



2002 Annual Report

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TEECO Energy, Inc.

TEECO Energy Inc. (NYSE: TEE) is an integrated utility company with a family of unregulated businesses. In addition to the regulated operations of Tampa Electric and Peoples Gas System, TEECO Energy is engaged in independent power generation, river and ocean transportation, coal mining, non-conventional fuels production and energy services. The company has major operations in Florida, the Southern U.S. and Central America.



Regulated Utilities



Tampa Electric

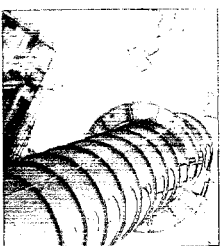


Peoples Gas

Unregulated Businesses



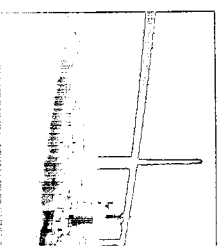
TEECO Coal



TEECO Power Services

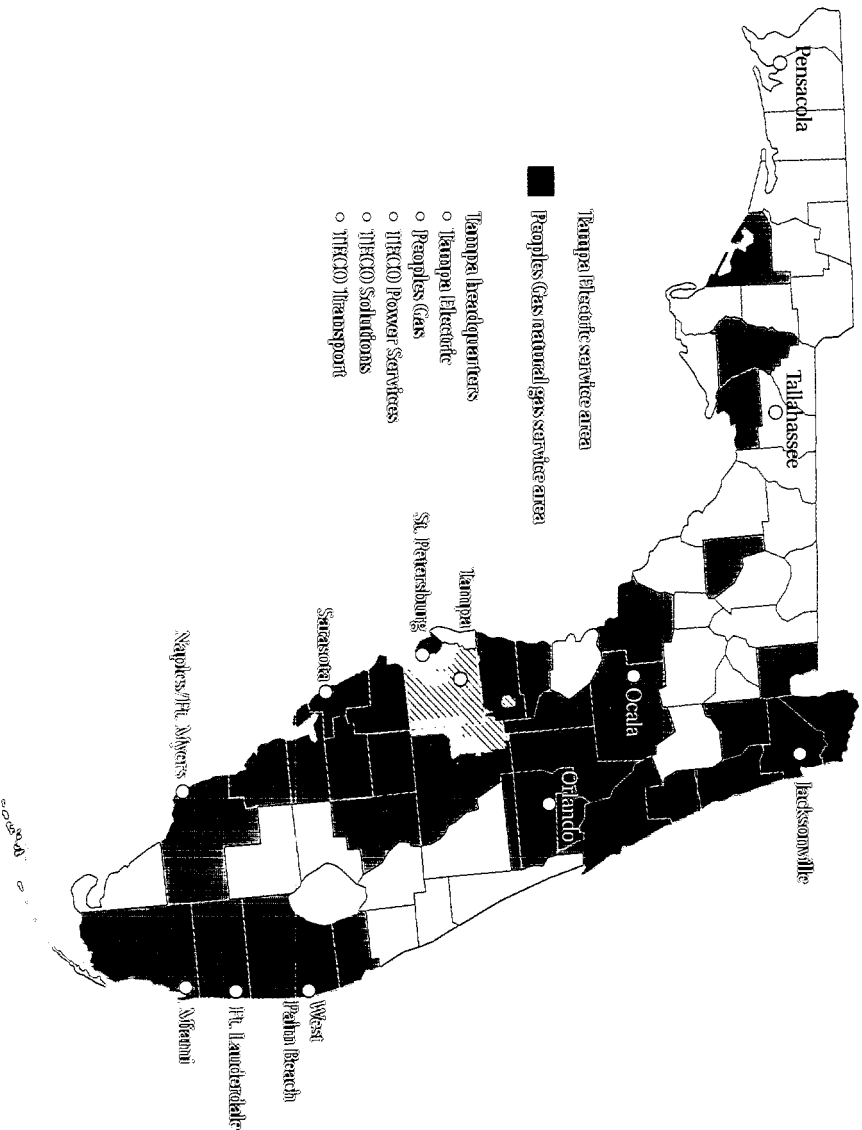


TEECO Solutions



TEECO Transport

Regulated utility locations



2002 Highlights

TECO Energy, Inc.

- Net income growth of 9 percent over 2001
- Return on equity of 14 percent
- \$900-million funding plan almost three-fourths complete by year-end
- Listed on the 2003 Forbes Platinum 400, "The Best Big Companies in America"

Florida Operations/Regulated Utilities

- Continued strong customer growth at regulated utilities; 2.5 percent at Tampa Electric and more than 4 percent at Peoples Gas
- First phase of Tampa Electric Gannon/Bayside repowering nearly complete
- Peoples Gas continues system expansion; receives \$12 million addition to base rates

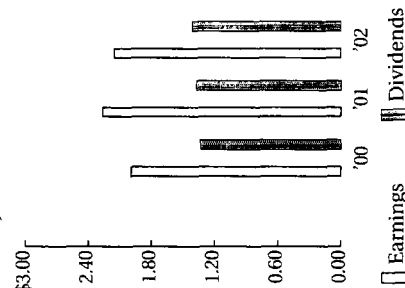
Unregulated Businesses

- TECO Coal increases synthetic fuel production
- Sale of TECO Coalbed Methane generates \$140 million in cash
- Construction on 4,400 megawatts of generation at TECO Power Services nearly complete
- Two smaller TPS generating projects suspended, pending power price improvement

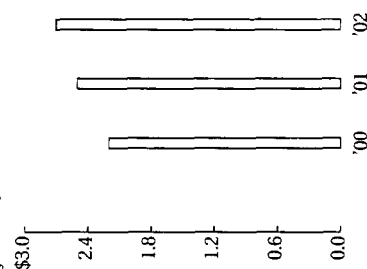
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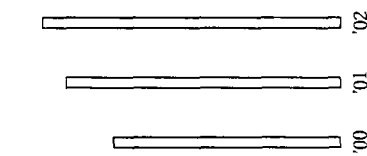
Earnings/Dividends Per Share⁽¹⁾
(dollars per share)



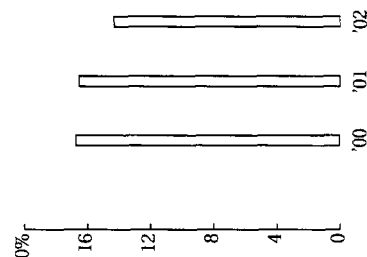
Operating Revenues⁽²⁾
(billions of dollars)



Net Income⁽¹⁾
(millions of dollars)



Return on Average Common Equity⁽¹⁾
(percent)



(1) Includes discontinued operations.

(2) Consolidated revenues from continuing operations.

February 9, 2003

Dear Fellow Shareholders:

Once, when asked what the stock market would do, J.P. Morgan replied, "It will fluctuate." In no year of my career has this simple truth seemed more real than in 2002, especially for the energy industry.

This year, the Dow Jones Utility Index bottomed out at a 12-year low point. Credit rating agencies issued 182 downgrades within the energy sector during the first three quarters of 2002. This has had a dramatic impact on our industry, shaking investor confidence and increasing the cost of capital.

To complicate matters further, pessimism about oversupply and lower earnings prospects in the independent power market has dampened the financial community's interest in companies with merchant power interests.

Even though TECO Energy continues to earn the majority of its net income from regulated utility operations, we have not been immune from downward pressure on our securities. As shareholders ourselves, we are disappointed in our stock's performance over the past year.

Even so, with return on equity of 14 percent and five years of net income growth, TECO Energy is one of 30 energy companies ranked in the 2003 Forbes Platinum 400, "The Best Big Companies in America."

We've made it clear to our investors that 2003 will be a challenging year for TECO Energy, as our construction program begins winding down.

Yet at the same time, we remain focused on — not threatened by — the coming year.

And while we recognize the realities of the market, the economy and our own challenges, we have positioned ourselves to maximize efficiencies within our operating units, with a renewed focus on our regulated utilities.

Tampa Electric Poised for Expansion

Tampa Electric continues to make steady progress on one of the largest construction projects underway in the State of Florida, adding nearly 600 megawatts of incremental capacity to its system.

The Gannon-to-Bayside repowering is on schedule and on budget, with its first phase nearly complete and scheduled to be commercially operational mid-year.

This additional capacity will serve a customer base that continues to grow at a rate of more than 2 percent per year. The company connected its 600,000th customer during the first quarter of 2003.

When the repowering is complete, Tampa Electric's system will be one of the cleanest in the nation, and the company will be aligned with all current and most proposed environmental regulations.

Tampa Electric continues to identify strategies for streamlining its operations and improving its overall efficiency.

Tampa Electric's employees continue to outpace previous customer satisfaction and safety records. Customer favorability for 2002 was 97 percent, and the number of reportable safety incidents continues to be at its lowest in decades.

Peoples Gas Thriving in Fertile Florida Energy Market

Peoples Gas' results improved nearly 5 percent over 2001, through customer growth and resulting higher usage.

In December, Peoples Gas received regulatory authorization to increase its rates, the first such increase in a decade. The company's annual base revenues are expected to increase by more than \$12 million as a result.

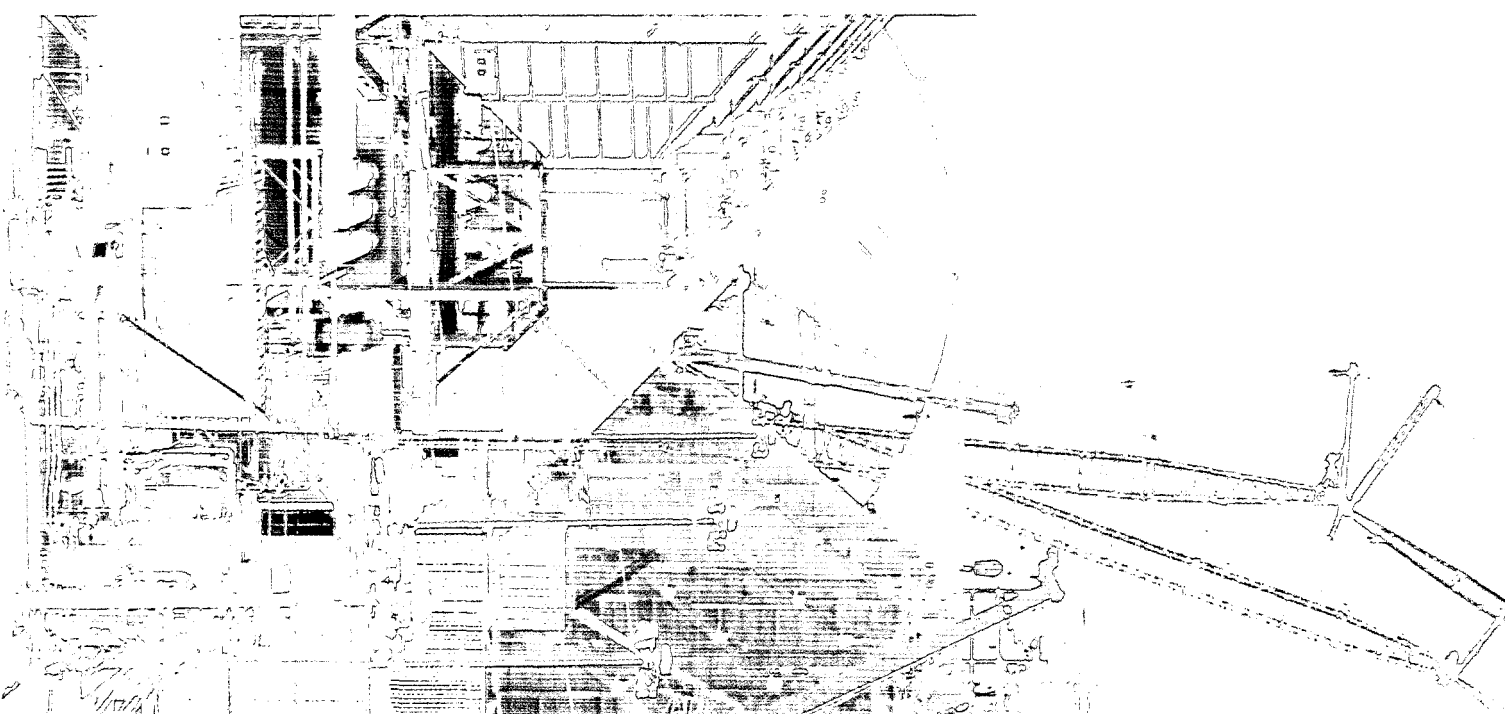
In the 10 years since the last Peoples Gas rate increase, the company has expanded its pipeline distribution system from 5,000 to 9,000 miles and added more than 100,000 homes and businesses to its customer base.

Municipal franchises are a key part of Peoples Gas' system, and a source of growth for the company. Over the past several years, the company has successfully negotiated more than 40 franchise agreements throughout the state, both new contracts and renewals.

In 2002, the utility also enjoyed record performance for safety and improved its already-strong customer satisfaction levels.

In the energy industry, customer satisfaction, in large part, is driven by reliable service. The new Gulfstream Pipeline, delivering natural gas via the Gulf of Mexico, began service this year.

Peoples Gas now has a contract and interconnections





Robert D. Fagan, Chairman, President and Chief Executive Officer

Tempe Electric's Bayshore Power Station readies for operation. When fully operational, the repowered facility will make Tempe Electric's system one of the cleanest in the nation.



with this new supplier, and continues its relationship with the Florida Gas Transmission line to the north.

Additional natural gas supplies in the state allow Peoples Gas to increase its market penetration and enhance the availability and reliability of its service for a growing customer base.

Unregulated Businesses Round Out the Mix

Beyond TECO Energy's base of stable utility operations, we benefit from a balanced mix of unregulated businesses, which have proven their worth over time.

TECO Coals net income jumped substantially in 2002, through higher production of synthetic fuel and improved pricing for all coal types. These factors helped offset increased production costs.

TECO Transport provided net income lower than in 2001, reflecting the continued economic downturn. Despite temporarily lower cargo volumes and weak pricing, this 40-year marine transportation veteran is a stable, proven contributor to TECO Energy's earnings.

At TECO Power Services, progress continues on the two largest independent power projects in the nation, Union Power Station in Arkansas and Gila River Power Station in Arizona. The plants are expected to be fully operational by June and August 2003, respectively.

Two smaller facilities — Dell and McAdams — have been postponed and all new project development curtailed.

In late 2002, to help maximize synergies among all of our businesses, regulated and unregulated, we tapped John Ramil, president of Tampa Electric Company, to take on additional responsibility at the holding company level.

In addition to his role at Tampa Electric, John is now executive vice president of TECO Energy. We are confident that bringing his leadership to more areas of the company will benefit our shareholders.

Cash Generation Plan for 2003 Nearly Complete by Year-End

In September, TECO Energy unveiled a preliminary plan for 2003, addressing its funding needs for the construction of our major power projects.

In addition to the capital expenditure reductions announced in early 2002, we identified \$900 million in savings from further capital expenditure reductions and cash generation from financial transactions and the sale of certain non-core assets.

By year-end, we had achieved nearly three-fourths of the cash needed for 2003. Clearly, we are off to a strong start.

To go the distance, we are poised to continue doing what we've done all along — executing a solid business plan and working toward our commitments to Wall Street and to our shareholders.

Moving Forward in Uncertain Times

Even the most experienced economist can't tell us precisely when the economic downturn will end, or when the energy sector will be back on its feet. But even within that gray area lie some absolutes.

The energy business, which closely tracks the U.S. economy, is cyclic in nature. It will rebound. Long-term, as I've said before, energy demand will only go up. That is our business, and it is essential to homes and businesses alike.

Further, Florida, home to our principal businesses, has the strongest growth in the nation. Our vibrant states' demand for energy grows at a similar pace.

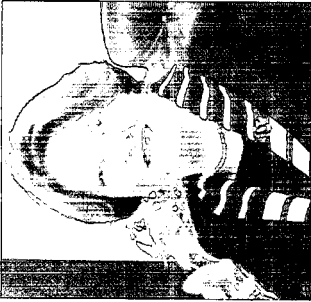
In any situation of uncertainty, flexibility is the key to success. At TECO Energy, we are all sharply focused on strategies that are shaped to realistically face market conditions. These strategies are honed as they should be — with shareholder value at their core.

Sincerely,



Robert D. Fagan
Chairman, President and Chief Executive Officer

More natural gas for Florida. The new Gulfstream Pipeline adds to Florida's fuel supplies, enhancing Peoples Gas Systems' reliability.



A Word from the General Counsel

In any business, it's smart to be ahead of the game. Several years ago, well before the recent emphasis on compliance issues, TECO Energy formalized its corporate compliance plan, and the company dedicates extensive resources to the compliance function. As a result, we have been recognized as a leader in that field.

We have long had a rigorous internal audit function, as well as industry-leading Standards of Integrity, which serve as our company's code of ethics. (These can be viewed on the company's Web site.)

In fact, the corporate governance and ethics guidelines recently proposed by the New York Stock Exchange and the Securities and Exchange Commission, as well as legal requirements passed by Congress, are already part of our corporate culture.

For many years, the vast majority of our directors have been independent, and these independent directors have made up our already existing Audit, Governance and Nominating, and Compensation committees.

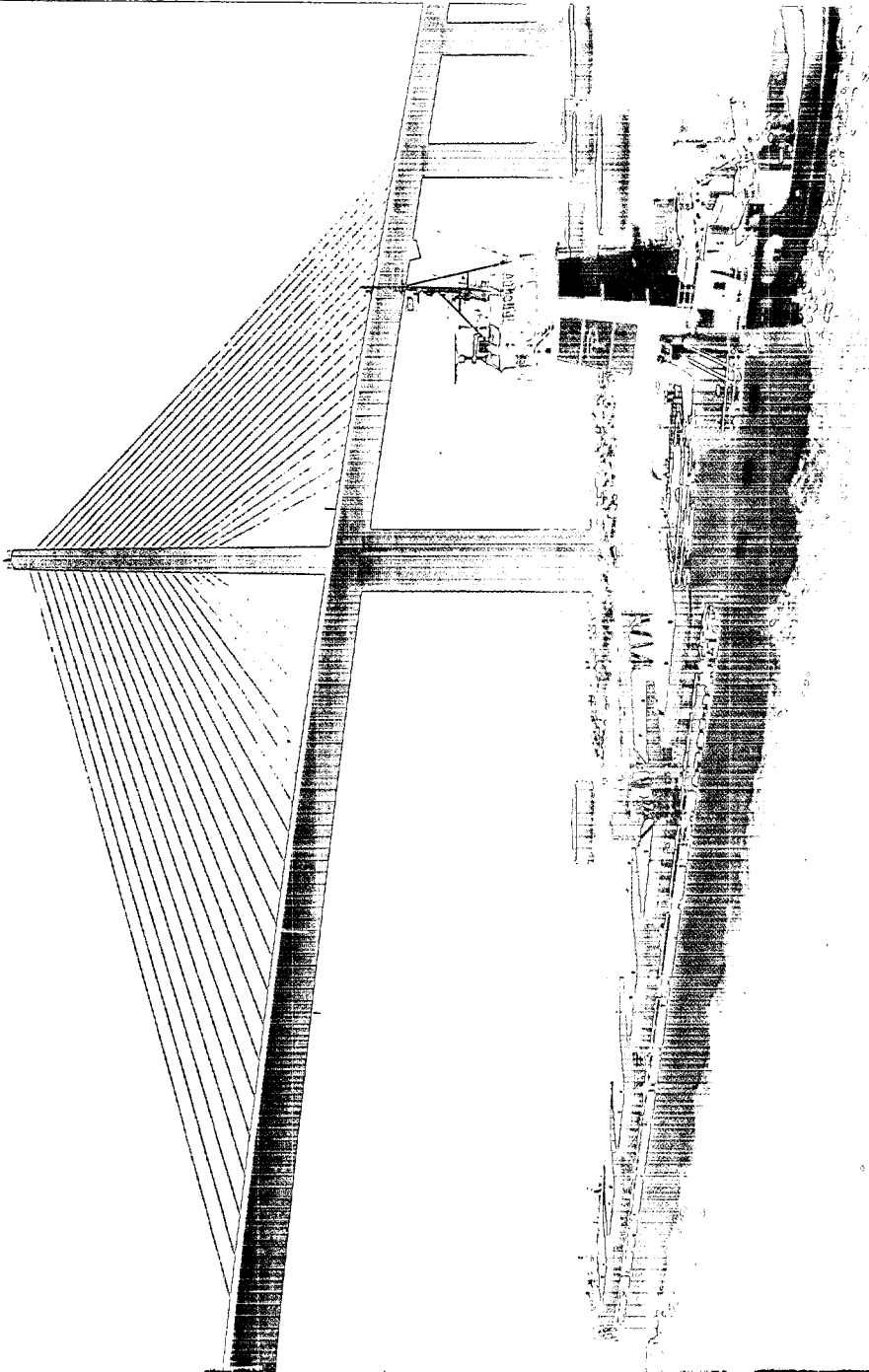
We also have a history of providing complete and open disclosure of material information to the public, well before the SEC's Regulation FD.

And, our alignment with you, our shareholders, goes far beyond our codes of conduct. For example, TECO Energy's stock ownership requirements for its officers are among the strongest in our industry.

As you can see, TECO Energy has strong standards in place, which we believe will benefit shareholders by contributing to the company's long-term success.

Sincerely,

Sheila M. McDevitt
Senior Vice President - General Counsel



Keeping products moving, TECO Energy's assets move cargo under the Stoney bridge.

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. These forward-looking statements include references to our anticipated capital investments, financing requirements, project completion dates, future transactions and other plans. Certain factors that could cause actual results to differ materially from those projected in these forward-looking statements include the following: energy price changes affecting TECO Power Services' (TPS) merchant plants; TPS' ability to sell the output of the merchant plants operating or under construction at a premium to the forward curve prices and to obtain power contracts to reduce earnings volatility; any unanticipated need for additional debt or equity capital that might result from lower than expected cash flow or higher than projected capital requirements; TECO Energy's ability to successfully complete the sale of its synthetic fuel and gasification facilities to successfully complete its cash generation plan; and TECO Energy's ability to maintain credit ratings sufficient to avoid posting letters of credit relating to TPS construction loans and to avoid providing additional assurances to counterparties. Other factors include: general economic conditions, particularly those in Tampa Electric's service area affecting energy sales; weather variations affecting energy sales and operating costs; potential competitive changes in the electric and gas industries, particularly in the area of retail competition; regulatory actions affecting Tampa Electric, Peoples Gas System or TPS; commodity price changes affecting the competitive positions of Tampa Electric and Peoples Gas System, as well as the margins at TECO Coal; changes in and compliance with environmental regulations that may impose additional costs or curtail some activities; TPS' ability to successfully construct and operate its projects on schedule and within budget; the ability of TECO Energy's subsidiaries to operate equipment without undue accidents, breakdowns or failures; interest rates, credit ratings and other factors that could impact TECO Energy's ability to obtain access to sufficient capital on satisfactory terms; and TECO Coal's ability to successfully operate its synthetic fuel production facilities in a manner qualifying for Section 29 federal income tax credits, the use of which could be limited by TECO Energy's taxable income or by changes in law, regulation or administration. Some of these factors and others are discussed more fully under "Investment Considerations."

2002 Earnings Summary

	2002	Change	2001	Change	2000
Consolidated revenues (millions)	\$ 2,675.8	7.5%	\$ 2,488.1	11.9%	\$ 2,223.1
Earnings per share - basic					
Continuing operations	\$ 1.95	-4.4%	\$ 2.04	12.7%	\$ 1.81
Discontinued operations	.20	-9.1%	.22	22.2%	.18
Earnings per share - diluted					
Continuing operations	\$ 1.95	-3.4%	\$ 2.02	12.8%	\$ 1.79
Discontinued operations	.20	-9.1%	.22	22.2%	.18
Earnings per share	\$ 2.15	-4.0%	\$ 2.24	13.7%	\$ 1.97
Net income from continuing operations (millions)	\$ 298.2	8.9%	\$ 273.8	20.3%	\$ 227.5
Average common shares outstanding					
Basic (millions)	153.2 ⁽¹⁾	13.9%	134.5 ⁽²⁾	6.8%	125.9 ⁽¹⁾
Diluted (millions)	153.3 ⁽³⁾	13.2%	135.4 ⁽²⁾	7.2%	126.3 ⁽¹⁾
Return on average common equity⁽⁴⁾	14.3%		16.5%		16.7%

(1) Average shares outstanding reflects the repurchase of 1.6 million shares in 2000.

(2) Average shares outstanding for 2001 reflects the issuance of 8,625 million shares in March and 3.5 million shares in October.

(3) Average shares outstanding for 2002 reflects the issuance of 15,525 million shares in June and 19,385 million shares in October.

(4) Includes results from Discontinued operations (TECO Coalbed Methane).

TECO Energy's revenues increased by more than 7 percent in 2002 to \$2.7 billion; revenues in 2001 increased 11.9 percent to \$2.5 billion. In 2002, net income from continuing operations rose almost 9 percent to \$298.2 million, up from \$273.8 million in 2001. Net income from continuing operations was \$227.5 million in 2000. Earnings per share - basic from continuing oper-

ations were \$1.95 per share in 2002 compared with \$2.04 per share in 2001. The number of average shares outstanding at Dec. 31, 2002 was almost 14 percent higher than at Dec. 31, 2001. Earnings per share - basic from continuing operations were \$1.81 in 2000.

Included in the 2002 results from continuing operations are a \$34.1-million pretax (\$20.9-

million after-tax) charge related to a debt refinancing and a \$5.8 million after-tax asset valuation charge related to the proposed sale of TPS' minority interest in power generating facilities in the Czech Republic. Excluding these unusual items, non-Generally Accepted Accounting Principles (GAAP), or pro forma, net income from continuing operations rose 19 percent to \$324.9 million or from \$2.04 per share in 2001 to \$2.12 per share in 2002. Results from discontinued operations reflect results at the coalbed methane business, which was sold in December 2002.

Total net income and earnings per share, including continuing operations and discontinued operations, were \$330.1 million and \$2.15 per share, respectively. Total non-GAAP net income and earnings per share, excluding the debt refinancing and asset valuation charges and the \$7.7 million gain on the sale of TECO Coalbed Methane, were \$349.1 million and \$2.28 per share, respectively.

The 2002 results reflect continued customer growth and increased energy usage in the Florida utility operations, higher allowance for funds used during construction (AFUDC - non-cash credit to income with a corresponding increase in utility plant which represents the cost of borrowed funds and a reasonable return on the equity funds used for construction) at Tampa Electric, improved results at TPS, and increased synthetic fuel production at TECO Coal. These improvements were partially offset by lower results at TECO Transport.

Net income from continuing operations in 2001 was \$273.8 million, up more than 20 percent from \$227.5 million in 2000. These results reflected continued customer growth and increased energy usage in the Florida operations, higher AFUDC at Tampa Electric, an 18 percent increase in net income at TPS from the new generation projects acquired or brought on line in 2000 and 2001 and improved results from the Guatemalan operations, and higher conventional coal production and prices and increased synthetic fuel production at TECO Coal. These improvements were partially offset by higher interest expense associated with increased borrowing levels and a \$6.1 million after-tax asset valuation charge related to TPS' sale of its interest in Energía Global International, Ltd. (EGI).

Strategy and Outlook

In late 1999, TECO Energy announced a three-pronged business strategy which was to focus on its Florida operations, which include Tampa Electric, Peoples Gas System (PGS) and the Florida energy services businesses, TECO Solutions; to expand its domestic independent power operations at TPS; and to use the returns of its family of other profitable unregulated businesses to support growth. Since that time, the company has undertaken a number of initiatives to advance the announced strategy. These initiatives include continued development of the regulated electric and gas businesses in Florida, including significant additions to Tampa Electric's electric generation facilities, development of independent power generation projects in the Sunbelt of the United States and continued good operations and returns from its family of other unregulated businesses. However, conditions in energy markets and the independent power business have changed since then.

In 2001, future wholesale power prices declined significantly in markets across the country due to a combination of the slowing of wholesale electric competition, uneconomic dispatch; the U.S. economic slowdown; and the large amount of new generating capacity either completed or under construction and expected to come online in 2002 and 2003. The price outlook remained weak throughout 2002 and the prospects for price recovery in 2003 are uncertain. The low power prices have caused weaker earnings expectations from independent power projects and have caused some developers to cancel or delay projects in some markets.

In light of the capital required to complete the committed regulated and unregulated power plant projects, during 2002 TECO Energy took a number of steps to provide the needed cash while, at the same time, strengthening its balance sheet. These steps included accessing the cap-

ital markets for funding, initiating other cash generation measures and reducing capital expenditures. During 2002, the company issued new common equity on two occasions totaling \$553 million in net proceeds. In January 2002, the company issued \$436 million in net proceeds of mandatorily convertible equity units, which will convert to TECO Energy common shares in January 2005. In addition, the company has reduced its capital expenditure forecast for 2002 through 2004 on two separate occasions. The first reduction in January 2002 totaled approximately \$700 million, primarily through delaying, for an extended period, generation projects that were not yet under construction for TPS and Tampa Electric. The second reduction was effected in September as part of a comprehensive cash business plan.

In September 2002, the company announced a preliminary 2003 business plan that focused on the generation of cash to support the construction of the Union and Gila River power stations at TPS and the Gannon to Bayside repowering project at Tampa Electric so as to avoid accessing the capital markets for incremental debt in 2003. This was done in the face of downgrades by equity analysts and the credit rating agencies of both TECO Energy and other companies in the energy sector. The industry's situation deteriorated in late 2002 to the state of a severe credit crisis, highlighting the importance of TECO Energy's execution of the announced plan.

The major components of the plan included: 1) a reduction of capital expenditures of \$250 million, including the suspension of construction of the Dell and McAdams power stations, changing the timing of the completion of Bayside Unit 2 and general capital spending reductions at all of the companies, which allowed TECO Energy to sustain its previously forecasted capital expenditure levels; 2) \$400 million from the sale of the TECO Coalbed Methane gas assets, the proposed sale of the majority of its interest in facilities that produce synthetic fuel which qualify for Section 29 tax credits at TECO Coal, and the proposed sale of the coal gasification unit at Tampa Electric's Polk Power Station; and 3) \$250 million of cash from other financial transactions or asset sales including the repatriation of cash and additional cash from non-recourse refinancing on generating facilities in Guatemala. In addition, TECO Energy ceased work on any new development in the independent power area beyond the already announced and initiated activities.

TECO Energy expects an extended period of lower earnings and to be in a weaker financial position during the current cycle of low wholesale power prices. As previously discussed, the company took decisive steps during 2002 to improve its financial position. The company will continue to take steps as necessary to position itself for a return to a stronger financial position and to a return to earnings growth in the future.

During this period of low wholesale power prices, TECO Energy expects to continue to benefit from deriving the majority of net income and cash flow from its regulated businesses, Tampa Electric and PGS, which operate in one of the highest growth utility markets in the nation. In 2003, about 75 percent of net income is expected to come from regulated utility operations in Florida. Growth is expected to continue in Florida because the state's economy, with its small industrial base, was not impacted by the economic slowdown to the same degree as some manufacturing-based areas of the country.

Operating Results

Management's Discussion & Analysis of Financial Condition & Results of Operations utilize TECO Energy's consolidated financial statements, which have been prepared in accordance with GAAP; to analyze the financial condition of the company.

TECO Energy's reported operating results are affected by a number of critical accounting policies that include such items as accounting for regulated activities, accounting for derivatives, asset impairment testing, accounting for unconsolidated affiliates and others. (See the **Critical Accounting Policies and Estimates** section.)

The following table shows the unconsolidated revenues, net income and earnings per share contributions from continuing operations of the significant business segments. (See Note Q to the Consolidated Financial Statements.)

(millions) Except per share amounts	2002	Change	2001	Change	2000
Unconsolidated Revenues⁽¹⁾					
Regulated Companies	\$1,583.2	12.1%	\$1,412.7	4.4%	\$1,353.8
Tampa Electric	318.1	-9.9%	352.9	12.2%	314.5
Peoples Gas System					\$1,668.3
Total Regulated	\$1,901.3	7.7%	\$1,765.6	5.8%	\$1,668.3
Unregulated Companies	\$309.8	7.9%	\$287.1	44.2%	\$199.1
TECO Power Services	254.6	-7.4%	274.9	1.9%	269.8
TECO Transport	317.1	4.5%	303.4	30.3%	232.8
TECO Coal	122.1	14.2%	106.9	30.5%	81.8
Other unregulated businesses					\$783.5
Total Unregulated	\$1,003.6	3.2%	\$972.3	24.1%	\$783.5
Net Income⁽²⁾					
Regulated Companies	\$171.8	11.6%	\$154.0	6.6%	\$144.5
Tampa Electric	24.2	4.8%	23.1	6.0%	21.8
Peoples Gas System					166.3
Total Regulated	196.0	10.7%	177.1	6.5%	166.3
Unregulated Companies	34.1	26.8%	26.9	18.0%	22.8
TECO Power Services	21.0	-23.9%	27.6	-5.5%	29.2
TECO Transport	76.5	29.7%	59.0	76.1%	33.5
TECO Coal	6.8	70.0%	4.0	233.3%	1.2
Other unregulated businesses					86.7
Total Unregulated	138.4	17.8%	117.5	35.5%	86.7
Financing/Other	(36.2)	74.0%	(20.8)	-18.4%	(25.5)
Net income from continuing operations	298.2	8.9%	273.8	20.3%	227.5
Discontinued operations	31.9	6.7%	29.9	27.7%	23.4
Net income total	\$330.1	8.7%	\$303.7	21.0%	\$250.9
Earnings per Share - Basic⁽²⁾					
Regulated Companies	\$1.12	-2.6%	\$1.15	—	\$1.15
Tampa Electric	.16	-5.9%	.17	—	.17
Peoples Gas System					1.32
Total Regulated	1.28	-3.0%	1.32	—	1.32
Unregulated Companies	.22	10.0%	.20	11.1%	.18
TECO Power Services	.14	-30.0%	.20	-13.0%	.23
TECO Transport	.50	13.6%	.44	63.0%	.27
TECO Coal	.04	33.3%	.03	200%	.01
Other unregulated businesses					.69
Total Unregulated	.90	3.4%	.87	26.1%	.69
Financing/Other	(.23)	53.3%	(.15)	-25.0%	(.20)
EPS from continuing operations	1.95	-4.4%	2.04	12.7%	1.81
Discontinued operations	.20	-9.0%	.22	22.2%	.18
EPS Total	\$2.15	-4.9%	\$2.26	13.6%	\$1.99

- (1) Revenues for all periods have been adjusted to reflect the presentation of energy marketing related revenues on a net basis, the reclassification of TECO Coalbed Methane results to discontinued operations, and the reclassification of earnings from equity investments from Revenues to Other Income.
- (2) Beginning in 2001, segment net income was reported on a basis that included internally allocated financing costs. Prior period net income has been reclassified to reflect estimated internally allocated financing costs that would have been attributable to such prior periods. Internally allocated finance costs for 2002, 2001 and 2000 were at pretax rates of 7%, 7%, and 6.75%, respectively, based on the average investment in each subsidiary.

