$ —	$ 9.8	$ 6.9
2004	$ 4.5	$ 8.4 [2]	$ 0.4	$ 5.3	$ 8.0
2003	$ 6.6	$ 7.0	$ (1.8) [3]	$ 7.3	$ 4.5

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(1) Write-off of individual bad debt accounts
(2) Includes $3.1 million charged to discontinued operations for asset impairments for BCH
(3) Includes $1.1 million of bad debt reserves for Prior Energy and BGA that were moved to assets held for sale

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

TAMPA ELECTRIC COMPANY
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
For the Years Ended Dec. 31, 2005, 2004 and 2003
(millions)

	Balance at Beginning of Period	Additions: Charged to Income	Additions: Other Charges	Payments & Deductions [1]	Balance at End of Period
Allowance for Uncollectible Accounts:					
2005	$ 1.0	$ 8.5	$ —	$ 8.2	$ 1.3
2004	$ 1.1	$ 4.7	$ —	$ 4.8	$ 1.0
2003	$ 1.1	$ 4.4	$ —	$ 4.4	$ 1.1

(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 on the 6th day of March, 2006.

TECO ENERGY, INC.

By: /s/ S. W. HUDSON

S. 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 March 6, 2006:

Signature	Title
/s/ S. W. HUDSON S. W. HUDSON	Chairman of the Board, Director and Chief Executive Officer (Principal Executive Officer)
/s/ G. L. GILLETTE G. L. GILLETTE	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ S. M. PAYNE S. M. PAYNE	Vice President-Corporate Accounting and Tax and Assistant Secretary (Principal Accounting Officer)

Signature	Title	Signature	Title
/s/ C. D. AUSLEY C. D. AUSLEY	Director	/s/ W. D. ROCKFORD W. D. ROCKFORD	Director
/s/ S. L. BALDWIN S. L. BALDWIN	Director	W. P. SOVEY	Director
/s/ J. L. FERMAN, JR. J. L. FERMAN, JR.	Director	/s/ J. T. TOUCHTON J. T. TOUCHTON	Director
/s/ L. GUINOT, JR. L. GUINOT, JR.	Director	/s/ J. O. WELCH, JR. J. O. WELCH, JR.	Director
/s/ L.A. PENN L.A. PENN	Director	/s/ P. L. WHITING P. L. WHITING	Director
/s/ T. L. RANKIN T. L. RANKIN	Director		

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 6th day of March, 2006.

TAMPA ELECTRIC COMPANY

By: /s/ S. W. HUDSON

S. 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 March 6, 2006:

Signature	Title
/s/ S. W. HUDSON S. W. HUDSON	Chairman of the Board, Director and Chief Executive Officer (Principal Executive Officer)
/s/ G. L. GILLETTE G. L. GILLETTE	Senior Vice President-Finance and Chief Financial Officer (Principal Financial Officer)
/s/ P. L. BARRINGER P. L. BARRINGER	Chief Accounting Officer (Principal Accounting Officer)

Signature	Title	Signature	Title
/s/ C. D. AUSLEY C. D. AUSLEY	Director	/s/ W. D. ROCKFORD W. D. ROCKFORD	Director
/s/ S. L. BALDWIN S. L. BALDWIN	Director	W. P. SOVEY	Director
/s/ J. L. FERMAN, JR. J. L. FERMAN, JR.	Director	/s/ J. T. TOUCHTON J. T. TOUCHTON	Director
/s/ L. GUINOT, JR. L. GUINOT, JR.	Director	/s/ J. O. WELCH, JR. J. O. WELCH, JR.	Director
/s/ L.A. PENN L.A. PENN	Director	/s/ P. L. WHITING P. L. WHITING	Director
/s/ T. L. RANKIN T. L. RANKIN	Director		

Supplemental Information to Be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act

No annual report or proxy material has been sent to Tampa Electric Company's security holders because all of its equity securities are held by TECO Energy, Inc.

