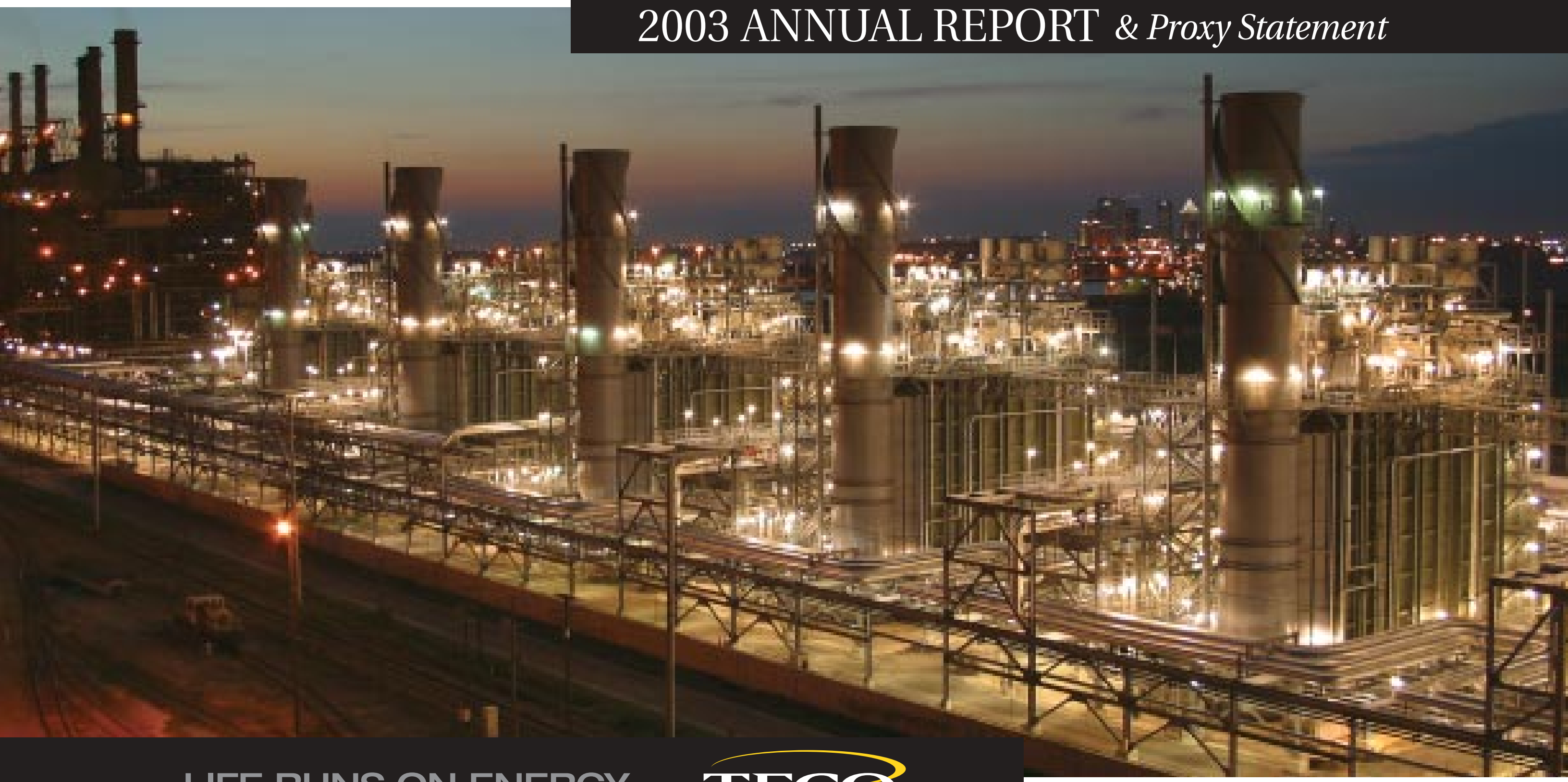
2003 ANNUAL REPORT *& Proxy Statement*



LIFE RUNS ON ENERGY[SM]

TECO ENERGY

TECO Energy, Inc. (NYSE: TE) is an integrated energy provider with core businesses in the utility sector, complemented by a family of unregulated businesses. In addition to the regulated operations of Tampa Electric and Peoples Gas System, TECO Energy has interests in waterborne transportation, coal and synthetic fuel production and independent power.

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(Cover) Tampa Electric's natural gas-fired Bayside Power Station.

March 25, 2004

Dear Fellow Shareholders:

The year 2003 was a turning point for TECO Energy, as we changed course from the strategy we embarked on in 1999.

Then, markets were opening to electric competition, and investors paid premiums for companies with prospects for growth through independent power. National environmental policy was poised to change the nation's electric generating fleet through stringent regulations that would force the retirement of older, more polluting facilities. Against this backdrop, scores of new, more efficient, environmentally friendly power facilities were built to take the place of older, less efficient plants.

The competitive marketplace most had anticipated, for a variety of reasons, has not yet emerged. But what has emerged is TECO Energy's need to reduce risk to earnings and cash flow and rebuild shareholder value. Given current market conditions, there was really only one way to start down that road. In April 2003, we announced TECO Energy's new strategic direction – to return our company to its utility roots and focus on our regulated Florida operations.

Throughout the year, we worked diligently to limit our exposure to the merchant energy business and to address investor concerns regarding our financial condition. Unfortunately, a very difficult step toward restoring our financial health was the April 2003 dividend reduction. While this was an unpleasant step for me, and for the Board of Directors, it was a step we took to maintain TECO Energy's financial integrity.

This month, TECO Energy took its most significant step toward implementing our "back to basics" utility-focused strategy. We made the decision to exit our two largest independent power projects, Union and Gila River, through a sale to either the project lending banks or a third party. We have entered into a letter of intent with the banks regarding the transfer of these projects.

The decision to end TECO Energy's ownership of these projects and cease further funding is not, however, dependent on reaching final agreement with lenders. As such, we no longer take a long-term view of Union or Gila River, and we took a fourth-quarter 2003 write-off of $762 million (after tax), which clearly impacted our results for the quarter, and the year.