Tampa Electric - Electric Operations

Tampa Electric Results

Tampa Electric's net income increased almost 12 percent in 2002, reflecting continued good residential and commercial customer growth, increased sales to phosphate customers and more favorable summer weather, partially offset by lower sales to other utilities and higher operations and maintenance expenses. The equity component of AFUDC, primarily from the Gannon to Bayside Units 1 and 2 repowering project, increased to \$24.9 million, compared to \$6.6 million in 2001.

Tampa Electric's net income increased almost 7 percent in 2001, reflecting good customer growth, slightly higher residential and commercial per-customer energy usage, and a favorable customer mix, partially offset by higher operations, maintenance and depreciation expenses. In addition, AFUDC equity, primarily from the Gannon to Bayside Units 1 and 2 repowering project, increased to \$6.6 million, compared with \$1.6 million in 2000.

Net income increased in both 2002 and 2001 while operating income decreased due to higher AFUDC and lower interest expense which affect net income but not operating income.

Summary of Operating Results

(millions)	2002	Change	2001	Change	2000
Revenues	\$1,583.2	12.1%	\$1,412.7	4.4%	\$1,353.8
Other operating expenses	212.3	11.3%	190.7	1.3%	188.3
Maintenance	108.7	9.2%	99.5	3.5%	96.1
Depreciation	189.8	9.5%	173.4	7.3%	161.6
Taxes, other than income	112.3	7.2%	104.8	6.2%	98.7
Non-fuel operating expenses	623.1	9.6%	568.4	4.4%	544.7
Fuel	424.1	22.4%	346.5	7.1%	322.5
Purchased power	253.7	21.0%	209.7	9.2%	192.1
Total fuel expense	677.8	21.9%	556.2	7.9%	515.6
Total operating expenses	\$1,300.9	15.7%	\$1,124.6	6.1%	\$1,060.3
Operating income	\$282.3	-2.0%	\$288.1	-1.8%	\$293.5
Net income	\$171.8	11.6%	\$154.0	6.6%	\$144.5

Tampa Electric Operating Revenues

The economy in Tampa Electric's service area continued to grow in 2002, aided by the region's relatively low labor rates, attractive cost of living and affordable housing. The Tampa metropolitan area's employment grew slightly in 2002, in spite of the continued U.S. economic slowdown. The local Tampa area unemployment rate rose to 4.2 percent in November 2002, up slightly from 4.0 percent in December 2001, compared to 5.0 percent for the State of Florida and 6.0 percent for the nation. The Tampa area, with its diverse service-based economy, did not experience the same drop in economic activities as those areas of the country with manufacturing-based economies. Tampa Electric experienced minimal impact by the slowdown in the tourist industry because the areas served are not as sensitive to changes in the tourist industry as some other areas of Florida.

Retail megawatt hour sales rose 5.6 percent in 2002, primarily from increased residential and commercial sales from higher numbers of customers, higher per-customer usage and warmer-than-normal summer weather. Electricity sales to the lower-margin industrial customers in the phosphate industry increased 18.2 percent in 2002 after a 10.9 percent decline in 2001. The phosphate industry saw increased demand and improved pricing worldwide which led to increased production in 2002. In 2001, the phosphate industry experienced a second year of a worldwide slowdown due to overcapacity and reduced usage that contributed to temporary facility closures during the year and the permanent closure of one phosphate processing facility. The company's phosphate customers have indicated that they expect to vary production to maintain stable prices in 2003. Revenues from phosphate sales represented slightly less than 3

percent of base revenues in 2002 and 2001. Non-phosphate industrial sales increased in 2002 and 2001, primarily reflecting continued economic growth in the area.

Base rates for all customers were unchanged in 2002. However, Tampa Electric refunded \$6.4 million to customers in 2002 related to 1999 revenues held subject to refund under agreements between the Florida Public Service Commission (FPSC), the Office of Public Counsel and Tampa Electric. Fuel-related revenues increased in 2002 under the FPSC approved fuel adjustment clause due to the recovery of a previous underrecovery of fuel expense in 2001 and increased customer usage. (See the Regulation section.)

Sales to other utilities for resale declined in 2002, primarily as a result of lower coal-fired generating unit availability due to more planned maintenance outages.

Based on expected growth from continued population increases and business expansion, Tampa Electric expects retail energy sales growth of approximately 2.5 percent annually over the next five years, with combined energy sales growth in the residential and commercial sectors of more than 3 percent annually. Tampa Electric's forecasts indicate that summer retail demand growth is expected to average more than 100 megawatts per year for the next five years.

These growth projections assume continued local area economic growth even in the current national economic climate, normal weather and a continuation of the current market structure. (See the Investment Considerations section.)

Megawatt-Hour Sales (thousands)	2002	Change	2001	Change	2000
Residential	8,046	6.0%	7,594	3.1%	7,369
Commercial	5,832	2.6%	5,685	2.6%	5,541
Industrial	2,612	12.2%	2,329	-2.6%	2,390
Other	1,435	4.9%	1,368	2.2%	1,338
Total retail	17,925	5.6%	16,976	2.0%	16,638
Sales for resale	1,084	-27.7%	1,499	-41.5%	2,564
Total energy sold	19,009	2.9%	18,475	-3.8%	19,202
Retail customers (average)	590.2	2.5%	575.8	2.8%	560.1

Tampa Electric Operating Expenses

Operating expenses increased almost 16 percent in 2002, reflecting higher fuel costs from an increased amount of power generated with higher-cost oil and natural gas, increased purchased power due to lower unit availability, higher Other operating expenses due to higher employee benefit costs and costs associated with a 7 percent reduction in the workforce, higher depreciation from normal plant additions to serve the growing customer base and the addition of a new peaking combustion turbine at the Polk Power Station in mid-2002, and accelerated depreciation associated with phasing out coal-related assets at the Gannon Power Station.

Operating expenses increased 6 percent in 2001, reflecting higher fuel costs from higher coal prices, increased purchased power costs due to lower unit availability, higher maintenance expenses associated with increased planned outages on coal-fired generating units, and higher depreciation from normal plant additions and accelerated depreciation associated with phasing out coal-related assets at the Gannon Power Station.

Non-fuel operations and maintenance expenses are expected to decrease in 2003 as a result of workforce reductions in 2002 and the repowering of the Gannon Station to natural gas with its lower manpower and maintenance requirements.

Depreciation expense is projected to increase in 2003, and in the future, from normal plant additions and the first phase of the Gannon to Bayside repowering project entering service in mid-2003. (See the Environmental Compliance section.)

Fuel costs increased 22 percent in 2002 despite lower coal costs, reflecting primarily increased generation with oil and natural gas due to lower coal unit availability. Natural gas and oil prices increased significantly in the second half of 2002. Average coal costs, on a cents-per-million Btu basis, decreased 6 percent in 2002 after a 7 percent increase in 2001. Purchased power expense increased in 2002 due to lower unit availability, primarily as a result of planned

maintenance outages on base load generating units and unplanned outages during peak load periods. The effects of higher fuel and purchased power costs are also reflected in the higher operating revenues, as these costs are recovered through the fuel adjustment clause.

Nearly all of Tampa Electric's own generation over the last three years has been produced from coal, and the fuel mix is expected to continue to be substantially comprised of coal until mid-year 2003, when the first of two repowered units at Bayside is scheduled to begin operating on natural gas. (See the Environmental Compliance section.) On a total energy supply basis, company generation accounted for 83 percent, 84 percent and 92 percent of the total system energy requirements in 2002, 2001 and 2000, respectively.

Peoples Gas System

PGS is the largest investor-owned gas distribution utility in Florida. It serves more than 280,000 customers in all of the major metropolitan areas of Florida.

PGS net income rose almost 5 percent in 2002. Contributing to these results were 4.1 percent customer growth, operations and maintenance expenses which were essentially unchanged from 2001, and higher volumes sold for off-system sales and higher volumes transported for power generation customers which more than offset the impact of mild winter weather.

Lower gas prices in the first half of 2002 made the use of natural gas more attractive for large customers than during the period of high prices in the first half of 2001. Gas prices increased in the second half of 2002 and into early 2003, but the differential between natural gas and other fuels has remained relatively constant, therefore, fuel switching is not expected to the same degree as was experienced in 2001.

PGS' net income rose 6 percent in 2001 from 4 percent customer growth and increased gas transported for off-system sales. The high cost of gas early in 2001 had a negative impact on sales to larger interruptible and power generation customers, many of whom have the ability to switch to alternative fuels or to alter consumption patterns.

Historically the natural gas market in Florida has been underserved with the lowest market penetration in the southeastern U.S. PGS is expanding its gas distribution system into areas of Florida not previously served and within areas currently served.

Summary of Operating Results

(millions)	2002	Change	2001	Change	2000
Revenues	\$ 318.1	-9.9%	\$ 352.9	12.2%	\$ 314.5
Cost of gas sold	149.0	-20.1%	186.4	18.7%	157.0
Operating expenses	115.6	-2%	115.4	4.4%	110.5
Operating income	\$ 53.5	4.7%	\$ 51.1	8.7%	\$ 47.0
Net Income	\$ 24.2	4.8%	\$ 23.1	6.0%	\$ 21.8
Therms sold - by customer segment					
Residential	60.2	2.4%	58.8	2.1%	57.6
Commercial	327.6	6.0%	308.9	5.8%	292.1
Industrial	423.8	22.3%	346.5	-7.4%	374.1
Power Generation	492.6	22.1%	403.5	-3.6%	418.6
Total	1,304.2	16.7%	1,117.7	-2.2%	1,142.4
Therms sold - by sales type					
System Supply	332.5	13.8%	292.2	-8.9%	320.6
Transportation	971.7	17.7%	825.5	.4%	821.8
Total	1,304.2	16.7%	1,117.7	-2.2%	1,142.4
Customers (thousands) - average					
	277.5	4.1%	266.6	4.1%	256.2

Residential and commercial therm sales increased from more than 4 percent customer growth in 2002, more than offsetting mild winter weather. Therm sales to large industrial and power generation customers also increased, primarily from significantly lower gas prices in the first half of 2002.

Residential therm sales increased in 2001, the result of more than 4 percent customer growth and increased per-customer usage. Commercial therm sales also increased, primarily from increased per-customer use.

The actual cost of gas and upstream transportation purchased and resold to end-use customers is recovered through a Purchased Gas Adjustment (PGA) clause approved by the Florida Public Service Commission annually.

In Florida, natural gas service is unbundled for all non-residential customers, affording these customers the opportunity to purchase gas from any provider. The net result of this unbundling is a shift from commodity sales to transportation sales. Because commodity sales are 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 services to these customers through its "NaturalChoice" program. At year-end 2002, 9,500 customers had elected to take service under this program.

Operating expenses were essentially unchanged from 2001 levels. This achievement represents significant cost reduction efforts in all areas of the company to offset the effect of the mild winter weather.

In 2001, operation and maintenance expenses were essentially unchanged from 2000 levels, while depreciation expense increased 8 percent, in line with the increased capital expenditures made over the past several years to expand the system.

On June 27, 2002, PGS requested a \$22.6-million annual base revenue increase. On Dec. 17, 2002, the FPSC authorized PGS to increase annual base revenues by \$12.05 million. The new rates allow for a return on equity range of 10.25 to 12.25 percent with an 11.25 percent midpoint, which is the same as its previously allowed return on equity and a capital structure of 57.43 percent equity. The increase went into effect on Jan. 16, 2003. Since its last rate increase 10 years ago, PGS has added more than 100,000 customers and expanded its pipeline system from 5,000 miles to 9,000 miles.

In May 2002, Gulfstream Natural Gas Pipeline initiated service. This interstate pipeline starts in Mobile Bay, Alabama, crosses the Gulf of Mexico and comes ashore in Florida just south of Tampa. Gulfstream is the first new pipeline serving peninsular Florida since 1959. This pipeline increases gas transportation capacity into Florida by 50 percent. PGS entered into a service agreement for capacity in 2002, which grows in 2003 and 2004. The addition of the Gulfstream pipeline enhances reliability of service and helps to meet the capacity needs for PGS' growing customer base.

PGS expects increases in sales volumes and corresponding revenues in 2003, and continued customer additions and related revenues from its expansion efforts throughout the state. These growth projections assume continued local economic growth, normal weather and other factors. (See the **Investment Considerations** section.)

TECO Power Services

Net income increased almost 27 percent in 2002 to \$34.1 million from higher earnings from construction-related and loan agreements with Panda Energy International (Panda), a full year of ownership of the Frontera Power Station and higher capacity payments due to higher prices and generation at the Guatemalan generating units. The improved results were partially offset by a \$5.8-million after-tax charge related to the proposed sale of its minority interest in generating assets in the Czech Republic, higher operations and maintenance expense, lower energy prices and sales from the Commonwealth Chesapeake Station and higher financing costs.

Net income increased 18 percent in 2001 to \$26.9 million from higher earnings from the Harnaka, Commonwealth Chesapeake, and Guatemalan generating stations and higher returns on TPS' investment through Panda in the Texas Independent Energy (TIE) projects. The improved operating performance was partially offset by weak results at the Frontera Station, which was acquired in March 2001, due to low power prices in the Texas market; increased financing costs; higher development costs; and a \$6.1-million after-tax valuation reserve recognized in connection with the sale of TPS' minority interest in EGI, which owns small generating projects in Central America.

Summary of Operating Results

(millions)	2002	Change	2001	Change	2000
Revenues	\$309.8	7.9%	\$287.1	44.2%	\$199.1
Operations, maintenance and A&G	73.1	8.9%	67.1	24.3%	54.0
Purchase power pass through	31.1	4.4%	29.8	-1.0%	30.1
Depreciation	28.1	-1.1%	28.4	53.5%	18.5
Taxes, other than income	8.4	15.1%	7.3	135.5%	3.1
Non-fuel operating expenses	140.7	6.1%	132.6	25.4%	105.7
Fuel	118.6	8.1%	109.7	60.9%	68.2
Total operating expense	259.3	7.0%	242.3	39.3%	173.9
Operating income	\$ 50.5	12.7%	\$ 44.8	77.8%	\$ 25.2
Net income	\$ 34.1	26.8%	\$ 26.9	18.0%	\$ 22.8

Generation	2002	Change	2001	Change	2000
Megawatt hours (thousands)	3,411	10.4%	3,089	89.2%	1,633

Increases in energy generation reflect incremental new capacity coming into service either in phases or part year in 2000 and 2001 or acquired in 2001 with full year results reflected in 2002. Increases in operations, maintenance and administrative and general (A&G) expenses reflect the increased manpower and facilities and a full year of operations of the energy marketing and management group. Increases in these expenses over the three-year period reflect the increased size of the generating portfolio, which increased from three operating plants in January 2000 to five at Dec. 31, 2002.

Increases in income and operating expenses related to the Union and Gila River power stations in 2003 and 2004 are expected to be reflected in TPS financial results on a net basis assuming these facilities continue to be accounted for as unconsolidated affiliates. (See the **Off-Balance Sheet Financing** section.) However, operations, maintenance and A&G expenses are expected to increase because of increased staffing in the energy marketing and management group related to these two plants.

TPS Project Summary

Project	Location	Size MW	TPS Economic Interest	TPS Net Size MW	In Service Participation Date ⁽¹⁾
Operating:					
Hardee Power Station	Florida	370	100%	370	1/93, 5/00
Alborada Power Station	Guatemala	78	96%	75	9/95
Empresa Eléctrica de Guatemala S.A. (EEGSA) (a distribution utility)	Guatemala		24%		9/98 ^(a)
San José Power Station	Guatemala	120	100%	120	1/00
Hamakua Energy Project	Hawaii	60	50%	30	8/00, 12/00
Frontiera Power Station	Texas	477	100%	477	5/00, 3/01 ^(a)
Odesa and Guadalupe Commonwealth Chesapeake	Texas	2,000	(2)	750	9/00, 8/01
Power Station	Virginia	315	100%	315	9/00, 8/01
Sub-total operating		3,420		2,137	
Under Construction:					
Union	Arkansas	2,200	(3)	1,650	1/03-6/03
Gila River	Arizona	2,145	(3)	1,609	2/03-8/03
Sub-total construction		4,345		3,259	
Total		7,765		5,396	
Suspended:					
Dell	Arkansas	599	100%		
McAdams	Mississippi	599	100%		
				1,198	

(1) Unless otherwise indicated, each date appearing in this column is an in-service date. When more than one in-service date appears, it indicates when different phases of the project went into operation. For projects under construction, a range of dates indicates when the first and last phases are expected to enter service under TECO Energy's current plans.

(2) Based on the effect of the preferred return, the effective economic interest is estimated at 75 percent of Panda's 50-percent interest in these projects over the life of the projects.

(3) Based on the effect of the preferred return, the effective economic interest is estimated at 75 percent over the life of the project.

(4) Dates on which TPS acquired its economic interest in the project.

Construction Activities

In 2000, TPS focused its efforts on the development or acquisition of domestic energy projects. TPS has net ownership interest in almost 5,400 megawatts of projects either operating or under construction.

In September 2000, TPS invested \$93 million in the form of a loan to Panda's TIE, which are the Odesa and Guadalupe power stations. An additional \$44 million was loaned to Panda in the first quarter of 2002 bringing the total investment to \$137 million. The interest earned on the loan to TIE is reflected in 2002, 2001 and 2000 earnings.

These loans converted in accordance with their terms into an ownership interest on Jan. 3, 2003 which is expected to be accounted for under the equity method. The conversion gives TPS an opportunity to have an effective economic interest estimated at 75 percent of Panda's 50-percent interest in these projects over the life of the projects. Based on information available from the other owners of these projects, these projects have realized lower than expected earnings and cash flows due to over capacity in the Texas market, uneconomic dispatch, and market design, and that trend is expected to continue in 2003. TPS is evaluating its options relative to its ownership position in these projects and is targeting to structure its interest in such a manner that it will cover its cash costs in 2003 and mitigate any impact on earnings.

In October 2000, TPS acquired two 599-megawatt, natural gas-fired, combined-cycle projects, Dell and McAdams, located in Arkansas and Mississippi, respectively. Construction com-

menced on these projects in 2001 but was suspended at the end of 2002 due to projected low energy prices in the markets that these plants were expected to serve. Interest will not be capitalized during the construction postponement period. The carrying costs associated with these suspended plants are expected to reduce TPS earnings in 2003. Market conditions will be monitored to determine when these plants will be completed. At the time of suspension, approximately \$690 million had been invested in these plants. It is currently estimated that the cost to complete these projects will be approximately \$100 million.

In November 2000, TPS entered into a 50/50 joint venture with Panda to build, own and operate the 2,200-megawatt Union Power Station in Arkansas and the 2,145-megawatt Gila River Power Station in Arizona. The partnership agreement calls for TPS to contribute all project equity and for TPS to earn a preferred return on the investment in these projects, which, over the project's life, could give TPS an effective economic interest estimated at 75 percent. Construction commenced on these projects in 2001. Each of these projects is expected to begin operation in four power blocks, beginning with the first 550-megawatt power block of Union which began operating in January 2003 and ending with the 540-megawatt final power block of Gila River expected in August of 2003. At Dec. 31, 2002, the TPS investment in these projects was \$1.2 billion of project equity including the remaining \$375 million equity bridge loan balance and \$55 million already contributed related to the TECO Energy construction undertaking, described below. At Dec. 31, 2001, TPS had invested \$624 million in these projects including \$500 million of the equity bridge loan.

In December 2001, Enron Corp., a large energy trading and services company, filed for protection under the U.S. Bankruptcy Code. An Enron subsidiary, NEPCO, was serving as the construction contractor for the Union, Gila River, Dell and McAdams power stations. Enron guaranteed certain of NEPCO's obligations under the construction contracts. The Union and Gila River power stations, have financing in place with a syndicate of banks. The Dell and McAdams power stations, are wholly owned by TPS and have not been financed.

As part of Enron's centralized cash management procedure, Enron swept NEPCO's cash before it was applied to pay project costs. Enron's bankruptcy permitted the project lenders to stop funding construction costs for the Union and Gila River projects until the condition was cured or waived. TPS received approval from the project lenders on a plan that allowed funding to resume.

The plan involved TECO Energy replacing Enron as the guarantor of certain of NEPCO's obligations under the construction contracts for these two projects, including payment by the company of any project cost overruns (estimated at \$62 million remaining at Dec. 31, 2002, against which TECO Energy could offset the unused construction contingency amount remaining after completion of construction) and guaranteeing the completion of construction. The plan also provided for TECO Energy to replace the letter of credit furnished by Enron that had been drawn upon and acceleration of project cash commitments to mid-year 2002, resulting in TECO Energy's total investment essentially being complete by the end of 2002 rather than mid-2003 as originally planned.

Under a series of agreements with TECO Panda Generating Co. (TPGC), NEPCO continued construction and engineering of all four plants until SNC Lavalin Constructors Inc., a large Canadian engineering and construction firm, replaced it as the contractor in May 2002. SNC Lavalin hired essentially all of NEPCO's management and staff, and construction continued without interruption. The agreements with SNC Lavalin provide for the projects to be completed on a cost-plus-fee basis, with the fee portion at-risk until the projects are completed.

In February 2002, the TPS and Panda affiliates that comprise the joint venture that owns the Union and Gila River projects entered into a purchase arrangement for TPS to purchase and Panda to sell Panda's interest in the joint venture in 2007 for \$60 million. Panda has the right to cancel the purchase arrangement by paying TPS \$20 million, or a lesser amount under certain circumstances. The purchase arrangement could result in TPS' purchase of the interest prior to 2007 if Panda defaults on a bank loan made to Panda using the purchase arrangement as collateral or if TECO Energy permits its debt-to-capital ratio to exceed 65.0 percent, permits its EBITDA/interest ratio to fall below 1.5 times or it defaults on the payment of indebtedness in

ments in the fall and winter is expected to repeat in 2003. Northbound river shipments of steel-related raw materials are expected to improve in 2003 as the U.S. economy improves. Southbound river shipments of grain products are expected to increase slightly in 2003, with a small increase in pricing expected. Even with the expected price increase, grain freight rates are expected to remain below historical levels, which will impact the pricing for all commodities moved on the rivers. In the meantime, TECO Transport expects to move increased volumes of fertilizers and petroleum coke northbound on the river system.

The phosphate fertilizer industry experienced an increase in worldwide demand in 2002 after a period of reduced demand in 2001 and 2000, which resulted in increased shipments of raw phosphate rock between Tampa and Louisiana. The outlook for TECO Ocean Shipping is for a slight increase in phosphate demand in 2003. Lower shipments for Tampa Electric and higher fuel and employee-related health care and pension costs are expected in 2003.

TECO Transport expects to continue diversifying into new markets and cargoes. Future growth at TECO Transport is dependent on improved pricing, higher asset utilization, and asset additions at both the river and ocean-going businesses. Significant factors that could influence results include weather, bulk commodity prices, fuel prices and domestic and international economic conditions. (See the **Investment Considerations** section.)

TECO Coal

Net income increased 30 percent in 2002, to \$76.5 million, driven primarily by better margins and higher synthetic fuel (synfuel) production and sales and the resulting higher Section 29 tax credits. Production of synthetic fuel at TECO Coal qualifies for Section 29 tax credits for non-conventional fuel production.

Synfuel production increased to 3.8 million tons in 2002 compared with 3.2 million tons and 1.9 million tons in 2001 and 2000, respectively. The net benefit increased to approximately \$77 million in 2002 compared with \$58 million in 2001 and approximately \$30 million in 2000. Synfuel production displaced some of the conventional coal production in all years.

Net income at TECO Coal increased 76 percent in 2001, driven primarily by better margins and higher synfuel production, increased coal production from Perry County Coal, Inc.'s mining facilities acquired in late 2000, and higher metallurgical coal prices in the second half of the year. 2001 was the first full year of production for the synfuel production facilities which entered service late in the second quarter of 2000.

In 2002, coal sales, including synfuel, decreased to 9.3 million tons from 10.1 million tons in 2001 due to soft market conditions. In 2003, total coal sales are expected to increase slightly due to more normal supply and demand in the market. Synfuel volumes are expected to increase to more than 5 million tons and conventional coal production is expected to decline to offset the higher synfuel production in 2003. In 2003, TECO Coal intends to sell the majority of its interest in the synfuel production facilities, but retain responsibility for operating the facilities. (See the **Strategy and Outlook** section.)

Metallurgical coal contracts, which normally renew in the first quarter of the year, resulted in lower prices in 2002 after a strong pricing environment in 2001. Prices are expected to remain near current levels in 2003. Steam coal pricing declined industry wide in the first quarter of 2002, due to high utility inventory levels as a result of the mild winter weather. TECO Coal, however, contracts much of its steam coal production for the coming year late in the preceding year and was less affected by the price declines than those companies that sell a higher percentage in the spot markets. Later in the year, after inventories were reduced to more normal levels, coal prices strengthened and contract renewals for 2003 were achieved at prices only slightly lower than 2002 levels.

In January 2000, TECO Coal purchased synfuel facilities from Headwaters Technologies, Inc. The facilities were relocated to the company's Premier Elkhorn and Clintwood Elkhorn mines in Kentucky, and were producing by the second quarter of 2000. These facilities produce synfuel from coal, coal fines and waste coal using a technology licensed from Headwaters.

TECO Coal has received private letter rulings from the Internal Revenue Service regarding

the production of synfuel from its facilities. The private letter rulings confirm that the facilities are located properly and produce a qualified fuel eligible for Section 29 tax credits which are available for the production of such non-conventional fuels through 2007.

Significant factors that could influence TECO Coal's results include weather, general economic conditions, commodity price changes, continued generation of Section 29 tax credits, the sale of interest in the synfuel production facilities, the ability to use Section 29 tax credits and changes in laws, regulations or administration. (See the **Investment Considerations** section.)

Other Unregulated Companies

In 2002, net income for the other unregulated companies increased 70 percent to \$6.8 million driven primarily by the full-year results of Prior Energy Corp., TECO Energy's end-use gas marketing company acquired in November 2001. In 2001, net income increased due to a full year of results from BCH Mechanical, which was acquired in September 2000.

Other unregulated companies include TECO Energy Services (formerly TECO BGA, Inc., and BCH Mechanical, Inc. and its affiliated companies), TECO Gas Services, TECO Properties, Prior Energy Corp., TECO Propane Ventures (TPV), TECO Partners and TECO Investments. Except for TECO Investments, these operating companies are organized under TECO Solutions, which was formed to offer customers (primarily in Florida) a comprehensive package of energy services and products including energy-efficient engineering and construction and gas management services.

In November 2001, TECO Solutions acquired Prior Energy Corp., a leading natural gas management company. Serving customers throughout the Southeast, Prior Energy handles all facets of natural gas energy management services for large industrial, power generation utility, municipal and other governmental agency customers, including natural gas acquisition and supply management, transportation management, asset management and consulting services.

TPV holds the company'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. As a result, TPV owns a 38-percent interest in the general partner that manages Heritage Propane Partners, L.P. (NYSE:HPG) and that general partner owns an approximate 29-percent limited partnership interest in Heritage Propane Partners.

Liquidity, Capital Resources

Sources of cash for TECO Energy and its operating companies in 2002 totaled \$3.4 billion, including operating cash flows of \$656 million and proceeds from the sale of debt and equity securities of \$2.8 billion. Cash was used to fund \$1.7 billion of capital spending (net of \$103 million from asset sales), debt maturities of \$788 million and refinancings of \$162 million, net reduction of short-term debt of \$278 million and dividends to common shareholders of \$216 million. The company began the year with \$109 million in cash and cash equivalents and ended the year with \$411 million in cash and cash equivalents and \$460 million of unused capacity available under the bank credit facilities at TECO Energy and Tampa Electric. The increased year-end cash position was attributable in part to the conversion of the TECO Energy bank credit facility to a term loan and other cash generating activities.

The company met 2001 cash needs with a mix of internally generated funds, short- and long-term borrowings and proceeds from the sale of equity. Cash from operations was \$503 million, and net cash from financing was \$614 million after common dividends of \$184 million. Capital spending totaled \$1.1 billion in 2001.

In light of the accelerated equity commitments for the Union and Gila River projects under the bank financing plan, an unexpected deterioration in the bank project finance market which caused a planned financing to not materialize, and the capital requirements for committed regulated and unregulated projects, TECO Energy took several steps to strengthen its balance sheet in 2002 and provide cash for its construction program. In January 2002, the company reduced its previous capital expenditure forecast for 2002 through 2004 by about \$700 million, primari-

ly by delaying indefinitely generation projects that were not yet under construction for TPS and Tampa Electric, including the Bayside Units 3 and 4 repowering projects announced in the fall of 2001.

In September 2002, the company announced additional plans to meet its 2003 construction commitments without raising incremental debt, identifying a total amount required of \$900 million. By the end of 2002, the company had completed 70 percent of its \$900 million target by: 1) reducing by \$250 million capital spending projections (which included amounts higher than earlier estimates); 2) selling the TECO Coalbed Methane gas assets for \$140 million, with \$42 million received in December and the remainder received in January 2003; 3) realizing \$55 million of cash from repatriation and additional cash from non-recourse-financing of the Guatemalan generating assets; and 4) raising \$207 million from the sale of common equity in October.

Tampa Electric has signed a letter of intent for the sale of its gasifier unit, and TECO Coal is continuing discussions with potential buyers of interests in its synthetic fuel production facilities. Completion of these activities, which will complete the 2003 funding plan, is expected late in the first quarter or early in the second quarter of 2003.

Estimated cash needs for 2003 include capital spending of \$727 million for normal renewal and replacement capital as well as project commitments of Tampa Electric and TPS, including \$375 million related to payment of the Union and Gila River projects equity bridge loan. (See the **Summary of Contractual Obligations** section.) Long-term debt maturities of \$127 million are due in 2003, and a bank term loan of \$350 million matures in November. TECO Energy expects to rely on cash on hand and internally generated cash from operations and from asset sales to fund these cash needs and the payment of dividends to shareholders. (See the **Bank Credit Facilities** and **Covenants in Financing Agreements** sections.) Based on its cash flow forecasts, the company expects to have at least \$600 million of cash and capacity under the bank credit facilities at the end of the first, second and third quarters of 2003 and, if it renews its bank facilities in full, at the end of 2003.

The company has identified in this Management's Discussion & Analysis (including in **Investment Considerations**), several factors that could cause its operating cash flow to be lower than forecasted. One of these factors is the margins the company may realize for production from its merchant power facilities. Because of the company's expansion in the merchant power business, the company's cash flow has become increasingly dependent upon power margins.

TECO Energy has not made a contribution to its defined benefit pension plan since the 1995 plan year because investment returns have been more than sufficient to cover liability growth. Negative stock market returns over the past three years have reduced the over-funding of the defined benefit plan. Based on plan asset values at Jan. 1, 2003, it is estimated that TECO Energy will be required to make a \$15 million contribution to its defined benefit plan in September 2004. (See Note K, to the **Consolidated Financial Statements**.)

Bank Credit Facilities

At Dec. 31, 2002, TECO Energy had a bank credit facility of \$350 million, and Tampa Electric had a bank credit facility of \$300 million, with maturity dates of November 2004 and November 2003, respectively. Both were undrawn at Dec. 31, 2002, except for outstanding letters of credit under the TECO Energy facility. In November 2002, TECO Energy converted another \$350 million bank credit line then in effect into a one-year term loan due November 2003. TECO Energy expects to have discussions with the bank-lending group with the objective of renewing the facility before the loan matures.

The TECO Energy bank credit facility maturing November 2004 includes a \$250 million sub-limit for letters of credit capacity. At Dec. 31, 2002, \$180 million of letters of credit were outstanding against that line, primarily related to the construction of the Union and Gila River power stations. These letters of credit of \$62 million and \$88 million for Union and Gila River, respectively, were replacements for the letters of credit posted by Enron and drawn by the TPS/Panda joint venture following Enron's bankruptcy filing. In addition, at Dec. 31, 2002, TECO Energy and its subsidiaries had \$5 million of letters of credit outside of its bank credit line facility outstanding. (See the **Covenants in Financing Agreements** section.)

The Tampa Electric bank credit facility requires commitment fees of 15 basis points, and drawn amounts are charged interest at LIBOR plus 85-97.5 basis points at current credit ratings. The TECO Energy credit facility requires commitment fees of 15-20 basis points and drawn amounts incur interest expense at LIBOR plus 35-60 basis points at current credit ratings. TECO Energy expects that the cost of its facility will increase upon renewal.

The September 2002 downgrade by Standard & Poor's Ratings Service (S&P) of TECO Energy's commercial paper program to A-3 eliminated TECO Energy's access to the commercial paper market. Tampa Electric continues to have access to the commercial paper market with its A2/P1/F2 rated commercial paper program and had \$11 million of commercial paper outstanding at Dec. 31, 2002. The lack of access to the commercial paper market has caused TECO Energy to utilize its bank credit facilities for short-term borrowing needs.

Credit Ratings/Senior Unsecured Debt

	Fitch	Moody's	Standard & Poor's
Tampa Electric	A-	A2	BBB
TECO Finance / TECO Energy	BBB	Baa2	BBB-

In September 2002, Moody's Investor Services, Inc. (Moody's), S&P and Fitch Investor Services, Inc. (Fitch), lowered the ratings on the senior unsecured debt securities of TECO Energy, TECO Finance and Tampa Electric. The outlook assigned to TECO Energy by Moody's and S&P is negative while the outlook assigned by Fitch is stable. The ratings actions were attributed to increased debt levels and the changing risk profile associated with the expansion of TECO Energy's investment in merchant generation facilities through TPS, as well as the required capital outlays of Tampa Electric, the outlook for low power prices in the merchant energy sector and the negative impacts on earnings and cash flow, and the additional risks and obligations undertaken by TECO Energy with respect to the Union and Gila River power stations. These downgrades followed downgrades in 2001 and 2000 by all of the rating agencies due to the changing risk profile of TECO Energy related to the increased emphasis on merchant power.