INDEX TO EXHIBITS

Exhibit No.	Description	
2.1.1	Purchase and Sales Agreement, dated as of Dec. 1, 2004, by and among TPS Tejas GP, LLC and TPS Tejas LP, LLC as the Sellers, and Frontera Generation GP, Inc. and Centrica US Holdings Inc. as the Purchasers. (Exhibit 2.1, Form 8-K dated Dec. 22, 2004 of TECO Energy, Inc.) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment under Rule 24b-2 of the Securities Exchange Act of 1934, as amended, and the omitted material has been separately filed with the Securities and Exchange Commission.).	*
2.1.2	Amendment No. 1, dated Dec. 22, 2004, to Purchase and Sales Agreement, by and among TPS Tejas GP, LLC and TPS Tejas LP, LLC as the Sellers, and Frontera Generation GP, Inc. and Centrica US Holdings Inc. as the Purchasers (Exhibit 2.2, Form 8-K dated Dec. 22, 2004 of TECO Energy, Inc.).	*
2.2	Stock Purchase Agreement dated as of Dec. 31, 2004, by and between TECO Solutions, Inc. as Seller, and BCH Holdings, Inc. as Purchaser (Exhibit 2.1, Form 8-K dated Jan. 7, 2005 of TECO Energy, Inc.).	*
3.1	Articles of Incorporation of TECO Energy, Inc., as amended on Apr. 20, 1993 (Exhibit 3, Form 10-Q for the quarter ended Mar. 31, 1993 of TECO Energy, Inc.).	*
3.2	Bylaws of TECO Energy, Inc., as amended effective Jul. 6, 2004 (Exhibit 3.2 to Registration Statement No. 333-117701 of TECO Energy, Inc.).	*
3.3	Articles of Incorporation of Tampa Electric Company (Exhibit 3 to Registration Statement No. 2-70653 of Tampa Electric Company).	*
3.4	Bylaws of Tampa Electric Company, as amended effective Apr. 16, 1997 (Exhibit 3 Form 10-Q for the quarter ended Jun. 30, 1997 of Tampa Electric Company).	*
4.1.1	Installment Purchase Contract between the Hillsborough County Industrial Development Authority and Tampa Electric Company, dated as of Jan. 31, 1984 (Exhibit 4.13, Form 10-K for 1993 of TECO Energy, Inc.).	*
4.1.2	First Supplemental Installment Purchase Contract between Hillsborough County Industrial Development Authority and Tampa Electric Company, dated as of Aug. 2, 1984 (Exhibit 4.14, Form 10-K for 1994 of TECO Energy, Inc.).	*
4.1.3	Second Supplemental Installment Purchase Contract between Hillsborough County Industrial Development Authority and Tampa Electric Company, dated as of Jul. 1, 1993 (Exhibit 4.3, Form 10-Q for the quarter ended Jun. 30, 1993 of TECO Energy, Inc.).	*
4.2	Loan and Trust Agreement among the Hillsborough County Industrial Development Authority, Tampa Electric Company and NCNB National Bank of Florida, as trustee, dated as of Sep. 24, 1990 (Exhibit 4.1, Form 10-Q for the quarter ended Sep. 30, 1990 of TECO Energy, Inc.).	*
4.3	Loan and Trust Agreement among the Hillsborough County Industrial Development Authority, Tampa Electric Company and NationsBank of Florida, N.A., as trustee, dated as of Oct. 26, 1992 (Exhibit 4.2, Form 10-Q for the quarter ended Sep. 30, 1992 of TECO Energy, Inc.).	*
4.4	Loan and Trust Agreement among the Hillsborough County Industrial Development Authority, Tampa Electric Company and NationsBank of Florida, N.A., as trustee, dated as of Jun. 23, 1993 (Exhibit 4.2, Form 10-Q for the quarter ended Jun. 30, 1993 of TECO Energy, Inc.).	*
4.5	Loan and Trust Agreement among Hillsborough County Industrial Development Authority, Tampa Electric Company and The Bank of New York Trust Company of Florida, N.A., as trustee, dated as of Jun. 1, 2002. (Exhibit 4.5, Amendment No. 1 to Form 10-K for 2004 of TECO Energy, Inc.).	*
4.6	Loan and Trust Agreement among the Polk County Industrial Development Authority, Tampa Electric Company and The Bank of New York, as trustee, dated as of Dec. 1, 1996 (Exhibit 4.22, Form 10-K for 1996 of TECO Energy, Inc.).	*
4.7	Loan and Trust Agreement dated as of Jan. 5, 2006 between Tampa Electric Company and The Bank of New York Trust Company, N.A., as trustee (including the form of bond) (Exhibit 4.1, Form 8-K dated Jan. 19, 2006 of Tampa Electric Company).	
4.8	Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of Jul. 1, 1998 (Exhibit 4.1, Registration Statement No. 333-55873 of Tampa Electric Company).	*
4.9	Third Supplemental Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of Jun. 15, 2001 (Exhibit 4.2, Form 8-K dated Jun. 25, 2001 of Tampa Electric Company).	*
4.10	Fourth Supplemental Indenture between Tampa Electric Company and The Bank of New York,	*

	as trustee, dated as of Aug. 15, 2002 (Exhibit 4.2, Form 8-K dated Aug. 26, 2002 of Tampa Electric Company).	
4.11.1	Amended and Restated Note Agreement dated as of May 30, 1997 between Tampa Electric Company (successor by merger to Peoples Gas System, Inc.) and The Prudential Insurance Company of America (Exhibit 4.2, Form 8-K dated Dec. 15, 2004 of TECO Energy, Inc.).	*
4.12.2	Letter Amendment No. 1 dated as of Dec. 9, 2004 to the Amended and Restated Note Agreement dated as of May 30, 1997 between Tampa Electric Company (successor by merger to Peoples Gas System, Inc.) and The Prudential Insurance Company of America (Exhibit 4.1, Form 8-K dated Dec. 15, 2004 of TECO Energy, Inc., and Tampa Electric Company).	*
4.13	Note Purchase Agreement among Tampa Electric Company and the Purchasers party thereto, dated as of Apr. 11, 2003 (Exhibit 10.1, Form 8-K dated Apr. 14, 2003 of Tampa Electric Company).	*
4.14	Indenture between TECO Energy, Inc. and The Bank of New York, as trustee, dated as of Aug. 17, 1998 (Exhibit 4.1, Form 8-K dated Sep. 20, 2000 of TECO Energy, Inc.).	*
4.15	Second Supplemental Indenture dated as of Sep. 15, 2000 between TECO Energy, Inc. and The Bank of New York (Exhibit 4.1, Form 8-K dated Sep. 28, 2000 of TECO Energy, Inc.).	*
4.16.1	Third Supplemental Indenture dated as of Dec. 1, 2000 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.21, Form 8-K dated Dec. 21, 2000 of TECO Energy, Inc.).	*
4.16.2	Amended and Restated Limited Liability Company Agreement of TECO Funding Company I, LLC dated as of Dec. 1, 2000 (Exhibit 4.24, Form 8-K dated Dec. 21, 2000 of TECO Energy, Inc.).	*
4.16.3	Amended and Restated Trust Agreement of TECO Capital Trust I among TECO Funding Company I, LLC, The Bank of New York and The Bank of New York (Delaware) dated as of Dec. 1, 2000 (Exhibit 4.22, Form 8-K dated Dec. 21, 2000 of TECO Energy, Inc.).	*
4.16.4	Guaranty Agreement between TECO Energy, Inc. and The Bank of New York, as trustee, dated of Dec. 1, 2000 (Exhibit 4.25, Form 8-K dated Dec. 21, 2000 of TECO Energy, Inc.).	*
4.17	Fourth Supplemental Indenture dated as of Apr. 30, 2001 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.28, Form 8-K dated May 1, 2001 of TECO Energy, Inc.).	*
4.18	Fifth Supplemental Indenture dated as of Sep. 10, 2001 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.16, Form 8-K dated Sep. 26, 2001 of TECO Energy, Inc.).	*
4.18.1	Sixth Supplemental Indenture dated as of Jan. 15, 2002 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.28, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.18.2	Amended and Restated Trust Agreement of TECO Capital Trust II among TECO Funding Company II, LLC, The Bank of New York and The Bank of New York (Delaware), dated as of Jan. 15, 2002 (Exhibit 4.31, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.18.3	Amended and Restated Limited Liability Agreement of TECO Funding Company II, LLC, dated as of Jan. 15, 2002 (Exhibit 4.33, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.).	*
4.18.4	Guarantee Agreement by and between TECO Energy, Inc., as Guarantor and The Bank of New York, dated as of Jan. 15, 2002 (Exhibit 4.35, Form 8-K dated Jan. 15, 2002 of TECO Energy, Inc.	*
4.19	Seventh Supplemental Indenture dated as of May 1, 2002 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.15, Form 8-K dated May 13, 2002 of TECO Energy, Inc.).	*
4.20	Eighth Supplemental Indenture dated as of Nov. 20, 2002 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.1, Form 8-K dated Nov. 20, 2002 of TECO Energy, Inc.).	*
4.21	Ninth Supplemental Indenture dated as of Jun. 10, 2003 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.15, Form 8-K dated Jun. 13, 2003 of TECO Energy, Inc.).	*
4.22	Tenth Supplemental Indenture dated as of May 26, 2005 between TECO Energy, Inc. and The Bank of New York, as trustee (including the form of 6.75% Note) (Exhibit 4.1, Form 8-K dated May 26, 2005 of TECO Energy, Inc.).	*
4.23	Eleventh Supplemental Indenture dated as of Jun. 7, 2005 between TECO Energy, Inc. and The Bank of New York, as trustee (including the form of Floating Rate Note) (Exhibit 4.1, Form 8-K dated Jun. 7, 2005 of TECO Energy, Inc.).	*
4.24	Installment Sales Agreement between the Plaquemines Port, Harbor and Terminal District (Louisiana) and Electro-Coal Transfer Corporation, dated as of Sep. 1, 1985 (Exhibit 4.19, Form 10-K for 1986 of TECO Energy, Inc.).	*
4.25	First Supplemental Installment Sales Agreement, between Plaquemines Port, Harbor, and Terminal District (Louisiana) and Electro-Coal Transfer Corporation, dated Dec. 20, 2000 (Exhibit 4.20, Form 10-K for 2000 of TECO Energy, Inc.).	*
4.26	Amended and Restated Reimbursement Agreement between TECO Energy, Inc. and Electro-Coal Transfer LLC, dated as of Apr. 5, 2001 (Exhibit 4.1, Form 8-K date Apr. 5, 2001 of TECO Energy,	*