But, in any event, these charges are behind us, and we've begun to return to our roots, which are centered in the State of Florida. Our Florida energy market continues to grow and thrive, and in that market, we've renewed our emphasis on our regulated utilities, Tampa Electric and Peoples Gas. The regulated utility model is a business model that provides more sustainable growth at substantially lower risk.

In the future, we expect that you will see a different TECO Energy, but one that is familiar to long-time shareholders – a strong holding company with valuable Florida utilities that have profitable electric and gas operations. Both Tampa Electric and Peoples Gas have strong, sustainable growth.

And, we expect to continue to benefit from stable earnings and cash flow from our long-term unregulated transportation and coal businesses. While we may continue to have some investments in independent power projects, we expect that these remaining projects will have long-term contracts or otherwise be self-sustaining.

Our capital expenditure program at Tampa Electric and the independent power facilities is now complete. TECO Energy has no significant corporate debt maturities until 2007, and we expect free cash flow generated between now and then to reduce the company's levels of debt outstanding.

As you know, we took decisive steps during 2003 to improve our financial position. We will continue to seek to position ourselves for a return to a stronger financial position, and a return to earnings growth in the future.

As we enter 2004, I would like to take this opportunity to thank John A. "Jack" Urquhart for his service as a member of TECO Energy's Board of Directors. Effective April 28, 2004, Jack is retiring, after more than 13 years of service to the company.

And as always, thank you for your investment in TECO Energy.

Sincerely,

Robert D. Fagan

Robert D. Fagan
Chairman, President and Chief Executive Officer

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 TECO Energy's anticipated capital investments, financing requirements, 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 the merchant plants at TECO Wholesale Generation, Inc. (formerly known as TECO Power Services) (TWG); TECO Energy's ability to complete the transfer of the ownership of the Union and Gila River power plants to the lending banks as described below or otherwise insulate itself from the adverse financial impact of those plants; TWG's ability to sell the output of its remaining merchant plants in the spot markets or 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; and TECO Coal's ability to successfully complete the sale of its synthetic fuel production facilities and to successfully operate its synthetic fuel production facilities in a manner qualifying for Section 29 federal tax credits which could be impacted by changes in law, regulation or administration. 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; regulatory actions affecting Tampa Electric, Peoples Gas System or TWG; 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; TWG's ability to successfully operate its projects; the ability of TECO Energy's subsidiaries to operate equipment without undue accidents, breakdowns or failures; and, interest rates, credit ratings and other factors that could impact TECO Energy's ability to obtain access to sufficient capital on satisfactory terms. Some of these factors and others are discussed more fully under "**Investment Considerations**."*

TECO Energy, Inc. is a holding company, and all of its business is conducted through its subsidiaries. In this Management's Discussion and Analysis "we," "our," "ours," and "us" refer to TECO Energy, Inc. and its consolidated group of companies unless the context otherwise requires.

Overview

Our results and many of our activities in 2003 were driven by the capital requirements to complete the construction of the Union and Gila River power stations and the Tampa Electric Bayside Station repowering; the initial operations of Union and Gila River power stations and the poor financial performance of these two large plants; the generally poor financial results from our other merchant power plants; and our decision to exit our ownership of the Union and Gila River power stations, (see the **TECO Wholesale Generation** company section). (Merchant power plants are power plants that do not have long-term contracts for the majority of their output. Most of the power from a merchant power plant is sold under short-term agreements or in the more volatile spot markets.) At the same time, we were focused on implementing plans that included the completion of our cash generation plan announced in September 2002 and the sale of common stock, debt securities and certain assets to provide adequate liquidity in 2003 and beyond.

In April, we announced that our strategy for the future was to return to basics and to focus on our regulated utility operations in the high-growth Florida markets and to minimize the risks from the merchant power plants. Our results in 2003 reflect the significant changes made in our strategic direction with respect to our merchant operations.

Driven by the poor financial performance of the Union and Gila River power plants, the diminished prospects for power price improvement in the near term, and increased rating agency concerns regarding our exposure to the merchant energy sector, in October, we announced that we would invest little, if any, additional cash in the merchant generation portfolio. Following this announcement we entered into negotiations with the Union and Gila River lending bank group. These negotiations resulted in a non-binding letter of intent containing a binding settlement agreement in February 2004 to transfer ownership to the lenders through a purchase and sale, or other, agreement. The letter of intent is described in the **TECO Wholesale Generation** company discussion.

Results Summary

Our financial results for 2003 reflect the write-offs associated with our decision to exit from our ownership of the two large merchant plants, which are included as discontinued operations, and losses incurred at the merchant plants. The net loss in 2003 was $909.4 million, primarily due to $1,084.1 million of charges detailed in the following table. These losses were partially offset by gains from the sale of Hardee Power Partners and the second installment on the sale of TECO Coalbed Methane. The net loss from continuing operations was $14.7 million, compared with net income from continuing operations of $277.2 million in 2002. Non-GAAP net income from continuing operations excluding the effects of Hardee Power Partners (HPP) and charges was $164.8 million in 2003, compared with $305.8 million in 2002. Results in 2003 from discontinued operations reflect the results from the Union and Gila River power stations and the associated charges; the results at the coalbed methane business, which was sold in December 2002; the results of Prior Energy, which was in the process of being sold at Dec. 31, 2003 and closed in February 2004 and the results of TECO Gas Services, whose gas marketing book of business was sold in the third quarter of 2003.

Results from continuing operations were lower primarily due to charges associated with rationalizing our remaining merchant portfolio, restructuring charges associated with a corporate restructuring and staffing reductions, valuation adjustments at the energy services companies and limitations on the use of tax credits. (See the table **2003 Non-operating Items Affecting Net Income.**) Results from continuing operations excluding charges were lower due to higher depreciation expense at Tampa Electric, as a result of a regulatory decision related to the timing of the shutdown of the Gannon Station and higher interest expense associated with the debt incurred to fund Tampa Electric's Bayside repowering project, continued weak results at TECO Transport due to lower coal tonnage for Tampa Electric due to the Bayside repowering to natural gas and continued weakness in the river business; higher interest expense associated with the debt incurred to fund the construction of the TWG power projects; lower results from TWG's Frontera Station in Texas due to power prices in that market; and the elimination of interest and support income from

Panda Energy related to the TIE projects. These results were partially offset by the gain on the sale of HPP and higher operating results at TECO Coal from increased synthetic fuel production and sales and the sale of the 49.5% interest in the synthetic fuel production facilities.