These downgrades and any future downgrades may affect TECO Energy's ability to borrow and may increase financing costs, which may decrease earnings. TECO Energy's interest expense is likely to increase when maturing debt is replaced with new debt with higher interest rates due to the lower credit ratings.

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 discussed in the following table.

	Total	Payments Due by Period			
		2003	2004	2005-2007	After 2007
(millions)					
Long-term debt	\$3,426.1	\$ 101.8	\$ 31.9	\$ 1,048.9	\$ 2,243.5
Capital lease obligation	25.3	25.3	—	—	—
Operating leases/rentals	230.4	27.8	26.9	63.0	112.7
Unconditional purchase obligations/commitments ⁽¹⁾	563.0	461.6	41.4	60.0 ⁽²⁾	—
Other long-term obligations ⁽³⁾	649.1	—	—	449.1	200.0
Total contractual obligations	\$4,893.9	\$ 616.5	\$ 100.2	\$ 1,621.0	\$ 2,556.2

(1) Includes the expected repayment of \$375 million on the TECO Energy guaranteed equity bridge loan at TPS for the construction of the Union and Gila River power stations.

(2) Includes the expected redemption of company preferred securities held as assets of TECO Capital Trusts I and II.

(3) TPS' obligation to purchase Panda's interest in the Union and Gila River power stations in 2007, unless Panda buys out that purchase agreement in advance. (See the **TECO Power Services - Construction Activities** section.)

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 the company's Consolidated Financial Statements.

(millions)	Total ⁽²⁾	Commitment Expiration		
		2003	2004	2005-2007
Letters of Credit ⁽¹⁾	\$ 185.0	\$ 128.0	\$ 27.1	\$ 29.9
Guarantees:				
Debt related	23.7	—	—	23.7
Construction undertaking ⁽³⁾	60.0	60.0	—	—

(1) Expected final expiration date with annual renewals.

(2) Expected maximum exposure.

(3) The construction undertaking of \$60 million reflected in the table represents the estimated maximum probable exposure associated with completing construction of the Union and Gila River power stations if actual costs exceed current estimates and in-service dates are delayed beyond current estimates. This contingent obligation estimate is net of retainage letters of credit posted for these projects. This estimate will decline rapidly as construction progresses and units are brought into service. (See the **TECO Power Services - Construction Activities** section.)

Covenants in Financing Agreements

In order to utilize their respective bank credit facilities, TECO Energy and Tampa Electric must meet certain financial tests. TECO Energy's credit facilities and the financing arrangements of TPS' Union and Gila River power stations require that at each quarter-end TECO Energy's debt-to-capital ratio, as defined in the applicable agreements, not exceed 65%. Under Tampa Electric's 364-day credit facility, renewed in November 2002, its debt-to-capital ratio may not exceed 60 percent at the end of the applicable quarter and its earnings before interest, taxes, depreciation and amortization (EBITDA) to interest coverage ratio (as defined in the agreement) can not be less than 2.5 times. Certain long-term debt at PGS contains a prohibition on the incurrence of funded debt if Tampa Electric's debt-to-capital ratio, as defined in the applicable agreement, exceeds 65%. The PGS debt also contains a Tampa Electric interest coverage requirement, as defined in the applicable agreement, of 2.0 times or greater for four consecutive quarters, and certain TPS financing arrangements require a TECO Energy consolidated interest coverage, as defined in the applicable agreement, equal to or exceeding 3.0 times for the twelve-month period ended each quarter. At Dec. 31, 2002, TECO Energy's and Tampa Electric's debt-to-capital ratios, as applicable, were 55.9 percent and 43.9 percent, respectively, and interest coverage, as applicable, was 3.6 times and 7.8 times, respectively. The company expects that renewal of TECO Energy's facility will require covenants similar to Tampa Electric's.

The TECO Energy guarantees of the Union and Gila River power stations equity bridge financing, equity contribution agreement and construction undertaking require that TECO Energy maintain senior unsecured credit ratings of not less than BBB and Baa3 or BBB- and Baa2. The company's current ratings are at the minimum required level. A further downgrade from either S&P or Moody's would trigger a failure to meet that requirement, thereby requiring the delivery of letters of credit, which the company currently estimates could approximate \$450 million, to secure the obligations. In the event of a downgrade, under the terms of the construction contract guarantees, TECO Energy is required to deliver letters of credit in an amount equal to the full construction contract price and any change orders and cost overruns or such lesser amount satisfactory to the majority of the lenders for the Gila River and Union power stations. TECO Energy believes that the amounts required would be based on the estimated amounts reasonably necessary to cover the remaining payment and performance obligations under the construction contracts. As of January 2002, when documenting the construction contract guarantees with the lenders for the Gila River and Union power projects, the maximum amount necessary to cover the payment and performance obligations of the contractor was estimated to be approximately \$310 million, net of approximately \$150 million in letters of credit it previously issued to the lenders as security for the projects. Based on the construction status

as of Dec. 31, 2002, TECO Energy estimates the maximum amount necessary to cover the payment and performance obligations of the contractor to be approximately \$60 million, net of the approximately \$150 million in letters of credit previously issued as security. This \$60 million is included in the \$450 million amount referenced above. The amount of the letters of credit that would be required to be delivered declines as equity is contributed to the projects, the bridge loan is repaid and the levels of construction completion increase.

The 10.5% 5-year notes issued in November 2002 contain covenants that will, among other things, in the event of certain ratings downgrades, limit TECO Energy's ability to pay dividends or distributions or make certain investments, incur additional liens or issue additional indebtedness. The covenants apply only if either the notes are rated non-investment grade by either S&P or Moody's or the notes are rated below the levels required by the equity bridge loan and Union and Gila River construction undertaking while those obligations are outstanding. If these covenants become applicable, they would restrict the company from paying dividends or distributions or making certain investments unless cumulative EBITDA to interest coverage is at least 1.7 times.

Capital Investments

(\$ millions)	Actual			Forecast		2003-2007 Total
	2002	2003	2004	2005-2007	2003-2007	
Florida Operations	\$ 662	\$ 272	\$ 266	\$ 725	\$ 1,263	
Independent Power	1,027	424	25	75	524	
Transportation	25	15	21	61	97	
Other	50	16	23	55	94	
Total	\$ 1,764	\$ 727	\$ 335	\$ 916	\$ 1,978	

TECO Energy's 2002 capital investments of \$1,764 million (without reduction for asset sale proceeds of \$103 million) included \$597 million for Tampa Electric (excluding \$35 million of AFUDC), \$54 million for PGS and \$11 million for the unregulated Florida operations. Tampa Electric's electric division capital investments in 2002 were \$169 million for equipment and facilities to meet its growing customer base and generating equipment maintenance, \$343 million for the repowering and conversion of the coal-fired Cannon Station to the natural gas-fired Bayside Station (see the **Environmental Compliance** section), and \$85 million for the 180 MW Polk Unit 3 peaking combustion turbine and future generation expansion requirements. Capital expenditures for PGS were approximately \$39 million for system expansion and approximately \$12 million for maintenance of the existing system. TECO Transport invested \$25 million in 2002 for river barge replacements and capitalized maintenance of ocean-going vessels. TECO Coal's capital expenditures included \$48 million for the expansion of production at Perry County and Clintwood as well as normal equipment replacements. TPS' capital investments totaled \$1,027 million primarily related to the Union, Gila River, Dell and McAdams power stations. This \$1,027 million includes \$672 million classified as Other Non-Current Investments, shown as notes receivable from TPGC (see the **Transactions With Related and Certain Other Parties** section), which represents TECO Energy's equity contributions for the Union and Gila River projects. The Union and Gila River contributions are initially made in the form of loans to TECO-Panda Generating Company (TPGC) and become equity as the units' specified phases come into service.

TPS expenditures represent the equity funding of project costs and exclude amounts funded by non-recourse project financing for the Union and Gila River power stations, which amounted to \$627 million in 2002. (see **TECO Power Services - Construction Activity** section.)

Asset sale proceeds of \$103 million in 2002 included proceeds from the sale of TECO Coalbed Methane's assets, real estate sales, and TECO Transport's sale and lease-back of vessels and barges accounted for as an operating lease.

TECO Energy estimates capital spending for ongoing operations, without reduction for pro-

ceeds from asset sales, to be \$727 million for 2003, \$335 million for 2004 and \$916 million during the 2005-2007 period. TECO Energy's funding plan for these expenditures includes the asset sales described in the **Strategy and Outlook** section.

For 2003, Tampa Electric, electric division, expects to spend \$232 million consisting of \$78 million for the repowering project at the Gannon Station and \$154 million to support system growth and generation reliability. At the end of 2002, Tampa Electric had outstanding commitments of about \$119 million for the Gannon Power Station repowering project. Tampa Electric's total capital expenditures over the 2004-2007 period are projected to be \$841 million, including \$67 million for the repowering project and \$141 million for compliance with the Environmental Consent Decree. (See the **Environmental Compliance** section.)

Capital expenditures for PCS are expected to be about \$40 million in 2003 and \$160 million during the 2004-2007 period. Included in these amounts are approximately \$25 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing renewal, replacement and system safety.

TPS expects to invest \$424 million in 2003 primarily for the completion of the Union and Gila River power stations. These investments include \$375 million to repay the outstanding amounts due under the project company's equity bridge loan guaranteed by TECO Energy, which is

expected to be repaid in three \$125 million installments in the second, third and fourth quarters. The other unregulated companies expect to invest \$31 million in 2003 and \$160 million during the 2004-2007 period. Included in these amounts is normal renewal and replacement capital including coal mining equipment.

Financing Activity

TECO Energy's 2002 year-end capital structure, excluding the effect of unearned compensation, was 53.7 percent debt, 9.1 percent company preferred securities and 37.2 percent common equity. TPS typically finances its power projects with non-recourse project debt. Excluding this non-recourse debt of \$232.4 million, the year-end capital structure was 52.1 percent debt, 9.4 percent company preferred securities and 38.5 percent common equity.

In 2002, TECO Energy was active in the debt and equity capital markets raising \$1 billion through the sale of equity or equity-linked securities and issuing \$1.8 billion of debt to refinance \$788 million of maturing debt, to refinance \$162 million of higher-cost debt, to reduce short-term borrowing by \$278 million and to fund capital investments at the operating companies. These transactions and financings in 2002 and 2001 are detailed in the following table.

Date	Security	Company	Net Proceeds (millions)	Coupon	Use
Dec. 2002	7-year non-recourse bank loan	TECO Power Services	\$30	6%	Refinance Alborada Power Station and general corporate purposes
Nov. 2002	5-year notes	TECO Energy	\$352	10.5%	Repay short- and long-term debt, and general corporate purposes
Oct. 2002	Common equity	TECO Energy	\$207	—	Repay short-term debt
Aug. 2002	5-year notes	Tampa Electric	\$149	5.375%	Repay maturing long- and short-term debt, and general corporate purposes
Aug. 2002	10-year notes	Tampa Electric	\$394	6.375%	Repay maturing long- and short-term debt, and general corporate purposes
Jun. 2002	Pollution control bonds	Tampa Electric	\$61	5.1%	Refinance higher cost debt
Jun. 2002	Pollution control bonds	Tampa Electric	\$86	5.5%	Refinance higher cost debt
Jun. 2002	Common equity	TECO Energy	\$346	—	Repay short-term debt, and general corporate purposes
May 2002	5-year notes	TECO Energy	\$297	6.125%	Repay maturing short-term debt, and general corporate purposes
May 2002	10-year notes	TECO Energy	\$397	7.0%	Repay maturing short-term debt, and general corporate purposes
Jan. 2002	Mandatorily convertible equity units	TECO Energy	\$436	9.5%	Repay short-term debt, and general corporate purposes
Oct. 2001	Common equity	TECO Energy	\$93	—	General corporate purposes
Sept. 2001	10-year notes	TECO Energy	\$206	7.2%	Repay maturing debt, and general corporate purposes
Jun. 2001	11-year notes	Tampa Electric	\$247	6.875%	Repay long- and short-term debt, and general corporate purposes
May 2001	1-year notes	TECO Energy	\$399	Variable	Repay short-term debt
May 2001	10-year notes	TECO Energy	\$396	7.2%	Repay short-term debt, and general corporate purposes
Apr. 2001	6-year notes	TECO Transport	\$111	5.0%	Convert floating rate debt to fixed rate debt
Mar. 2001	Common equity	TECO Energy	\$232	—	Repay short-term debt, and general corporate purposes

Off-Balance Sheet Financing

Unconsolidated affiliates in which TPS has a 50% ownership interest or less have non-recourse project debt balances as follows at Dec. 31, 2002. This debt is recourse only to the unconsolidated affiliate, and TECO Energy has no debt payment obligations with respect to these financings. Although TECO Energy is not obligated on the debt, TECO Energy's equity interest in those unconsolidated affiliates and its commitments with respect to those power projects are at risk if those projects are not successfully developed.

Affiliate	Affiliate Debt Balance (millions)	TPS Ownership Interest
Union & Gila River	\$ 1,175	50%
EEGSA	\$ 200	24%
Hamakua	\$ 86	50%

The equity method of accounting is used to account for investments in partnership and corporate entities in which TECO Energy or its subsidiary companies do not have either a majority ownership or exercise control. On Jan. 17, 2003, the Financial Accounting Standards Board issued FASB Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51*, which requires a new approach in 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 or VIEs. Based on a preliminary review, TECO Energy believes it is reasonably possible that FIN 46 may impact certain unconsolidated affiliates. (See the **Other Accounting Standards - Variable Interest Entities** section.)

In June 2001, TPS and its joint venture partner, Panda, closed on a \$2.175 billion syndicated bank financing for the construction of the Union and Gila River power stations. The financing includes \$1.675 billion in five-year non-recourse debt (including facilities for letters of credit) and \$500 million in equity bridge loans guaranteed by TECO Energy of which \$125 million was repaid in 2002. Pricing for the non-recourse segment is 162.5 basis points over LIBOR during the construction period and increases to 175 basis points for year one of operation and 200 basis points for years two and three.

The TPGC debt balance is expected to reach \$1.4 billion upon completion of construction of the Union and Gila River power stations in 2003.

In addition, TECO Energy has other debt-related items totaling \$23.7 million. These facilities are not included in liabilities on TECO Energy's consolidated balance sheet, but do represent payment obligations of the company.

In March 2001, TPS converted the third-party construction financing for the Hamakua Power Station into a synthetic equipment operating lease with a term of five years. The lessor is an unaffiliated entity.

Critical Accounting Policies and Estimates

The following accounting policies are considered critical in the view of management. These critical accounting policies require that critical estimates be made based on the assumptions and judgment of management. The preparation of consolidated financial statements requires management to make various estimates and assumptions that affect revenues, expenses, assets, liabilities and disclosure of contingencies. The policies and estimates identified below are the more significant accounting policies and estimates used in the preparation of TECO Energy's 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 the **Notes to the Consolidated Financial Statements** for a description of TECO Energy's accounting policies and the estimates and assumptions used in the preparation of the Consolidated Financial Statements.

Asset Impairments

TECO Energy and its subsidiaries periodically evaluate whether there has been a permanent impairment of an asset as follows:

- Long-lived assets, when indicators of impairment exist, in accordance with Financial Accounting Standard No. (FAS) 121, *Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of*, and beginning in 2002, with FAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*; and
- Recognized goodwill and other intangible assets with indefinite lives, annually in accordance with FAS 142. (See **Goodwill and Other Intangible Assets** section.)

The company believes that the accounting estimate related to asset impairments is a critical estimate for the following reasons: 1) it is highly susceptible to change each reporting period 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) electricity markets continue to experience significant price uncertainty with respect to market fundamentals; 3) the ongoing expectations of management regarding the future use of the asset; and 4) the impact of an impairment on reported assets and earnings would be material. The company's assumptions relating to future results of operations are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities. (See **Notes A, C and S to the Consolidated Financial Statements**.)

Long-Lived Assets

TECO Energy adopted FAS 144, with no significant impact on earnings, effective Jan. 1, 2001. During the year ended Dec. 31, 2002, the company evaluated certain merchant generation plants for impairment in accordance with FAS 144. The company concluded that the sum of the undiscounted expected future cash flows (excluding interest charges) from each individual plant exceeded the then-current carrying value of the plant. In accordance with FAS 144, the company did not recognize an impairment charge. If an impairment charge were required to be recognized, the amount of the loss would be determined by calculating the difference of the fair value and the then-current carrying value of the asset.

Goodwill and Other Intangible Assets

Prior to 2002, goodwill was amortized each year. As of Dec. 31, 2001, TECO Energy had \$166 million of goodwill, net of accumulated amortization of \$10 million. The adoption of FAS 142 on Jan. 1, 2002 resulted in the elimination of approximately \$5 million of annual amortization. (See **Notes C and S to the Consolidated Financial Statements**.)

In accordance with the transition provisions of FAS 142, TECO Energy evaluated all reporting units where goodwill is recorded for impairment. Reporting units are generally determined as one level below the operating segment level; however, reporting units with similar characteristics may be grouped under the accounting standard for the purpose of determining the impairment, if any, of goodwill and other intangible assets. For each reporting unit evaluated, the fair value exceeded the carrying value, including goodwill, as of the valuation date, Jan. 1, 2002. During 2002, in accordance with the ongoing requirements of the standard, the company evaluated all reporting units where goodwill is recorded for impairment. The fair value for the reporting units evaluated was generally determined using discounted cash flow models appropriate for the business model of each significant group of assets within each reporting unit. No impairment loss was recorded during 2002 for goodwill or other intangible assets with indefinite lives.

Asset Retirement Obligations

In July 2001, the FASB issued FAS 143, Accounting for Asset Retirement Obligations, which requires the recognition of a liability at fair value for an asset retirement obligation in the period in which it is incurred. Retirement obligations associated with long-lived assets included within the scope of FAS 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel. Retirement obligations are included in the scope of the standard 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 useful life of the asset. The liability must be revalued each period based on current market prices. FAS 143 is effective for fiscal years beginning after June 15, 2002. The company estimates that the adoption of FAS 143 will result in a non-cash increase to net property, plant and equipment of approximately \$8 million, a non-cash increase to asset retirement obligation of approximately \$10 million, and, as a cumulative effect of change in accounting principle, a non-cash pretax charge of approximately \$2 million.

Asset retirement obligations are comprised of significant estimates which, if different, could materially impact the results of TECO Energy. The company believes these are critical estimates because: 1) the fair value of the costs associated with meeting the obligation are impacted by assumptions on discount rates and estimated profit mark-ups by third-party contractors; 2) probability factors associated with the future sale, abandonment or retirement of an asset must be forecasted and considered in the calculations; 3) the expectations and intent of management regarding the future use of long-lived assets; and 4) the impact of the recognition of an asset impairment obligation could be significant. Upon adoption, effective Jan. 1, 2003, TECO Energy and affiliates are maintaining controls and periodically reviewing all new legal arrangements and contractual commitments to ensure that any new potential asset retirement obligations are reviewed and recognized as appropriate. (See Note A to the Consolidated Financial Statements.)

Unconsolidated Affiliates

The company has investments in unconsolidated affiliates that are accounted for using the equity method of accounting. See the Other Accounting Standards section for a detailed discussion of the accounting policies for unconsolidated affiliates; the anticipated impact of the adoption of a new accounting policy (FIN 46) for consolidation of certain legal entities; and critical assumptions and judgments which must be made regarding the application of the accounting policies. (See Note A to the Consolidated Financial Statements.)

Employee Postretirement Benefits

The company has a funded non-contributory defined benefit retirement plan covering substantially all employees. The company's policy is to fund the plan based on actuarially determined contributions within the guidelines set by the Employee Retirement Income Security Act of 1974, as amended (ERISA), for the minimum annual contribution and the maximum allowable as a tax deduction by the IRS. Plan assets are invested in a mix of equity and fixed income securities. In addition, 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. In addition, the company has unfunded supplemental executive retirement benefit plans—non-qualified, non-contributory defined benefit retirement plans available to certain senior management.

The determination of the benefit expense is a critical estimate due to the following factors: 1) management must make significant assumptions regarding the discount rate, return on assets, rate of salary increases and health care cost trend rates; 2) costs are based on actual employee demographics, including the turnover rate, retirement rate, mortality rate, employment periods, compensation levels and age, each of which are subject to change in any given

period; 3) the plan provisions may be changed by management action in future periods; and 4) the impact of changes in any of these assumptions is likely to result in a material impact on the recorded pension obligation and expense. Management reviews these assumptions periodically to reflect the company's actual experience.

The discount rate for pension cost purposes is the rate at which the pension obligations could be effectively settled. At Dec. 31, 2002, the discount rate used for actuarial purposes was 6.75%, as determined by reference to Moody's Aa bond rate as of Sep. 30, 2002. A hypothetical 25 basis point change in the discount rate would impact pension expense by approximately \$2 million.

The assumed rate of return on assets is the weighted average of expected long-term asset return assumptions. In selecting an assumed rate of return on plan assets, the company considers past performance and economic forecasts for the types of investments held by the plan. At Dec. 31, 2002 the return on assets used for actuarial purposes was 9%. A hypothetical 25 basis point change in the return on assets would impact pension expense by approximately \$1 million.

The assumed health care cost trend rate was 12.5% in 2002 and decreases to 5.0% in 2013 and thereafter. A 100 basis point increase in the trend rate would impact the aggregate service and interest cost by \$1.1 million for 2002 and the accumulated postretirement benefit obligation by \$9.5 million, and a 100 basis point decrease in the trend rate would impact the aggregate service and interest cost by \$(0.5) million for 2002 and the accumulated postretirement benefit obligation by \$(5.0) million, as of Sept. 30, 2002. (See Note K to the Consolidated Financial Statements.)

Derivative Instruments and Hedging

From time to time, TECO Energy enters into derivative instruments to reduce the exposure to market risks. The company does not enter into derivatives for speculative purposes. See the Quantitative and Qualitative Disclosures About Market Risk section for a discussion of the accounting policy for derivatives and hedging activities, variables used in estimating the fair value of derivative instruments, assumptions made with respect to forecasted transactions, and a discussion of the strategy and objectives related to the use of energy derivatives to mitigate various exposures to risk and uncertainty. (See Notes A and B to the Consolidated Financial Statements.)

Deferred Income Taxes

TECO Energy uses the liability method in the measurement of deferred income taxes. Under the liability method, the company estimates its current tax exposure and assesses 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. The company assesses the likelihood that deferred tax assets will be recovered from future taxable income and, to the extent recovery of some portion or all of the deferred tax asset is not believed to be likely, the company would establish a valuation allowance.

At Dec. 31, 2002, TECO Energy had deferred income tax assets of \$340 million attributable primarily to alternative minimum tax credit carryover of Section 29 non-conventional fuels tax credits and property-related items. The carrying value of the company's deferred income tax assets assumes that the company will be able to realize this asset as an offset to future income taxes payable. The company periodically reviews the deferred income tax assets and, to the extent that recovery would be determined to be unlikely, a valuation reserve would be charged to income. The company believes that the accounting estimate related to deferred income taxes, and any related valuation allowance, is a critical estimate for the following reasons: 1) recoverability of future Section 29 non-conventional fuel tax credits is dependent on the generation of sufficient taxable income to use these credits; and 2) administrative actions of the Internal Revenue Service or the U.S. Treasury or changes in law or regulation could eliminate or reduce the availability of Section 29 tax credits. A change in the recoverability of Section 29 tax

credits could have a material impact on reported assets and results of operations. (See Notes A and M to the Consolidated Financial Statements.)

Cost Capitalization

During 2002, TECO Energy devoted resources to the completion and construction of additional generation capacity at Tampa Electric and TPS, extension of the transmission network and enhancement to the system's reliability at Tampa Electric, expansion of the pipeline distribution infrastructure at PGS, normal river barge replacement at TECO Electric and expansion of production capacity at TECO Coal. The cost of additions, including improvements and replacements of property is charged to plant. TECO Energy capitalizes direct costs and certain indirect costs, including the cost of debt and equity capital as appropriate, associated with its construction and retirement activity as prescribed by generally accepted accounting principles and recognized policies prescribed or permitted by the FPSC and/or the FERC. (See the Regulation section.)

The amount of capitalized overhead construction costs is based upon analysis of company and affiliate construction activity. Costs are capitalized based on the activity level of resources allocated to construction activities. As a result, the company's net income could be impacted by the manner and timing of the deployment of resources to construction activities. However, total cash flow is not impacted by the allocation of these costs to the various construction or maintenance activities. Due to the magnitude of construction undertakings, fluctuations in net income, as a result of cost capitalization, could be significant. Capitalized costs will be expensed as a component of depreciation when the assets are placed in service. (See Notes A and D to the Consolidated Financial Statements.)

Depreciation Expense

TECO Energy provides for depreciation primarily by the straight-line method at annual rates that amortize the original cost, less net salvage, of depreciable property over its estimated service life. The provision for utility plant in service, expressed as a percentage of the original cost of depreciable property, was 4.2% for 2001 and 2002. The company believes the estimated service life corresponds to the anticipated physical life for most assets. However, the company's estimation of service life is a critical estimate for the following reasons: 1) forecasting the salvage value for long-lived assets over a long timeframe is subjective; 2) changes may take place that could render a technology obsolete or uneconomical; and 3) a change in the useful life of a long-lived asset could have a material impact on reported results of operations and reported assets. Although it is difficult to predict values far into the future, TECO Energy has a long history of actual costs and values that are considered in reaching a conclusion as to the appropriate useful life of an asset. (See Note A to the Consolidated Financial Statements.)

Regulatory Accounting

Tampa Electric's and PGS' retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by the FERC. (See the Regulation section.) 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 they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers from previous collections for costs that are not likely to be incurred.

TECO Energy periodically assesses whether the regulatory assets are probable of future recovery 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 Notes A and D to the Consolidated Financial Statements.)

Revenue Recognition

TECO Energy and its subsidiaries recognize revenues, except as discussed below, 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. (See the Regulation section.)

The percentage of completion method is used to recognize revenues for certain transportation services at TECO Transport and for long-term engineering or construction-type contracts at TECO Energy Services (formerly known as TECO BGA and BCH Mechanical). The percentage of completion method requires management to make estimates regarding the distance traveled and/or time elapsed for TECO Transport and total costs and work-in-progress for TECO Energy Services. Revenue is recognized by comparing the estimated current total distance traveled or work completed with the total distance or cost estimate for each project. Each month, revenue recognition and realized profit are adjusted to reflect only the percentage of distance traveled or work completed.

Revenues for energy marketing services at Prior Energy and 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*, to reflect the nature of the contractual relationships with customers and suppliers. Revenues for risk management and merchant power sales at TPS are reported on a gross basis, except for gains or losses related to hedge accounting, which are reported net of the hedged item or transaction.

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

Other Accounting Standards

Business Combinations

In June 2001, the FASB issued FAS 141, *Business Combinations*. FAS 141 requires all business combinations initiated after June 30, 2001, to be accounted for using the purchase method of accounting. TECO Energy has applied the provisions of FAS 141 since June 30, 2001 to all business combinations initiated after that date. (See the Goodwill and Other Intangible Assets section and Note S to the Consolidated Financial Statements.)

Lease Accounting Amendment

In April 2002, the FASB issued FAS 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections*. In addition to rescinding the aforementioned statements, FAS 145 amends FAS 13, *Accounting for Leases*, to eliminate an inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. This statement also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their appli-

capability under changed conditions. The implementation of FAS 145 has not had a significant impact on the company's results.

Exit or Disposal Costs

In July 2002, the FASB issued FAS 146, *Accounting for Costs Associated with Exit or Disposal Activities*, which addresses the accounting for costs under certain circumstances, including costs to terminate a contract that is not a capital lease, costs to consolidate facilities or relocate employees, and termination benefits provided to employees that are involuntarily terminated under the terms of a one-time benefit arrangement that is not an ongoing benefit arrangement or an individual deferred compensation contract. FAS 146 is effective for disposal activities initiated after Dec. 31, 2002 with early adoption allowed.

Gains and Losses on Energy Trading Contracts

On Oct. 25, 2002, the Emerging Issues Task Force issued EITF 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under Issues No. 98-10 and 00-17*, which eliminates mark-to-market accounting for certain energy trading contracts and changes the presentation of gains and losses for certain derivative contracts. The measurement provisions of the issue are effective for all fiscal periods beginning after Dec. 15, 2002. The net presentation provisions are effective for all financial statements issued after Dec. 15, 2002. In accordance with the recommended transition provisions, TECO Energy reclassified certain amounts in prior periods to present gains and losses on a net basis. (See Note A to the Consolidated Financial Statements.) The adoption of the measurement provisions is not expected to have a material impact.

Guarantor's Accounting and Disclosure Requirements for Guarantees

In November 2002, the FASB issued FIN 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Guarantees of Indebtedness of Others (an interpretation of FAS No. 5, 57 and 107 and rescission of FAS Interpretation No. 34)*, which modifies the accounting and enhances the disclosure of certain types of guarantees. FIN 45 requires that upon issuance of certain guarantees, the guarantor must recognize a liability for the fair value of the obligation it assumes under the guarantee. FIN 45's provisions for the initial recognition and measurement are to be applied to guarantees issued or modified after Dec. 31, 2002. The disclosure requirements are effective for financial statements of annual periods that end after Dec. 15, 2002. (See Note R to the Consolidated Financial Statements.)

Stock-Based Compensation

In December 2002, the FASB issued FAS 148, *Accounting for Stock-Based Compensation - Transition and Disclosure*, an amendment of FASB Statement No. 123. This standard amends FAS 123, *Accounting for Stock-Based Compensation*, to provide alternative methods of transition for companies that voluntarily change to the fair value based method of accounting 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 transition provisions and annual disclosure requirements are effective for all fiscal years ending after Dec. 15, 2002, while the interim period disclosure requirements are effective for all interim periods beginning after Dec. 15, 2002. TECO Energy does not anticipate the adoption of the disclosure provisions of this standard to have a material impact. (See Note I to the Consolidated Financial Statements.)

Variable Interest Entities

The equity method of accounting is used to account for investments in partnership and corporate entities in which TECO Energy or its subsidiary companies do not have either a majority ownership or exercise control. On Jan. 17, 2003, the FASB issued FIN No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51*, which requires a new approach in

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 or VIEs. A legal entity is considered a VIE if it does not have sufficient equity at risk to finance its own activities without relying on financial support from other parties. If the legal entity is a VIE, then the reporting entity that is the primary beneficiary 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. Certain transition disclosures are required for all financial statements issued after Jan. 31, 2003. The on-going disclosure and consolidation requirements are effective for all interim financial periods beginning after Jun. 15, 2003.

The determination of the applicability of FIN 46 is complex and requires management to make significant assumptions related to: 1) the reasonable possibility that an entity may be a VIE in which the company has a significant variable interest at Dec. 31, 2002; 2) the rights, obligations, and activities of all other equity investors in the potential VIE; 3) the anticipated variability in the potential VIE's net income or loss, the fair value of its assets not already included in net income or loss, and certain fees paid to related and unrelated third parties; and 4) the magnitude of the company's variable interest as compared to the variable interests of all other variable interest holders. Each of these assumptions could significantly impact the conclusion of the company to consolidate the legal entity.

Based on a preliminary review, TECO Energy believes it is reasonably possible that FIN 46 may impact certain unconsolidated affiliates. Management is continuing to assess the extent of the relationships and obtain adequate information upon which to base appropriate conclusions. Below is a discussion of the legal entities existing as of Dec. 31, 2002 that the company considers to be possibly subject to either: 1) additional disclosure requirements; or 2) consolidation by the company, in accordance with FIN 46.

TPS entered into a joint venture, TPGC, to build, own and operate the Union and Gila River power stations. As of Dec. 31, 2002, TPGC is a development stage partnership that may meet the definition of a VIE. The third-party debt financing at TPGC is non-recourse and does not create an estimated loss exposure to TECO Energy. The estimated maximum theoretical loss exposure is approximately the current and guaranteed equity investment in the partnership. (See the TECO Power Services - Construction Activities section, the Capital Investments section, Project Financing of Unconsolidated Affiliates section and Notes A, N and R to the Consolidated Financial Statements.)

TPS completed a transaction whereby certain equipment at the Hardee Power Station was sold to a third party (the Lessor) and leased back under an operating lease agreement with an initial term of 12 years. The original cost of the equipment was \$46.6 million. The sole purpose of the Lessor is to own and lease back the equipment to Hardee Power. The lease financing arrangement includes \$41.6 million of subordinated debt and \$1.4 million of equity contributed by an unrelated third party. If the Lessor were to be consolidated, TPS estimates that it would incur after-tax incremental expenses of approximately \$9.5 million over the 12-year term of the lease. (See Note R to the Consolidated Financial Statements.)

TECO Properties formed two limited liability companies with project developers which may meet the definition of a VIE. Herrando Oaks, LLC was formed by TECO Properties with the Pensacola Group to buy and develop a residential community in Hernando County, Florida. Herrando Oaks, LLC had total assets at Dec. 31, 2002 of \$18.9 million. TECO Properties' estimated maximum theoretical loss exposure is its equity investment in this project of approximately \$9.7 million.

B-T One, LLC is a limited liability company formed by TECO Properties with Boyd Development Co., the project developer, to develop a residential community. B-T One, LLC had total assets at Dec. 31, 2002 of \$13.1 million. TECO Properties' estimated maximum theoretical loss exposure is its equity investment in this project of approximately \$7.5 million.

TECO Propane Ventures (TPV) has an investment in a partnership formed to combine propane operations with the propane operations of three third-party entities. At Dec. 31, 2002, the estimated maximum theoretical loss exposure faced by TPV is its equity investment of

derivative transaction volumes are limited to the anticipated volume for customer sales or supplier procurement activities.

The TECO Energy Authorizing Committee, directed by the CEO of TECO Energy, administers the risk management policy with respect to interest rate risk exposures. Under the policy for interest rate risk management the committee 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, is 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 TECO Energy enters into futures, forwards, swaps and option contracts for the following purposes:

- To limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric, PGS, TECO Gas Services and Prior Energy;
- To limit the exposure to interest rate fluctuations on debt issuances at TECO Energy and its other 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 TPS; and
- To limit the exposure to price fluctuations for physical purchases of fuel at TECO Transport.