	Inc.).	
4.27	Renewed Rights Agreement between TECO Energy, Inc. and The Bank of New York., as Rights Agent, as amended and restated as of Feb. 2, 2004 (Exhibit 1, Form 8-A/A, of TECO Energy, Inc. filed on Feb. 23, 2004).	*
10.1.1	TECO Energy Group Supplemental Executive Retirement Plan, as amended and restated as of Jul. 1, 1998, as further amended as of Jul. 15, 1998. (Exhibit 10.1, Form 10-K for 2001 of TECO Energy, Inc.).	*
10.1.2	First Amendment to TECO Energy Group Supplemental Executive Retirement Plan, dated as of May 26, 2005.	
10.2	TECO Energy Group Supplemental Retirement Benefits Trust Agreement, as amended and restated as of Jan. 1, 1998, as further amended as of Jul. 15, 1998. (Exhibit 10.2, Form 10-K for 2001 of TECO Energy, Inc.).	*
10.3	Annual Incentive Compensation Plan for TECO Energy and subsidiaries, revised as of Apr. 17, 2002. (Exhibit 10.1, Form 10-Q for the quarter ended Jun. 30, 2002 of TECO Energy, Inc.).	*
10.4	TECO Energy Group Supplemental Disability Income Plan, dated as of Mar. 20, 1998 (Exhibit 10.22, Form 10-K for 1988 of TECO Energy, Inc.).	*
10.5	Form of Change-in-Control Severance Agreement between TECO Energy, Inc. and Executive Officers.	
10.6	TECO Energy Directors' Deferred Compensation Plan, as amended and restated effective as of Apr. 1, 1994 (Exhibit 10.1, Form 10-Q for the quarter ended Mar. 31, 1994 of TECO Energy, Inc.)	*
10.7	Form of Nonstatutory Stock Option under the TECO Energy, Inc. 1996 Equity Incentive Plan (and its successor plan) (Exhibit 10.5, Form 10-Q for the quarter ended Jun. 30, 1999 of TECO Energy, Inc.).	*
10.8	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 1996 Equity Incentive Plan as amended and restated (and its successor plan) (Exhibit 10.2, Form 10-Q for the quarter ended Mar. 31, 2003 of TECO Energy, Inc.).	*
10.9	TECO Energy, Inc. 1997 Director Equity Plan (Exhibit 10.1, Form 8-K dated Apr. 16, 1997 of TECO Energy, Inc.).	*
10.10.1	Compensatory Arrangements with Executive Officers of TECO Energy, Inc.	
10.10.2	Compensatory Arrangements with Directors of TECO Energy, Inc.	
10.11	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 1996 Equity Incentive Plan, dated as of Jan. 28, 2003 (Exhibit 10.27, Form 10-K for 2002 of TECO Energy, Inc.).	*
10.12	Form of Nonstatutory Stock Option under the TECO Energy, Inc. 1997 Director Equity Plan, dated as of Jan. 29, 2003 (Exhibit 10.28, Form 10-K for 2002 of TECO Energy, Inc.).	*
10.13	TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.2, Form 10-Q for the quarter ended Mar. 31, 2004 of TECO Energy, Inc.).	*
10.14	Form of Performance Shares Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.19, Form 10-K for 2004 of TECO Energy, Inc.).	*
10.15	Nonstatutory Stock Option granted to S. W. Hudson, dated as of Jul. 6, 2004, under the TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.1, Form 10-Q for the quarter ended Jun. 30, 2004 of TECO Energy, Inc.).	*
10.16	Form of Restricted Stock Agreement between TECO Energy, Inc. and S.W. Hudson under the TECO Energy, Inc. 2004 Equity Incentive Plan.	
10.17	Insurance Agreement dated as of Jan. 5, 2006 between Tampa Electric Company and Ambac Assurance Corporation (Exhibit 10.1, Form 8-K dated Jan. 19, 2006 of Tampa Electric Company).	*
10.18	Amended and Restated Construction Contract Undertaking by TECO Energy, Inc. in favor of Union Power Partners, L.P., as Borrower, and Citibank, N.A., as Administrative Agent under the Union Power Project Credit Agreement, dated as of May 14, 2002 (Exhibit 99.5 to Registration Statement No. 333-102019 of TECO Energy, Inc.).	*
10.19	Amended and Restated Construction Contract Undertaking by TECO Energy, Inc. in favor of Panda Gila River, L.P., as Borrower, and Citibank. N.A., as Administrative Agent under the Gila River Project Credit Agreement, dated as of May 14, 2002 (Exhibit 99.4 to Registration Statement No. 333-102019 of TECO Energy, Inc.).	*
10.20	Consent and Acceleration Agreement dated as of Feb. 7, 2002 by and among TECO Power Services Corporation, TECO Energy, Inc., TPS GP, Inc., TPS LP, Inc., Panda GS V, LLC, Panda GS VI, LLC, Panda Energy International, Inc. and Bayerische Hypo-Und Vereinsbank AG, New York Branch (Exhibit 10.38, Form 10-K for 2002 of TECO Energy, Inc.).	*
10.21	Suspension of Rights and Amendment Agreement dated Oct. 22, 2003, by and among Union Power	*