The net loss on a per-share basis was $5.05 in 2003, compared with earnings of $2.15 per share in 2002. The loss from continuing operations on a per-share basis was $0.08 in 2003, including charges and gains totaling $1.00 per share detailed below, compared with earnings per share from continuing operations of $1.81 per share in 2002, including charges totaling $0.18 per share. The number of average shares outstanding at Dec. 31, 2003 was more than 17 percent higher than at Dec. 31, 2002.

In 2002, net income was $330.1 million. Net income from continuing operations was $277.2 million, compared with $265.5 million in 2001. The 2002 results reflect continued customer growth and increased energy usage in the Florida utility operations, higher allowance for funds used during construction (AFUDC – a 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, the results at TWG, and increased synthetic fuel production and sales at TECO Coal. These improvements were partially offset by lower results at TECO Transport. Revenues in 2002 increased 7 percent to $2.7 billion.

Included in the 2002 results from continuing operations were a $20.9 million after-tax charge related to a debt refinancing, a $10.9 million after-tax charge associated with an employee staffing reduction program at Tampa Electric and others, and a $5.8 million after-tax asset valuation charge related to the sale of TWG's minority interest in power generating facilities in the Czech Republic.

In 2002, earnings per share from continuing operations were $1.81 per share, compared with $1.98 per share in 2001. The number of average shares outstanding at Dec. 31, 2002 was almost 14 percent higher than at Dec. 31, 2001. Total non-GAAP net income and earnings per share in 2002, excluding the restructuring, debt refinancing and asset valuation charges, the impact of HPP operations and the $7.7 million gain on the sale of TECO Coalbed Methane, were $305.8 million and $1.99 per share, respectively.

Our 2003 results reflect the gain on the sale of HPP and the 2003 net income from HPP's operations through the date of sale in continuing operations. The gain on the sale and the operations were originally reported in discontinued operations for the quarter ended Sept. 30, 2003. A re-evaluation of the accounting originally applied to the sale, by us and our independent auditors caused us to reclassify the results from HPP to continuing operations and record the gain on the sale in the fourth quarter. This change did not impact our overall results for 2003. See **Note 24** to the **Consolidated Financial Statements** for a comparison of revised results to previously reported results.

2003 Earnings Summary

(millions)	*2003*	*2002*	*2001*
Consolidated revenues	**$2,740.0**	$2,664.9	$2,483.3
Earnings (loss) per share – basic			
Earnings per share	**$ (5.05)**	$ 2.15	$ 2.26
Less: Discontinued operations	**(4.95)**	0.34	0.28
Cumulative effect of change in accounting principle	**(0.02)**	–	–
Earnings from continuing operations before cumulative effect of change in accounting principle	**$ (0.08)**	$ 1.81	$ 1.98
Less: Charges and gains from continuing operations	**(1.00)**	(0.18)	–
Earnings per share from continuing operations before charges and gains	**$ 0.92**	$ 1.99	$ 1.98
Earnings (loss) per share – diluted			
Earnings per share	**$ (5.05)**	$ 2.15	$ 2.24
Less: Discontinued operations	**(4.95)**	0.34	0.28
Cumulative effect of change in accounting principle	**(0.02)**	–	–
Earnings from continuing operations before cumulative effect of change in accounting principle	**$ (0.08)**	$ 1.81	$ 1.96
Less: Charges and gains from continuing operations	**(1.00)**	(0.18)	–
Earnings per share from continuing operations before charges and gains	**$ 0.92**	$ 1.99	$ 1.96
Net income (loss)	**$ (909.4)**	$ 330.1	$ 303.7
Less: Net income (loss) from discontinued operations	**(890.4)**	52.9	38.2
Cumulative effect of change in accounting principle	**(4.3)**	–	–
Charges and gains from continuing operations	**(179.5)**	(28.6)	9.0
Net income from continuing operations before charges and gains	**$ 164.8**	$ 305.8	$ 256.5
Average common shares outstanding			
Basic	**179.9**(3)	153.2(2)	134.5(1)
Diluted	**179.9**(3)	153.3(2)	135.4(1)

(1) Average shares outstanding for 2001 reflects the issuance of 8.625 million shares in March 2001 and 3.5 million shares in October 2001.
(2) Average shares outstanding for 2002 reflects the issuance of 15.525 million shares in June 2002 and 19.385 million shares in October 2002.
(3) Average shares outstanding for 2003 reflects the issuance of 11 million shares in September 2003.

2003 Non-operating Items Affecting Net Income

Net income impact (millions)	*Tampa Electric*	*TWG*	*Peoples Gas*	*TECO Transport*	*TECO Coal*	*Coalbed Methane*	*Other Unregulated*	*TECO Energy*	*Total*
Merchant power valuation (1)	$ –	$ 762.0	$ –	$ –	$ –	$ –	$ –	$ –	$ 762.0
Turbine valuations	48.9	–	–	–	–	–	28.5	–	77.4
Goodwill impairment	–	61.2	–	–	–	–	12.8	–	74.0
Loss on joint venture termination (1)	–	94.7	–	–	–	–	–	–	94.7
TMDP arbitration reserve	–	26.7	–	–	–	–	–	–	26.7
Restructuring costs	6.1	0.3	2.6	1.0	–	–	3.6	1.6	15.2
Project cancellation costs	–	–	–	–	–	–	9.0	–	9.0
Valuation adjustment	–	–	–	–	–	–	11.1	–	11.1
Tax credit reversals	–	–	–	–	7.0	–	2.7	–	9.7
Change in accounting	–	–	–	0.8	0.3	–	–	3.2	4.3
Total Charges	$ 55.0	$ 944.9	$ 2.6	$ 1.8	$ 7.3	$ –	$ 67.7	$ 4.8	$1,084.1
Gain on Asset sales	$ –	$ –	$ –	$ 3.5	$ –	$ 23.5 (1)	$ 35.2	$ –	$ 62.2

(1) Included in discontinued operations.