TECO Energy uses 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. For unregulated operations, the company uses derivative instruments primarily to optimize the value of physical assets, primarily including generation capacity and natural gas delivery.

Derivative and Hedge Accounting

Effective Jan. 1, 2001, TECO Energy adopted FAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as subsequently amended and interpreted. FAS 133 requires TECO Energy and its 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 either components of other comprehensive income (OCI) or in net income, depending on the designation of those instruments. The effect of the adoption of FAS 133, at Jan. 1, 2001 on continuing operations was not material.

The accounting literature establishes specific criteria and requirements in order to apply hedge accounting. Due to the strict criteria and extensive requirements, certain derivatives do not qualify for hedge accounting, even though the derivative may efficiently and economically reduce the exposure to a particular type of risk. For accounting purposes, a derivative may only be designated as one of the following, resulting in the prescribed treatment in the financial statements:

Non-hedge: derivative must be recorded on the balance sheet at fair value; changes in the fair value of the derivative are recorded as a net gain or loss in earnings.

Cash Flow Hedge: derivative must be recorded on the balance sheet at fair value; changes in the fair value of the derivative are initially recorded in OCI; when the hedged item or anticipated hedged transaction impacts earnings, the current deferred gain or loss recorded in OCI is reclassified to earnings as an offset to the revenue or cost of the hedged item or anticipated hedged transaction.

approximately \$35.1 million and \$9.5 million of other potential liabilities. (See the **Other Unregulated Companies** section and **Note S** to the **Consolidated Financial Statements**.)

TECO Transport entered into two separate sale-leaseback transactions for certain vessels which were recognized as sales at the time of each transaction, and are currently recognized as operating leases for the assets. The sale-leaseback transactions were entered into with a third party that may 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. The estimated maximum loss exposure faced by TECO Transport is the incremental cost of obtaining suitable equipment to meet contractual obligations. (See **Note R** to the **Consolidated Financial Statements**.)

TECO Energy Services 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 for use, primarily, in air conditioning systems. The partnership may meet the definition of a VIE in accordance with FIN 46. The estimated maximum theoretical loss exposure associated with this partnership is its equity investment of approximately \$3.6 million.

In November 2000, TECO Energy established TECO Capital Trust I (Trust I) for the sole purpose of issuing Trust Preferred Securities (TRuPS) and using the proceeds to purchase company preferred securities from TECO Funding Company I, LLC (TECO Funding). Trust I may be a VIE in accordance with FIN 46. TECO Energy has guaranteed the payments to the holders of the company preferred securities and indirectly, the payments to the holders of the TRuPS, as a result of their beneficial interest in the company preferred securities. In January 2002, TECO Energy sold 17,965 million units of mandatorily convertible equity units in the form of 9.5% equity units at \$25 per unit. Each equity unit consisted of \$25 in principal amount of a trust preferred security of TECO Capital Trust II (Trust II), a Delaware business trust formed for the purpose of issuing these securities and using the proceeds to purchase company preferred securities from TECO Funding Company II, LLC. Trust II may meet the definition of a VIE in accordance with FIN 46. The estimated maximum loss exposure is not expected to be incrementally significant to obligations currently recognized by TECO Energy for activities associated with Trust I or Trust II. (See **Note G** to the **Consolidated Financial Statements**.)

As a result of the conversion of a loan to a Panda subsidiary on Jan. 3, 2003, TPS has an equity interest in the TIE projects. (See the **TECO Power Services — Construction Activities** section.) The estimated maximum theoretical loss exposure is TPS' equity investment of \$137 million. (See **Note N** to the **Consolidated Financial Statements**.)

Quantitative and Qualitative Disclosures About Market Risk

Risk Management Infrastructure

TECO Energy and its affiliates are subject to various types of market risk in the course of daily operations, as discussed below. The company has 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) and report to the Chief Financial Officer of TECO Energy. Front Office functions report to the various operating company presidents responsible for energy transaction activities.

The TECO Energy Risk Management Policy (Policy) governs all energy transacting activity at TECO Energy. The Policy is approved by the TECO Energy Board of Directors and administered by a Risk Authorizing Committee (RAC) that is comprised of senior management, chaired by TECO Energy's Chief Executive Officer (CEO), and advised by the Vice President of Energy Risk Management. Within the bounds of the Policy, the RAC approves specific hedging strategies, new transaction types or products, limits, and transacting authorities. The Policy further requires that, for all merchant generation asset management activities, power sales and gas purchases must be substantially matched, and that the volume of power sales commitments is limited to the volume of owned and available generating capacity. Transaction activity is reported daily and measured against limits. For all other commodity risk management activities,

Fair Value Hedge: derivative must be recorded on the balance sheet at fair value; changes in the fair value of the derivative are recorded in earnings; the hedged item is adjusted on the balance sheet to reflect the change in fair value from the hedge designation date; changes in the fair value of the hedged item are recorded as an offset to the change in fair value of the derivative recorded in earnings.

The designation of a derivative as either a cash flow or fair value hedge is dependent on the effectiveness of the derivative at offsetting the changes in future cash flows or fair value of the designated hedged transaction or item. The majority of the company's derivatives are used to reduce the variability in cash flows for anticipated sales or purchases of energy as a result of subsequent price movements (cash flow hedges). For example, a derivative to purchase natural gas at a fixed price may be designated as a cash flow hedge of the variability of future cash flows associated with an anticipated purchase of natural gas for the same time period. When the forecasted physical purchases of natural gas occurs, the gain or loss on the derivative, which has been deferred in OCI, will be reclassified to the income statement to adjust the actual purchase price to the committed fixed price of natural gas under the derivative instrument. Amounts recorded in OCI related to an effective designated cash flow hedge must be reclassified to current earnings if the anticipated hedging transaction is no longer probable of occurring.

Designation of a hedging relationship requires management to make assumptions about the future probability of the timing and amount of the 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. (See **Unregulated Companies** section below, and **Notes A and B** to the **Consolidated Financial Statements**.)

Interest Rate Risk

TECO Energy is exposed to changes in interest rates primarily as a result of its borrowing activities. TECO Energy or its affiliates 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, 2002, a hypothetical 10% increase in TECO Energy's weighted average interest rate on its variable rate debt during 2003, as compared to 2002, would not result in a material impact on pretax earnings. Comparatively, as of Dec. 31, 2001, a hypothetical 10% increase in TECO Energy's weighted average interest rate on its variable rate debt and required refinancings during 2002, as compared to 2001, would have resulted in an estimated \$3.2 million decrease in pretax earnings. These amounts were determined based on the variable rate obligations existing on the indicated date at TECO Energy and its subsidiaries. The reduction of the sensitivity to hypothetical interest rate movements is due to the amount of variable rate debt outstanding and substantially lower debt maturities. Due to the uncertainty of future events, as discussed in the **Investment Considerations** section, and management's responses to those events, the sensitivities assume no changes to TECO Energy's financing structure. A hypothetical 10% change in interest rates would increase the fair value of long-term debt 5.6 percent at Dec. 31, 2002. A hypothetical 10% change in interest rates would not have a significant impact on the estimated fair value of TECO Energy's long-term debt at Dec. 31, 2001. (See **Financing Activity** section, and **Notes E and F** to the **Consolidated Financial Statements**.)

Credit Risk

TECO Energy has 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. TECO Energy's Credit Guidelines require transactions with counterparties below investment grade to be collateralized. The Credit Guidelines are administered and monitored within the Middle Office, independent of the Front Office.

Financial instability and significant uncertainties relating to liquidity in the entire merchant energy sector have increased the perceived credit risk. Credit exposures for merchant generation activities are calculated, compared to limits and reported to management on a daily basis. Contracts with different legal entities of the same counterparty are consolidated and managed as appropriate, considering the legal structure and any netting agreements in place. Below is a summary of TECO Energy's credit risk exposure on energy contracts related to merchant generation activities at Dec. 31, 2002.

Rating ⁽¹⁾	Exposure Before Credit Collateral ⁽²⁾	Credit Collateral ⁽³⁾	Net Exposure	Number of Counterparties >10% ⁽⁴⁾	Net Exposure Counterparties >10% ⁽⁵⁾
Investment grade	\$13.1	—	\$13.1	4	\$12.7
Split rating	—	—	—	—	—
Non-investment grade	—	—	—	—	—
No external ratings (internally rated)	—	—	—	—	—
Investment grade	<0.1	—	<0.1	—	—
Non-investment grade	—	2.5	—	—	—
Total	\$13.1	\$2.5	\$13.1	4	\$12.7

- Ratings are principally determined based on publicly available credit ratings, as determined by independent ratings agencies. If the counterparty has provided a guarantee by a higher rated entity, the assigned rating is that of the guarantor. Included in Investment grade are those counterparties with a minimum S&P or Fitch's rating of BBB- or higher and a Moody's rating of Baa3 or higher.
- Exposure before credit collateral includes the fair value of net energy contract assets for open positions and the net account receivable for realized energy contracts. Exposures are offset by a legal counterparty where legally enforceable netting and setoff arrangements are in place.
- Credit collateral is required from time-to-time based on contractual provisions and may generally include cash deposits and letters of credit. At Dec. 31, 2002, credit collateral was required from two non-investment grade counterparties. However, TECO EnergySource was not exposed to these counterparties based on the unrealized fair value of the open energy contracts at Dec. 31, 2002.
- The number of counterparties that individually, after considering legally enforceable netting arrangements, represent a significant concentration of credit risk (i.e., more than 10% of the total credit exposure) at TECO EnergySource. Also, the combined exposure, less credit collateral, if any, of each significant concentration.

Commodity Risk

TECO Energy and its 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. The company assesses and monitors risk using a variety of state-of-the-art 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

At Tampa Electric, fuel costs used for generation are currently most affected by the cost of coal. Future fuel costs will be impacted by the cost of natural gas, in addition to coal, as the repowering of the Gannon Station is completed. (See the **Environmental Compliance** section.) PGS is primarily subject to costs for purchased gas and pipeline capacity. Increasing costs for the regulated utilities impact their competitive position in the marketplace versus other energy sources and suppliers.

Currently, Tampa Electric and PGS are subject to relatively little commodity price risk exposure. This is primarily due to the fact that commodity price increases due to changes in market conditions for fuel, purchased power and natural gas are recovered through cost recovery clauses, with no anticipated effect on earnings. Commodity price risk is mitigated by the use of long-term fuel supply agreements, prudent operation of plant facilities to reduce the reliance on purchased power, and derivative instruments designated as cash flow hedges of anticipated

purchases of natural gas. At Dec. 31, 2002 and 2001, a change in commodity prices would not have a material impact on earnings for Tampa Electric or PGS.

Unregulated Companies

Most of the unregulated subsidiaries at TECO Energy are subject to significant commodity risk. These include TECO Coal, TECO Transport, TECO Gas Services, Prior Energy and TPS. 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 literature to dynamic transactions, as discussed above in the **Derivative and Hedge Accounting** section.

TECO Coal is exposed to commodity price risk through coal sales as a part of its daily operations. Fixed price sales agreements are used, where possible and economical, to mitigate the variability in coal prices. At Dec. 31, 2002 and 2001, a hypothetical 10% change in the average annual market price of coal for each year would have resulted in a decrease to pretax earnings of approximately \$5 million and \$15 million, respectively.

Fuel price risk exists at TECO Transport as a result of periodic purchases of diesel fuel. 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, 2002, substantially all of the projected fuel price risk for 2003 was removed via price adjustment clauses and a derivative instrument. As a result, a hypothetical 10% change in the average annual market price of fuel would not result in a material impact on pretax earnings as of Dec. 31, 2002 and would have resulted in an impact to pretax earnings of approximately \$1 million as of Dec. 31, 2001.

Prior Energy and TECO Gas Services are exposed to variability in natural gas prices as a result of their commitments to purchase from suppliers and deliver physical natural gas to customers. Prior Energy and TECO Gas Services generally enter into fixed price agreements to provide procurement and fuel optimization services to customers. At the same time, derivative instruments and fixed price purchase agreements from suppliers are used to meet customers' requirements. As a result, a hypothetical change in natural gas prices would not have had a material impact for such operations as of Dec. 31, 2002 and 2001.

Prior Energy also provides hedge management and storage solutions for customers. Derivative instruments are carefully used to reduce or eliminate natural gas price risk associated with these activities. As of Dec. 31, 2002 and 2001, a hypothetical 10% change in natural gas prices would not result in a material impact on earnings.

For TPS, results of operations are impacted primarily by changes in the market prices for electricity and natural gas. The profitability of merchant power plants is heavily dependent on the spread between electric and gas prices (spark spread) in the markets they serve.

The spark spread calculates the relative profitability of converting gas into electricity, which exists as the best indicator of a gas-fired plant's profitability. The variable cost of producing electricity is primarily a function of gas commodity prices and the heat rate of the plant. The heat rate is the measure of efficiency in converting the input fuel into electricity. When the conversion price equals the market price, the spark spread would be zero. A power plant operating at this level would theoretically break even with respect to variable costs.

Wholesale power prices are set by the market assuming a cost for the input energy and conversion efficiency, but the fixed costs are not necessarily reflected in the market-observed spark spread. TPS uses derivative instruments to reduce the commodity price risk exposure of the merchant plants. The commodity price risk of each plant is managed on both a portfolio and asset-specific basis. The following table summarizes the impact of a hypothetical 10% change in commodity prices on the fair value of merchant energy derivative contracts at Dec. 31, 2002 and Dec. 31, 2001.

Sensitivity of the Fair Value of Merchant Energy Derivative Contracts (millions)

	Dec. 31, 2002	Dec. 31, 2001
Change in Fair Value due to a 10%⁽¹⁾:		
Decrease in natural gas prices	\$ (16.9)	\$ (4.0)
Increase in electricity prices	(24.4)	— ⁽²⁾
Increase in electricity and natural gas prices	(7.5)	— ⁽²⁾

(1) Reflects the fair value associated with merchant energy derivative contracts only. The change shown for the contracts due to price movements would be more than offset by a change in the fair value of the underlying physical plant assets.

(2) No material impact.

Below is a summary of the percentage of merchant plant output and fuel requirements hedged.

Estimated Merchant Plant Hedging Information	2003	2004
Forecasted plant output and fuel requirements hedged	37%	15%

The following tables summarize the changes in and the fair value balances of energy derivative assets (liabilities) for the years ended Dec. 31, 2001 and 2002.

Changes in Fair Value of Energy Derivatives (millions)	
Net fair value of derivatives as of Dec. 31, 2000	\$ (19.0)
Net change in unrealized fair value of derivatives	(29.2)
Changes in valuation techniques and assumptions	—
Realized net settlement of derivatives	21.1
Net fair value of derivatives as of Dec. 31, 2001	(27.1)
Net change in unrealized fair value of derivatives	4.7
Changes in valuation techniques and assumptions	—
Realized net settlement of derivatives	30.8
Net fair value of derivatives as of Dec. 31, 2002	\$ 8.4

Roll-Forward of Energy Derivatives Net Assets (Liabilities) (millions)

Total energy contracts net assets (liabilities) as of Dec. 31, 2000	\$ (19.0)
Change in fair value of net derivative assets (liabilities):	
Recorded in OCI	(1.2)
Recorded in earnings	21.1
Net option premium payments	2.3
Net purchase (sale) of existing contracts	(30.3)
Total energy contracts net assets (liabilities) as of Dec. 31, 2001	(27.1)
Change in fair value of net derivative assets (liabilities):	
Recorded in OCI	4.7
Recorded in earnings	30.8
Net option premium payments	—
Net purchase (sale) of existing contracts	—
Net fair value of derivatives as of Dec. 31, 2002	\$ 8.4

When available, the company uses quoted market prices to record the fair value of energy derivative contracts. However, certain energy derivative contracts are not exchange-traded, but rather, are traded in the over-the-counter (OTC) market, through multiple-party on-line trading platforms, or in the bilateral market. TECO Energy uses industry-accepted valuation techniques based on pricing models or matrix pricing for energy derivative contracts when third-party price data is infrequent or not available. 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 for and between commodities. Mathematical approaches are applied on a frequent basis to validate and corroborate the results of valuation calculations.

Below is a summary table of sources of fair value, by maturity period, for energy derivative contracts at Dec. 31, 2002.

Maturity and Source of Energy Derivative Contracts (Liabilities) at Dec. 31, 2002	Contracts Maturing in		Total fair Value
	2003	2004	
Source of Fair Value (millions)			
Actively quoted prices	\$ 8.7	\$ 0.1	\$ 8.8
Other external sources ⁽¹⁾	(0.3)	(0.1)	(0.4)
Model Prices ⁽²⁾	—	—	—
Total	\$ 8.4	\$ —	\$ 8.4

(1) Information from external sources includes information obtained from over-the-counter brokers, industry price services or surveys and multiple-party on-line platforms.

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

For all unrealized 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.

Non-Operating Items Impacting Net Income From Continuing Operations

2002 Items

In 2002, TECO Energy's results included a \$3.0-million after-tax charge at TECO Investments related to an aircraft leased to US Airways, which has filed for bankruptcy. Results at TPS include a \$5.8-million after-tax asset valuation adjustment for the proposed sale of its interests in generating facilities in the Czech Republic. Results at TECO Energy include a \$34.1-million pretax (\$20.9-million after-tax) charge related to a debt refinancing.

2001 Items

In 2001, TECO Energy's results included charges to adjust asset valuations totaling \$7.2 million after-tax. The adjustments included a \$6.1-million after-tax adjustment related to the sale of TPS' minority interests in EGI, which owns smaller power generation projects in Central America, and a \$1.1-million after-tax charge related to the sale of leveraged leases at TECO Investments.

2000 Items

In 2000, TECO Energy's results included an \$8.3-million after-tax gain from the US Propane and Heritage Propane transactions offset by after-tax charges of \$5.2 million to adjust the value of leveraged leases and \$3.8 million to adjust property values at TECO Properties.

Discontinued Operations

In September 2002, as a component of its cash raising plans, TECO Energy initiated activities to sell the TECO Coalbed Methane gas assets. That sale was substantially completed in December 2002 to the Municipal Gas Authority of Georgia. Proceeds from the sale were \$140 million, of which \$42 million was paid in cash at closing and \$98 million was paid in January 2003. TECO Coalbed Methane's results are accounted for as discontinued operations for all periods reported.

TECO Coalbed Methane's 2002 net income was \$31.4 million including a \$7.7-million after-tax net gain on the \$42 million portion of the sale proceeds. These results reflect production of 14.2 billion cubic feet (Bcf), compared to 15 Bcf in 2001 at an effective gas price, including the effects of hedging, of about \$2.80 per thousand cubic feet (Mcf), an almost 20 percent lower realized price than in 2001.

2001 net income increased as a result of higher gas prices which more than offset naturally declining production. Effective gas prices, including the effects of hedging, increased 33 percent to \$3.66 per Mcf and production was 15 Bcf. Effective Jan. 1, 2001, the company had derivatives in place at TECO Coalbed Methane that qualified for cash flow hedge accounting treatment under FAS 133. As a result of the adoption of FAS 133, the company recorded an initial derivative liability of \$19.0 million and an after-tax reduction to OCI of \$12.6 million.

Production from TECO Coalbed Methane's reserves was eligible for Section 29 non-conventional fuels tax credits through 2002. The credit is estimated to be \$1.10 for 2002 and was \$1.08 per million Btu in 2001, \$1.06 in 2000. This rate escalated with inflation but could be limited by domestic oil prices. In 2002, domestic oil prices would have had to exceed \$49 per barrel for this limitation to have been effective. In 2002, TECO Coalbed Methane's Section 29 tax credits were \$15.9 million, compared to \$16.1 million in 2001.

Other Income (Expense)

In 2002, Other Income (Expense) of \$47.2 million included \$60.7 million from construction-related and loan agreements with Panda Energy and earnings on the equity investment in EFGSA at TPS, and income from the investment in TPV, partially offset by the \$9.4 million pretax (\$5.8 million after-tax) asset valuation charge for TPS' proposed sale of its minority interest in generating facilities in the Czech Republic and a \$34.1 million (\$20.9 million after-tax) pretax charge related to a TECO Energy debt refinancing completed in 2002.

In 2001, Other Income (Expense) of \$51.9 million included \$27.1 million from construction-related and loan agreements with Panda Energy and earnings on the equity investment in EFGSA at TPS, and income from the investment in TPV, partially offset by a \$9.9 million pretax (\$6.1 million after-tax) charge for TPS' sale of its minority interest in EGI.

Equity AFUDC at Tampa Electric, which is included in Other Income, was \$24.9 million in 2002, \$6.6 million in 2001 and \$1.6 million in 2000. AFUDC is expected to be about \$20 million in 2003 before declining in 2004, primarily reflecting Tampa Electric's growing investment in the Cannon to Bayside repowering. With the conversion of the loan to Panda Energy related to the TPS projects to an ownership interest, (see the TECO Power Services - Construction Activities section) the interest income related to these loans will be eliminated in 2003.

Interest Charges

Interest expense was \$147.1 million in 2002 compared with \$164.0 million in 2001 and \$167.6 million in 2000. The decline in 2002 was primarily because of lower short-term debt rates and balances and a favorable settlement with the Internal Revenue Service regarding disputed income tax amounts for which interest had been previously paid, partially offset by higher distributions on preferred securities due to the issuance of mandatorily convertible equity units in January 2002. The slight decrease in 2001 was primarily because of lower short-term debt rates.

Income Taxes

Income taxes decreased in 2002, reflecting greater non-taxable AFUDC equity and a substantial increase in tax credits associated with the production of non-conventional fuels. In 2001 income tax expense decreased, reflecting higher taxable income offset by an increase in tax credits associated with the production of non-conventional fuels. Income tax expense as a percentage of income from continuing operations before taxes was -14.8 percent in 2002, -0.8 percent in 2001 and 11.4 percent in 2000.

The cash payment for federal income taxes, as required by the alternative minimum tax rules, was \$71.9 million, \$52.4 million and \$83.9 million in 2002, 2001 and 2000, respectively.

Total income tax expense was reduced by the Federal tax credit related to the production of non-conventional fuels, under Section 29 of the Internal Revenue Code. This tax credit totaled \$107.3 million in 2002, \$86.2 million in 2001 and \$52.1 million in 2000. These tax credits are generated annually on qualified production at TECO Coal through Dec. 31, 2007, subject to changes in law, regulation or administration that could impact the qualification of Section 29 tax credits.

The tax credit is determined annually and is estimated to be \$1.08 for 2002 and was \$1.08 per million Btu in 2001 and \$1.06 in 2000. This rate escalates with inflation but could be limited by domestic oil prices. In 2002, domestic oil prices would have had to exceed \$49 per barrel for this limitation to have been effective.

In 2002, 2001 and 2000, the decreased income tax expense also reflected the impact of increased overseas operations with deferred U.S. tax structures. The decrease related to these deferrals was \$8.1 million, \$7.2 million and \$9.3 million for 2002, 2001 and 2000, respectively.

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

Enron Related Matters

TPS has filed a claim in the Enron bankruptcy proceeding associated with the NEPCO "swept cash" (see the **TECO Power Services - Construction Activities** section) for the four projects in the amount of \$214 million. This is a gross amount and does not take into account efficiencies in the projects and other similar credits. The bankruptcy judge appointed an examiner in October 2002 to evaluate whether the "swept cash" lost by all NEPCO customers at the time of the bankruptcy can be traced from NEPCO to Enron and then to Enron's use of the funds. That report is expected by the end of the first quarter, and if it is favorable, the judge should require that the amount of the traceable funds be returned to the bankrupt estate of NEPCO. This result would improve significantly TPS' likelihood of recovering most of the cash. Since the appointment of the examiner, TPS and others have filed adversary proceedings in the bankruptcy.

TECO Energy has negotiated an agreement with Enron, pending approval of the Creditors Committee, to settle the previously reported \$3.5 million of potential trade payables exposure as a result of the Enron bankruptcy. Action by the Creditors Committee is expected by the end of March 2003. The net financial impact of the agreement is reflected in consolidated net income and no future financial impact is expected.

Environmental Compliance

Consent Decree

Tampa Electric Company, in cooperation with the Environmental Protection Agency (EPA) and the U.S. Department of Justice, signed a Consent Decree which became effective Oct. 5, 2000, and a Consent Final Judgment with the Florida Department of Environmental Protection (FDEP), effective Dec. 7, 1999. 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 will 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 sulfur dioxide (SO₂), projects for nitrogen oxides (NOx) reduction efforts on Big Bend Units 1 through 4, and the repowering of the coal-fired Gannon Station to natural gas. When these units are repowered, the station will be renamed the Bayside Power Station and will have total station capacity of about 1,800 megawatts (nominal) of natural gas-fueled electric generation. Tampa Electric anticipates commercial operation for the first repowered Bayside unit by May 1, 2003. The repowering of the second unit is scheduled for completion by May 1, 2004. By May 1, 2005, Tampa Electric must decide whether to install NOx controls, repower, or shutdown Big Bend Unit 4, and it must implement the chosen methodology by Jun. 1, 2007. By May 1, 2007, Tampa Electric

will decide whether to install NOx controls, repower, or shutdown Big Bend Units 1, 2 and 3 and it must implement the chosen methodology beginning in 2008. Tampa Electric's capital investment forecast includes amounts in the 2006 and 2007 period for compliance with the NOx reduction requirements.

Emission Reductions

Since 1998, Tampa Electric has reduced annual SO₂, NOx, and particulate matter (PM) emissions from its facilities by 105,418 tons, 11,206 tons, and 1,113 tons, respectively.

Reductions in SO₂ emissions were primarily accomplished through the installation of scrubber systems on Big Bend Units 1 and 2. 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. Currently, the scrubbers at Big Bend Station remove more than 95 percent of the SO₂ emissions from the flue gas streams. In addition, reductions in NOx have been accomplished through combustion tuning and optimization projects at Big Bend and Gannon Stations.

Particulate matter is controlled at Big Bend and Gannon Stations through the use of electrostatic precipitators, which remove more than 99.9 percent of the PM generated during the combustion process.

Significant reductions in emissions outlined in the consent decree and consent final judgment will result from the ongoing repowering of the Gannon to Bayside Power Station and, should Tampa Electric decide to continue to burn coal, the installation of additional NOx emissions controls on all Big Bend Units. By 2010, these projects will result in the additional phased reduction of SO₂ by 47,467 tons per year, NOx by 50,488 tons per year, and PM by 1,981 tons per year. In total, Tampa Electric's emission reduction initiatives will result in the reduction of SO₂, NOx, and PM emissions by 87 percent, 89 percent, and 60 percent, 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.

In November 2000, the FPSC approved recovery, through the Environmental Cost Recovery Clause of costs incurred to improve the availability and removal efficiency for its Big Bend 1, 2 and 3 scrubbers, to reduce PM emissions, and for early NOx emissions reduction projects. The approved cost recovery for these various environmental projects through customers' bills started in January 2001.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party 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, 2002, Tampa Electric Company has estimated its ultimate financial liability to be approximately \$20 million, 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 the 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 potentially responsible parties (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 PRRs to pay their pro rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. These costs are recoverable through customer rates established in subsequent base rate proceedings.

Regulation

Tampa Electric Rate Stabilization Strategy

Tampa Electric's objectives of stabilizing prices from 1996 through 1999 and securing fair earnings opportunities during this period were accomplished through a series of agreements entered into in 1996 with Florida's Office of Public Counsel (OPC) and the Florida Industrial Power Users Group (FIPUG), which were approved by the FPSC. Prior to these agreements, the FPSC approved a plan submitted by Tampa Electric to defer certain 1995 revenues.

In general, under these agreements Tampa Electric was allowed to defer revenues in 1995 and 1996 during the construction of Polk Unit 1 and recognize these revenues in 1997 and 1998 after commercial operation of the unit. Other components of the agreements were a base rate freeze through 1999 and refunds to customers totaling \$50 million during the period from October 1996 through December 1998, while Tampa Electric was allowed recovery of the capital costs incurred for the Polk Unit 1 project.

In October 2000, the FPSC staff recommended a refund of \$6.1 million for the final year of the agreements. OPC objected to certain interest expenses recognized in 1999 that were associated with prior years' tax positions and used to calculate the amount to be refunded. Following a review by the FPSC staff, the FPSC agreed in December 2000 that the original \$6.1 million was to be refunded to customers. In February 2001, OPC protested the FPSC's decision. The FPSC held hearings on the issue in August 2001 and upheld its original decision. In January 2002, the OPC filed a motion with the FPSC asking for reconsideration of its decision, alleging the FPSC relied on erroneous information. This was not granted, and Tampa Electric made refunds of about \$6.4 million associated with 1999 in 2002.

Since the expiration of the agreements, Tampa Electric is not under a new stipulation. Therefore, its rates and allowed return on equity (ROE) range of 10.75 percent to 12.75 percent with a midpoint of 11.75 percent 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.

Peoples Gas Rate Proceeding

On Jun. 27, 2002, PCS filed a petition with the FPSC to increase its service rates. The requested rates would have resulted in a \$22.6 million annual base revenue increase, reflecting a ROE midpoint of 11.75 percent.

On the date of the FPSC hearing, PCS agreed to a settlement with all parties involved, and a final Commission order was granted on Dec. 17, 2002. The company received authorization to increase annual base revenues by \$12.05 million. The new rates allow for an 11.25 percent midpoint ROE and a capital structure with 57.43 percent equity and were effective after Jan. 16, 2003.

Cost Recovery Clauses

In September 2002, Tampa Electric filed with the FPSC for approval of fuel and purchased power, capacity, environmental and conservation cost recovery clause rates for the period January through December 2003. In November, the FPSC approved Tampa Electric's requested changes. Accordingly, Tampa Electric's residential customer rate per 1,000-kilowatt hours decreased by \$4.26 to \$89.68. The rates include projected costs associated with environmental projects required under the EPA Consent Decree and the FDEP Consent Final Judgment. They also reflect natural gas purchases for the company's repowered Bayside Unit 1.

During 2002, PCS' purchased gas adjustment remained stable, as no significant natural gas

spikes occurred. The actual purchased gas adjustment rate paid by consumers was significantly lower than the FPSC approved cap. In December 2002, PCS' purchased gas adjustment cap for 2003 was approved as filed.

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.

There is presently active 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 February 2002, the FPSC began holding workshops to discuss suggested changes to an associated rule originally adopted by the FPSC in 1994, requiring investor-owned electric utilities (IOUs) to issue Requests for Proposals (RFP) prior to filing a petition for Determination of Need. The RFP process has been used as a tool to measure the cost-effectiveness of new generation. After a series of workshops, a rule hearing was held in December 2002 and, as a result, the FPSC made modifications to the rule that provide a mechanism for expedited dispute resolution, allow bidders to submit new bids whenever the IOU revises its costs 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 costs overruns in the event the self-build option is deemed the most cost-effective. The new rule will become effective for requests for proposal for applicable capacity additions, prospectively.

Regional Transmission Organization (RTO)

In December 1999, the Federal Energy Regulatory Commission (FERC) issued Order No. 2000, encouraging the development of RTOs. This rule was driven by the FERC's continuing effort to increase open access to transmission facilities in large, regional markets.

The peninsular Florida IOUs made joint RTO filings to the FERC in October and December 2000. In the filing, Tampa Electric agreed with the other Florida IOUs to form an RTO to be known as GridFlorida LLC. GridFlorida would independently control the transmission assets of the filing utilities, as well as other utilities in the region that choose to join. The RTO would be an independent, investor-owned organization that would have control of the planning and operations of the bulk power transmission systems of the utilities within peninsular Florida. In addition, GridFlorida was proposed to be a transmission company that would own transmission assets. Tampa Electric planned to contribute its transmission assets to GridFlorida in exchange for a passive interest.

In March 2001, the FERC conditionally approved GridFlorida. In May 2001, the FPSC decided to investigate whether the peninsular Florida IOUs were prudent in complying with FERC's Order No. 2000. In October 2001, the FPSC ruled that, while the companies were prudent in forming GridFlorida, the FPSC was not satisfied with the transmission-owning features of the GridFlorida filing nor with the proposal that any of the filing utilities transfer ownership of their assets to GridFlorida. Accordingly, the FPSC ordered the companies to develop a new RTO model.

In September 2002, the FPSC issued an order which gave final approval to some aspects of the latest GridFlorida proposal; set some items for further discussion by parties and the FPSC; and set a hearing to address market design. The applicants filed joint testimony that addressed the principles for developing a Florida-specific market design that is consistent with the prin-

ciples identified in the FERC's proposed order on standard market design.

In October 2002, the process was held in abeyance after 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. Tampa Electric and the other peninsular IOUs will take varying roles to support the FPSC and their prudence determinations. Oral arguments are expected during the first half of 2003, and a decision by the Supreme Court is not expected until late 2003. All activity in development of GridFlorida has ceased pending the outcome of the case and the resolution of certain issues by the FPSC subsequent to that outcome.

Federal Energy Regulatory Commission (FERC) Restructuring Initiatives

The FERC has increased its focus on creating a more efficient electric industry, and it has begun several key initiatives since its RTO order in late 1999 (see the Regional Transmission Organization section). These include the development of a Standard Market Design (SMD) for electric wholesale markets; standard generator interconnection terms, conditions and pricing; enhanced affiliate standards of conduct; and more comprehensive public information initiatives. The most significant of these initiatives relates to development of a SMD through rulemaking that will provide certain structural changes to how transmission service is provided, accessed and priced. A final rule in this matter is expected sometime in 2003. TECO Energy, through its appropriate operating companies, is active in providing comments on all initiatives and plans to remain active in ensuring its positions are fairly represented. Many of the initiatives being proposed by the FERC would be beneficial both to Tampa Electric and TPS.

TPS Federal and State Regulatory and Legislative Involvement

Along with TECO Energy's active involvement in restructuring initiatives, TPS has been proactively involved in regulatory and legislative forums in the markets in which it competes including Arizona, Texas, Arkansas, Mississippi, and Louisiana. This has included repeal in part and sometimes in total of wholesale and retail deregulation rules and laws in Arizona and Arkansas.