	Partners, L.P., and Panda Gila River, L.P., as Borrowers, TECO Energy, Inc., Societe Generale, as LC Bank, and Citibank, NA, as Administrative Agent (Exhibit 10.1, Form 10-Q for the quarter ended Sep. 30, 2003 of TECO Energy, Inc.).	
10.22	Excerpt of Joint Plan of Reorganization Pursuant to Chapter 11 of the Bankruptcy Code of Union Power Partners, L.P., Panda Gila River, L.P., Trans-Union Interstate Pipeline, L.P., and UPP Finance Co., LLC, dated Feb. 2, 2005 (Exhibit 10.1, Form 8-K dated Jun. 1, 2005 of TECO Energy, Inc.).	*
10.23	Master Release Agreement and Amendment to Undertakings dated Jan. 24, 2005, by and among TECO-Panda Generating Company, L.P., TECO Energy Source, Inc., TECO Energy, Inc., Union Power I, LLC, Union Power II, LLC, Panda Gila River I, LLC, Panda Gila River II, LLC, Trans-Union Interstate I, LLC, Trans-Union Interstate II, LLC, Union Power Partners, L.P., Panda Gila River, L.P., Trans-Union Interstate Pipeline, L.P., UPP Finance Co., LLC, Citibank, N.A., as Administrative Agent; and the financial institutions named therein (Exhibit 10.2, Form 8-K dated Jun. 1, 2005 of TECO Energy, Inc.).	*
10.24	Representation and Indemnification Agreement dated as of Jun. 1, 2005 by and among Entegra Power Group LLC, Union Power LLC, Gila River Power LLC and Trans-Union Pipeline LLC, as Transferees, and TECO Energy, Inc. (Exhibit 10.3, Form 8-K dated Jun. 1, 2005 of TECO Energy, Inc.).	*
10.25.1	Agreement to Acquire and Charter dated as of Dec. 21, 2001, among GTC Connecticut Statutory Trust, as Shipowner, Fleet Capital Corporation, as Owner Participant, Gulfcoast Transit Company, as Seller and Charterer and TECO Energy, Inc., as Guarantor (Exhibit 10.34, Form 10-K for 2003 of TECO Energy, Inc.).	*
10.25.2	Demise charter dated as of Dec. 21, 2001, between State Street Bank And Trust Company of Connecticut, National Association, as trustee of the GTC Connecticut Statutory Trust, as Shipowner, and Gulfcoast Transit Company, as Charterer (Exhibit 10.35, Form 10-K for 2003 of TECO Energy, Inc.).	*
10.25.3	First Amendment to Demise Charter dated as of Jan. 18, 2002, between State Street Bank And Trust Company of Connecticut, National Association, as trustee of the GTC Connecticut Statutory Trust, as Shipowner, and Gulfcoast Transit Company, as Charterer (Exhibit 10.36, Form 10-K for 2003 of TECO Energy, Inc.).	*
10.25.4	First Modification Agreement, dated as of Mar. 12, 2004, among State Street Bank And Trust Company of Connecticut, National Association, solely as Trustee of GTC Connecticut Statutory Trust, as Shipowner, Fleet Capital Corporation, as Owner Participant, TECO Ocean Shipping, Inc., as Charterers, and TECO Energy, Inc., and TECO Transport Corporation, as Guarantors (Exhibit 10.43, Form 10-K for 2003 of TECO Energy, Inc.)	*
10.25.5	Amended and Restated Guarantee, dated as of Mar. 12, 2004, by TECO Energy, Inc., and TECO Transport Corporation, jointly and severally in favor of the Guaranteed Parties as defined therein (Exhibit 10.1, Form 10-Q for the quarter ended Mar. 31, 2004 of TECO Energy, Inc.).	*
10.26.1	Agreement to Acquire and Charter dated as of Dec. 30, 2002, among State Street Bank and Trust Company of Connecticut, National Association, as Trustee of TTC Trust, Ltd., as Shipowner, General Electric Capital Corporation, as Initial Owner Participant, TECO Barge Line, Inc., as Seller and Charterer, and TECO Energy, Inc. and TECO Transport Corporation, as Guarantors (Exhibit 10.38, Form 10-K for 2003 of TECO Energy, Inc.).	*
10.26.2	Demise charter dated as of Dec. 30, 2002, between State Street Bank And Trust Company of Connecticut, National Association, as trustee of TTC Trust, Ltd., as Shipowner, and TECO Barge Line, Inc., as Charterer (Exhibit 10.39, Form 10-K for 2003 of TECO Energy, Inc.).	*
10.26.3	Demise charter dated as of Dec. 30, 2002, between State Street Bank And Trust Company of Connecticut, National Association, as trustee of TTC Trust, Ltd., as Shipowner, and TECO Ocean Shipping, Inc., as Charterer (Exhibit 10.40, Form 10-K for 2003 of TECO Energy, Inc.).	*
10.26.4	First Modification Agreement dated as of Mar. 28, 2003, among State Street Bank and Trust Company of Connecticut, National Association, as Trustee of TTC Trust, Ltd., as Shipowner, General Electric Capital Corporation, as Initial Owner Participant, TECO Shipping, Inc., and TECO Barge Line, Inc., as Charterers, and TECO Energy, Inc. and TECO Transport Corporation, as Guarantors (Exhibit 10.41, Form 10-K for 2003 of TECO Energy, Inc.).	*
10.26.5	Second Modification Agreement, dated as of Mar. 9, 2004, among State Street Bank And Trust Company of Connecticut, National Association, solely as Trustee of TTC Trust, Ltd., as Shipowner, General Electric Capital Corporation and OFS Marine One, Inc., as Owner Participants, TECO Ocean Shipping, Inc., and TECO Barge Line, Inc., as Charterers, and TECO Energy, Inc., and TECO Transport Corporation as Guarantors (Exhibit 10.44, Form 10-K for 2003 of TECO Energy, Inc.).	*
10.27	Purchase and Sale Agreement dated as of Jan. 13, 2005, by and between TM Delmarva Power, L.L.C. as Seller, and TPF Chesapeake, LLC as Purchaser (Exhibit 10.1, Form 8-K dated Jan. 7, 2005	*