The table below reconciles GAAP net income to non-GAAP net income after elimination of Hardee Power Partners and the charges referred to above that are not expected to recur. Management believes that this non-GAAP presentation provides useful supplemental information by providing a measure that is more closely related to the company's ongoing operations.

Net Income Reconciliation

(millions)	*2003*	*2002*	*2001*
GAAP net income (loss)	**$ (909.4)**	$ 330.1	$ 303.7
Add change in accounting	**4.3**	–	–
Exclude discontinued operations	**(890.4)**	52.9	38.2
GAAP net income (loss) from continuing operations	**$ (14.7)**	$ 277.2	$ 265.5
Add: Tax credit reversals	**9.7**	–	–
Project cancellation costs	**9.0**	–	–
TECO Solutions valuation adjustment	**7.9**	–	–
Hamakua FIN 46 accounting valuation adjustment	**3.2**	–	–
Restructuring costs	**15.2**	10.9	–
TMDP arbitration reserve	**26.7**	–	–
Debt extinguishment costs	**–**	20.9	–
ECKG valuation adjustment	**–**	5.8	–
Goodwill impairments	**74.0**	–	–
Turbine valuations	**77.4**	–	–
Subtract: Hardee gain on sale	**(34.6)**	–	–
Hardee operating results	**(9.0)**	(9.0)	(9.0)
Non-GAAP net income from continuing operations (1)(2)	**$ 164.8**	$ 305.8	$ 256.5

(1) Excludes adoption of FAS 143, FAS 142 adjustments and items noted in table above.
(2) A non-GAAP financial measure is a numerical measure of historical or future financial performance, financial position or cash flow that includes that amounts, or is subject to adjustments that have the effect of including amounts, that are excluded from the most directly comparable measure GAAP so calculated and presented.

Strategy and Outlook

In late 1999, TECO Energy announced a three-pronged business strategy which was to focus on its Florida operations, which included Tampa Electric, Peoples Gas System (PGS) and the Florida energy services businesses, TECO Solutions; to expand its domestic independent power operations at TWG; and to use the returns of its family of other profitable unregulated businesses to support growth. Since that time, the company undertook a number of initiatives to advance the announced strategy. These initiatives included 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 on investments from the other unregulated businesses.

However, conditions in energy markets and the independent power business have changed since the announcement of this strategy, which have dramatically changed the prospects for the investments in the domestic independent power generation facilities. Starting in 2001, future wholesale power prices declined significantly in markets across the country driven by high profile events such as the failure of deregulation in California and the Enron bankruptcy combined with a general slowing of wholesale electric competition; less than full economic dispatch in some areas of the country; the U.S. economic slowdown; and the large amount of new generating capacity that came online in 2002 and 2003 that contributed to significant excess generating capacity in many areas of the country. While wholesale power prices improved in a few markets in 2003, in general they remained weak and the prospects for long-term price recovery remained uncertain for the next several years in markets where we had made major investments. In addition to the impacts of lower prices, potential buyers of firm power under long-term contracts have been unwilling to enter into such longer-term contracts for a variety of reasons, including the current excess capacity in many areas. The low power prices and lack of long-term contracts have caused weaker earnings and cash flow expectations from merchant power projects and caused us, and other developers, to cancel or delay projects in some markets.

In April 2003, we announced that we were ceasing any new development activities in the independent power business, and that we were changing our strategy to refocus on the regulated utility operations. At the time of the decision to expand the independent power operations, our announced strategy was to construct facilities and sign contracts for the majority of the output and have only a small percentage of the output in the spot, or merchant market. This is not consistent with the current wholesale power market model, where most transactions are short term agreements and spot sales. The weakened wholesale power markets and the changing market dynamics resulted in a change in our strategy.

Following the completion of the large Union and Gila River power stations, in the face of weak conditions in the merchant energy markets, in October 2003, we announced that we would invest little, if any, additional cash in the existing merchant generating plants. Following a thorough review of the outlook for the non-recourse project-financed Union and Gila River power plants, and assessment of our ability to continue to support the plants, we determined to cease providing equity funding to the projects, and to sell our ownership interest in these projects to the lending banks or others.

With the reduction of business risk and elimination of the associated losses expected from these plants over the next several years, we will be positioned to focus on our electric and gas utilities, which operate in one of the best energy markets in the country, the high-growth Florida market. In addition, we will have the earnings and cash flow from our long-term profitable unregulated coal and transportation businesses and those wholesale power generating plants with contracts.

Over the last two years, we have taken significant steps, including asset sales, dividend reduction and capital markets transactions to meet our cash and liquidity needs associated with our large construction program. As discussed in the **Liquidity and Capital Resource** section, we have made significant progress in improving our liquidity position over the past few years and look forward in 2004 to having to meet our needs for significantly lower levels of capital expenditures which should result in positive cash flow. Accordingly, the strong cash-producing assets previously considered for potential sale, TECO Transport and the Guatemalan assets, are not being offered for sale. It is possible, however, that unforeseen cash shortfalls or increased capital spending requirements could cause us to revisit our liquidity plans. (See the **Investment Considerations** section.)

Without the losses from the large merchant power projects we expect improved financial results primarily from our regulated businesses, Tampa Electric and PGS. Our major capital expenditure program is complete, and capital expenditures are expected to be at maintenance levels for the next several years. We have no significant corporate debt maturities due until 2007. We expect to use free cash flow generated in the 2004 through 2006 period to reduce the levels of debt outstanding and therefore the refinancing needs in 2007. We continue to take steps as necessary to position ourselves for a return to a stronger financial position and a return to earnings growth in the future.

Operating Results

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

TECO Energy's reported operating results are affected by a number of critical accounting estimates such as those involved in our accounting for regulated activities, asset impairment testing, 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 (as we have redefined them). (See **Note 19** to the **Consolidated Financial Statements**.)