Arizona Public Service (APS), the largest investor-owned electric utility in the state, filed with the Arizona Corporation Commission (ACC) a request for a partial variance from the state's competition rules established in 1999. APS requested that it be exempt from its obligation, beginning on Jan. 1, 2003, to purchase at least 50 percent (about 3,000 MW) of its load requirements through a formal, arms-length, competitive procurement process and sought instead to purchase almost all of its load requirements from its unregulated affiliate, Pinnacle West Energy Corporation (PWEC). APS asserted that, due to the California crisis and the Enron collapse, the competitive wholesale market was not mature or reliable enough to meet its needs, so it should be permitted to execute a 23-year power purchase agreement between itself and PWEC. Tucson Electric Power Company (TEP) filed a similar variance request with the ACC, although it only sought a postponement of the implementation date, not a long-term power purchase agreement with an affiliated entity. The two requests were stayed by the ACC in late April 2002, and a docket was opened to review the future of competition in Arizona. In August 2002, the Commission ordered APS not to divest its current rate-based generating facilities to its affiliate, and to continue to participate in a parallel proceeding to determine what portion of its needs will be competitively bid for delivery beginning in the summer of 2003.

Regarding the competitive procurement process, the ACC Staff held numerous workshops, followed by a hearing in November 2002 to determine the amount and procedures for APS' and TEP's acquisition of their power requirements. TPS has been active in all aspects of the state's proceedings. A final determination is expected during the first quarter of 2003 with the competitive procurement process slated to begin by spring.

During this year's legislative session, the Arkansas Legislature will consider repealing its earlier legislation, which was to initiate retail electric deregulation in Arkansas sometime between October 2003 and October 2005. The incumbent IOUs are advocating a complete repeal of retail deregulation and/or a ten-year postponement of its implementation date. The large consumers

and the independent power producers are lobbying for a commitment to wholesale deregulation in Arkansas, access to the state's transmission grid, and a "pilot" project for large customers to be able to shop for power in the interim. TPS is supporting this approach while also aligning with other independent power producers to analyze the beneficial impacts to ratepayers from implementing a region-wide, security-constrained, economic dispatch, with consideration given for units' efficiency and environmental characteristics, including emissions. This is a strategy for displacing the region's older, less efficient, more polluting generating units so that state-of-the-art, gas-fired, combined-cycle units, such as Union Power Partners, can serve the growing needs of the area. This is a strategy that TPS has advanced at the federal level and other markets it serves.

In Texas, TPS has taken an active role on ERCOT committees, in proceedings at the Public Utility Commission of Texas (PUCT) and in the Legislature, whose session begins in mid-January. Transmission congestion is a major concern in the ERCOT market, and has negatively affected Frontera's ability to economically operate. Several initiatives within the ERCOT committees and at the PUCT are underway to address these ongoing congestion problems.

Frontera appealed specific ERCOT protocols with the PUCT, because of inadequate compensation for ERCOT's high usage levels of Frontera's units during times of regional congestion. Originally, the intent of the protocols was to allow ERCOT to acquire energy and capacity, when only critically necessary and on an infrequent basis from the region's existing generating units. Due to local transmission congestion in the Rio Grande Valley, Frontera was frequently requested by ERCOT to start-up and relieve the region's congestion. Frontera, however was not compensated sufficiently for providing this ancillary service in 2002. The appeal process is underway and is expected to be concluded by the end of the first quarter of 2003.

Transmission Rates

In October 2002, Tampa Electric submitted a FERC filing to change its transmission and ancillary services rates under the company's open access transmission tariff. These rates apply to wholesale transmission users of Tampa Electric's transmission system and do not affect retail service rates. In December, the FERC accepted the filing and set the matter for settlement negotiations and a potential hearing should the settlement process fail. Settlement discussions began in January 2003.

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, thereby bypassing PGS facilities. In response to this competition, various programs have been developed 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.

In March 2000, the City of Lakeland (City) filed suit against PGS and sought a declaration that it had the right to purchase PGS facilities located within the city limits. In October 2002, the City came to the conclusion that it no longer desired to pursue owning the gas utility in Lakeland and agreed to voluntarily dismiss the lawsuit. The City and PGS entered into a new

10-year franchise agreement, similar in terms and conditions to the majority of the agreements PGS has with other municipalities.

Corporate Governance

Recently, legislation, rules and proposed rules and guidelines were issued by the United States Congress, the Securities and Exchange Commission (SEC), the New York Stock Exchange (NYSE) and other interested groups designed to ensure corporate accountability, improve corporate governance and restore investor confidence. In 2002, the NYSE issued proposed standards for listed companies; the SEC issued the requirement that the largest public companies certify quarterly financial reports; one of 18 directives issued from December 2001 through December 2002. Also in 2002, the President signed the Sarbanes-Oxley Act which, among other things, requires certification of financial statements with criminal penalties for filing false statements.

These rules and proposals require independence by the Board of Directors, define committees of the Board of Directors with charters and review processes, require an internal audit function, a code of ethics for senior financial officers, adequate internal controls to detect fraud, adequate training for members of the Board of Directors, increased oversight of financial disclosure by the Audit Committee of the Board, shorter time period to report insider selling of company shares and other important items.

For many years, TECO Energy's Board of Directors has primarily consisted of independent directors, the committee structures recommended in the various proposals were already in place and the company has an effective internal audit function. In addition, the company has had a code of ethics for all officers and employees, and it was expanded to include the Board of Directors in 2002. TECO Energy has always had controls for full and complete financial reporting and disclosure, and in response to the new requirements, they have been formalized and are reviewed for effectiveness quarterly.

TECO Energy's CEO and CFO certified its first and second quarter Reports on Form 10-Q for 2002, all Interim Reports on Form 8-K and its Annual Report on Form 10-K for 2001 as required by the SEC in August 2002. The certifications, which contained no exceptions, attested to the accuracy of the reports and was signed following a review by the Audit Committee of the company's Board of Directors. In compliance with the Sarbanes-Oxley Act, certifications of second and third quarter Reports on Form 10-Q have been filed with the SEC.

In addition, the CEO and CFO evaluated the effectiveness of the company's disclosure controls and procedures in conjunction with the filing of quarterly financial statement certifications, as required under the new legislation, and found that the disclosure controls and procedures are effective in alerting them on a timely basis to material information relating to the company required to be included in the company's reports. Processes are in place to meet these requirements on a quarterly basis.

Transactions with Related and Certain Other Parties

The company and its subsidiaries had certain transactions, in the ordinary course of business, with entities in which directors of the company had interests that are reported in TECO Energy's annual proxy statement and Tampa Electric's annual regulatory filings. These transactions, primarily for legal services, were not material for the periods ended Dec. 31, 2002 and 2001. There are no material transactions of this type where the payments are in excess of those that would be paid under an arms-length transaction. TECO Energy has interests in unconsolidated affiliates, which are discussed in the **TECO Power Services, Other Unregulated Companies and Off-Balance Sheet Financing** sections.

TPS Arkansas Operations Company and TPS Arizona Operations Company, both wholly-owned subsidiaries of TPS, had a combined receivable from Union and Gila River of \$0.8 million as of Dec. 31, 2002.

In addition, TPS recognized income on the non-TPS portion of notes receivable from unconsolidated affiliates in which TPS holds joint venture interests and from credit support for the TPCC joint venture (see **Notes A and N to the Consolidated Financial Statements**). The notes receivable from unconsolidated affiliates include:

(\$ millions)	Rate	Dec. 31, 2002	Dec. 31, 2001
Notes receivable from:			
Panda Energy	14%	\$137.0	\$92.7
Energeticke Centrum Kladrno	6%	1.4	—
Mosbacher Power Partners L.P.	12%	—	13.1
Mosbacher Power Partners L.P.	9%	13.7	21.1
Mosbacher Power Partners L.P.	12%	—	6.2
EEGSA	6.81% ⁽¹⁾	11.1	10.9
TPGC - Gila River	7.79% ⁽¹⁾	369.5	37.5
TPGC - Union Power	6.58% ⁽¹⁾	426.3	86.7

(1) Current rate at Dec. 31, 2002.

TPS' position in the Odessa and Guadalupe power stations in Texas was in the form of a \$137 million loan to a Panda Energy International subsidiary, which is a partner in TIE at Dec. 31, 2002. This loan converted into an ownership interest on Jan. 3, 2003. The conversion gives TPS an opportunity to have an effective economic interest estimated at 75 percent of Panda's 50 percent interest in these projects (approximately 1,000 MW) over the life of the projects. TPS is evaluating its options relative to its ownership position in these projects and is targeting to structure its interest in such a manner that it will cover its cash costs in 2003 and mitigate any impact on earnings at TPS in 2003. (See **Strategy and Outlook** section.)

In February 2002, the TPS and Panda affiliates that comprise the joint venture that owns the Union and Gila River projects entered into an arrangement obligating TPS to purchase and Panda to sell Panda's interest in the joint venture in 2007 for \$60 million. Panda has the right to cancel the purchase arrangement by paying TPS \$20 million or a lesser amount under certain circumstances. The purchase arrangement can result in TPS' purchase of the interest prior to 2007 if Panda defaults on a bank loan made to Panda using the purchase arrangement as collateral or if TECO Energy permits its debt-to-capital ratio to exceed 65.0 percent, permits its EBITDA/interest ratio to fall below 1.5 times or it defaults on the payment of indebtedness in excess of \$50 million. TECO Energy's debt-to-capital ratio at Dec. 31, 2002 was 55.9 percent and its EBITDA/interest ratio was 3.6 times.

Investment Considerations

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

Financing Risks

TECO Energy has substantial indebtedness, which could adversely affect its financial condition and financial flexibility.

In recent years, TECO Energy has significantly expanded its indebtedness. This increase in debt levels has increased the amount of fixed charges TECO Energy is obligated to pay. The level of indebtedness and restrictive covenants contained in its debt obligations could limit its ability to obtain additional financing or refinancing existing debt.

Some of TECO Energy's debt obligations contain financial covenants related to debt-to-capital ratios and interest coverage that could prevent the repayment of subordinated debt and the

payment of dividends if those payments would cause a violation of the covenants. (See **Covenants in Financing Agreements** section.) TECO Energy's failure to comply with any of these covenants, as well as its ratings maintenance covenants discussed below, or to meet its 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. TECO Energy may not have sufficient working capital or liquidity to satisfy its debt obligations in the event of an acceleration of all or a significant portion of its outstanding obligations. Additionally, such an acceleration would also affect the company's ability to pay dividends. Furthermore, if TECO Energy had to defer interest payments on its subordinated notes that support the distributions on its outstanding trust preferred securities, TECO Energy would be prohibited from paying cash dividends on its common stock until all unpaid distributions on the subordinated notes were made.

TECO Energy also incurs obligations in connection with the operations of its subsidiaries and affiliates, which do not appear on the balance sheet, including in connection with the development of power projects by unconsolidated affiliates. These obligations take the form of guarantees, letters of credit and contractual commitments, as are described in the sections titled **Off-Balance Sheet Financing and Liquidity**, **Capital Resources**. In addition, TECO Energy's unconsolidated affiliates from time to time incur non-recourse debt to finance their power projects. Although TECO Energy is not obligated on that debt, its investments in those unconsolidated affiliates and its commitments with respect to those power projects are at risk if the projects are not successfully developed.

TECO Energy's financial condition and ability to access capital and pay dividends may be materially adversely affected by further ratings downgrades.

In September 2002, Moody's, S&P, Inc. and Fitch, lowered their ratings on the senior uncured debt securities of TECO Energy.

Those downgrades and any future downgrades may affect TECO Energy's ability to borrow and may increase its financing costs, which may decrease earnings. TECO Energy is also likely to experience greater interest expense than it may have otherwise if, in future periods, it replaces maturing debt with new debt bearing higher interest rate spreads due to its lower credit ratings. In addition, such downgrades could adversely affect TECO Energy's relationships with customers and counterparties.

In addition to affecting the cost of borrowing, lower credit ratings may affect the amount of indebtedness, types of financing structures and debt markets that are available. Finally, TECO Energy's failure to comply with its ratings maintenance covenants could result in an event of default under certain of its debt obligations, which if not cured or waived, could result in the acceleration of other outstanding debt obligations and would affect its ability to pay dividends. (See the **Bank Credit Facilities and Covenants in Financing Agreements** sections.)

IF TECO Energy is unable to reduce capital expenditures or successfully complete planned asset sales and other transactions to the extent anticipated, its financial condition and results could be adversely affected.

Part of the business plan for 2003 includes reducing previously anticipated capital expenditures by approximately \$250 million in order to maximize cash flows and reduce the need for external financings. TECO Energy cannot be sure that it will be successful in achieving reductions in that amount. The business plan also includes the sale of the majority of its interest in facilities that produce synthetic fuel which qualifies for Section 29 tax credits at TECO Coal, and Tampa Electric's Polk Power Station's coal gasification unit. TECO Energy cannot be certain, however, that it will find purchasers or realize the expected value of these transactions with the anticipated impact on its cash flow position. Depending on the success of these planned expenditure reductions and asset sales transactions, TECO Energy may need to seek external financings, which, in the case of debt financings, could adversely affect the balance sheet strength and apply downward pressure on the credit ratings, and, in the case of equity financings, could have a dilutive effect to equity holders and earnings-per-share results.

Because TECO Energy is a holding company, it is dependent on cash flow from its subsidiaries, which may not be available in the amounts and at the times it is needed.

TECO Energy is a holding company and dependent on cash flow from its subsidiaries to meet its cash requirements that are not satisfied from external funding sources. Some subsidiaries have indebtedness containing restrictive covenants which, if violated, would prevent them from making cash distributions to TECO Energy. In particular, Tampa Electric's first mortgage bonds indenture contain restrictions on distributions on its common stock, and certain long-term debt at Tampa Electric's PCS division prohibits payment of dividends to TECO Energy if Tampa Electric Company's consolidated shareholders' equity is not at least \$500 million. At Dec. 31, 2002, Tampa Electric's unrestricted retained earnings available for dividends on its common stock were approximately \$189 million and its consolidated shareholders' equity was approximately \$1.8 billion. Also, TECO Energy's wholly-owned subsidiary, TECO Diversified, 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 to TECO Energy.

TECO Energy is vulnerable to interest rate changes and may not have access to capital at favorable rates, if at all.

Changes in interest rates and capital markets generally affect TECO Energy's cost of borrowing and access to these markets. TECO Energy cannot be sure that it will be able to accurately predict the effect those changes will have on the cost of borrowing or access to capital markets.

Independent Power Project Risks

TPS' existing and planned power plants are affected by market conditions, and it may not be able to sell power at prices that enable it to recover its investments in the plants.

TPS is currently operating, constructing and investing in power plants that do not currently have long-term contracts for the sale of power. These power plants may sell at least a portion of their power based on market conditions at the time of sale, so TPS cannot predict with certainty:

- the amount or timing of revenue it may receive from power sales from operating plants;
- the differential between the cost of operations (in particular, natural gas prices) and power sales revenue;
- the effect of competition from other suppliers of power;
- regulatory actions that may affect market behavior, such as price limitations or bidding rules imposed by the FERC or reimposition of regulation in power markets;
- the demand for power in a market served by its plants relative to available supply;
- the availability of transmission to accommodate the sale of power; or
- whether TPS will recover its initial investment in these plants.

At present, several of the wholesale markets supplied by so-called "merchant" power plants are experiencing significant pricing declines due to excess supply and weak economies. Consequently, only a portion of the projected output of TPS' plants has been hedged for 2003 and 2004. TPS' results could be adversely affected if it is unable to sufficiently sell the output of its plants at a premium to forward curve prices or if TECO Energy needs to write off any capital already invested in projects.

TECO Energy's forecast assumes that TPS will manage these risks by:

- optimizing amongst a mix of forward on-peak energy sales, daily and hourly spot market sales of capacity, energy and ancillary services, and longer-term structured transactions;
- avoiding short positions; and
- retaining flexibility to defer, if and where possible and advisable, construction of output capacity in a market that has become oversupplied.

However, TECO Energy cannot be sure how successfully it will be able to implement these risk management measures. For instance, in oversupplied markets, entering into forward contracts could be difficult.

TPS may be unable to successfully complete and finance current and future projects on schedule and within budget.

TPS currently has new power generating facilities under construction. The construction of these facilities, as well as any future construction projects, involves risks of shortages and inconsistent qualities of equipment and material, labor shortages and disputes, engineering problems, work stoppages, unanticipated cost increases, and environmental or geological problems. In addition, the development of independent power plants involves considerable risks, including successful siting, permitting, financing and construction, contracting for necessary services, fuel supplies and power sales and performance by project partners. Any of these events could delay a project's construction schedule or increase its costs, which may impact TPS' ability to generate sufficient cash flow and service its related non-recourse project debt.

TPS marketing and risk management policies may not work as planned, and it may suffer economic losses despite such policies.

TPS actively manages the market risk inherent in its energy and fuel positions. Nonetheless, adverse changes in energy and fuel prices may result in losses in earnings or cash flows and adversely affect the balance sheet. TPS marketing and risk management procedures may not always be followed or may not work as planned. As a result, it cannot predict with precision the impact that its marketing, trading and risk management decisions may have on its business, operating results or financial position. In addition, to the extent it does not cover the entire exposure of assets or positions to market price volatility, or the hedging procedures do not work as planned, fluctuating commodity prices could cause sales and net income to be volatile.

TPS' marketing and risk management activities also are exposed to the credit risk that counterparties to its transactions will not perform their obligations. Should counterparties to these arrangements fail to perform, TPS may be forced to enter into alternative hedging arrangements, honor underlying commitments at then-current market prices or otherwise satisfy its obligations on unfavorable terms. In that event, its financial results would likely be adversely affected.

General Business and Operational Risks

General economic conditions may adversely affect TECO Energy's businesses.

TECO Energy's 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 PCS' forecasts for annual energy sales growth. An unanticipated downturn in the local areas or Florida's economy could adversely affect Tampa Electric's or PCS' expected performance.

TECO Energy's unregulated businesses, particularly TECO Transport, TECO Coal and TPS, are also affected by general economic conditions in the industries and geographic areas they serve, both nationally and internationally. TPS' investment in Empresa Eléctrica de Guatemala, S.A. depends on growth in the relevant service areas and in annual energy sales.

Potential competitive changes may adversely affect TECO Energy's gas and electricity 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. 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 cannot be predicted could adversely affect PGS.

TECO Energy's gas and electricity businesses, both utility and independent, are highly regulated and any changes in regulatory structures could lower revenues or increase costs or competition.

Tampa Electric, TPS and PGS operate in highly regulated industries. Retail operations, including the prices charged, are regulated by the FPSC, and Tampa Electric's and TPS' 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 their performance by, for example, increasing competition or costs, threatening investment recovery or impacting rate structure.

TECO Energy's businesses are sensitive to variations in weather and have seasonal variations.

Most of TECO Energy's businesses are affected by variations in general weather conditions and unusually severe weather. Tampa Electric's, PGS' and TPS' 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.

PGS, which has a single winter peak period, 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, as well as electric power sales from TPS' merchant power plants. 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.

Electric power marketing may be seasonal. For example, in some parts of the country, demand for, and market prices of, electricity peak during the hot summer months, while in other parts of the country such peaks occur in the cold winter months. As a result, power marketing results may fluctuate on a seasonal basis. The pattern of this fluctuation may change depending on the nature and location of the facilities operated and the terms under which they sell electricity.

Commodity price changes may affect the operating costs and competitive positions of TECO Energy's businesses.

Most of TECO Energy's 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, currently fuel costs used for generation are mostly affected by the cost of coal. Future fuel costs will be impacted by the cost of natural gas as well as coal. Tampa Electric is able to recover the cost 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.

Regarding wholesale sales of electricity, the ability to make sales and margins on power sales is currently affected by the cost of coal to Tampa Electric, particularly as it compares to the cost of gas and oil to other power producers.

In the case of TPS, results are impacted by changes in the market price for electricity. The profitability of merchant power plants is heavily dependent on the price for power in the mar-

kets they serve. Wholesale power prices are set by the market assuming a cost for the input energy and conversion efficiency, but the fixed costs may not be reflected in the price for spot, or excess power.

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.

TECO Energy relies on some transmission and distribution assets that it does not own or control to deliver wholesale electricity as well as natural gas. If transmission is disrupted, or if capacity is inadequate, its ability to sell and deliver power and natural gas may be hindered.

TECO Energy depends on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver the electricity and natural gas it sells to the wholesale market, as well as the natural gas it sells and purchases for use in its electric generation facilities. If transmission is disrupted, or if capacity is inadequate, the ability to sell and deliver products and satisfy 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 desired. TECO Energy cannot predict the timing of industry changes as a result of these initiatives or the adequacy of transmission facilities in specific markets.

In addition, the independent system operators that oversee the transmission systems in certain wholesale power markets have from time to time been authorized to impose price limitations and other mechanisms to address volatility in the power markets. These types of price limitations and other mechanisms may adversely impact the profitability of TECO Energy's wholesale power marketing business.

The uncertain outcome regarding the creation of regional transmission organizations, or RTOs, may impact operations, cash flows or financial condition.

Tampa Electric is continuing to make progress towards the development of its RTO, which would independently control the transmission assets of participating utilities in peninsular Florida. Given the regulatory uncertainty of the ultimate timing, structure and operations of GridFlorida or an alternate combined transmission structure, TECO Energy cannot predict what effect its creation will have on future consolidated results of operations, cash flow or financial condition.

TECO Energy may be unable to take advantage of its existing tax credits.

TECO Energy derives a portion of its net income from Section 29 tax credits related to the production of non-conventional fuels. Although TECO Energy currently plans to sell a significant portion of the production facilities, until and unless TECO Energy successfully does so, the use of these tax credits is dependent on the generation of sufficient taxable income against which to use the credits. TECO Energy's forecast assumes that it will generate sufficient taxable income to use these credits. These credits, and their sale value, could be impacted by or become unavailable due to administrative actions of the Internal Revenue Service or the U.S. Treasury or changes in law, regulation or administration.

Problems with operations could cause TECO Energy to incur substantial costs.

Each of TECO Energy's subsidiaries is subject to various operational risks, including accidents or equipment breakdown or failure and operations below expected levels of performance or efficiency. As operators of power generation facilities, Tampa Electric and TPS could incur problems such as the breakdown or failure of power generation equipment, transmission lines, pipelines or other equipment or processes which would result in performance below assumed levels of output or efficiency. TECO Energy's forecast assumes normal operations and normal maintenance periods for its subsidiaries' facilities.

The international projects and operations of TPS and TECO Ocean Shipping are subject to risks that could result in losses or increased costs.

TPS is involved in several international projects. These 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. TECO Energy's forecast assumes that TPS will manage these risks through a variety of risk mitigation measures, including specific contractual provisions, teaming with strong international and local partners, obtaining non-recourse financing and obtaining political risk insurance where appropriate.

TECO Ocean Shipping is exposed to operational risks in international ports, primarily in the form of its need to obtain suitable labor and equipment to safely discharge its cargoes in a timely manner. TECO Energy's forecast assumes that TECO Ocean Shipping will 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.

Changes in the environmental laws and regulations to which TECO Energy's regulated businesses are subject could increase costs or curtail activities.

TECO Energy's 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 or require curtailment of some businesses' activities.

Consolidated Financial Statements

Consolidated Balance Sheets

Assets (millions)

Dec. 31,

2002

2001

Current assets	
Cash and cash equivalents	\$ 411.1
Restricted cash	1.6
Receivables, less allowance for uncollectibles of \$6.6 million and \$7.1 million at Dec. 31, 2002 and 2001, respectively	422.7
Current notes receivable	235.1
Inventories, at average cost	113.7
Fuel	96.1
Materials and supplies	42.9
Prepayments and other current assets	1,323.2
Total current assets	776.3

Property, plant and equipment

Utility plant in service	5,054.4	4,861.1
Electric	746.7	699.4
Gas	1,556.8	897.0
Construction work in progress	857.4	865.1
Other property	8,215.3	7,322.6
Property, plant and equipment, at original cost	(2,751.3)	(2,572.0)
Accumulated depreciation	5,464.0	4,750.6
Property held for sale (net)	—	87.6
Total property, plant and equipment (net)	5,464.0	4,838.2

Other assets

Other investments	845.3	210.4
Investment in unconsolidated affiliates	149.2	172.9
Goodwill	193.7	165.8
Deferred income taxes	340.2	242.0
Regulatory assets	163.2	198.3
Deferred charges and other assets	159.0	159.5
Total other assets	1,850.6	1,148.9

Total assets

\$8,637.8

\$6,763.4

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

Liabilities and Capital (millions)

Dec. 31,

2002

2001

Current liabilities	
Long-term debt due within one year	\$ 127.1
Notes payable	360.5
Accounts payable	377.4
Current derivative liability	3.9
Customer deposits	94.6
Interest accrued	49.8
Taxes accrued	95.9
Total current liabilities	1,109.2

Other liabilities

Deferred income taxes	495.0	498.7
Investment tax credits	27.5	32.3
Regulatory liabilities	98.1	106.2
Deferred credits and other liabilities	322.9	189.9
Long-term debt, less amount due within one year	3,324.3	1,842.5
Total other liabilities	4,267.8	2,669.6

Preferred securities

Company preferred securities

649.1

200.0

Capital

Common equity (400 million shares authorized; 175.8 million and 139.6 million outstanding at Dec. 31, 2002 and 2001, respectively)	175.8	139.6
Additional paid in capital	1,094.5	600.7
Retained earnings	1,413.7	1,298.0
Accumulated other comprehensive (loss) income	(41.2)	(22.4)
Common equity	2,642.8	2,015.9
Unearned compensation	(31.1)	(44.3)
Total capital	2,611.7	1,971.6

Total liabilities and capital

\$8,637.8

\$6,763.4

Consolidated Statements of Income

	Year Ended Dec. 31,		
(millions, except per share amounts)	2002	2001	2000
Revenues			
Regulated electric and gas (includes franchise fee and gross receipts taxes of \$73.8 million in 2002, \$71.1 million in 2001 and \$59.7 million in 2000)	\$ 1,867.0	\$ 1,733.0	\$ 1,635.9
Unregulated	808.8	755.1	587.2
Total revenues	2,675.8	2,488.1	2,223.1
Expenses			
Regulated operations			
Fuel	312.7	218.2	201.2
Purchased power	202.3	144.7	124.5
Cost of natural gas sold	148.9	186.4	157.0
Other	273.8	250.0	247.1
Other operations	710.4	689.8	546.9
Maintenance	162.1	151.3	140.0
Depreciation	303.4	288.2	258.0
Taxes, other than income	173.2	161.3	147.9
Total expenses	2,286.8	2,089.9	1,822.6
Income from operations	389.0	398.2	400.5
Other income (expense)			
Allowance for other funds used during construction	24.9	6.6	1.6
Other income (expense)	62.4	38.6	13.9
Loss on debt refinancing	(34.1)	--	--
Earnings from equity investments	(6.0)	6.7	7.7
Total other income (expense)	47.2	51.9	23.2
Interest charges			
Interest expense	147.1	164.0	167.6
Distribution on preferred securities	38.9	17.0	--
Allowance for borrowed funds used during construction	(9.6)	(2.6)	(0.7)
Total interest charges	176.4	178.4	166.9
Income before provision for income taxes	259.8	271.7	256.8
Provision (benefit) for income taxes	(38.4)	(2.1)	29.3
Net income from continuing operations	298.2	273.8	227.5
Discontinued operations			
Income from discontinued operations	26.1	21.9	12.6
Income tax benefit	(5.8)	(8.0)	(10.8)
Total discontinued operations	31.9	29.9	23.4
Net income	\$ 330.1	\$ 303.7	\$ 250.9
Average common shares outstanding during year			
- Basic	153.2	134.5	125.9
- Diluted	153.3	135.4	126.3
Earnings per average common share outstanding			
From continuing operations - Basic	\$ 1.95	\$ 2.04	\$ 1.81
- Diluted	\$ 1.95	\$ 2.02	\$ 1.79
Net income - Basic	\$ 2.15	\$ 2.26	\$ 1.99
- Diluted	\$ 2.15	\$ 2.24	\$ 1.97

Consolidated Statements of Comprehensive Income

	Year Ended Dec. 31,		
(millions)	2002	2001	2000
Net income	\$ 330.1	\$ 303.7	\$ 250.9
Other comprehensive (loss) income, net of tax			
Foreign currency translation adjustments	(1.2)	--	--
Net unrealized losses on cash flow hedges	(13.2)	(19.2)	--
Minimum pension liability adjustments	(4.4)	0.3	2.0
Other comprehensive (loss) income, net of tax	(18.8)	(18.9)	2.0
Comprehensive income	\$ 311.3	\$ 284.8	\$ 252.9

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

Consolidated Statements of Cash Flows

	Year Ended Dec. 31,			
(millions)	2002	2001	2000	
Cash flows from operating activities	\$ 330.1	\$ 303.7	\$ 250.9	
Net income				
Adjustments to reconcile net income to net cash from operating activities:				
Depreciation	303.4	288.2	258.0	
Deferred income taxes	(96.5)	(102.9)	(77.6)	
Investment tax credits, net	(4.8)	(4.9)	(4.8)	
Allowance for funds used during construction	(34.5)	(9.2)	(2.3)	
Amortization of unearned compensation	13.9	9.7	9.2	
Gain on asset sales, pretax	(15.1)	—	(13.6)	
Equity in earnings of unconsolidated affiliates	15.3	(3.1)	(7.6)	
Asset valuation adjustment, pretax	14.1	11.1	14.2	
Deferred recovery clause	72.2	(19.0)	(68.7)	
Refund to customers	(6.4)	—	(13.2)	
Receivables, less allowance for uncollectibles	(64.1)	57.1	(95.5)	
Inventories	(39.4)	(22.8)	7.5	
Taxes accrued	24.1	16.4	17.6	
Interest accrued	14.2	(6.3)	25.5	
Accounts payable	98.3	(51.3)	42.6	
Other	30.9	36.0	44.1	
Cash flows from operating activities	655.7	502.7	386.3	
Cash flows from investing activities	(1,065.2)	(965.9)	(688.4)	
Capital expenditures	34.5	9.2	2.3	
Allowance for funds used during construction	(9.9)	—	(52.6)	
Purchase of minority interest	—	(315.8)	(31.3)	
Purchase of business	103.3	43.2	61.3	
Net proceeds from sales of assets	(7.6)	27.6	(7.7)	
Investment in unconsolidated affiliates	(715.6)	95.7	(333.4)	
Other non-current investments	(1,660.5)	(1,106.0)	(1,049.8)	
Cash flows from investing activities	(215.8)	(184.2)	(167.4)	
Cash flows from financing activities	572.6	348.4	18.3	
Dividends	—	—	(29.9)	
Common stock	1,758.4	1,255.9	394.9	
Purchase of treasury stock	(949.7)	(236.5)	(145.6)	
Proceeds from long-term debt	(278.4)	(570.0)	395.3	
Repayment of long-term debt	435.6	—	200.0	
Net increase (decrease) in short-term debt	(15.3)	—	—	
Issuance of preferred securities	—	—	—	
Equity contract adjustment payments	1,307.4	613.6	665.6	
Cash flows from financing activities	302.6	103	2.1	
Net increase in cash and cash equivalents	108.5	98.2	96.1	
Cash and cash equivalents at beginning of year	\$ 411.1	\$ 108.5	\$ 98.2	
Cash and cash equivalents at end of year				
Supplemental disclosure of cash flow information	Cash paid during the year for			
Interest (net of amounts capitalized)	\$ 160.2	\$ 178.1	\$ 166.7	
Income taxes	\$ 71.9	\$ 52.4	\$ 83.9	

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

Consolidated Statements of Common Equity

(millions)	Shares ⁽¹⁾	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Unearned Compensation	Total Common Equity
Balance, Dec. 31, 1999	126.7	\$ 132.1	\$ 368.9	\$(114.8)	\$ 1,091.8	\$ (5.5)	\$ (54.7)	\$ 1,417.8
Net income for 2000					250.9			250.9
Other comprehensive income, after tax						2.0		2.0
Common stock issued	1.2	1.2	26.8				(3.9)	24.1
Treasury shares purchased	(1.6)			(29.9)	(167.4)			(29.9)
Cash dividends declared								(167.4)
Amortization of unearned compensation							9.2	9.2
Tax benefits-ESOP dividends and stock options			1.6		1.8			3.4
Performance shares							(3.2)	(3.2)
Balance, Dec. 31, 2000	126.3	133.3	397.3	(144.7)	1,177.1	(3.5)	(52.6)	1,506.9
Net income for 2001					303.7			303.7
Other comprehensive (loss) income, after tax						(18.9)		(18.9)
Common stock issued	13.3	6.3	203.2	144.7	(184.2)		(5.8)	348.4
Cash dividends declared								(184.2)
Amortization of unearned compensation							9.7	9.7
Tax benefits-ESOP dividends and stock options			0.2		1.4			1.6
Performance shares							4.4	4.4
Balance, Dec. 31, 2001	139.6	139.6	600.7	—	1,298.0	(22.4)	(44.3)	1,971.6
Net income for 2002					330.1			330.1
Other comprehensive (loss) income, after tax						(18.8)		(18.8)
Common stock issued	36.2	36.2	544.4				(8.0)	572.6
Cash dividends declared					(215.8)			(215.8)
Amortization of unearned compensation							13.9	13.9
Convertible preferred stock - present value of contract adjustment payments			(53.1)					(53.1)
Tax benefits-ESOP dividends and stock options			2.5		1.4			3.9
Performance shares							7.3	7.3
Balance, Dec. 31, 2002	175.8	\$ 175.8	\$ 1,094.5	\$ —	\$ 1,413.7	\$ (41.2)	\$ (31.1)	\$ 2,611.7

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

(1) TECO Energy had 400 million shares of \$1 par value common stock authorized in 2002, 2001 and 2000.

Notes to Consolidated Financial Statements

A. Summary of 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. (TECO Energy or the company) and its wholly-owned subsidiaries.

The equity method of accounting is used to account for investments in partnership arrangements in which TECO Energy or its subsidiary companies do not have majority ownership or exercise control.

The proportional share of expenses, revenues and assets reflecting TECO Coalbed Methane's undivided interest in joint venture property is included in the consolidated financial statements. Results of operations for TECO Coalbed Methane are included in discontinued operations.

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.

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.

Investments in Unconsolidated Affiliates

Investments in unconsolidated affiliates are accounted for using the equity method of accounting. At Dec. 31, 2002, these investments included TECO Propane Ventures' (TPV) 38 percent ownership interest in US Propane, TECO Power Services' (TPS) 24 percent ownership interest in Empresa Eléctrica de Guatemala, S.A. (EEGSA), the Guatemalan electric utility, TPS' 50 percent voting interest in the TECO-Panda Generating Company, L.P. (TPGC), TPS' 50 percent ownership interest in the Hanakua Power Station in Hawaii, TECO Energy Services' 50 percent ownership interest in a chiller plant project, TECO Partners' 65 percent ownership interest in Lifestream Technologies, a fiber optic cable project, and TECO Properties' 50 percent ownership interest in four real estate projects (See Note T). At Dec. 31, 2001, the investment in unconsolidated affiliates included the US Propane, EEGSA, TPGC, Hanakua and real estate investments.