	of TECO Energy, Inc.).	
10.28	Registration Rights Agreement dated as of May 26, 2005 between TECO Energy, Inc. and UBS Securities LLC (as representative of the Purchasers named therein) (Exhibit 10.1, Form 8-K dated May 26, 2005 of TECO Energy, Inc.).	*
10.29	Registration Rights Agreement dated as of Jun. 7, 2005 between TECO Energy, Inc. and UBS Securities LLC (as representative of the Purchasers named therein) (Exhibit 10.1, Form 8-K dated Jun. 7, 2005 of TECO Energy, Inc.).	*
10.30	Asset Purchase and Sale Agreement dated as of Jun. 10, 2005 between TPS Dell, LLC and Associated Electric Cooperative, Inc. (Exhibit 10.1, Form 8-K dated Jun. 10, 2005 of TECO Energy, Inc.).	*
10.31	Amended and Restated Credit Agreement dated as of Oct. 11, 2005, among TECO Energy, Inc., as Borrower, TECO Finance, Inc., as LC Obligor, the Lenders and LC Issuing Banks named therein and JPMorgan Chase Bank, N.A., as Administrative Agent (Exhibit 4.1, Form 8-K dated Oct. 11, 2005 of TECO Energy, Inc. and Tampa Electric Company).	*
10.32	Amended and Restated Credit Agreement dated as of Oct. 11, 2005, among Tampa Electric Company, as Borrower, Citibank, N.A., as Administrative Agent, and the Lenders and LC Issuing Banks party thereto (Exhibit 4.2, Form 8-K dated Oct. 11, 2005 of TECO Energy, Inc. and Tampa Electric Company).	*
10.33.1	Purchase and Contribution Agreement dated as of Jan. 6, 2005, between Tampa Electric Company as the Originator and TEC Receivables Corporation as the Purchaser (Exhibit 4.1, Form 8-K dated Jan. 6, 2005 of TECO Energy, Inc. and Tampa Electric Company).	*
10.33.2	Loan and Servicing Agreement dated as of Jan. 6, 2005, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citicorp North America, Inc. as Program Agent (Exhibit 4.2, Form 8-K dated Jan. 6, 2005 of TECO Energy, Inc. and Tampa Electric Company).	*
12.1	Ratio of Earnings to Fixed Charges – TECO Energy, Inc.	
12.2	Ratio of Earnings to Fixed Charges – Tampa Electric Company.	
21	Subsidiaries of the Registrant.[ ]	
23.1	Consent of Independent Certified Public Accountants – TECO Energy, Inc.	
23.2	Consent of Independent Certified Public Accountants – Tampa Electric Company.	
23.3	Consent of Marshall Miller & Associates	
31.1	Certification of the Chief Executive Officer of TECO Energy, Inc. pursuant to Securities Exchange Act Rules 13a-14(a) and 15d-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
31.2	Certification of the Chief Financial Officer of TECO Energy, Inc. pursuant to Securities Exchange Act Rules 13a-14(a) and 15d-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
31.3	Certification of the Chief Executive Officer of Tampa Electric Company pursuant to Securities Exchange Act Rules 13a-14(a) and 15d-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
31.4	Certification of the Chief Financial Officer of Tampa Electric Company to Securities Exchange Act Rules 13a-14(a) and 15d-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
32.1	Certification of the Chief Executive Officer and Chief Financial Officer of TECO Energy, Inc. pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (1)	
32.2	Certification of the Chief Executive Officer and Chief Financial Officer of Tampa Electric Sarbanes-Oxley Act of 2002. (1)	

(1) This certification accompanies the Annual Report on Form 10-K and is not filed as part of it.