(millions) Except per share amounts		*2003*	*2002*	*2001*
Unconsolidated Revenues (1)				
Regulated Companies	Tampa Electric	**$ 1,586.1**	$ 1,583.2	$ 1,412.7
	Peoples Gas System	**408.4**	318.1	352.9
Total Regulated		**$ 1,994.5**	$ 1,901.3	$ 1,765.6
Unregulated Companies	TWG	**$ 95.9**	$ 111.1	$ 81.8
	TECO Transport	**260.6**	254.6	274.9
	TECO Coal	**296.3**	317.1	303.5
	Other unregulated businesses	**263.5**	297.7	298.8
Total Unregulated		**$ 916.3**	$ 980.5	$ 959.0
Net Income (2)				
Regulated Companies	Tampa Electric	**$ 98.9**	$ 171.8	$ 154.0
	Peoples Gas System	**24.5**	24.2	23.1
Total Regulated		**$ 123.4**	$ 196.0	$ 177.1
Unregulated Companies	TWG	**$ (147.6)**	$ (7.9)	0.5
	TECO Transport	**15.3**	21.0	27.6
	TECO Coal	**77.1**	76.4	59.0
	Other unregulated businesses	**(5.4)**	27.8	22.1
Total Unregulated		**(60.6)**	117.3	109.2
Financing/Other		**(77.5)**	(36.1)	(20.8)
Net income (loss) from continuing operations		**(14.7)**	277.2	265.5
Discontinued operations		**(890.4)**	52.9	38.2
Net income (loss) before cumulative effect of change in accounting principle		**(905.1)**	330.1	303.7
Cumulative effect of a change in accounting principle		**(4.3)**	–	–
Net income		**$ (909.4)**	$ 330.1	$ 303.7
Earnings per Share - Basic (2)				
Regulated Companies	Tampa Electric	**$ 0.55**	$ 1.12	$ 1.15
	Peoples Gas System	**0.14**	0.16	0.17
Total Regulated		**0.69**	$ 1.28	$ 1.32
Unregulated Companies	TWG	**$ (0.82)**	$ (0.05)	$ 0.00
	TECO Transport	**0.08**	0.14	0.20
	TECO Coal	**0.43**	0.50	0.44
	Other unregulated businesses	**(0.03)**	0.18	0.17
Total Unregulated		**(0.34)**	0.77	0.81
Financing/Other		**(0.43)**	(0.24)	(.15)
Earnings (loss) per share from continuing operations		**(0.08)**	1.81	1.98
Discontinued operations		**(4.95)**	0.34	0.28
Earnings (loss) per share before cumulative effect of change in accounting principle		**(5.03)**	2.15	2.26
Cumulative effect of a change in accounting principle		**(0.02)**	–	–
EPS Total		**$ (5.05)**	$ 2.15	$ 2.26

(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, Hardee Power Partners, Prior Energy and TECO Gas Services results to discontinued operations, and the reclassification of earnings from equity investments from Revenues to Other Income.

(2) Segment net income is reported on a basis that includes internally allocated financing costs. Internally allocated finance costs for 2003, 2002 and 2001 were at pre-tax rates of 8%, 7%, and 7%, respectively, based on the average investment in each subsidiary.

Tampa Electric - Electric Operations Results

Tampa Electric's net income decreased 42 percent in 2003 to $98.9 million, reflecting a $48.9 million after-tax write-off associated with combustion turbine purchase cancellations, accelerated depreciation related to Gannon Station coal fired assets of $15.6 million after tax, a $5.1 million after-tax disallowance by the Florida Public Service Commission (FPSC) in the November 2003 fuel adjustment hearings for operations and maintenance expenses for the Gannon Station (see the **Regulation** section), lower AFUDC equity, a $6.1 million after-tax restructuring charge associated with a staffing reduction program and higher interest expense. Tampa Electric's net income before the restructuring and turbine cancellation charges was $153.9 million. The expense items previously noted and lower sales to other utilities and decreased sales to phosphate customers more than offset continued good residential and commercial customer growth, lower operations and maintenance expenses and more favorable summer weather. The equity component of AFUDC, primarily from the Gannon to Bayside Units 1 and 2 repowering project, decreased to $19.8 million, compared to $24.9 million in 2002.

Tampa Electric's net income increased almost 12 percent in 2002, reflecting good customer growth, slightly higher residential and commercial per-customer energy usage, and a favorable customer mix, lower interest expense and higher AFUDC equity, primarily from the Gannon to Bayside Units 1 and 2 repowering project, partially offset by higher operations, maintenance and depreciation expenses. AFUDC equity increased to $24.9 million, compared with $6.6 million in 2001. Net income increased in 2002 while operating income decreased, due to higher AFUDC and lower interest expense which affect net income but not operating income.

Summary of Operating Results – Tampa Electric

(millions)	*2003*	*Change*	*2002*	*Change*	*2001*
Revenues	**$1,586.1**	0.2%	$1,583.2	12.1%	$1,412.7
Other operating expenses	**202.8**	-4.5%	212.3	11.3%	190.7
Maintenance	**90.8**	-16.4%	108.7	9.2%	99.5
Depreciation	**210.3**	10.8%	189.8	9.5%	173.4
Taxes, other than income	**112.6**	0.3%	112.3	7.2%	104.8
Non-fuel operating expenses	**616.5**	-1.1%	623.1	9.6%	568.4
Fuel	**443.3**	4.5%	424.1	22.4%	346.5
Purchased power	**234.9**	-7.4%	253.7	21.0%	209.7
Total fuel expense	**678.2**	0.1%	677.8	21.9%	556.2
Turbine valuation adjustment	**79.6**	–	–	–	–
Total operating expenses	**$1,374.3**	5.6%	$1,300.9	15.7%	$1,124.6
Operating income	**$ 211.8**	-25.0%	$ 282.3	-2.0%	$ 288.1
Net income	**$ 98.9**	-42.4%	$ 171.8	11.6%	$ 154.0
Turbine cancellation charges after tax	**48.9**	–	–	–	–
Restructuring charges after tax	**6.1**	–	10.3	–	–
Net income before charges	**$ 153.9**	-15.5%	$ 182.1	18.2%	$ 154.0