Summary financial information for TPGC, a development stage enterprise, as of Dec. 31, 2002 and 2001 is presented in the following table. Results from operations were primarily attributable to financing and general administrative costs associated with construction activities.

	2002	2001
Current assets	\$ 50.1	\$ 102.6
Non-current assets	\$ 3,117.1	\$ 1,854.1
Current liabilities	\$ 504.0	\$ 372.8
Non-current liabilities	\$ 2,732.4	\$ 1,686.6
<i>(millions) For the year ended Dec. 31,</i>		
	2002	2001
Net revenues	\$ 0.7	\$ 0.5
Operating loss	\$ (22.0)	\$ (5.4)
Loss available for allocation to partners	\$ (22.0)	\$ (5.4)

Other Investments

Other investments, which include longer-term passive investments, at Dec. 31, 2002 and 2001 were as follows:

	Rate	Due Date	2002	2001
Notes receivable from:				
Panda Energy ⁽¹⁾	14.00%	1/3/03	\$ 137.0	\$ 92.7
Energetike Centrum Kladno	6.00%	10/31/10	1.4	—
Mosbacher Power Partners L.P.	12.00%	5/16/02	—	13.1
Mosbacher Power Partners L.P.	9.00%	8/1/08	13.7	21.1
Mosbacher Power Partners L.P.	12.00%	5/16/02	—	6.2
EEGSA	6.81% ⁽²⁾	9/11/07	11.1	10.9
TECO-Panda Generating Company, L.P.	7.79% ⁽³⁾	11/30/04	369.5	37.5
TECO-Panda Generating Company, L.P.	6.58% ⁽³⁾	11/30/04	426.3	86.7
Municipal Gas Authority of Georgia ⁽⁴⁾	1.38%	3/31/03	98.1	—
Investment in Energy Center Kladno				
Generating (ECKG) ⁽⁵⁾	—	—	13.6	18.2
Continuing Investments in Leveraged Leases				
	—	—	9.4	15.6
Other investments	—	—	0.3	1.1
Current notes receivable				
			1,080.4	303.1
Current non-current investments				
			235.1	92.7
			\$ 845.3	\$ 210.4

(1) On Jan. 3, 2003, this note receivable converted to an ownership interest (see Note N).

(2) Current rate at Dec. 31, 2002.

(3) Received payment of this note receivable on Jan. 30, 2003 (see Note U).

(4) 13.35% ownership interest in an electric generating power project in the Czech Republic.

These financial investments have no quoted market prices and, accordingly, a reasonable estimate of fair market value could not be made without incurring excessive costs. However, the company believes by reference to stated interest rates and security description, the fair value of these assets would not differ significantly from the carrying value.

Deferred Credits and Other Liabilities

Other deferred credits primarily include the accrued post-retirement benefit liability, the pension liability, deferred gains and the liability for future contract adjustment payments related to the mandatorily convertible equity securities.

Revenue Recognition

TECO Energy recognizes revenues in accordance with the Securities and Exchange Commission's Staff Accounting Bulletin (SAB) 101, *Revenue Recognition in Financial Statements*. The criteria outlined in SAB 101 are that a) there is persuasive evidence that an arrangement exists; b) delivery has occurred or services have been rendered; c) the fee is fixed and determinable; and d) 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 Company and Peoples Gas System) retail businesses and the prices charged to customers are regulated by the Florida Public Service Commission (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 Financial Accounting Standard No. (FAS) 71, *Accounting for the Effects of Certain Types of Regulation*. See Note D for a discussion of 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 long-term engineering or construction-type contracts at TECO Energy Services (formerly TECO BGA and BCH Mechanical) are recognized on a percentage of completion basis, which includes estimates of the total costs for the project compared to the estimated work progress already completed for the contract. Each month, revenue recognition and realized profit are adjusted to reflect only the percentage of the estimated costs that have been completed.

Revenues for energy marketing operations at Prior Energy and 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 were \$539.4 million, \$105.5 million and \$28.4 million, respectively, for 2002, 2001 and 2000.

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 Peoples Gas System (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.

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 author-

ized 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 April 1, 1995. In each of the years 2002, 2001 and 2000, \$2.7 million of buy-out costs were amortized to expense.

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.

Tampa Electric's objectives of stabilizing prices from 1996 through 1999 and securing fair earnings opportunities during this period were accomplished through a series of agreements entered into in 1996 with Florida's Office of Public Counsel (OPC) and the Florida Industrial Power Users Group which were approved by the FPSC. Prior to these agreements, the FPSC approved a plan submitted by Tampa Electric to defer certain 1995 revenues.

In general, under these agreements Tampa Electric was allowed to defer revenues in 1995 and 1996 during the construction of Polk Unit 1 and recognize these revenues in 1997 and 1998 after commercial operation of the unit. Other components of the agreements were a base rate freeze through 1999 and refunds to customers totaling \$50 million during the period October 1996 through December 1998 while Tampa Electric was allowed recovery of the capital costs incurred for the Polk Unit 1 project.

In October 2000, the FPSC staff recommended a refund of \$6.1 million for the final year of the agreements. OPC objected to certain interest expenses recognized in 1999 that were associated with prior years' tax positions and used to calculate the amount to be refunded. Following a review by the FPSC staff, the FPSC agreed in December 2000 that the original \$6.1 million was to be refunded to customers. In February 2001, OPC protested the FPSC's decision. The FPSC held hearings on the issue in August 2001 and upheld its original decision. In January 2002, the OPC filed a motion with the FPSC asking for reconsideration of its decision, alleging the FPSC relied on erroneous information. This was not granted and Tampa Electric made refunds associated with 1999 earnings in 2002. Over the terms of the agreements, the company refunded in total about \$69 million.

Since the expiration of the agreements, Tampa Electric is not under a new stipulation. Therefore its rates and allowed return on equity (ROE) range of 10.75 percent to 12.75 percent with a midpoint of 11.75 percent 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.

On June 27, 2002, PGS filed a petition with the FPSC to increase its service rates. The requested rates would have resulted in a \$22.6 million annual base revenue increase, reflecting a ROE midpoint of 11.75 percent.

On the date of the FPSC hearing, PGS agreed to a settlement with all parties involved, and a final FPSC order was granted on Dec. 17, 2002. PGS received authorization to increase annual base revenues by \$12.05 million. The new rates allow for an ROE range of 10.25 to 12.25 percent with an 11.25 percent midpoint ROE and a capital structure with 57.43 percent equity. The increase went into effect on Jan. 16, 2003.

Purchased Power

Tampa Electric purchases power on a regular basis primarily to meet the needs of its retail customers. For the years ended Dec. 31, 2002, 2001 and 2000, Tampa Electric purchased power of \$202.3 million, \$144.7 million and \$124.5 million, respectively. These purchased power costs are recoverable through an FPSC-approved cost recovery clause.

TPS, through its wholly-owned subsidiary, Hardee Power Partners (Hardee), has agreements with Seminole Electric Cooperative and Tampa Electric to supply all the power and capacity of its Hardee Power Station for 20 years beginning in 1993. Under the Seminole agreement, Hardee agreed to supply Seminole with an additional 145 megawatts of capacity during the first 10 years of the contract, which ended on Dec. 31, 2002. This additional capacity was purchased

from Tampa Electric's Big Bend Unit 4 for resale to Seminole. To meet other firm commitment contracts, TPS' merchant plants may also purchase power from time to time. Total unregulated purchased power for 2002, 2001 and 2000 was \$51.3 million, \$34.0 million and \$30.1 million, 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 expenses major maintenance costs as incurred. Concurrent with a planned major maintenance outage, the cost of adding or replacing retirement units-of-property is capitalized in conformity with FPSC and HERC regulations.

At TPS, each of the San José and Alborada plants in Guatemala has 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. All other TPS operating projects expense major maintenance costs when incurred.

Depreciation

TECO Energy provides for depreciation primarily by the straight-line method at annual rates that amortize the original cost, less net salvage, of depreciable property over its estimated service life. The provision for utility plant in service, expressed as a percentage of the original cost of depreciable property, was 4.2% for 2002 and 2001, and 4.1% for 2000.

The original cost of utility plant retired or otherwise disposed of and the cost of removal less salvage are charged to accumulated depreciation.

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 regulatory process. The amounts included in customers' bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Statement of Income. These amounts totaled \$73.8 million, \$71.1 million and \$59.7 million, respectively, for 2002, 2001 and 2000. Franchise fees and gross receipt taxes payable by the regulated utilities are included as an expense on the Consolidated Statement of Income in Taxes, other than income. For 2002, 2001 and 2000 these totaled \$73.7 million, \$71.0 million and \$59.8 million, respectively.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is a non-cash credit to income with a corresponding charge to utility plant which represents the cost of borrowed funds and a reasonable return on other funds used for construction. The rate used to calculate AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. The rate was 7.79% for 2002, 2001 and 2000. Total AFUDC for 2002, 2001 and 2000 was \$34.5 million, \$9.2 million, and \$2.3 million, respectively. The base on which AFUDC is calculated excludes construction work in progress which has been included in rate base.

Interest Capitalized

Interest costs for the construction of non-utility facilities are capitalized and depreciated over the service lives of the related property. TECO Energy capitalized \$63.2 million, \$23.0 million and \$6.5 million of interest costs in 2002, 2001 and 2000, respectively.

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 PCS 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 to income tax expense over the service lives of the related property.

Asset Impairments

Effective Jan. 1, 2002, TECO Energy and its subsidiaries 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 segment of a business.

The company periodically assesses whether there has been a permanent impairment of its long-lived assets and certain intangibles held and used by the company in accordance with FAS 144, and prior to 2002 with FAS 121.

TECO Energy recorded after-tax charges of \$8.8 million, \$7.2 million and \$9.0 million in 2002, 2001 and 2000, respectively, to adjust asset valuations (see Note 1).

Reporting on the Costs of Start-up Activities

In 1998, the AICPA issued Statement of Position (SOP) 98-5, *Reporting on the Costs of Start-up Activities*. It requires costs of start-up activities and organization costs to be expensed as incurred. Start-up activities are broadly defined as those one-time activities related to events such as opening a new facility, conducting business in a new territory and organizing a new entity. Some costs, such as the costs of acquiring or constructing long-lived assets and bringing them into service, are not subject to SOP 98-5. Start-up costs, as defined by SOP 98-5, are expensed as incurred.

Foreign Operations

The functional currency of the company's foreign investments is primarily the U.S. dollar. Transactions in the local currency are remeasured to the U.S. dollar for financial reporting purposes. The aggregate remeasurement gains or losses included in net income in 2002, 2001 and 2000 were not significant.

The 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.

Restrictions on Dividend Payments and Transfer of Assets

Dividends on TECO Energy's common stock are at the discretion of its Board of Directors. Should TECO Energy exercise its right to defer payments on its subordinated notes issued in connection with the issuance of trust preferred securities by TECO Capital Trust I or TECO Capital Trust II, TECO Energy would be prohibited from paying cash dividends on its common

and other relevant metrics are performed by a centralized risk management group which is independent of all operating companies.

Effective Jan. 1, 2001, the company adopted FAS 133, *Accounting for Derivative Instruments and Hedging Activities*. The new standard requires 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 defined 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 adoption, the company had derivatives in place at TECO Coalbed Methane that qualified for cash flow hedge accounting treatment under FAS 133, and recorded an opening swap liability of \$19.0 million and an after-tax reduction to OCI of \$12.6 million.

At Dec. 31, 2002, the company had derivative assets totaling \$12.5 million and liabilities totaling \$4.1 million. At Dec. 31, 2001, the company had derivative assets totaling \$9.9 million and liabilities totaling \$37.0 million. At Dec. 31, 2002 and 2001, accumulated OCI included \$32.4 million and \$19.2 million, respectively, of unrealized after-tax losses, representing the fair value of cash flow hedges whose transactions will occur in the future, including an unrealized loss of \$37.3 million and \$11.2 million for 2002 and 2001, respectively, on an equity investee's interest rate swap and other fuel hedges designated as cash flow hedges. Amounts recorded in OCI reflect the 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.

As of Dec. 31, 2002, TECO Energy had transactions in place to hedge commodity price risk and interest rate risk that qualify for cash flow hedge accounting treatment under FAS 133. During 2002, TECO Energy reclassified net pretax losses of \$29.0 million to earnings for cash flow hedges, compared to pretax losses of \$19.7 million in 2001. Amounts reclassified from OCI were primarily related to cash flow hedges of physical purchases of natural gas 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 for spot purchases of natural gas. Conversely, reclassification of a gain from OCI to earnings is offset by the increased cost of spot purchases of natural gas.

As a result of 1) the suspension of construction on the Dell and McAdams power plants at TPS, and 2) the maintenance activity on the Frontera Power Station at TPS in early 2003, the company discontinued hedge accounting for purchases of natural gas and sales of electricity which are 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. This gain is included in the net pretax loss reported above for 2002. Gains and losses on these derivative instruments subsequent to the discontinuation of hedge accounting treatment were recorded in earnings.

Based on the fair values at Dec. 31, 2002, pretax gains of \$7.1 million are expected to be reversed from OCI to the Consolidated Statement of Income within the next twelve months. However, these gains and other future reclassifications from OCI, will fluctuate with movements in the underlying market price of the derivative instruments. Excluding interest rate risk exposures, the company does not currently have any cash flow hedges for transactions forecasted to take place in periods subsequent to 2004.

At Dec. 31, 2002 and 2001, TECO Energy had transactions in place to hedge gas storage inventory that qualify for fair value hedge accounting treatment under FAS 133. During 2002,

stock until the unpaid distributions on the subordinated notes are made. TECO Energy has not exercised that right. In addition, TECO Energy's \$380 million note indenture contains covenants which would apply only if either 1) notes are rated below BBB- by Standard & Poor's (S&P) or below Baa3 by Moody's or 2) notes are rated below Special Ratings Trigger (minimum of BBB- by S&P and Baa2 by Moody's or BBB by S&P and Baa3 by Moody's) if TECO Energy construction undertakings for the TECO/Panda projects are not discharged. These covenants include limitation on restricted payments, limitations on certain liens and limitation on indebtedness.

The primary sources of funds to pay dividends on TECO Energy's common stock are dividends from its operating companies. Tampa Electric's first mortgage bond indenture and certain long-term debt at PGS contain restrictions that limit the payment of dividends on the common stock of Tampa Electric. Tampa Electric's first mortgage bond indenture does not limit loans or advances. In addition, TECO Diversified, Inc., a wholly-owned subsidiary of TECO Energy and the holding company for TECO Transport, TECO Coal, TECO Coalbed Methane and TECO Solutions, has a guarantee related to a coal supply agreement that limits the payment of dividends to its common shareholder, but does not limit loans or advances. As of Dec. 31, 2002 and 2001, the balances restricted as to transfers to the parent company in the form of loans, advances or cash dividends were less than 25 percent of consolidated common equity. (See Note R.)

Lease Accounting Amendment

In April 2002, the Financial Accounting Standards Board (FASB) issued FAS 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections*. In addition to rescinding the aforementioned statements, FAS 145 amends FAS 13, *Accounting for Leases*, to eliminate an inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. This statement also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The implementation of FAS 145 has not had a significant impact on the company's results.

Reclassifications

Certain prior year amounts were reclassified to conform with current year presentation.

B. Derivatives and Hedging

From time to time, TECO Energy enters into futures, forwards, swaps and option contracts for the following purposes:

- To hedge the selling price for the physical production of natural gas at TECO Coalbed Methane;
- To limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric, PGS and Prior Energy;
- To limit the exposure to interest rate fluctuations on debt issuances at TECO Energy and its other 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 TPS; and
- To limit the exposure to price fluctuations for physical purchases of fuel at TECO Transport.

TECO Energy uses 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. For unregulated operations, the company 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 TECO Energy provide a framework through which management monitors various risk exposures. Daily and periodic reporting of positions

the company recognized pretax gains of \$0.7 million compared to \$0.1 million in 2001. For the years ended Dec. 31, 2002 and 2001, the company also recognized pretax losses of \$2.4 million and \$1.5 million, respectively, relating to derivatives that do not qualify for cash flow or fair value hedge treatment that are marked to market.

C. Goodwill and Other Intangible Assets

Effective Jan. 1, 2002, TECO Energy and its subsidiaries adopted FAS 141, *Business Combinations*, and FAS 142, *Goodwill and Other Intangible Assets*. FAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method of accounting. With the adoption of FAS 142, goodwill is no longer subject to amortization. Rather, goodwill is subject to an annual assessment for impairment by applying a fair-value-based test. Under the new rules, an acquired intangible asset should be separately recognized if the benefit of the intangible asset is obtained through contractual or other legal rights, or if the intangible asset can be sold, transferred, licensed, rented, or exchanged, regardless of the acquirer's intent to do so. These intangible assets are required to be amortized over their useful lives.

The amount of goodwill included on the consolidated balance sheets at Dec. 31, 2002 and 2001 was \$193.7 million and \$165.8 million, respectively, net of accumulated amortization of \$9.5 million. Amortization of goodwill ceased effective Jan. 1, 2002 with the adoption of FAS 142, resulting in savings of approximately \$5 million of annual amortization expense. Results for 2001 and 2000 included \$4.8 million and \$2.7 million of goodwill amortization expense, respectively.

The amount of intangible assets included in deferred charges and other assets on the Consolidated Balance Sheet at Dec. 31, 2002 was \$111.1 million, which is net of accumulated amortization of \$35.4 million, and at Dec. 31, 2001 was \$28.5 million, which was net of accumulated amortization of \$12.3 million. Amortizable intangible assets of \$4.4 million at Dec. 31, 2002 represent customer backlog and supply agreements related to the Prior Energy acquisition in November 2001. The company is amortizing these intangibles over the current year period. Amortization expense of \$23.1 million and \$12.3 million, respectively, was recorded in 2002 and 2001. There were no intangible assets at Dec. 31, 2000. Unamortizable intangible assets of \$6.7 million at Dec. 31, 2002 represent licenses held by TFS related to gasification technologies.

TECO Energy continues to review recorded goodwill and intangibles as required under FAS 142, and has not identified any impairments. The reconciliation of reported net income and earnings per share to adjusted net income excluding goodwill amortization expense for 2002, 2001 and 2000 follows:

Pro Forma Effect of FAS 142 Adoption (millions, except per share amounts)		2002	2001	2000
Net income:				
As reported		\$330.1	\$303.7	\$250.9
Add: Goodwill amortized, net of tax		—	3.7	2.4
Adjusted net income		\$330.1	\$307.4	\$253.3
Earnings per share – basic:				
As reported		\$ 2.15	\$ 2.26	\$ 1.99
Add: Goodwill amortized, net of tax		—	.03	.02
Adjusted basic earnings per share		\$ 2.15	\$ 2.29	\$ 2.01
Earnings per share – diluted:				
As reported		\$ 2.15	\$ 2.24	\$ 1.97
Add: Goodwill amortized, net of tax		—	.03	.02
Adjusted diluted earnings per share		\$ 2.15	\$ 2.27	\$ 1.99

D. 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 generally accepted accounting principles 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 changes 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, 2002 and 2001 are presented in the following table:

Regulatory Assets and Liabilities (millions) Dec. 31,		2002	2001
Regulatory assets:			
Regulatory tax asset ⁽¹⁾		\$ 54.9	\$ 41.3
Other:			
Cost recovery clauses		34.7	105.2
Coal contract buy-out ⁽²⁾		5.4	8.1
Unamortized refinancing costs ⁽³⁾		35.9	13.7
Environmental remediation		20.3	22.3
Competitive rate adjustment		7.4	5.9
Other		4.6	1.8
Total regulatory assets		\$108.3	\$157.0
Regulatory liabilities:			
Regulatory tax liability ⁽¹⁾		\$ 36.6	\$ 43.1
Other:			
Deferred allowance auction credits		2.1	1.1
Cost recovery clauses		2.2	0.5
Revenue refund		—	6.3
Environmental remediation		20.3	22.3
Transmission and distribution storm reserve		36.0	32.0
Deferred gain on property sales ⁽⁴⁾		0.9	0.9
Total regulatory liabilities		\$ 98.1	\$106.2

(1) Related primarily to plant life. Includes excess deferred taxes of \$20.9 million and \$24.6 million as of Dec. 31, 2002 and 2001, respectively.

(2) Amortized over a 10-year period ending December 2004.

(3) Unamortized refinancing costs: Related to debt transactions as follows (millions):

Amortized until:	2003	2005	2007	2011	2012	2014	2021	2022
\$155.0	\$51.6	\$22.1	\$25.0	\$50.0	\$150.0	\$85.9	\$25.0	\$100.0

(4) Amortized over a 5-year period with various ending dates

E. Long-Term Debt (millions)

Dec. 31,

	2002	2001
	\$	\$
TECO Energy		
Notes: 5.31% for 2001 ⁽¹⁾	—	200.0
Notes: 7.2% (effective rate of 7.38%) ⁽²⁾	600.0	600.0
Floating rate notes: 5.2% for 2001 ⁽¹⁾	—	400.0
Notes: 6.125% (effective rate of 6.31%) ⁽²⁾	300.0	—
Notes: 7% (effective rate of 7.08%) ⁽²⁾	400.0	—
Notes: 10.5% (effective rate of 12.29%) ⁽²⁾	380.0	—
	1,680.0	1,200.0
Tampa Electric		
First mortgage bonds (issuable in series):		
7.75% (effective rate of 7.96%)	75.0	75.0
6.125% (effective rate of 6.61%)	75.0	75.0
Installment contracts payable ⁽³⁾ :		
5.75%	—	22.5
7.875% Refunding bonds ⁽⁴⁾	—	25.0
8% Refunding bonds ⁽⁴⁾	—	100.0
6.25% Refunding bonds (effective rate of 6.81%) ⁽⁵⁾	86.0	86.0
5.85% (effective rate of 5.88%)	75.0	75.0
5.1% Refunding bonds (effective rate of 5.78%) ⁽⁶⁾	60.7	—
5.5% Refunding bonds (effective rate of 6.35%) ⁽⁶⁾	86.4	—
4% for 2002 (effective rate of 4.21%) and variable rate of 1.45% for 2001 ⁽¹⁾⁽⁷⁾	51.6	51.6
4% for 2002 (effective rate of 4.16%) and variable rate of 1.47% for 2001 ⁽¹⁾⁽⁷⁾	54.2	54.2
4.25% for 2002 (effective rate of 4.43%) and variable rate of 1.52% for 2001 ⁽¹⁾⁽⁷⁾	20.0	20.0
Notes: 5.86% ⁽¹⁾	—	100.0
Notes: 6.875% (effective rate of 6.98%) ⁽²⁾	210.0	210.0
Notes: 6.375% (effective rate of 7.34%) ⁽²⁾	330.0	—
Notes: 5.375% (effective rate of 5.58%) ⁽²⁾	125.0	—
	1,248.9	894.3
Peoples Gas System		
Senior Notes ⁽⁸⁾		
10.35%	4.2	5.0
10.33%	5.6	6.4
10.3%	7.2	7.8
9.93%	7.4	8.0
8%	25.4	27.5
Notes: 5.86% ⁽¹⁾	—	50.0
Notes: 6.875% (effective rate of 6.98%) ⁽²⁾	40.0	40.0
Notes: 6.375% (effective rate of 7.34%) ⁽²⁾	70.0	—
Notes: 5.375% (effective rate of 5.58%) ⁽²⁾	25.0	—
	184.8	144.7
Diversified companies		
Dock and wharf bonds, 5% ⁽¹⁾	110.6	110.6
Non-recourse secured facility notes, Series A: 7.8%	111.0	118.5
Non-recourse secured facility notes: 9.875%	—	17.1
Non-recourse secured facility notes: variable rate: 4.63% for 2002 and 5.43% for 2001 ⁽¹⁾	50.1	57.9
Non-recourse secured facility notes: 10.1%	16.4	16.9
Non-recourse secured facility notes: 9.629%	24.8	28.0
Non-recourse secured facility note, variable rate: 6.88% for 2002 ⁽¹⁾	16.0	—
Non-recourse secured facility note, variable rate: 5% for 2002 ⁽¹⁾	14.0	—
Capital lease: implicit rate of 8.5%	25.3	27.6
	368.2	376.6
TECO Finance		
Medium-term notes payable: 7.54% for 2001 ⁽¹⁾	—	9.0
Unamortized debt premium (discount), net	(30.5)	6.7
	3,451.4	2,631.3
Less amount due within one year ⁽⁹⁾	127.1	788.8
	\$3,324.3	\$1,842.5

(1) Composite year-end interest rate.

(2) These notes are subject to redemption in whole or in part, at any time, at the option of the company.

(3) Tax-exempt securities.

(4) Proceeds of these bonds were used to refund bonds with interest rates of 11.625%–12.625%. For accounting purposes, interest expense has been recorded using blended rates of 8.28%–8.66% on the original and refunding bonds, consistent with regulatory treatment.

(5) 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.

(6) Proceeds of these bonds were used to refund bonds with interest rates of 5.75%–8%.

(7) The interest rate on these bonds was fixed for a five-year term on Aug. 5, 2002.

(8) These long-term debt agreements contain various restrictive covenants, including provisions related to interest coverage, maximum levels of debt to total capitalization and limitations on dividends.

(9) Of the amount due in 2003, \$0.8 million may be satisfied by the substitution of property in lieu of cash payments.

TECO Transport entered into a capital lease agreement with Midwest Marine Management Company in March 1998 for the charter of additional capacity. This lease covers 110 river barges and three towboats, classified as property, plant and equipment on the balance sheet; the corresponding \$35 million five-year lease commitment was recorded as long-term debt on the balance sheet. The future minimum lease payments under the capitalized lease as of Dec. 31, 2002 are \$25.8. This represents \$25.3 million present value of net minimum lease payments and \$0.5 million of interest, all due in 2003.

Substantially all of the property, plant and equipment of Tampa Electric is pledged as collateral to secure its first mortgage bonds and certain pollution control equipment is pledged to secure certain installment contracts payable. TECO Energy's maturities and annual sinking fund requirements of long-term debt for the years 2004, 2005, 2006 and 2007 are \$31.9 million, \$35.7 million, \$38.0 million and \$975.2 million, respectively. Of these amounts \$0.8 million per year for 2004 through 2007 may be satisfied by the substitution of property in lieu of cash payments.

At Dec. 31, 2002, total long-term debt had a carrying amount of \$3,324.3 million and an estimated fair market value of \$3,286.7 million. The estimated fair market value of long-term debt was based on quoted market prices for the same or similar issues, on the current rates offered for debt of the same remaining maturities, or for long-term debt issues with variable rates that approximate market rates, at carrying amounts. The carrying amount of long-term debt due within one year approximated fair market value because of the short maturity of these instruments.

F. Short-Term Debt

At Dec. 31, 2002 and 2001, notes payable consisted of the following:

Notes Payable (millions) Dec. 31,	2002	2001
Credit facilities outstanding	\$ 350.0	\$ —
Commercial paper	10.5	638.9
Total notes payable	\$ 360.5	\$ 638.9

The weighted average interest rate on outstanding notes payable at Dec. 31, 2002 and 2001 was 1.88% and 1.99%, respectively.

At Dec. 31, 2002 and 2001, the following credit facilities and related borrowings existed:

Credit Facilities (millions)	Dec. 31, 2002		Dec. 31, 2001	
	Letters of Credit	Letters of Credit	Letters of Credit	Letters of Credit
Tampa Electric	—	—	—	—
1-year facility	\$ 300.0	\$ —	\$ 300.0	\$ —
TECO Energy	350.0	350.0	—	—
1-year facility	—	—	—	—
TECO Energy	350.0	—	179.8	350.0
3-year facility	—	—	—	—
Totals	\$1,000.0	\$350.0	\$179.8	\$1,000.0

Tampa Electric's credit facility has a maturity date of November 2003. TECO Energy's one-year facility also matures in November 2003 and its 3-year facility matures in November 2004. These credit facilities require facility fees ranging from 15 to 20 basis points. Within its 3-year facility, TECO Energy has \$250 million of capacity to issue letters of credit. These letters of credit require issuance fees of 12.5 basis points and lenders fees of 55 basis points.

In order to utilize the credit facilities, TECO Energy's debt-to-capital ratio, as defined in the credit agreement, may not exceed 65.0% at the end of the applicable quarter. At Dec. 31, 2002, TECO Energy's debt-to-capital ratio was 55.9%. Under Tampa Electric's credit facility, Tampa

Electric's debt-to-capital ratio may not exceed 60.0% measured at the end of the applicable quarter and its earnings before interest, taxes, depreciation and amortization (EBITDA) to interest coverage ratio must be at least 2.5 times. At Dec. 31, 2002, Tampa Electric's debt-to-capital ratio was 43.9% and its EBITDA to interest coverage ratio was 7.8 times. (See Note R.)

G. Preferred Securities

In November 2000, TECO Energy established TECO Capital Trust I (the Trust) for the sole purpose of issuing Trust Preferred Securities (TRuPS) and using the proceeds to purchase company preferred securities from TECO Funding Company I, LLC (TECO Funding). On Dec. 20, 2000, the Trust issued 8 million shares of \$25 par, 8.5% TRuPS, due 2041, with an aggregate liquidation value of \$200 million. Currently, all 8 million shares of the TRuPS are outstanding. Each TRuPS represents an undivided beneficial interest in the assets of the Trust. The Trust used the proceeds from the sale of the TRuPS to purchase a corresponding amount of company preferred securities of TECO Funding. TECO Funding used the proceeds from the sale of the company preferred securities to the Trust of \$200 million and the sale of \$6.2 million of its common securities to TECO Energy, to purchase \$206.2 million of 8.5% junior subordinated notes of TECO Energy, due 2041. The junior subordinated notes are the sole assets of TECO Funding and the company preferred securities are the sole assets of the Trust. TECO Energy's proceeds from the sale of the junior subordinated notes were used to reduce the commercial paper balances of TECO Finance and for general corporate purposes. TECO Energy has guaranteed the payments to the holders of the company preferred securities and indirectly, the payments to the holders of the TRuPS, as a result of their beneficial interest in the company preferred securities. Distributions are payable quarterly in arrears on January 31, April 30, July 31, and October 31 of each year. Distributions were \$17.0 million and \$14.6 million in 2002 and 2001, respectively. No distributions were made in 2000.

The 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. If TECO Energy redeems the junior subordinated notes in full before their maturity date, then TECO Funding is required to redeem the company preferred securities and common securities, in accordance with their terms. If TECO Energy redeems the junior subordinated notes in part but not in full before their maturity date, then TECO Funding will redeem the company preferred securities in full prior to any payment being made on the common securities. 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.

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 represent an indirect interest in a corresponding amount of TECO Energy 5.11% subordinated debt. The holders of these contracts are 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. The net proceeds from the offering were used to repay short-term debt and for general corporate purposes.

H. Preferred Stock

Preferred stock of TECO Energy - \$1 par 10 million shares authorized, none outstanding.
 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 value 1.5 million shares authorized, none outstanding.

I. Common Stock

Stock-Based Compensation

In April 1996, the shareholders approved the 1996 Equity Incentive Plan (the "1996 Plan"). The 1996 Plan superseded the 1990 Equity Incentive Plan (the "1990 Plan"), and no additional grants will be made under the 1990 Plan. The rights of the holders of outstanding options under the 1990 Plan were not affected. The purpose of the 1996 Plan is to attract and retain key employees 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 1996 Plan amended the 1990 Plan to increase the number of shares of common stock subject to grants by 3,750,000 shares, expand the types of awards available to be granted and specify a limit on the maximum number of shares with respect to which stock options and stock appreciation rights may be made to any participant under the plan. Under the 1996 Plan, the Compensation Committee of the Board of Directors may award stock grants, stock options and/or stock equivalents to officers and key employees 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.

In 2002, under the 1996 Plan, 1,769,880 stock options were granted, with a weighted average option price of \$27.97 and a maximum term of 10 years. In addition, 255,242 shares of restricted stock were awarded, each with a weighted average fair value of \$27.97. Compensation expense recognized for stock grants awarded under the 1996 Plan was \$1.7 million, \$2.8 million and \$4.6 million in 2002, 2001 and 2000, respectively. Half the stock grants awarded in 2002 and all of the stock grants awarded in 2001 and 2000 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, 2002 and 2001 reflected a (\$6.3) million and a \$1.1 million liability respectively, classified as other deferred credits, for these contingent shares. The remaining stock grants are restricted subject generally to continued employment, with the 2002 stock grants vesting in three years, the 1998 stock grants vesting in five years, and the 1997 and 1996 stock grants vesting at normal retirement age.

In April 2001, the shareholders approved an amendment to the 1996 Plan, to increase the number of shares of common stock subject to grants by 6.3 million.

Stock option transactions during the last three years under the 1996 Plan and the 1990 Plan (collectively referred to as the "Equity Plans") are summarized as follows:

Stock Options - Equity Plans

	Option Shares (thousands)	Weighted Avg. Option Price
Balance at Dec. 31, 1999	3,827	\$ 22.64
Granted	1,264	\$ 21.33
Exercised	(488)	\$ 20.15
Cancelled	(44)	\$ 23.61
Balance at Dec. 31, 2000	4,559	\$ 22.54
Granted	1,268	\$ 31.39
Exercised	(605)	\$ 21.53
Cancelled	(32)	\$ 26.88
Balance at Dec. 31, 2001	5,190	\$ 24.79
Granted	1,770	\$ 27.97
Exercised	(487)	\$ 20.93
Cancelled	(57)	\$ 27.03
Balance at Dec. 31, 2002	6,416	\$ 25.94
Exercisable at Dec. 31, 2002	0	—
Available for future grant at Dec. 31, 2002	4,288	—

As of Dec. 31, 2002, the 6.4 million options outstanding under the Equity Plans are summarized below.

Stock Options Outstanding at Dec. 31, 2002

Option Shares (thousands)	Range of Option Prices	Weighted Avg. Option Price	Weighted Avg. Remaining Contractual Life
2,099	\$19.44-\$22.48	\$21.16	6 Years
705	\$23.55-\$25.97	\$24.07	4 Years
3,612	\$27.56-\$31.58	\$29.08	8 Years

In April 1997, the Shareholders approved the 1997 Director Equity Plan (the "1997 Plan"), as an amendment and restatement of the 1991 Director Stock Option Plan (the "1991 Plan"). The 1997 Plan supersedes 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 current fixed formula grant by giving the Board discretionary authority to determine the amount and timing of awards under the Plan.