* Indicates exhibit previously filed with the Securities and Exchange Commission and incorporated herein by reference. Exhibits filed with periodic reports of TECO Energy, Inc. and Tampa Electric Company were filed under Commission File Nos. 1-8180 and 1-5007, respectively.

Certain instruments defining the rights of holders of long-term debt of TECO Energy, Inc. and its consolidated subsidiaries authorizing in each case a total amount of securities not exceeding 10% of total assets on a consolidated basis are not filed herewith. TECO Energy, Inc. will furnish copies of such instruments to the Securities and Exchange Commission upon request.

Certain instruments defining the rights of holders of long-term debt of Tampa Electric Company authorizing in each case a total amount of securities not exceeding 10% of total assets on a consolidated basis are not filed herewith. Tampa Electric Company will furnish copies of such instruments to the Securities and Exchange Commission upon request.

Executive Compensation Plans and Arrangements

Exhibits 10.1 through 10.16 above are management contracts or compensatory plans or arrangements in which executive officers or directors of TECO Energy, Inc. participate.

Exhibit 10.10.1

Compensatory Arrangements with Executive Officers

Compensation for executives at TECO Energy, Inc. (the "Corporation") consists of several components. Included among these are base salary and an annual incentive award program.

Base salary information for named executive officers for 2006 is set forth in the table below.

The Corporation's annual incentive plan, last amended in 2002, is included as Exhibit 10.3 to the Corporation's Annual Report on Form 10-K to which this document is an exhibit (the "Report"). The 2006 target award percentages for awards under the annual incentive plan for the named executive officers are set forth in the table below.

Compensatory arrangements relating to other aspects of the Corporation's executive compensation program are included as exhibits to the Report.

Named Executive Officer Salary and Target Award Percentage Information for 2006

Name	Title	Salary	Target Award %
Sherrill W. Hudson	Chairman and CEO	$775,000*	70%
John B. Ramil	President and Chief Operating Officer	$500,000	65%
Gordon L. Gillette	Executive Vice President and Chief Financial Officer	$427,000	55%
Charles R. Black	President of Tampa Electric	$345,000	50%
William N. Cantrell	President of Peoples Gas System	$345,000	40%

* Mr. Hudson's 2006 salary consists of $250,000 in cash and TECO Energy restricted shares valued at $525,000, with the restrictions lapsing in four quarterly installments. Mr. Hudson also receives a monthly housing and travel allowance of $5,000, in recognition of his retaining his primary residence in Miami.

TECO ENERGY, INC.
2004 EQUITY INCENTIVE PLAN

Restricted Stock Agreement

TECO Energy, Inc. (the "Company") and Sherrill W. Hudson (the "Grantee") have entered into this Restricted Stock Agreement (the "Agreement") dated ___________ under the Company's 2004 Equity Incentive Plan (the "Plan"). Capitalized terms not otherwise defined herein have the meanings given to them in the Plan.

1. Grant of Restricted Stock. Pursuant to the Plan and subject to the terms and conditions set forth in this Agreement, the Company hereby grants, issues and delivers to the Grantee ________ shares of its Common Stock (the "Restricted Stock").

2. Restrictions on Stock. Until the restrictions terminate under Section 3, unless otherwise determined by the Committee:

(a) the Restricted Stock may not be sold, assigned, pledged or transferred by the Grantee; and

(b) all shares of Restricted Stock will be forfeited and returned to the Company if the Grantee ceases to be an employee of the Company or any business entity in which the Company owns directly or indirectly 50% or more of the total voting power or has a significant financial interest as determined by the Committee (an "Affiliate").

3. Termination of Restrictions. The restrictions on all shares of Restricted Stock will terminate on the earliest to occur of the following events:

(a) the Grantee's death;

(b) the termination of Grantee's employment with the Company or any Affiliate because of a disability that would entitle the Grantee to benefits under the long-term disability benefits program of the Company for which the Grantee is eligible, as determined by the Committee;

(c) the termination by the Company or any Affiliate of Grantee's employment other than for Cause as determined by the Committee. "Cause" means (i) willful and continued failure of the Grantee to substantially perform his duties with the Company or such Affiliate (other than by reason of physical or mental illness) after written demand specifically identifying such failure is given to the Grantee by the Company, or (ii) willful conduct by the Grantee that is demonstrably and materially injurious to the Company. For purposes of this subsection, "willful" conduct requires an act, or failure to act, that is not in good faith and that is without reasonable belief that the action or omission was in the best interest of the Company or the Affiliate;

(d) upon a resignation of employment in which the Committee determines in its sole discretion that the removal of restrictions is appropriate;

(e) upon a Change in Control. For purposes of this Agreement, a "Change in Control" means a change in control of the Company of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), whether or not the Company is in fact required to comply therewith; provided, that, without limitation, such a Change in Control shall be deemed to have occurred if:

(1) any "person" (as such term is used in Sections 13(d) and 14(d) of the Exchange Act), other than the Company, any trustee or other fiduciary holding securities under an employee benefit plan of the Company or a corporation owned, directly or indirectly, by the shareholders of the Company in substantially the same proportions as their ownership of stock of the Company is or becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Company representing 30% or more of the combined voting power of the Company's then outstanding securities;

(2) during any period of twenty-four (24) consecutive months (not including any period prior to the date of this Agreement), individuals who at the beginning of such period constitute the Board of Directors of the Company and any new director (other than a director designated by a person who has entered into an agreement with the Company to effect a transaction described in subsections (1), (3) or (4) of this Section 3(e)) whose election by the Board of Directors of the Company or nomination for election by the shareholders of the Company was approved by a vote of at least two-thirds (2/3) of the directors then still in office who either were directors at the beginning of such period or whose election or nomination for election was previously so approved, cease for any reason to constitute a majority thereof;

(3) the shareholders of the Company approve a merger or consolidation of the Company with any other corporation, other than (i) a merger or consolidation which would result in the voting securities of the Company outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity) at least 50% of the combined voting securities of the Company or such surviving entity outstanding immediately after such merger or consolidation or (ii) a merger or consolidation effected to implement a recapitalization of the Company (or similar transaction) in which no "person" (as defined above) acquires 30% or more of the combined voting power of the Company's then outstanding securities; or

(4) the shareholders of the Company approve a plan of complete liquidation of the Company or an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets; or

(f) ________, 20__.