Tampa Electric Operating Revenues

Retail megawatt hour sales rose 1.8 percent in 2003, primarily from increased residential and commercial sales from customer growth and higher per-customer usage among residential customers. Electricity sales to the lower-margin industrial customers in the phosphate industry decreased 7.4 percent in 2003 after an 18.2 percent increase in 2002. Low prices for phosphate fertilizers and high raw material costs contributed to temporary closures of phosphate production facilities during the year. Domestic phosphate consumption is expected to remain relatively stable for the next several years with increased demand from China driving the export market. The company's phosphate customers have indicated that prices have improved from the low levels experienced in 2003, but production may vary to maintain stable prices in 2004. Base revenues from phosphate sales represented slightly less than 3 percent of base revenues in 2003 and 2002. Non-phosphate industrial sales increased in 2003 and 2002, primarily reflecting continued economic growth in the area.

Base rates for all customers were unchanged in 2003. Fuel-related revenues increased in 2003 under the FPSC approved fuel adjustment clause due to the recovery of a previous under recovery of fuel expense in 2002 and higher natural gas prices starting in late 2002 and continuing in 2003. Rates under the fuel adjustment clause will increase in 2004 under the rates approved by the FPSC in November 2003 to reflect the increased use and higher cost of natural gas with the completion of the Bayside Power Station repowering to natural gas.

Sales to other utilities for resale declined in 2003, primarily as a result of lower coal-fired generating unit availability due to the shut down of the Gannon Station coal fired generation in preparation of the conversion to natural gas, and the scheduled Jan. 1, 2003 expiration of the Big Bend Station power sales agreement with Hardee Power Partners. Energy sales to other utilities are expected to remain stable in 2004, due to incremental generation being gas fired, which is at a higher cost due to gas prices.

Based on projected growth from continued population increases and business expansion, Tampa Electric expects average retail energy sales growth of more than 2.5 percent annually over the next five years, with combined energy sales growth in the residential and commercial sectors of 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, normal weather and a continuation of the current energy market structure. (See the **Investment Considerations** section.)

The economy in Tampa Electric's service area continued to grow in 2003, 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 2003, in spite of the continued U.S. economic slowdown in the first half of the year. The local Tampa area unemployment rate peaked in January 2003 at 4.9 percent before falling to 3.7 percent in December 2003, (compared with 4.3 percent in December 2002), and 4.7 percent for the State of Florida and 5.7 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. Studies by local economic development agencies have shown that the Tampa Bay region has been one of the last regions in Florida to enter a recession and one of the first to recover from an economic slowdown.

Megawatt-Hour Sales

(thousands)	*2003*	*Change*	*2002*	*Change*	*2001*
Residential	**8,265**	2.7%	8,046	6.0%	7,594
Commercial	**5,860**	0.5%	5,832	2.6%	5,685
Industrial	**2,579**	-1.2%	2,612	12.2%	2,329
Other	**1,538**	7.2%	1,435	4.9%	1,368
Total retail	**18,242**	1.8%	17,925	5.6%	16,976
Sales for resale	**691**	-36.2%	1,084	-27.7%	1,499
Total energy sold	**18,933**	-0.4%	19,009	2.9%	18,475
Retail customers (average)	**604.9**	2.5%	590.2	2.5%	575.8

Tampa Electric Operating Expenses

Total operating expenses, excluding the $79.6 million pre-tax charge for combustion turbine purchase cancellations, were almost unchanged in 2003 as lower non-fuel operations and maintenance expenses for power generation plants and lower purchased power expenses virtually offset higher fuel costs from increased use of higher cost natural gas; higher depreciation from normal plant additions and accelerated depreciation on the Gannon coal assets, which ceased operations in 2003, and increased employee benefits costs. 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 operating expenses due to higher employee benefit costs and costs associated with a staffing reduction program which resulted in 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.

Non-fuel operations and maintenance expenses are expected to decrease in 2004 as a result of workforce reductions in 2003 and 2002 and the operation of Bayside Power Station, which has lower manpower and maintenance requirements.

Depreciation expense is projected to decrease in 2004 due to the end of the accelerated depreciation on the now retired Gannon Station coal-fired assets, partially offset by normal plant additions and the completion of the Bayside repowering project where commercial service began on the first phase in April 2003 and the second phase on Jan. 15, 2004. (See the **Environmental Compliance** section.) Accelerated depreciation on the Gannon Station coal fired assets was $25 million pre-tax in 2003.

Fuel costs increased 4.5 percent in 2003, primarily due to increased use of natural gas at the first phase of the Bayside Power Station and across the board increases for fuel costs that ranged from 5 percent per million BTU for coal to 10 percent for natural gas. 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. Coal prices have varied from year to year from a 5 percent increase in 2003, a 6 percent decrease in 2002 and a 7 percent increase in 2001 due to supply and demand and the prices of other fuels.

Purchased power decreased in 2003, primarily due to the operations of the first phase of the Bayside Power Station in time for summer peak loads. 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. Purchased power is expected to decline significantly in 2004, due to the operation of the newly repowered Bayside Station.

Prior to 2003, nearly all of Tampa Electric's own generation was produced from coal. Starting in April 2003, the mix started to shift with increased use of natural gas at the Bayside Station. Coal is expected to be more than half of the fuel in the Tampa Electric mix due to the base-load units at Big Bend and the coal gasification unit, Polk Unit One. Natural gas use is expected to increase again in 2004 with the commercial operation of the second phase of the Bayside Station on Jan. 15, 2004. (See the **Environmental Compliance** section.) On a total energy supply basis, company generation accounted for 81 percent, 83 percent and 84 percent of the total system energy requirements in 2003, 2002 and 2001, respectively.

Peoples Gas System Operations Results

PGS is the largest investor-owned gas distribution utility in Florida. It serves almost 292,000 customers in all of the major metropolitan areas of Florida.

Net income increased in 2003 from customer growth of 5.2 percent and a $12 million base revenue increase effective in January 2003, which more than offset the impact of milder than normal late winter weather, the effects of higher natural gas prices and higher operations expenses.