In 2002, 27,500 options were granted, with a weighted average option price of \$27.97. 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, 1999	273	\$21.25
Granted	30	\$23.49
Exercised	(33)	\$18.57
Cancelled	(12)	\$25.15
Balance at Dec. 31, 2000	258	\$21.68
Granted	35	\$31.26
Exercised	(91)	\$19.12
Cancelled	—	—
Balance at Dec. 31, 2001	202	\$24.49
Granted	28	\$27.97
Exercised	(22)	\$20.95
Cancelled	(2)	\$27.56
Balance at Dec. 31, 2002	206	\$25.31
Exercisable at Dec. 31, 2002	0	—
Available for future grant at Dec. 31, 2002	270	—

As of Dec. 31, 2002, the 206,000 options outstanding under the 1997 Plan with option prices of \$19.81-\$31.575, had a weighted average option price of \$25.31 and a weighted average remaining contractual life of six years.

TECO Energy has adopted the disclosure-only provisions of FAS 123, *Accounting for Stock-Based Compensation*, but applies Accounting Principles Board Opinion No. 25 and related interpretations in accounting for its plans. Therefore, since stock options are granted with an option price greater than or equal to the fair value on date of grant, no compensation expense has been recognized for stock options granted under the 1996 Plan and the 1997 Plan. 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 per share would have been reduced to the pro forma amounts as follows. These pro forma

amounts were determined using the Black-Scholes valuation model with weighted average assumptions as follows.

Pro Forma Disclosure — Stock Options

	2002	2001	2000	
Net income from continuing operations	As reported	\$ 298.2	\$ 273.8	\$ 227.5
(millions)	Pro forma expense ⁽¹⁾	5.1	4.3	2.6
Net income (millions)	As reported	\$ 293.1	\$ 269.5	\$ 224.9
	Pro forma expense ⁽¹⁾	5.1	4.3	2.6
	Pro forma	\$ 325.0	\$ 299.4	\$ 248.3
Net income from continuing operations	As reported	\$ 1.95	\$ 2.04	\$ 1.81
- EPS basic	Pro forma	\$ 1.91	\$ 2.00	\$ 1.79
Net income	As reported	\$ 2.15	\$ 2.26	\$ 1.99
- EPS basic	Pro forma	\$ 2.12	\$ 2.23	\$ 1.97
Assumptions				
Risk-free interest rate	5.09%	4.86%	6.24%	
Expected lives (in years)	6	6	6	
Expected stock volatility	25.92%	27.45%	22.93%	
Dividend yield	5.47%	5.46%	5.15%	

(1) Compensation expense for stock options determined under fair-value based method, after-tax.

Dividend Reinvestment Plan

In 1992, TECO Energy implemented a Dividend Reinvestment and Common Stock Purchase Plan (DRP). TECO Energy raised \$11.2 million, \$8.6 million and \$8.1 million of common equity from this plan in 2002, 2001 and 2000, respectively.

Common Stock and Treasury Stock

In September 1999, TECO Energy began a program to repurchase up to \$150 million of its outstanding common stock. Shares acquired constituted treasury shares. In 1999 and 2000, the company acquired 7.0 million shares of its outstanding common stock at a cost of \$144.7 million, or an average per share price of \$20.55. The company's share repurchase program favorably impacted earnings in 2000 by approximately \$0.06 per share.

On March 12, 2001, the company completed a public offering of 8,625 million common shares at \$27.75 per share, 7.0 million shares of which were reissued from treasury shares. On Oct. 4, 2001, S&P announced the inclusion of TECO Energy shares in the S&P 500 Index effective as of the market close on Oct. 9, 2001. On Oct. 12, 2001, TECO Energy issued 3.5 million additional common shares at \$26.72 per share. The sales of the common shares resulted in total net proceeds to TECO Energy of \$325.5 million in 2001, which were used to fund capital expenditures, for working capital requirements, general corporate purposes and to repay short-term debt.

In June 2002, the company completed a public offering of 15,525 million common shares at a price to the public of \$23.00 per share. The sale of these shares resulted in net proceeds to the company of approximately \$346.4 million, which were used to repay short-term debt and for general corporate purposes. In October 2002, the company issued 19,385 million common shares at a price to the public of \$11.00 per share. The sale of these shares resulted in net pro-

ceeds to the company of approximately \$206.8 million, which were used to repay short-term debt.

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 percent or more of the company's outstanding common stock or commences a tender offer that would result in such person owning 10 percent or more of such stock. If any person acquires 10 percent 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 percent 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 is at a fixed interest rate of 9.3% and will be repaid from dividends on ESOP shares and from TECO Energy's contributions to the ESOP.

TECO Energy's contributions to the ESOP were \$13.6 million, \$5.6 million and \$6.8 million in 2002, 2001 and 2000, 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 past three years are as follows:

ESOP Expense (millions)	2002	2001	2000
Interest expense	\$ 4.3	\$ 5.2	\$ 6.0
Compensation expense	12.2	7.4	6.9
Dividends	(8.5)	(8.5)	(8.5)
Net ESOP expense	\$ 8.0	\$ 4.1	\$ 4.4

Compensation expense was determined by the shares allocated method.

At Dec. 31, 2002, the ESOP had 4.0 million allocated shares, 0.3 million committed-to-be-released shares, and 1.7 million unallocated shares. Shares are 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. The dividends received by the ESOP are used to pay debt service on the loan between TECO Energy and the ESOP.

For financial statement purposes, the unallocated shares of TECO Energy stock are reflected as a reduction of common equity, classified as unearned compensation. Dividends on all ESOP shares are recorded as a reduction of retained earnings, as are dividends on all TECO Energy common stock. The tax benefit related to the dividends paid to the ESOP for allocated shares is a reduction of income tax expense and for unallocated shares is an increase in retained earnings. All ESOP shares are considered outstanding for earnings per share computations.

J. Comprehensive Income

FAS 130, *Reporting Comprehensive Income*, requires that comprehensive income, which includes net income as well as certain changes in assets and liabilities recorded in common equity, be reported in the financial statements. TECO Energy reported the following comprehensive income (loss) in 2002, 2001 and 2000 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 supplemental executive retirement plan:

Comprehensive Income (loss) (millions)	Gross	Tax	Net
2002			
Unrealized (loss) gain on cash flow hedges	\$ (8.7)	\$ (4.0)	\$ (4.7)
Less: Loss (gain) reclassified to net income	29.0	11.4	17.6
Gain (loss) on cash flow hedges	20.3	7.4	12.9
Portion of equity investee's loss on cash flow hedges	(42.5)	(16.4)	(26.1)
Foreign currency adjustments	(1.2)	—	(1.2)
Pension adjustments	(7.2)	(2.8)	(4.4)
Total other comprehensive income (loss)	\$ (30.6)	\$ (11.8)	\$ (18.8)
2001			
Initial adoption of FAS 133	\$ (19.0)	\$ (7.3)	\$ (11.7)
Unrealized (loss) gain on cash flow hedges	(13.9)	(5.5)	(8.4)
Less: Loss (gain) reclassified to net income	19.7	7.6	12.1
Gain (loss) on cash flow hedges	(13.2)	(5.2)	(8.0)
Portion of equity investee's loss on cash flow hedges	(18.2)	(7.0)	(11.2)
Pension adjustments	0.5	0.2	0.3
Total other comprehensive income (loss)	\$ (30.9)	\$ (12.0)	\$ (18.9)
2000			
Pension adjustments	\$ 3.3	\$ 1.3	\$ 2.0
Total other comprehensive income (loss)	\$ 3.3	\$ 1.3	\$ 2.0

K. Employee Postretirement Benefits

Pension Benefits

TECO Energy has a non-contributory defined benefit retirement plan which covers substantially all employees. Benefits are based on employees' age, years of service and final average earnings. On April 1, 2000, the plan was amended to provide for benefits to be earned and payable substantially on a lump sum basis through an age and service credit schedule for eligible participants leaving the company on or after July 1, 2001. Other significant provisions of the plan, such as eligibility, definitions of credited service, final average earnings, etc., were largely unchanged. This amendment resulted in decreased pension expense of approximately \$8 million and \$2.0 million in 2001 and 2000, respectively, and a reduction of benefit obligation of \$6.2 million and \$14.4 million at Sept. 30, 2001 and Dec. 31, 2000, respectively.

The company's policy is to fund the plan within the guidelines set by ERISA for the minimum annual contribution and the maximum allowable as a tax deduction by the IRS. About 53 percent of plan assets were invested in common stock and 47 percent in fixed income investments at Sept. 30, 2002.

Amounts shown also include the unfunded obligations for the supplemental executive retirement plans, non-qualified, non-contributory defined benefit retirement plans available to certain senior management. TECO Energy reported other comprehensive loss of \$4.4 million in

2002 and other comprehensive income of \$0.3 million and \$2 million in 2001 and 2000, respectively, related to adjustments to the minimum pension liability associated with the supplemental executive retirement plans.

In 2001, TECO Energy elected to change the measurement date for pension obligations and plan assets from Dec. 31 to Sept. 30. The effect of this accounting change was not material.

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 June 30, 2001, is limited to a defined dollar benefit based on years of service. On April 1, 2000, the company adopted changes to this program for participants retiring from the company on or after July 1, 2001. The company contribution toward pre-65 and post-65 health care coverage for most employees retiring on or after July 1, 2001, is limited to a defined dollar benefit based on an age and service schedule. The impact of this amendment, including a change in the company's commitment for future retirees combined with a grandfathering provision for current retired participants, resulted in a reduction in the benefit obligation of \$1.4 million in 2001. 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.

In 2001, TECO Energy elected to change the measurement date for benefit obligations from Dec. 31 to Sept. 30. The effect of this accounting change was not material.

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	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2000	2000
(millions)	2002	2001	2000	2000
Components of net periodic benefit expense				
Service cost (benefits earned during the period)	\$ 11.8	\$ 11.2	\$ 10.7	\$ 3.4
Interest cost on projected benefit obligations	28.7	27.9	27.5	10.9
Expected return on assets	(42.9)	(42.0)	(40.8)	—
Amortization of:				
Transition obligation (asset)	(1.1)	(1.1)	(1.0)	2.7
Prior service cost (benefit)	(0.5)	(0.5)	0.2	1.7
Actuarial (gain) loss	(3.7)	(4.4)	(5.6)	0.4
Pension expense (benefit)	(7.7)	(8.9)	(9.0)	19.4
Special termination benefit charge	2.7	—	1.1	0.6
Additional amounts recognized	—	—	—	—
Net pension expense (benefit) recognized in the Consolidated Statements of Income	\$ (5.0)	\$ (8.9)	\$ (7.9)	\$ 20.0
	\$ 19.4	\$ 19.4	\$ 19.4	\$ 17.2

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for non-qualified pension plans with accumulated benefit obligations in excess of plan assets were \$41.3 million, \$32.8 million and \$0, respectively, as of Sept. 30, 2002 and \$27.3 million, \$23.5 million and \$0, respectively, as of Sept. 30, 2001.

Employee Postretirement Benefits

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
<i>(millions)</i>				
Change in benefit obligation				
Net benefit obligation at prior measurement date	\$ 382.3	\$ 379.9	\$ 150.2	\$ 130.8
Service cost	11.8	11.2	3.5	3.4
Interest cost	28.7	27.9	11.2	10.9
Plan participants' contributions	—	—	1.0	0.9
Actuarial (gain) loss	58.3	(8.7)	25.6	11.6
Plan amendments	1.1	(6.2)	—	(1.4)
Special termination benefits	2.7	—	0.6	—
Gross benefits paid	(29.8)	(21.8)	(7.5)	(6.0)
Net benefit obligation at measurement date	\$ 455.1	\$ 382.3	\$ 184.6	\$ 150.2
Change in plan assets				
Fair value of plan assets at prior measurement date	\$ 428.0	\$ 493.8	\$ —	\$ —
Actual return on plan assets	(24.9)	(43.7)	—	—
Employer contributions	1.7	2.1	6.5	5.1
Plan participants' contributions	—	—	1.0	0.9
Gross benefits paid (including expenses)	(32.9)	(24.2)	(7.5)	(6.0)
Fair value of plan assets at measurement date	\$ 371.9	\$ 428.0	\$ —	\$ —
Funded status				
Funded status at measurement date	\$ (83.2)	\$ 45.7	\$ (184.6)	\$ (150.2)
Net contributions after measurement date	0.4	0.4	1.9	1.7
Unrecognized net actuarial (gain) loss	88.9	(44.0)	42.4	16.9
Unrecognized prior service cost (benefit)	(7.4)	(9.0)	22.4	24.3
Unrecognized net transition obligation (asset)	(2.5)	(3.6)	27.4	30.1
Accrued liability at end of year	\$ (3.8)	\$ (10.5)	\$ (90.5)	\$ (77.2)
Amounts recognized in the statement of financial position				
Prepaid benefit cost	\$ 14.7	\$ 6.3	\$ —	\$ —
Accrued benefit cost	(18.5)	(16.8)	(90.5)	(77.2)
Additional minimum liability	(13.8)	(6.2)	—	—
Intangible asset	1.5	1.1	—	—
Accumulated other comprehensive income	12.3	5.1	—	—
Net amount recognized at end of year	\$ (3.8)	\$ (10.5)	\$ (90.5)	\$ (77.2)
Assumptions used in determining actuarial valuations				
Discount rate to determine projected benefit obligation	6.75%	7.5%	6.75%	7.5%
Rate of increase in compensation levels	4.8%	4.7%	—	—
Plan asset growth rate through time	9.0%	9.0%	—	—

The assumed health care cost trend rate for medical costs was 12.5% in 2002 and decreases to 5.0% in 2013 and thereafter.

A 100 basis point increase in the medical trend rates would produce a 7 percent (\$1.1 million) increase in the aggregate service and interest cost for 2002 and a 5 percent (\$9.5 million) increase in the accumulated postretirement benefit obligation as of Sept. 30, 2002.

A 100 basis point decrease in the medical trend rates would produce a 3 percent (\$0.5 million) decrease in the aggregate service and interest cost for 2002 and a 3 percent (\$5.0 million) decrease in the accumulated postretirement benefit obligation as of Sept. 30, 2002.

L. Other Non-Operating Items Affecting Net Income

2002

In 2002, TECO Energy recorded \$8.8 million after-tax charges (\$14.1 million pretax) to adjust asset valuations. The adjustments included a \$5.8 million after-tax adjustment (\$9.2 million pretax) related to the proposed sale of TPS' investment in the FCKG project, and a \$3.0 million after-tax charge (\$4.9 million pretax) at TECO Investments related to an aircraft leased to US Airways, which has filed for bankruptcy.

In November 2002, the proceeds from the issuance of TECO Energy notes were used, in part, to pay the \$34.1 million option premium associated with the refinancing of \$200 million of notes. The \$34.1 million option premium (\$20.9 million after-tax) was recognized as a charge in 2002.

2001

In the first quarter of 2001, TECO Energy recorded \$7.2 million of after-tax charges (\$11.1 million pretax) to adjust asset valuations. The adjustments included a \$6.1 million after-tax adjustment (\$9.3 million pretax) related to the sale of TPS' minority interests in Energia Global International, Ltd. (EGI) which owned smaller power generation projects in Central America, and a \$1.1 million after-tax adjustment (\$1.8 million pretax) to adjust the carrying value of leveraged leases at TECO Investments.

2000

In 2000, TECO Energy's results included an \$8.3-million, after-tax gain from the US Propane and Heritage Propane transactions offset by after-tax charges of \$5.2 million to adjust the value of leveraged leases and \$3.8 million to adjust property values at TECO Properties. Because of the offsetting nature of these items, there was no significant effect on earnings in 2000.

M. Income Tax Expense

Income tax expense consists of the following components:

Income Tax Expense (millions)	Federal	State	Total
2002			
Currently payable	\$ 41.1	\$ 14.0	\$ 55.1
Deferred	(81.7)	(7.0)	(88.7)
Amortization of investment tax credits	(4.8)	—	(4.8)
Income tax benefit from continuing operations	(45.4)	7.0	(38.4)
Currently payable	—	2.0	2.0
Deferred	(7.4)	(0.4)	(7.8)
Income tax benefit from discontinued operations	(7.4)	1.6	(5.8)
Total income tax expense (benefit)	\$ (52.8)	\$ 8.6	\$ (44.2)
2001			
Currently payable	\$ 85.7	\$ 18.3	\$ 104.0
Deferred	(94.1)	(7.1)	(101.2)
Amortization of investment tax credits	(4.9)	—	(4.9)
Income tax benefit from continuing operations	(13.3)	11.2	(2.1)
Currently payable	(7.9)	1.6	(6.3)
Deferred	(1.4)	(0.3)	(1.7)
Income tax benefit from discontinued operations	(9.3)	1.3	(8.0)
Total income tax expense (benefit)	\$ (22.6)	\$ 12.5	\$ (10.1)
2000			
Currently payable	\$ 103.3	\$ 8.4	\$ 111.7
Deferred	(79.5)	2.0	(77.5)
Amortization of investment tax credits	(4.9)	—	(4.9)
Income tax expense from continuing operations	18.9	10.4	29.3
Currently payable	(10.7)	—	(10.7)
Deferred	(1.6)	1.5	(0.1)
Income tax benefit from discontinued operations	(12.3)	1.5	(10.8)
Total income tax expense (benefit)	\$ 6.6	\$ 11.9	\$ 18.5

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,	2002	2001
Deferred income tax assets ⁽¹⁾		
Property related	\$ 86.8	\$ 87.7
Basis differences in oil and gas producing properties	(0.1)	1.2
Alternative minimum tax credit carry forward	201.3	105.5
Other	52.2	47.6
Total deferred income tax assets	340.2	242.0
Deferred income tax liabilities ⁽¹⁾		
Property related	(565.3)	(522.8)
Basis differences in oil and gas producing properties	(13.9)	(8.9)
Other	84.2	33.0
Total deferred income tax liabilities	(495.0)	(498.7)
Accumulated deferred income taxes	\$ (154.8)	\$ (256.7)

(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 following reasons:

Effective Income Tax Rate (millions)	2002	2001	2000
Net income from continuing operations	\$ 298.2	\$ 273.8	\$ 227.5
Total income tax provision (benefit)	(38.4)	(2.1)	29.3
Income from continuing operations before income taxes	\$ 259.8	\$ 271.7	\$ 256.8
Income taxes on above at federal statutory rate of 35%	\$ 90.9	\$ 95.1	\$ 89.9
Increase (Decrease) due to			
State income tax, net of federal income tax	4.6	7.3	7.5
Amortization of investment tax credits	(4.8)	(4.9)	(4.9)
Non-conventional fuels tax credit	(107.3)	(86.2)	(52.1)
Permanent reinvestment-foreign income	(8.1)	(7.2)	(9.3)
AFUDC Equity	(8.7)	(2.3)	(0.6)
Other	(5.0)	(3.9)	(1.2)
Total income tax provision from continuing operations	\$ (38.4)	\$ (2.1)	\$ 29.3
Provision for income taxes as a percent of income from continuing operations,			
before income taxes	-14.8%	-0.8%	11.4%

The provision for income taxes as a percent of income from discontinued operations was -22.4%, -36.5% and -46.1%, respectively, in 2002, 2001 and 2000. 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 by the alternative minimum tax rules in 2002, 2001, and 2000 was \$71.9 million, \$52.4 million and \$83.9 million, respectively.

N. Related Parties

The company and its subsidiaries had certain transactions, in the ordinary course of business, with entities in which directors of the company had interests. These transactions, primarily for legal services, were not material for 2002, 2001 and 2000. No material balances were payable as of Dec. 31, 2002 or 2001.

TPS recognized income on the non-TPS portion of notes receivable from unconsolidated affiliates in which TPS holds joint venture interests and from credit support for the TPGC joint venture. The notes receivable from unconsolidated affiliates are as follows:

Notes Receivable From Related Parties (millions) Dec. 31,	Rate	2002	2001
Panda Energy	14.00%	\$ 137.0	\$ 92.7
Energetecka Centrum Kladno	6.00%	1.4	—
Mosbacher Power Partners L.P.	12.00%	—	13.1
Mosbacher Power Partners L.P.	9.00%	13.7	21.1
Mosbacher Power Partners L.P.	12.00%	—	6.2
EEGSA	6.81% ⁽¹⁾	11.1	10.9
TPGC - Gila River	7.79% ⁽¹⁾	369.5	37.5
TPGC - Union Power	6.58% ⁽¹⁾	426.3	86.7

(1) Current rate at Dec. 31, 2002

Other Income (Expense) included pretax income from construction-related and loan agreements with Panda Energy, and interest income of \$78.9 million and \$32.8 million for 2002 and 2001, respectively from the other notes receivable shown on the preceding table.

At Dec. 31, 2002, TPS' position in the Odessa and Guadalupe power stations in Texas was in the form of a \$137 million loan to a Panda Energy International subsidiary, which is a partner in Texas Independent Energy (TIE). On Jan. 3, 2003 the loan converted to an ownership interest in these projects.

TPS Arkansas Operations Company and TPS Arizona Operations Company, both wholly-owned subsidiaries of TPS, have a combined receivable from TPGC of \$0.8 million as of Dec. 31, 2002.

TPS has agreed to purchase the interests of Panda Energy in the TPGC projects in 2007 for \$60 million, and TECO Energy has guaranteed payment of TPS' purchase obligation. This obligation may be accelerated if Panda Energy defaults on a bank loan for which the TPS purchase obligation is collateral or if TECO Energy permits its debt-to-capital ratio to exceed 65.0%, permits its EBITDA/Interest ratio to fall below 1.5 times or defaults on the payment of indebtedness in excess of \$50 million. TECO Energy's debt-to-capital ratio at Dec. 31, 2002, was 55.9% and its EBITDA/Interest ratio was 3.6 times (See Note R). Panda Energy may cancel the purchase obligation at any time prior to 2007 by paying TPS a cancellation fee that ranges from \$8 million to \$20 million based on the time of such cancellation.

O. Discontinued Operations

TECO Coalbed Methane, a subsidiary of TECO Energy had developed jointly the natural gas potential in a portion of 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, TECO Energy sold substantially all of its coalbed methane assets in Alabama 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 (See Note U). TECO Coalbed Methane's results were accounted for as discontinued operations for all periods reported. The gas assets are included in Property held for sale net of accumulated depreciation on the Consolidated Balance Sheets as of Dec. 31, 2001. Operating revenues from TECO Coalbed Methane were \$39.7 million, \$55.0 million and \$43.0 million, and pretax operating income was \$14.9 million, \$24.3 million and \$12.6 million for the years ended Dec. 31, 2002, 2001 and 2000, respectively.

TECO Coalbed Methane utilized the successful efforts method to account for its gas operations, in which expenditures for unsuccessful exploration activities were expensed currently.

Capitalized costs were amortized on the unit-of-production method using estimates of proven reserves. Investments in unproven properties and major development projects were not amortized until proven reserves associated with the projects could be determined or until impairment occurred.

Aggregate capitalized costs related to producing wells at Dec. 31, 2001 were \$220.8 million. Net proven reserves at Dec. 31, 2001 were as follows:

Net Proven Reserves - Coalbed Methane Gas	2001
(billion cubic feet)	
Proven reserves, beginning of year	181.7
Production	(15.0)
Revisions of previous estimates	0.4
Proven reserves, end of year	167.1
Number of wells	682

P. Earnings Per Share

In 1997, the FASB issued FAS 128, *Earnings per Share*, which requires disclosure of basic and diluted earnings per share and a reconciliation (where different) of the numerator and denominator from basic to diluted earnings per share. The reconciliation of basic and diluted earnings per share is shown as follows:

Earnings Per Share	2002	2001	2000
(millions, except per share amounts)			
Numerator			
Net income from continuing operations, basic	\$ 298.2	\$ 273.8	\$ 227.5
Effect of contingent performance shares	—	—	(1.9)
Net income from continuing operations, diluted	\$ 298.2	\$ 273.8	\$ 225.6
Net income, basic	\$ 330.1	\$ 303.7	\$ 250.9
Effect of contingent performance shares	—	—	(1.9)
Net income, diluted	\$ 330.1	\$ 303.7	\$ 249.0
Denominator			
Average number of shares outstanding - basic	153.2	134.5	125.9
Plus: incremental shares for assumed conversions:			
Stock options at end of period and contingent performance shares	2.1	4.2	3.3
Less: Treasury shares which could be purchased	(2.0)	(3.3)	(2.9)
Average number of shares outstanding - diluted	153.3	135.4	126.3
Earnings per share from continuing operations			
Basic	\$ 1.95	\$ 2.04	\$ 1.81
Diluted	\$ 1.95	\$ 2.02	\$ 1.79
Earnings per share			
Basic	\$ 2.15	\$ 2.26	\$ 1.99
Diluted	\$ 2.15	\$ 2.24	\$ 1.97

For the year ended Dec. 31, 2002, stock options for 4.5 million shares and 14.9 million common shares issuable under the purchase contract associated with the mandatorily convertible equity units issued in January 2002 were excluded from the computation of diluted earnings per share due to their antidilutive effect. For the year ended Dec. 31, 2001, stock options for 1.2 million shares were excluded from the computation of diluted earnings per share due to their antidilutive effect.

Q. Segment Information

TECO Energy is an electric and gas utility holding company with significant diversified activities. The management of TECO Energy determined its reportable segments based on each subsidiary's contribution of revenues, net income and total assets. All significant intercompany transactions are eliminated in the consolidated financial statements of TECO Energy but are included in determining reportable segments in accordance with FAS 131, *Disclosures about Segments of an Enterprise and Related Information*. In December 2002, TECO Energy sold the assets of TECO Coalbed Methane. Information presented here excludes TECO Coalbed Methane's results, which are reflected in the consolidated financial statements as discontinued operations.

Segment Information

(millions)	Revenues ⁽¹⁾⁽²⁾	Net Income ⁽³⁾	Depreciation ⁽⁴⁾	Assets at Dec. 31,	Capital Expenditures
2002	\$1,583.2⁽⁴⁾	\$171.8⁽⁵⁾	\$189.8	\$3,737.0	\$ 632.2
Tampa Electric	318.1	24.2 ⁽⁶⁾	30.5	571.7	53.5
Peoples Gas System	309.8 ⁽⁵⁾	34.1 ⁽¹¹⁾	28.1	2,875.0 ⁽¹⁰⁾⁽¹⁶⁾	299.9
TECO Power Services	254.6 ⁽⁶⁾	21.0 ⁽¹²⁾	22.3	355.1	25.2
TECO Transport	317.1 ⁽⁷⁾	76.5 ⁽¹³⁾	31.4	283.5	48.2
TECO Coal	122.1 ⁽⁸⁾	6.8 ⁽¹⁴⁾	1.3	312.4 ⁽¹⁷⁾⁽¹⁸⁾	3.0
Other unregulated businesses	2,904.9	334.4	303.4	8,134.7	1,062.0
Other and eliminations	(229.1)	(36.2)	—	503.1 ⁽⁹⁾	3.2 ⁽¹⁹⁾
TECO Energy consolidated	\$2,675.8	\$298.2	\$303.4	\$8,637.8	\$1,065.2
2001	\$1,412.7⁽⁴⁾	\$154.0⁽⁵⁾	\$173.4	\$3,315.5	\$ 426.3
Tampa Electric	352.9	23.1 ⁽⁶⁾	27.9	528.9	73.0
Peoples Gas System	287.1 ⁽⁵⁾	26.9 ⁽¹¹⁾	28.4	1,935.4 ⁽¹⁰⁾⁽¹⁶⁾	397.5
TECO Power Services	274.9 ⁽⁶⁾	27.6 ⁽¹²⁾	24.1	333.1	38.8
TECO Transport	303.4 ⁽⁷⁾	59.0 ⁽¹³⁾	28.3	258.5	25.8
TECO Coal	106.9 ⁽⁸⁾	4.0 ⁽¹⁴⁾	6.1	295.5 ⁽¹⁷⁾⁽¹⁸⁾	(0.1)
Other unregulated businesses	2,737.9	294.6	288.2	6,666.9	961.3
Other and eliminations	(249.8)	(20.8)	—	96.5 ⁽⁹⁾	4.6 ⁽¹⁹⁾
TECO Energy consolidated	\$2,488.1	\$273.8	\$288.2	\$6,763.4	\$ 965.9
2000	\$1,353.8⁽⁴⁾	\$144.5⁽⁵⁾	\$161.6	\$2,997.1	\$ 267.1
Tampa Electric	314.5	21.8 ⁽⁶⁾	25.8	513.3	82.2
Peoples Gas System	199.1 ⁽⁵⁾	22.8 ⁽¹¹⁾	18.5	1,350.6 ⁽¹⁰⁾⁽¹⁶⁾	243.5
TECO Power Services	269.8 ⁽⁶⁾	29.2 ⁽¹²⁾	22.0	311.3	21.1
TECO Transport	232.8 ⁽⁷⁾	33.5 ⁽¹³⁾	26.9	246.3	64.0
TECO Coal	81.8 ⁽⁸⁾	1.2 ⁽¹⁴⁾	3.2	213.3 ⁽¹⁷⁾⁽¹⁸⁾	6.9
Other unregulated businesses	2,451.8	253.0	258.0	5,631.9	684.8
Other and eliminations	(228.7)	(25.5)	—	142.4 ⁽⁹⁾	3.6 ⁽¹⁹⁾
TECO Energy consolidated	\$2,223.1	\$227.5	\$258.0	\$5,774.3	\$ 688.4

(1) From continuing operations. Revenues, net income and depreciation for all periods have been adjusted to reflect the reclassification of TECO Coalbed Methane results as discontinued operations.

(2) Revenues for all periods have been adjusted to reflect the presentation of energy marketing related revenues on a net basis and the reclassification of earnings from equity investments from Revenues to Other income.

(3) Segment net income is reported on a basis that includes internally allocated financing costs. Internally allocated costs for 2002, 2001, and 2000 were at pretax rates of 7%, 7%, and 6.75%, respectively, based on the average investment in each subsidiary.

(4) Revenues from sales to affiliates were \$34.4 million, \$32.6 million and \$32.4 million in 2002, 2001 and 2000, respectively.

(5) Revenues from sales to affiliates were \$51.4 million, \$65.0 million and \$67.6 million in 2002, 2001 and 2000, respectively.

(6) Revenues from sales to affiliates were \$110.7 million, \$123.2 million and \$118.0 million in 2002, 2001 and 2000, respectively.

(7) Revenues from sales to affiliates were \$0.7 million, \$5.1 million and \$4.3 million in 2002, 2001 and 2000, respectively.

(8) Revenues from sales to affiliates were \$31.9 million, \$23.8 million and \$6.5 million in 2002, 2001 and 2000, respectively.

(9) Net income includes net interest expense of \$51.5 million, \$60.8 million and \$67.4 million in 2002, 2001 and 2000, respectively. Net income also includes provisions for income taxes of \$85.7 million, \$83.4 million and \$82.5 million, respectively, for the same periods.

(10) Net income includes net interest expense of \$14.7 million, \$14.3 million and \$12.6 million in 2002, 2001 and 2000, respectively. Net income also includes provisions for income taxes of \$14.7 million, \$14.2 million and \$13.3 million, respectively, for the same periods.

(11) Net income includes net interest expense of \$57.2 million, \$51.8 million and \$23.0 million for 2002, 2001 and 2000, respectively, of which \$102.6 million, \$54.1 million and \$23.0 million for the same periods was internally allocated financing costs (see Note A). Net income also includes provisions for income taxes of \$9.2 million and \$0.7 million for 2002 and 2001, respectively, and an income tax benefit of \$0.6 million for 2000.

(12) Net income includes net interest expense of \$6.3 million, \$8.9 million and \$6.5 million for 2002, 2001 and 2000, respectively, of which \$1.7 million, \$0.7 million and \$0.9 million for the same periods was internally allocated financing income. Net income also includes provisions for income taxes of \$10.8 million, \$14.2 million and \$16.2 million, respectively, for the same periods.

(13) Net income includes internally allocated financing costs of \$8.1 million, \$7.6 million and \$6.5 million for 2002, 2001 and 2000, respectively. Net income also includes income tax benefits of \$22.9 million, \$19.0 million and \$14.8 million, respectively, for the same periods.

(14) Net income includes internally allocated financing costs of \$4.5 million, \$4.4 million and \$2.7 million for 2002, 2001 and 2000, respectively. Net income also includes provisions for income taxes of \$0.3 million, \$3.1 million and \$0.9 million, respectively, for the same periods.

(15) Total assets include \$97.4 million, \$120.4 million and \$145.5 million in investments in unconsolidated affiliates at Dec. 31, 2002, 2001 and 2000, respectively. Total assets also includes \$72.6 million, \$286.4 and \$383.1 million in other non-current investments at Dec. 31, 2002, 2001 and 2000, respectively.

(16) Total assets include \$154.5 million, \$129.4 million and \$65.7 million in goodwill net of amortization at Dec. 31, 2002, 2001 and 2000, respectively.

(17) Total assets include \$51.8 million, \$52.5 million and \$50.4 million in investments in unconsolidated affiliates at Dec. 31, 2002, 2001 and 2000, respectively.

(18) Total assets include \$39.1 million, \$36.4 million and \$27.4 million in goodwill net of amortization at Dec. 31, 2002, 2001 and 2000, respectively.

(19) Total assets and capital expenditures for all periods include amounts for the discontinued operations of TECO Coalbed Methane.

Tampa Electric Company provides retail electric utility services to almost 598,000 customers in West Central Florida. Its Peoples Gas System division is engaged in the purchase, distribution and marketing of natural gas for more than 281,000 residential, commercial, industrial and electric power generation customers in the state of Florida.

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 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. In 2000, these subsidiaries began operating two synthetic fuel processing facilities, whose production qualifies for the non-conventional fuels tax credit. With plans to continue growth in the production and sales of synfuel, TECO Coal has formed a new LLC and has transferred the synfuel units into this LLC effective Jan. 1, 2003. Selling partial interest in the LLC will facilitate efforts to maximize production as well as increase overall cash flow. TECO Coal's subsidiaries sell their coal production to third parties.