4. Rights as Shareholder. Subject to the restrictions and other limitations and conditions provided in this Agreement, the Grantee as owner of the Restricted Stock will have all the rights of a shareholder, including but not limited to the right to receive all dividends paid on, and the right to vote, such Restricted Stock.

5. Stock Certificates. Each certificate issued for shares of Restricted Stock will be registered in the name of the Grantee and deposited by the Grantee, together with a stock power endorsed in blank, with the Company and will bear a legend in substantially the following form:

THE TRANSFERABILITY OF THIS CERTIFICATE AND THE SHARES OF STOCK REPRESENTED HEREBY ARE SUBJECT TO THE TERMS, CONDITIONS AND RESTRICTIONS (INCLUDING RESTRICTIONS ON TRANSFER AND FORFEITURE PROVISIONS) CONTAINED IN AN AGREEMENT BETWEEN THE REGISTERED OWNER AND TECO ENERGY, INC. A COPY OF SUCH AGREEMENT WILL BE FURNISHED TO THE HOLDER OF THIS CERTIFICATE UPON WRITTEN REQUEST AND WITHOUT CHARGE.

Upon the termination of the restrictions imposed under this Agreement as to any shares of Restricted Stock deposited with the Company hereunder, the Company will return to the Grantee (or to such Grantee's legal representative, beneficiary or heir) certificates, without such legend, for such shares.

6. Adjustment of Terms. In the event of corporate transactions affecting the Company's outstanding Common Stock, the Committee will equitably adjust the number and kind of shares subject to this Agreement to the extent provided by the Plan.

7. Notice of Election Under Section 83(b). If the Grantee makes an election under Section 83(b) of the Internal Revenue Code of 1986, as amended, he will provide a copy thereof to the Company within thirty days of the filing of such election with the Internal Revenue Service.

8. Withholding Taxes. The Grantee will pay to the Company, or make provision satisfactory to the Committee for payment of, any taxes required by law to be withheld in respect of the Restricted Stock no later than the date of the event creating the tax liability. In the Committee's discretion, such tax obligations may be paid in whole or in part in shares of Common Stock, including the Restricted Stock, valued at Fair Market Value on the date of delivery (which is defined as the average of the high and low trading price on the New York Stock Exchange on the previous trading day). The Company and its Affiliates may, to the extent permitted by law, deduct any such tax obligations from any payment of any kind otherwise due to the Grantee.

9. The Committee. Any determination by the Committee under, or interpretation of the terms of, this Agreement or the Plan will be final and binding on the Grantee.

10. Limitation of Rights. The Grantee will have no right to continued employment by virtue of this grant of Restricted Stock.

11. <u>Amendment</u>. The Company may amend, modify or terminate this Agreement, including substituting another Award of the same or a different type and changing the date of realization, provided that the Grantee's consent to such action will be required unless the action, taking into account any related action, would not adversely affect the Grantee.

12. <u>Governing Law</u>. This Agreement will be governed by and interpreted in accordance with the laws of Florida.

TECO ENERGY, INC.

By: ______________________________

C.E. Childress
Chief Human Resources Officer

____

Sherrill W. Hudson

Exhibit 12.1

TECO ENERGY, INC.
RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth TECO Energy's ratio of earnings to fixed charges for the periods indicated.

	Year Ended December 31,				
(millions)	2005	2004	2003	2002	2001
(Loss) income from continuing operations, before income taxes	$ 312.9	$ (600.6)	$ 32.8	$ 206.6	$ 241.7
Interest expense	299.1	337.1	354.4	252.2	209.9
Less: Capitalized interest	(0.1)	(0.7)	(17.3)	(63.2)	(23.0)
Plus: Amortization of capitalized interest	0.1	0.3	1.3	0.3	0.3
Less: (Income) loss from equity investments	(60.4)	(36.1)	0.4	(5.5)	(9.1)
Earnings before taxes and fixed charges	$ 551.6	$ (300.0)	$ 371.6	$ 390.4	$ 419.8
Interest expense	$ 299.1	$ 337.1	$ 354.4	$ 252.2	$ 209.9
Interest on refunding bonds	(0.7)	(0.8)	(0.8)	(0.9)	(1.0)
Total fixed charges	$ 298.4	$ 336.3	$ 353.6	$ 251.3	$ 208.9
Ratio of earnings to fixed charges	1.85x	— (1)	1.05x	1.55x	2.01x

For the purposes of calculating these ratios, earnings consist of income from continuing operations before income taxes, income or loss from equity investments and fixed charges, less capitalized interest. Fixed charges consist of interest expense on indebtedness and interest capitalized, amortization of debt premium, and the interest component of rentals. TECO Energy, Inc. does not have any preferred stock outstanding, and there were no preferred stock dividends paid or accrued during the periods presented. Certain prior year amounts have been adjusted to conform to the current year presentation. Further, the company had significant charges (most of which were non-cash) and gains in the periods presented. Reference is made to the financial statements and related notes and the sections titled "Management's Discussion & Analysis of Financial Condition & Results of Operations" herein as well as in TECO Energy, Inc. Annual Reports on Form 10-K, and any amendments filed thereto for the years presented (other than 2004, for which reference is made to TECO Energy, Inc.'s Current Report on Form 8-K dated May 23, 2005).

All prior periods presented reflect the classification of Commonwealth Cheasapeake Company, LLC (CCC), Frontera Generation Limited Partnership (Frontera), BCH Mechanical (BCH), TECO Thermal, AGC, Ltd., TECO BGA, Prior Energy, TECO-Panda Generating Company (TPGC), and TECO Coalbed Methane as discontinued operations. The transfer of TPGC was completed in May 2005, CCC was sold in April 2005 and the sale of BCH was completed in January 2005. Frontera was sold in December 2004 and the sales of Prior Energy and TECO BGA were completed in February 2004. In December 2002, TECO Coalbed Methane sold substantially all of its assets to the Municipal Gas Authority of Georgia.