Gas prices rose significantly in the second half of 2002 and again in 2003 and have remained high compared to 2001 levels. The higher cost of gas has had a negative impact on sales to larger interruptible and power generation customers, especially in the second half of 2003. Many of these customers have the ability to switch to alternative fuels or to alter consumption patterns. Initially the gas price increases in 2003 did not cause significant fuel switching as the differential between natural gas and other fuels remained relatively constant; however, the persistent high natural gas prices and the forecast for continued high prices caused fuel switching to increase in the second half of 2003.

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.

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 – Peoples Gas System

(millions)		*2003*	*Change*	*2002*	*Change*	*2001*
Revenues		**$ 408.4**	28.4%	$ 318.1	-9.9%	$ 352.9
Cost of gas sold		**224.0**	50.3%	149.0	-20.1%	186.4
Operating expenses		**130.0**	12.5%	115.6	.2%	115.4
Operating income		**$ 54.4**	1.7%	$ 53.5	4.7%	$ 51.1
Net Income		**$ 24.5**	1.2%	$ 24.2	4.8%	$ 23.1
Restructuring charges		**$ 2.6**	—	$ 0.0	—	$ 0.0
Net income before charges		**$ 27.1**	12.0%	$ 24.2	4.8%	$ 23.1
Therms sold - by customer segment	Residential	**64.2**	6.6%	60.2	2.4%	58.8
	Commercial	**354.8**	8.3%	327.6	6.0%	308.9
	Industrial	**406.3**	-4.1%	423.8	22.3%	346.5
	Power Generation	**363.7**	-26.2%	492.6	22.1%	403.5
Total		**1,189.0**	-8.8%	1,304.2	16.7%	1,117.7
Therms sold - by sales type	System Supply	**337.3**	1.4%	332.5	13.8%	292.2
	Transportation	**851.7**	-12.3%	971.7	17.7%	825.5
Total		**1,189.0**	-8.8%	1,304.2	16.7%	1,117.7
Customers (thousands) - average		**291.9**	5.2%	277.5	4.1%	266.6

In 2003, residential and commercial therm sales increased from customer growth of over 5 percent in 2003, and colder than normal early winter weather. Therm sales to large industrial and power generation customers decreased, primarily from significantly higher gas prices.

Residential therm sales increased in 2002, the result of customer growth of more than 4 percent and increased per-customer usage, more than offsetting milder-than-normal weather. 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 FPSC 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 2003, 10,500 customers had elected to take service under this program.

Operating expenses increased in 2003, driven primarily by higher employee-related costs, including restructuring costs. Operating expenses in 2002 were essentially unchanged from 2001 levels. Depreciation expense increased in both years, 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. (See the **Regulation** section.)

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 increases 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.

In 2003, PGS decreased the level of capital expenditures to expand its system into areas of Florida previously unserved by natural gas to $42 million, a level below the prior three years. PGS expansion strategy for the next several years is to take advantage of the significant capital investments in main pipeline expansions made over the past five years and connect customers to that existing infrastructure. PGS expects increases in sales volumes and corresponding revenues in 2004, and continued customer additions and related revenues from its build-out efforts throughout the state of Florida. These growth projections assume continued local economic growth, normal weather and other factors. (See the **Investment Considerations** section.)

TECO Wholesale Generation, Inc.
(Formerly TECO Power Services)

In 1999, we announced that a component of our strategy was to expand our presence in the domestic independent energy industry. (See the **Strategy and Outlook** section.) Our decision to invest in this industry was made more than three years ago, based on the outlook then for the energy markets beyond 2001. Many states were opening their markets to more competitive models, electric demand was growing with the growing economy, and we saw opportunities to earn attractive returns on our investments.

We have rethought our independent power strategy in the face of many factors. These factors include lack of support for deregulation that was originally anticipated to materialize, the existence of supply well in excess of demand, and the outlook for a continuing weak power price environment in the markets where we have built plants.

In September 2002, we announced that we had ceased all new project development at TWG. In April 2003, we announced that we would seek to increase our flexibility to be able to mitigate the risk from the merchant portfolio through a number of steps, including the termination of joint ventures with Panda Energy in the Union and Gila River power stations (TPGC) and in the Texas Independent Energy (TIE) plants. The termination of the joint venture with Panda Energy was accomplished by mid-year for the Union and Gila River projects and in the third quarter for the TIE projects .

In October 2003, we announced that we would put little if any additional cash into the merchant generation portfolio. In February 2004, we established a plan to exit from our ownership of the Union and Gila River plants that included a non-binding letter of intent with the lending banks for those projects that would allow such an exit. Completion of the plan is subject to the lender group's approval and execution of definitive agreements, which will contain customary closing conditions and require certain regulatory approvals. Definitive agreements are expected by the end of the second quarter with final closing targeted for the end of the third quarter of 2004. Until closing, TWG will continue to operate the plants consistent with previous operations and be compensated for these operations, while working with the lenders to effect a smooth transition upon change of ownership. Our decision to exit from our ownership of these projects is not dependent on reaching a final agreement with the lenders for a consensual transfer.

As part of our renewed focus on our utility operations, we have revised certain internal reporting information used for decision-making purposes. The results of TWG are now focused on the results of operations for the Frontera, Commonwealth Chesapeake, Dell and McAdams power plants, as well as the equity investment in the TIE, the Odessa and Guadalupe power plants, and TECO EnergySource, Inc. (TES), the energy marketing operation for the merchant plants. The non-merchant power assets that were formerly reported with TECO Power Services include our interest in the Hamakua Power Station in Hawaii, the Guatemalan operations (which include the San José and Alborada power stations and our interest in the Guatemalan distribution utility, EEGSA) and Hardee Power Partners, which was sold in October 2003. These are now reported with **Other Unregulated Companies**.