TPS has subsidiaries that have interests in independent power projects in Florida, Virginia, Texas, Arkansas, Mississippi, Arizona, Hawaii and Guatemala, and transmission and distribution facilities in Guatemala. TPS also has investments in unconsolidated affiliates that participate in independent power projects in other parts of the U.S. and the world.

TECO Energy's other diversified businesses are engaged in natural gas production from coalbeds, the marketing of natural gas, and energy services and engineering. Also included is the company's investment in the propane business.

Foreign Operations

TPS has independent power operations and investments in Guatemala. TPS, through its subsidiaries, has a 96 percent ownership interest and operates a 78-megawatt power station that supplies energy to EEGSA, an electric utility in Guatemala, under a U.S. dollar-denominated power sales agreement.

At Dec. 31, 2002, TPS, through a wholly-owned subsidiary, had a 100 percent ownership interest in a 120-megawatt power station and in transmission facilities in Guatemala. The plant provides capacity under a U.S. dollar-denominated power sales agreement to EEGSA.

TPS, through a subsidiary, owns a 30 percent interest in a consortium that includes Iberdrola, an electric utility in Spain, and Electricidade de Portugal, an electric utility in Portugal. The consortium owns an 80.9 percent interest in EEGSA.

Total assets at Dec. 31, 2002, 2001 and 2000 included \$415.9 million, \$454.2 million and \$442.6 million, respectively, related to these Guatemalan operations and investments. Revenues included \$88.5 million, \$79.9 million and \$69.0 million for the years ended Dec. 31, 2002, 2001 and 2000, respectively, and operating income included \$33.0 million, \$38.0 million and \$23.7 million for the same periods from these Guatemalan operations and investments.

R. Commitments and Contingencies

Capital Investments

TECO Energy has made certain commitments in connection with its continuing capital improvements program. At Dec. 31, 2002, these forecasted capital investments total approximately \$2.0 billion for the years 2003 through 2007 and are summarized as follows.

	Forecasted-Capital Investments				Total 2003-2007
	2003	2004	2005 - 2007		
(millions)					
Florida operations	\$272	\$266	\$725		\$1,263
Independent power	424	25	75		524
Transportation	15	21	61		97
Other	16	23	55		94
	\$727	\$335	\$916		\$1,978

For 2003, Tampa Electric expects to spend \$232 million, consisting of \$78 million for the repowering project at the Gannon Station, and \$154 million to support system growth and generation reliability. Tampa Electric's estimated capital expenditures over the 2004-2007 period are projected to be \$841 million, including \$67 for the Gannon repowering project. At the end of 2002, Tampa Electric had outstanding commitments of about \$119 million for the Gannon repowering project.

Capital expenditures for PCS are expected to be about \$40 million in 2003 and \$160 million during the 2004-2007 period. Included in these amounts are approximately \$25 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing maintenance and system safety.

TPS expects to invest \$424 million in 2003 for completion of the Union and Gila River power stations and \$100 million in 2004 through 2006, mainly for the completion of the Dell and McAdams power stations. Estimates for TPS include net contributions to projects of unconsolidated affiliates and other investments of \$393 million. TPS had outstanding commitments at Dec. 31, 2002 of approximately \$384 million related to the Union and Gila River power stations.

The other unregulated companies expect to invest \$31 million in 2003 and \$160 million during 2004 through 2007, mainly for normal renewal and replacement capital.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party 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, 2002, Tampa Electric has estimated its ultimate financial liability to be \$20 million, 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. The estimates to perform the work are based on actual estimates obtained from contractors, or the 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 and other potentially responsible parties (PRPs) is based on each party's relative ownership interest in or usage of a site. Accordingly, Tampa Electric's share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered creditworthy. Factors that could impact these estimates include the ability of other PRPs to pay their pro rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. These costs are recoverable through customer rates established in subsequent base rate proceedings.

Long Term Operating Lease Commitments

TECO Energy has commitments under long-term operating leases, primarily for building space, office equipment and heavy equipment, marine assets at TECO Transport, and certain equipment at TPS' Hardee Power Station. On Dec. 30, 2002 TECO Transport completed a sales 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 sales leaseback transaction to be accounted for as an operating lease. Both lease terms are 12 years with early buyout options

after 5 years. TPS completed a transaction on Dec. 29, 2000, where certain equipment at its Hardee Power Station was sold to a third party and leased back under a 12-year operating lease. Total rental expense for these operating leases, included in the Consolidated Statements of Income for the years ended Dec. 31, 2002, 2001 and 2000 was \$26.1 million, \$20.4 million and \$17.6 million, respectively. The following is a schedule of future minimum lease payments at Dec. 31, 2002 for all operating leases with noncancelable lease terms in excess of one year:

Year ended Dec. 31:	Amount (millions)
2003	\$ 27.4
2004	26.5
2005	23.3
2006	20.7
2007	17.9
Later Years	107.1
Total minimum lease payments	\$ 222.9

Guarantees and Letters of Credit

The company has outstanding letters of credit of \$185.0 million at Dec. 31, 2002, which guarantee performance to third parties related to debt service, major maintenance requirements and various trade activities. The company also has financial guarantees of \$755.6 million at Dec. 31, 2002, primarily for fuel purchases, energy management and construction related debt for projects in which TPS is a participant. Most of the guarantees are renewable annually. In addition, TECO Energy has guaranteed a \$375 million equity bridge loan and the \$60 million construction undertaking related to the Gila River and Union power stations. A summary of TECO Energy's letters of credit and guarantees are as follows:

Letters of Credit and Guarantees for the Benefit of:	2003				2004		2005-2007		After 2007		Liabilities Recognized at Dec. 31, 2002	
	\$	—	128.0	\$	—	27.1	\$	—	\$	0.9	\$	0.9
Tampa Electric												
Letters of credit												
Guarantees:												
Debt related												
Fuel purchase/energy management												10.0
Construction/Investment related			435.0					60.0				500.0
			563.0			27.1		60.0		489.3		1,139.4
TECO Transport												
Letters of credit										1.5		1.5
TECO Coal												
Letters of credit										0.1		0.1
Guarantees: Fuel purchase related										1.5		1.5
Other unregulated subsidiaries												
Letters of credit										2.7		2.7
Guarantees:												
Debt related										8.0		8.0
Fuel purchase/energy management										221.5		221.5
										232.2		232.2
										\$ 725.5		\$ 1,375.6
			\$ 563.0			\$ 27.1		\$ 60.0				\$ 57.9

Financial Covenants

A summary of TECO Energy's significant financial covenants is as follows:

TECO Energy Significant Financial Covenants (millions)		Financial Covenant ⁽¹⁾	Requirement/Restriction	Calculation at Dec. 31, 2002
Tampa Electric	Mortgage bond indenture	Dividend restriction	Cumulative distributions cannot exceed cumulative net income plus \$4	\$189 unrestricted
	PCCS senior notes	EBIT/interest Restricted payments Funded debt/capital	Minimum of 2.0 times Shareholder equity at least \$500	3.7 times \$1,838
	Credit facility	Sale of assets Debt/capital EBITDA/interest	Cannot exceed 65% Less than 20% of total assets Cannot exceed 60% Minimum of 2.5 times	44.8% 0% 43.9% 7.8 times
TECO Energy	Credit facilities \$380 million note indenture ⁽²⁾	Debt/capital Various	Cannot exceed 65%	55.9%
	TECO/Panda guarantees ⁽³⁾	Debt/capital EBITDA/interest Minimum ratings Debt/capital EBITDA/interest	Cannot exceed 65% Minimum of 3.0 times BBB and Baa3, or BBB- and Baa2 Cannot exceed 65% Minimum of 1.5 times	55.9% 3.6 times BBB- and Baa2 55.9% 3.6 times
TECO	Energy management services agreement guarantee	Consolidated tangible net worth	Minimum of \$200	\$575
	Coal supply agreement guarantee	Dividend restriction	Cannot exceed 60% Net worth not less than \$200 or \$446 (40% of tangible net assets)	19.1% \$536

(1) As defined in applicable instrument.

(2) Indenture contains covenants which would apply only if either (a) Notes are rated below BBB- by S&P or below Baa3 by Moody's or (b) Notes are rated below Special Ratings Trigger (minimum of BBB- by S&P and Baa2 by Moody's or BBB by S&P and Baa3 by Moody's) if TECO Energy Construction Undertakings for the TECO/Panda guarantees are not discharged. These covenants include Limitation on Restricted Payments, Limitations on Certain Liens and Limitation on Indebtedness.

(3) Includes Equity Bridge, Equity Contribution and Construction Undertaking Guarantees related to the TPCC projects.

Other Contingencies

In December 2001, Enron Corp., a large energy trading and services company, filed for protection under the U.S. Bankruptcy Code. TECO Energy announced it believed it had exposure in operations from trade payables and other trading positions due to the Enron bankruptcy of \$3.5 million or less after-tax at its subsidiaries TPS, PGS and Prior Energy. TECO Energy has negotiated an agreement with Enron, pending approval of the Creditors Committee, to settle the previously reported \$3.5 million of potential trade payables exposure as a result of the Enron bankruptcy. The net financial impact of the agreement is reflected in consolidated net income and no future financial impact is expected.

S. Mergers and Acquisitions

In May 2002, TPS purchased Moshbacher Power Partners' interest in TM Power Ventures (TMPV) for \$29.3 million. The majority of the purchase price was allocated to TMPV's investment in the 312-megawatt Commonwealth Chesapeake Power Station located on the Delmarva Peninsula in Virginia, and has been recorded as an increase in goodwill. The acquisition increased TPS' ownership interest in TMPV to 100 percent.

In November 2001, TECO Solutions acquired Prior Energy Corporation, a leading natural gas management company serving customers in Alabama, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee and Texas. Prior Energy handles all facets of natural gas energy management services, including natural gas purchasing and marketing. The company has an established market base in the Southeast and one of the top customer service reputations in the region. The acquisition was accounted for by the purchase method of accounting and, accordingly, the results of operations of Prior Energy are included as part of TECO Solutions' results beginning Nov. 1, 2001. The final working capital adjustment and purchase price allocation was completed in 2002. The total cost of the acquisition was \$23.0 million plus a net working capital payment of \$6.4 million. Goodwill of \$9.6 million was recorded, repre-

senting the excess of purchase price over the fair market value of assets acquired. Under EAS 141, effective for all business combinations initiated after June 30, 2001, goodwill is no longer subject to amortization. Net intangible assets of \$39.8 million were recorded, representing the value of customer backlog and supply agreements as well as the open cash flow hedges as of Nov. 1, 2001, which are being amortized over 2001 through 2004.

In March 2001, TPS acquired the Frontera Power Station located near McAllen, Texas, accounting for the transaction using the purchase method of accounting. This 477-megawatt, natural gas-fired combined-cycle plant, originally developed by CSW Energy (CSW), began commercial operation in May 2000. As a condition of the merger of Central & South West Corporation, CSW's parent company with American Electric Power Company, Inc., the FERC required CSW to divest its ownership in this facility. The total cost of the acquisition was \$265.3 million. Goodwill of \$70.4 million, representing the excess of purchase price over the fair market value of assets acquired, was recorded, and was amortized on a straight-line basis over 40 years until the requirements of FAS 141 became effective on Jan. 1, 2002 (See Note C). The results of operations of Frontera Power Station are included as part of TPS' results beginning March 16, 2001.

The following pro forma disclosures include Prior Energy and the Frontera Power Station as if they had been included in TECO Energy's financial statements for the years ended Dec. 31, 2001 and 2000.

Pro Forma Disclosure — Mergers and Acquisitions

Year ended Dec. 31,	Actual		Pro Forma	
	2002	2001	2001	2000
Revenues (millions)	\$ 2,675.8	\$ 2,557.4	\$ 2,308.6	\$ 2,308.6
Net income from continuing operations (millions)	\$ 298.2	\$ 270.4	\$ 230.5	\$ 230.5
Earnings per share from continuing operations — basic	\$ 1.95	\$ 2.01	\$ 1.83	\$ 1.83

This pro forma information is not necessarily indicative of the operating results that would have occurred had the acquisitions been completed as of the dates indicated, nor are they indicative of future operating results.

In October 2001, TECO BGA, a unit of TECO Solutions, purchased a district cooling business from FPL Energy Services, a subsidiary of FPL Group. The acquisition includes a 12,000-ton design capacity cooling plant located in downtown Miami. This acquisition provides TECO BGA with a stronger presence in the growing South Florida energy market, long-term contract business, a franchise agreement with the city of Miami and the potential for expansion. The acquisition was accounted for by the purchase method of accounting and, accordingly, its results of operations are included as part of TECO BGAs results beginning Oct. 25, 2001. The total cost of the acquisition was \$12.5 million. No goodwill was recorded for the acquisition. The acquisition was not material to the financial statements; no pro forma disclosures are presented.

On Nov. 1, 2000, TECO Coal acquired all of the outstanding stock of Perry County Coal for \$14.9 million, comprised of \$12.1 million in cash and \$2.8 million in notes. Perry County Coal owns or controls more than 23 million tons of low-sulfur reserves, and operates both deep and surface contract mines. The acquisition was accounted for by the purchase method of accounting and, accordingly, the results of operations and assets of Perry County Coal are included as part of TECO Coals' results beginning Nov. 1, 2000. The acquisition was not material to the financial statements; no pro forma disclosures are presented.

In September 2000, TECO Energy acquired BCH Mechanical, Inc. and its affiliated companies ("BCH") accounting for the transaction using the purchase method of accounting. BCH is one of the leading mechanical contracting firms in Florida. TECO Energy purchased a combination of stock and assets of the BCH companies for \$34.8 million, comprised of \$26.1 million in cash, \$2.9 million in notes, and 233,819 shares of TECO Energy common stock. Goodwill of \$25.9 million representing the excess of purchase price over the fair market value of assets acquired was recorded, and was amortized on a straight-line basis over 20 years, until the requirements of FAS 141 became effective on Jan. 1, 2002 (See Note C). The result of operations of BCH are included as part of TECO Energy's results beginning Sept. 1, 2000. The acquisition was not material to the financial statements; no pro forma disclosures are presented.

In connection with this transaction, TECO Solutions was formed to support TECO Energy's strategy of offering customers a comprehensive and competitive package of energy services and products. Operating companies under TECO Solutions include TECO Energy Services (formerly TECO BGA and BCH Mechanical), TECO Partners, TPV, TECO Gas Services, Prior Energy and TECO Properties.

In February 2000, TECO Energy entered into an agreement to form US Propane, a joint venture to combine its Peoples Gas Company (PGC) propane operations with the propane operations of Atmos Energy Corporation, AGL Resources Inc. and Piedmont Natural Gas Company, Inc. Through a series of transactions completed Aug. 10, 2000, US Propane combined its propane operations with those of Heritage Propane Partners, L.P. US Propane now owns the general partner interest and 29 percent of the limited partnership interests of Heritage Propane Partners. TECO Energy through its wholly-owned subsidiary TPV, is accounting for its interest in US Propane under the equity method of accounting. As a result of these transactions, TPV also received \$19.3 million in cash and recognized a pretax gain of \$13.6 million (\$8.3 million after-tax) on the sale of PGC assets and liabilities to the extent acquired by US Propane and Heritage Propane Partners.

T. New Accounting Pronouncements

Accounting for Asset Retirement Obligations

In July 2001, the FASB issued FAS 143, *Accounting for Asset Retirement Obligations*, which requires the recognition of a liability at fair value for an asset retirement obligation in the period in which it is incurred. Retirement obligations associated with long-lived assets included within the scope of FAS 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract, or by legal construction under the doctrine

of promissory estoppel. Retirement obligations are included in the scope of the standard 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 useful life of the asset. The liability must be revalued each period based on current market prices. FAS 143 is effective for fiscal years beginning after June 15, 2002. The company estimates that the adoption of FAS 143 will result in a non-cash increase to net property, plant and equipment of approximately \$8.0 million, a non-cash net increase to asset retirement obligation of approximately \$10.0 million, and as a cumulative effect of change in accounting principle, a non-cash pretax charge of approximately \$2.0 million.

Exit or Disposal Costs

In July 2002, the FASB issued FAS 146, *Accounting for Costs Associated with Exit or Disposal Activities*, which addresses the accounting for costs under certain circumstances, including costs to terminate a contract that is not a capital lease, costs to consolidate facilities or relocate employees, and termination benefits provided to employees that are involuntarily terminated under the terms of a one-time benefit arrangement that is not an ongoing benefit arrangement or an individual deferred compensation contract. FAS 146 is effective for disposal activities initiated after Dec. 31, 2002 with early adoption allowed.

Gains and Losses on Energy Trading Contracts

On Oct. 25, 2002, the Emerging Issues Task Force released EITF 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under Issues No. 98-10 and 00-17*, which 1) precludes mark-to-market accounting for energy trading contracts that are not derivatives pursuant to FAS 133, 2) requires that gains and losses on all derivative instruments within the scope of FAS 133 be presented on a net basis in the income statement if held for trading purposes, and 3) limits the circumstances in which a reporting entity may recognize a "day one" gain or loss on a derivative contract. The measurement provisions of the issue are effective for all fiscal periods beginning after Dec. 15, 2002. The net presentation provisions are effective for all financial statements issued after Dec. 15, 2002. In accordance with the recommended transition provisions, TECO Energy reclassified certain amounts in prior periods to present gains and losses on a net basis (see Note A). The adoption of the measurement provisions is not anticipated to have a material impact.

Guarantees

In November 2002, the FASB issued Interpretation No. (FIN) 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of others (an interpretation of FAS No. 5, 57, and 107 and rescission of FAS Interpretation No. 34)*, which modifies the accounting and enhances the disclosure of certain types of guarantees. FIN 45 requires that upon issuance of certain guarantees, the guarantor must recognize a liability for the fair value of the obligation it assumes under the guarantee. FIN 45's provisions for the initial recognition and measurement are to be applied to guarantees issued or modified after Dec. 31, 2002. The disclosure requirements are effective for financial statements of annual periods that end after Dec. 15, 2002 (see Note R).

Stock-Based Compensation

In December 2002, the FASB issued FAS 148, *Accounting for Stock-Based Compensation - Transition and Disclosure*, an amendment of FASB Statement No. 123. This standard amends FAS 123, *Accounting for Stock-Based Compensation*, to provide alternative methods of transition for companies that voluntarily change to the fair value based method of accounting 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 transition provisions and annual disclosure requirements are effective for all fiscal years ending after Dec. 15, 2002, while the interim period disclosure requirements are effective for all interim periods beginning after Dec. 15, 2002. The adoption of the disclosure provisions of this standard does not have a material impact.

Consolidation of Variable Interest Entities

The equity method of accounting is used to account for investments in partnership arrangements in which TECO Energy or its subsidiary companies do not have a majority ownership or exercise control. On Jan. 17, 2003, the FASB issued FASB Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51*, which imposes a new approach in 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 or VIEs. A legal entity is considered a VIE 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 is not obligated to consolidate a VIE, then equity 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. Certain transition disclosures are required for all financial statements issued after Jan. 31, 2003. The on-going disclosure and consolidation requirements are effective for all interim financial periods beginning after June 15, 2003.

Based on a preliminary review, TECO Energy believes it is reasonably possible that FIN 46 may impact certain unconsolidated affiliates. Management is continuing to assess the extent of the relationships and obtain adequate information upon which to base appropriate conclusions. Below is a discussion of the legal entities existing as of Dec. 31, 2002 that TECO Energy considers to be possibly subject to either 1) additional disclosure requirements or 2) consolidation by the company, in accordance with FIN 46.

TPS entered into a joint venture, TPGC, to build, own and operate the Union and Gila River power stations. As of Dec. 31, 2002, TPGC is a development stage partnership that may meet the definition of a VIE in accordance with FIN 46. The third-party debt financing at TPGC is non-recourse and does not create an estimated loss exposure to TECO Energy. The estimated maximum loss exposure is approximately the current and guaranteed equity investment in the partnership. (See Notes A, N and R.)

TPS completed a transaction whereby certain equipment at the Hardlee Power Station was sold to a third party (the Lessor) and leased back under an operating lease agreement with an initial term of 12 years. The original cost of the equipment was \$46.6 million. The sole purpose of the Lessor is to own and lease back the equipment to Hardlee Power. The Lessor may be a VIE in accordance with FIN 46. The lease financing arrangement includes \$41.6 million of subordinated debt and \$1.4 million of equity contributed by an unrelated third party. If the Lessor were to be consolidated, TPS estimates that it would incur after-tax incremental expenses of approximately \$9.5 million over the 12 year term of the lease. (See Note R.)

TECO Properties formed two limited liability companies with project developers which may meet the definition of a VIE. Hernando Oaks, LLC was formed by TECO Properties with the Pensacola Group to buy and develop 627 acres of land in Hernando County, Florida into a residential golf community comprised of an 18-hole golf course and 975 single-family lots for sale

to homebuilders. Hernando Oaks, LLC had total assets at Dec. 31, 2002 of \$18.9 million. TECO Properties' estimated maximum loss exposure in this project is approximately \$9.7 million.

B-T One, LLC is a limited liability company formed by TECO Properties with Boyd Development Co., the project developer, to buy 592 acres of land in Ocala, Florida and to develop and sell 585 single-family lots to homebuilders. B-T One, LLC had total assets at Dec. 31, 2002 of \$13.1 million. TECO Properties' estimated maximum loss exposure in this project is approximately \$7.5 million.

TECO Propane Ventures (TPV) has an investment in a partnership formed to combine propane operations with the propane operations of three third-party entities. The partnership may meet the definition of a VIE as established in FIN 46. At Dec. 31, 2002, the estimated maximum loss exposure faced by TPV is approximately \$44.6 million. (See Note S.)

TECO Transport entered into two separate sale-leaseback transactions for certain vessels which were recognized as sales at the time of each transaction, and are currently recognized as operating leases for the assets. The sale-leaseback transactions were entered into with a third party that may 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. The estimated maximum loss exposure faced by TECO Transport is the incremental cost of obtaining suitable equipment to meet contractual obligations. (See Note R.)

TECO Energy Services (formerly TECO BGA) 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 for use, primarily, in air conditioning systems. The partnership may meet the definition of a VIE in accordance with FIN 46. The estimated maximum loss exposure associated with this partnership is approximately \$3.6 million as of Dec. 31, 2002.

In November 2000, TECO Energy established TECO Capital Trust I (Trust I) for the sole purpose of issuing Trust Preferred Securities (TRuPS) and using the proceeds to purchase company preferred securities from TECO Funding. Trust I may be a VIE in accordance with FIN 46. TECO Energy has guaranteed the payments to the holders of the company preferred securities and indirectly, the payments to the holders of the TRuPS, as a result of their beneficial interest in the company preferred securities.

Subsequently, in January 2002, TECO Energy sold 17,965 million units of mandatorily convertible equity units in the form of 9.5% equity units at \$25 per unit. Each equity unit consisted of \$25 in principal amount of a trust preferred security of TECO Capital Trust II (Trust II), a Delaware business trust formed for the purpose of issuing these securities. Trust II may meet the definition of a VIE in accordance with FIN 46. The estimated maximum loss exposure is not expected to be incrementally significant to obligations currently recognized by TECO Energy for the activities of either Trust I or Trust II. (See Note G.)

As a result of the conversion of a loan to a Panda Energy International subsidiary on Jan. 3, 2003, TPS has an equity interest in the TIE partnership (See Note N). The TIE partnership owns and operates the Odessa and Guadalupe power stations in Texas. The partnership may be a VIE in accordance with FIN 46. The estimated maximum loss exposure is approximately \$137 million, representing TPS' equity investment as of Jan. 3, 2003.

U. Subsequent Event

On Jan. 30, 2003, TECO Energy received \$98.1 million in cash for the repayment of a note receivable from the Municipal Gas Authority of Georgia, related to the sale of its coalbed methane assets on Dec. 20, 2002.

V. Quarterly Data (unaudited)

Financial data by quarter is as follows:

Quarter ended	March 31	June 30	Sept. 30	Dec. 31
2002				
Revenues ⁽¹⁾	\$ 606.6	\$ 677.7	\$ 731.0	\$ 660.5
Income from operations ⁽¹⁾	\$ 89.2	\$ 97.8	\$ 142.5	\$ 59.5
Net income ⁽¹⁾				
Net income from continuing operations	\$ 69.9	\$ 80.9	\$ 112.8	\$ 34.6
Net income	\$ 75.4	\$ 85.7	\$ 118.9	\$ 50.1
Earnings per share (EPS) - basic				
EPS from continuing operations	\$ 0.50	\$ 0.56	\$ 0.72	\$ 0.20
EPS	\$ 0.54	\$ 0.59	\$ 0.76	\$ 0.29
Earnings per share (EPS) - diluted				
EPS from continuing operations	\$ 0.50	\$ 0.56	\$ 0.72	\$ 0.20
EPS	\$ 0.54	\$ 0.59	\$ 0.76	\$ 0.29
Dividends paid per common share ⁽²⁾	\$ 0.345	\$ 0.355	\$ 0.355	\$ 0.355
Stock price per common share ⁽³⁾				
High	\$ 28.940	\$ 29.050	\$ 24.710	\$ 16.480
Low	\$ 23.400	\$ 22.700	\$ 14.200	\$ 10.020
Close	\$ 28.630	\$ 24.750	\$ 15.880	\$ 15.470
2001				
Revenues ⁽¹⁾	\$ 641.3	\$ 613.2	\$ 659.6	\$ 574.0
Income from operations ⁽¹⁾	\$ 103.0	\$ 95.4	\$ 131.7	\$ 68.1
Net income ⁽¹⁾				
Net income from continuing operations	\$ 62.1	\$ 61.8	\$ 90.8	\$ 59.1
Net income	\$ 69.7	\$ 71.9	\$ 97.3	\$ 64.8
Earnings per share (EPS) - basic				
EPS from continuing operations	\$ 0.48	\$ 0.46	\$ 0.67	\$ 0.43
EPS	\$ 0.54	\$ 0.53	\$ 0.72	\$ 0.47
Earnings per share (EPS) - diluted				
EPS from continuing operations	\$ 0.47	\$ 0.44	\$ 0.66	\$ 0.42
EPS	\$ 0.53	\$ 0.52	\$ 0.71	\$ 0.47
Dividends paid per common share ⁽²⁾	\$ 0.335	\$ 0.345	\$ 0.345	\$ 0.345
Stock price per common share ⁽³⁾				
High	\$ 32.125	\$ 32.970	\$ 31.650	\$ 28.300
Low	\$ 26.100	\$ 28.780	\$ 25.530	\$ 24.750
Close	\$ 29.960	\$ 30.500	\$ 27.100	\$ 26.240

(1) Millions.

(2) Dividend paid on TECO Energy common stock.

(3) Trading prices for common shares.

Report of Independent Certified Public Accountants

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, common equity and cash flows present fairly, in all material respects, the financial position of TECO Energy, Inc. and its subsidiaries at Dec. 31, 2002 and Dec. 31, 2001, and the results of their operations and their cash flows for each of the three years in the period ended Dec. 31, 2002, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which 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.

As discussed in the Notes C and B to the Financial Statements, the Company adopted the provisions of Financial Accounting Standard 142, *Goodwill and Other Intangible Assets*, on Jan. 1, 2002 and Financial Accounting Standard 133, *Accounting for Derivative Instruments and Hedging*, on Jan. 1, 2001, respectively.



Tampa, Florida, Jan. 22, 2003, except for the information in Note U as to which the date is Jan. 30, 2003.

Selected Financial Data

(Millions, except per share amounts)

	Year ended Dec. 31,		1999		1998
	2002	2001	2000	1999	1998
Revenues	\$ 2,675.8	\$ 2,488.1	\$ 2,223.1	\$ 1,932.6	\$ 1,905.1
Net income from continuing operations	\$ 298.2 ⁽¹⁾	\$ 273.8 ⁽¹⁾	\$ 227.5 ⁽¹⁾	\$ 179.2 ⁽²⁾	\$ 179.2 ⁽²⁾
Income from discontinued operations	26.1	21.9	12.6	(16.3)	10.3
Income tax benefit - discontinued operations	(5.8)	(8.0)	(10.8)	(23.2)	(17.0)
Net income from discontinued operations	31.9	29.9	23.4	6.9	27.3
Net income	\$ 330.1 ⁽¹⁾	\$ 303.7 ⁽¹⁾	\$ 250.9 ⁽¹⁾	\$ 186.1 ⁽²⁾	\$ 206.5 ⁽²⁾
Total assets	\$ 8,637.8	\$ 6,763.4	\$ 5,774.3	\$ 4,733.0	\$ 4,218.3
Long-term debt	\$ 3,324.3	\$ 1,842.5	\$ 1,374.6	\$ 1,207.8	\$ 1,279.6
Earnings per share (EPS) - basic					
From continuing operations	\$ 1.95 ⁽¹⁾	\$ 2.04 ⁽¹⁾	\$ 1.81 ⁽¹⁾	\$ 1.37 ⁽²⁾	\$ 1.36 ⁽²⁾
From discontinued operations	.20	.22	.18	.05	.21
EPS basic	\$ 2.15 ⁽¹⁾	\$ 2.26 ⁽¹⁾	\$ 1.99 ⁽¹⁾	\$ 1.42 ⁽²⁾	\$ 1.57 ⁽²⁾
Dividends paid per common share ⁽⁴⁾	\$ 1.41	\$ 1.37	\$ 1.33	\$ 1.285	\$ 1.225

(1) Includes other non-operating items affecting net income (see Note 1).

(2) Includes the effect of charges, which reduced net income by \$19.6 million and earnings per share by \$0.15 in 1999.

(3) Includes the effect of charges, which reduced net income by \$19.6 million and earnings per share by \$0.15 in 1998.

(4) Dividend paid on TECO Energy common stock.

Corporate Directory

TECO Energy Executive Officers

Robert D. Fagan	Chairman of the Board, President and Chief Executive Officer
John B. Ramil	Executive Vice President – TECO Energy and President, Tampa Electric
William N. Cantrell	President, Peoples Gas System and TECO Solutions
Royston K. Eustace	Senior Vice President – Business Development
Gordon L. Gillette	Senior Vice President – Finance and Chief Financial Officer
Richard Lehigh	Senior Vice President – External Affairs
Richard E. Ludwig	President, TECO Power Services
Sheila M. McDevitt	Senior Vice President – General Counsel
D. Jeffrey Rankin	President, TECO Transport
J.J. Shackleford	President, TECO Coal

TECO Energy Staff Officers

Charles A. Attal III	Vice President and Deputy General Counsel
Paul R. Bogenrieder	Vice President – Energy Risk Management
Deirdre A. Brown	Vice President – Regulatory Affairs
Sandra W. Callahan	Vice President – Treasury and Risk Management (Treasurer)
Clinton E. Childress	Chief Human Resources Officer
Margarita N. Dominguez	Chief Information Officer
Charles O. Hinson III	Vice President – State Government Affairs
Wayne W. Hopkins	Vice President – Corporate Communications
Burnis L. Kilpatrick, Jr.	Corporate Compliance Officer
Shirley A. Myers	Vice President – Corporate Accounting and Tax (Chief Accounting Officer)
David E. Schwartz	Vice President, Assistant General Counsel and Corporate Secretary
Janet L. Sena	Vice President – Federal Affairs

Board of Directors

Robert D. Fagan ⁽¹⁾	Chairman of the Board, President and Chief Executive Officer, TECO Energy, Inc., Tampa, Florida
DuBose Ausley ⁽²⁾	Chairman, Ausley & McMullen (attorneys), Tallahassee, Florida
Sara L. Baldwin ⁽²⁾	Private Investor, former Vice President, Baldwin and Sons, Inc. (insurance agency), Tampa, Florida
James L. Ferma, Jr. ⁽¹⁾⁽²⁾	President, Ferma Motor Car Company, Inc. (automobile dealerships), Tampa, Florida
Luis Guinot, Jr. ⁽²⁾	Partner, Shapiro Sher & Guinot, P.A. (attorneys), Washington, D.C., former United States Ambassador to the Republic of Costa Rica
Ira D. Hall ⁽¹⁾	President and Chief Executive Officer, Urendahl Capital Management, L.P. (money management), New York, New York, former Treasurer, Texaco, Inc. (integrated oil company), White Plains, New York
Sherrill W. Hudson ⁽¹⁾	Former Managing Partner for South Florida, Deloitte & Touche LLP (public accounting), Miami, Florida
Tom L. Rankin ⁽¹⁾⁽²⁾	Independent Investment Manager, Tampa, Florida, former Chief Executive Officer, Lykes Energy, Inc. (the former holding company for Peoples Gas System)
William D. Rockford ⁽²⁾	President, Private Power, LLC (power generation), Oak Brook, Illinois, former Managing Director, Chase Securities Inc. (financial services), New York, New York
William P. Sovey ⁽²⁾⁽⁴⁾	Chairman of the Board and former Chief Executive Officer, Newell Rubbermaid, Inc. (consumer products), Freeport, Illinois
J. Thomas Touchton ⁽¹⁾⁽²⁾	Managing Partner, The Witt-Touchton Company (private investment partnership), Tampa, Florida
John A. Urquhart ⁽²⁾⁽³⁾⁽⁴⁾	President, John A. Urquhart Associates (management consultants), Fairfield, Connecticut, former Senior Vice President/Executive Vice President, G.E. Industrial & Power Systems, General Electric Company
James O. Welch, Jr. ⁽²⁾	Former Vice Chairman, RJR Nabisco, Inc. and former Chairman, Nabisco Brands, Inc. (tobacco and food products), East Hanover, New Jersey

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

Information for Investors

Internet
For current information about TECO Energy, its own Web Internet site
www.tecoenergy.com

TECO Energy is listed on the New York Stock Exchange
symbol: TE

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Analysts
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Tampa, FL

Annual Meeting
The Annual Meeting of Shareholders will be held on April 22,
2003, 11:30 a.m. at
TECO Plaza
702 N. Franklin Street
Tampa, FL 33602

Shareholder Inquiries
Communication concerning transfers (requirements, lost cer-
tificates, dividends and change of address should be directed
to the Transfer Agent

Transfer Agent & Registrar
Equiserve
P.O. Box 43010
Phoenix, AZ 02310
800-450-9722
www.equiserve.com

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

Equiserve
P.O. Box 9223
Chelsea, MA 02150

Form 10-K Available
TECO Energy's Annual Report on Form 10-K, which is filed
with the Securities and Exchange Commission, is available to
shareholders at no charge on the Internet at www.tecoenergy.com
through the Investor Relations page at www.tecoenergy.com.
Requests should be addressed to:

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