Interest expense includes total interest expensed and capitalized excluding AFUDC, and an estimate of the interest component of rentals.

(1) Earnings were insufficient to cover fixed charges by $636.3 million. The ratio was -0.89x.

Exhibit 12.2

TAMPA ELECTRIC COMPANY
RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth Tampa Electric Company's ratio of earnings to fixed charges for the periods indicated.

	Year Ended December 31,				
(millions)	2005	2004	2003	2002	2001
Income from continuing operations, before income tax	$ 285.7	$ 274.9	$ 187.4	$ 296.8	$ 275.1
Interest expense	114.9	115.9	112.6	80.4	81.8
Earnings before taxes and fixed charges	$ 400.6	$ 390.8	$ 300.0	$ 377.2	$ 356.9
Interest expense	$ 114.9	$115.9	$ 112.6	$ 80.4	$ 81.8
Interest on refunding bonds	(0.7)	(0.7)	(0.7)	(0.9)	(1.0)
Total fixed charges	$ 114.2	$ 115.2	$ 111.9	$ 79.5	$ 80.8
Ratio of earnings to fixed charges	3.51x	3.39x	2.68x	4.74x	4.42x

For the purposes of calculating these ratios, earnings consist of income from continuing operations before income taxes, income or loss from equity investments and fixed charges. Fixed charges consist of interest expense on indebtedness, amortization of debt premium, the interest component of rentals and preferred stock dividend requirements. Tampa Electric Company had a significant non-cash charge in the 2003 period presented. Reference is made to the financial statements and related notes and the sections titled "Management's Discussion & Analysis of Financial Condition & Results of Operations" herein as well as in Tampa Electric Company's Annual Report on Form 10-K for that year, and any amendments filed thereto.

Interest expense includes total interest expense, excluding AFUDC, and an estimate of the interest component of rentals.

Consent of Independent Registered Certified Public Accounting Firm

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-02563, 333-25563, 333-60776, 333-72542, and 333-115954), and on Form S-3 (Nos.333-43512, 333-83958, 333-102018 and 333-110273) of TECO Energy, Inc. of our report dated February 22, 2006 relating to the financial statements, financial statement schedules, management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

PricewaterhouseCoopers LLP
Tampa, Florida
March 2, 2006

Consent of Independent Registered Certified Public Accounting Firm

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 33-61636, 333-55090 and 333-91602) of Tampa Electric Company of our report dated February 22, 2006 relating to the financial statements and financial statement schedule, which appears in this Form 10-K.

PricewaterhouseCoopers LLP
Tampa, Florida
March 2, 2006

Exhibit 23.3

CONSENT OF INDEPENDENT EXPERTS

Marshall Miller & Associates, Inc. hereby consents to the incorporation by reference into the Registration Statement on Form S-3 (Registration Statement No. 333-102018) of TECO Energy, Inc. (the "Company") of the information contained in our audit report, dated as of January 26, 2006, regarding the coal reserves of the Company's subsidiaries, the results of which audit are reflected in this Annual Report on Form 10-K.

Marshall Miller & Associates, Inc.
By: /s/ Karl Scott Keim
Name: Karl Scott Keim
Title: President

February 27, 2006

Exhibit 31.1

CERTIFICATIONS

I, Sherrill W. Hudson, certify that:

1. I have reviewed this annual report on Form 10-K of TECO Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 6, 2006

/s/ S. W. HUDSON
S. W. HUDSON
Chairman of the Board, and
Chief Executive Officer
(Principal Executive Officer)

CERTIFICATIONS

I, Gordon L. Gillette, certify that:

1. I have reviewed this annual report on Form 10-K of TECO Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 6, 2006

/s/ G. L. GILLETTE
G. L. GILLETTE
Executive Vice President
and Chief Financial Officer
(Principal Financial Officer

CERTIFICATIONS

I, Sherrill W. Hudson, certify that:

1. I have reviewed this annual report on Form 10-K of Tampa Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 6, 2006

/s/ S. W. HUDSON
S. W. HUDSON
Chairman of the Board, and
Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.4

CERTIFICATIONS

I, Gordon L. Gillette, certify that:

1. I have reviewed this annual report on Form 10-K of Tampa Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 6, 2006

/s/ G. L. GILLETTE
G. L. GILLETTE
Senior Vice President – Finance
and Chief Financial Officer
(Principal Financial Officer

Exhibit 32.1

TECO ENERGY, INC

Certification of Periodic Financial Report
Pursuant to 18 U.S.C. Section 1350

Each of the undersigned officers of TECO Energy, Inc. (the "Company") certifies, under the standards set forth in and solely for the purposes of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge, the Annual Report on Form 10-K of the Company for the year ended December 31, 2004 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and information contained in that Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 6, 2006

/s/ S. W. HUDSON
S. W. HUDSON
Chief Executive Officer

Dated: March 6, 2006

/s/ G. L. GILLETTE
G. L. GILLETTE
Chief Financial Officer

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Form 10-K and shall not be considered filed as part of the Form 10-K.

TAMPA ELECTRIC COMPANY

Certification of Periodic Financial Report Pursuant to 18 U.S.C. Section 1350

Each of the undersigned officers of Tampa Electric Company (the "Company") certifies, under the standards set forth in and solely for the purposes of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge, the Annual Report on Form 10-K of the Company for the year ended December 31, 2004 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and information contained in that Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 6, 2006

/s/ S. W. HUDSON
S. W. HUDSON
Chief Executive Officer

Dated: March 6, 2006

/s/ G. L. GILLETTE
G. L. GILLETTE
Chief Financial Officer

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Form 10-K and shall not be considered filed as part of the Form 10-K.