TWG Project Summary

	Project	Location	TWG Economic Size MW	TWG Net Interest	In Service/ Participation Size MW	Date [(1)]
Operating:	Frontera Power Station	Texas	477	100%	477	5/00, 3/01[(2)]
	Odessa and Guadalupe	Texas	2,000	50%	1,000	9/00, 8/01
	Commonwealth Chesapeake Power Station	Virginia	315	100%	315	9/00, 8/01
			2,792		1,792	
Suspended:	Dell	Arkansas	599	100%	599	
	McAdams	Mississippi	599	100%	599	
			1,198		1,198	
Held for Sale:	Union	Arkansas	2,200	100%	2,200	1/03-6/03
	Gila River	Arizona	2,145	100%	2,145	2/03-8/03
			4,345		4,345	

(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.
(2) Dates on which TWG acquired its economic interest in the project.

Merchant Generation Facilities

Continuing operations at TWG recorded a $147.6 million loss in 2003, primarily due to its portion of the $61.2 million after-tax goodwill write-offs associated with the Frontera and Commonwealth Chesapeake plants, the $26.7 million after-tax arbitration reserve associated with the ownership of the Commonwealth Chesapeake Power Station and the operating losses from the merchant generating plants. Other factors influencing results in 2003 were the loss of interest income from the TIE plants when the loan to Panda Energy converted into an equity ownership position in January 2003, and the cessation of capitalization of interest on the Dell and McAdams plants.

The loss for the merchant portfolio in 2002 (restated to reflect continuing operations) was $7.9 million, primarily from full year of ownership of the Frontera Power Station. The results included a $5.8 million after-tax charge related to the sale of TWG's 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.

Results in 2001 included earnings from the Commonwealth Chesapeake and Frontera generating stations and higher returns on TWG's investment through Panda in the TIE projects, and a $6.1 million after-tax valuation reserve recognized in connection with the sale of TWG's minority interest in EGI, which owns small generating projects in Central America.

TWG's two investments, in the form of a loan to Panda, converted into an indirect ownership interest in TIE in early 2003, totaled $137 million. In September 2003, TWG completed the foreclosure on Panda's interest in TIE for a default on a $23 million note receivable which resulted in TWG becoming a 50-percent owner in the plants and a total investment of $160 million. In 2003, improved peak season power prices and a new power and gas manager retained to increase the energy sales from these plants resulted in improved financial performance; however, the plants still had a negative impact on earnings. The interest on the loans to TIE was reflected in 2002 and 2001 earnings.

In 2003, the 477 megawatt, natural gas-fired, combined-cycle Frontera Power Station, located near McAllen, Texas sold its output in the spot market in Texas. While prices in Texas improved during the peak summer months due to an outage at a large nuclear facility in south Texas, the plant had a negative impact on earnings due to power prices and increased maintenance expenses. In 2002, the Frontera plant facility sold energy and ancillary services to the Electric Reliability Council of Texas (ERCOT) under a reliability-must-run contract which contributed to higher earnings that year.

In 2003, weaker results for the 315 megawatt simple-cycle, oil-fired Commonwealth Chesapeake Power Station on the Delmarva Peninsula in Virginia were impacted by the mild and wet summer weather in that area of the nation, which reduced peak summer load. 2003's results also included its portion of a $61.2 million after-tax goodwill write off required under FAS 142, *Goodwill and Other Intangible Assets,* and a $26.7 million after-tax reserve for an arbitration award against TMDP, the indirect owner of this plant. This plant is a peaking plant that is designed to operate primarily in the summer and sell in the PJM market. The plant's location on the Delmarva Peninsula gives it a location advantage due to few competing generating resources in the area and transmission system constraints on the peninsula. In addition to electric energy, the plant sells ancillary services such as spinning reserve and capacity in the PJM market.

TWG owns two 599-megawatt, natural gas-fired, combined-cycle projects, Dell and McAdams, located in Arkansas and Mississippi, respectively. Construction on these projects was suspended at the end of 2002 due to projected low energy prices in the markets that these plants were expected to serve. The carrying costs, primarily due to the cessation of interest capitalization, associated with these suspended plants reduced TWG 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 estimated that the total construction cost to complete these projects would be approximately $100 million.

Energy Markets

TWG's operating merchant power plants are located in markets with a history of high load growth. However, the general U. S. economic slowdown over the past several years slowed the growth in demand for power in some of these markets. In addition, the slowdown of electricity deregulation initiatives across the United States, including the markets that TWG serves, caused in part by the failure of deregulation in California and other events, has allowed the traditional, incumbent utilities to continue to operate older, less efficient generating facilities in lieu of purchasing power from newer, more efficient independent power plants. These factors have combined with aggressive plans by the independent power industry to add merchant power facilities to cause excess generating capacity that is either being built or has come on line in many markets. This excess supply has depressed both spot and forward wholesale power prices.

Studies by numerous outside groups, such as Cambridge Energy Research Associates, Standard & Poor's and others, present conflicting outlooks on power price improvement , but most experts indicate that while spot power prices stabilized in some markets in 2003, power prices are expected to remain low well beyond 2004.

TWG has been unable to secure long-term contracts for the output of these plants; therefore, their production has been sold under a mix of spot market sales and shorter-term transactions in 2003 and 2002. TECO Energy's policy is to balance power contract commitments with necessary purchases of natural gas in order to know the margins for such sales at the time of commitment. These sales usually do not include the value for capacity payments, ancillary services, dispatchability and the premium associated with owning physical assets. These incremental value components are often captured in the spot market at the time of physical sales or through more structured transactions.

In 2001, TECO EnergySource (TES) began entering into power marketing and fuel procurement transactions. TES is actively seeking both short- and long-term contracts with purchasers for the output from the Frontera Power Station. Our current below investment grade credit rating limits TES' ability to hedge significant amounts of forward sales without posting collateral, which it is not doing.

The merchant operations normally balance their fixed-price physical and financial fuel purchase and energy sales contracts in terms of contract volumes and the timing of performance and delivery obligations. Net open positions may exist for short periods due to the origination of new transactions. When net open positions exist, the merchant operations will be exposed to fluctuating market prices. All fuel purchase and energy sales contracts and open positions are monitored closely by the TECO Energy risk management function, which is independent of the merchant operations.

In addition to price risk, credit risk is inherent in TWG's energy risk management activities. The marketing business may be exposed to counterparty credit risk from a counterparty not fulfilling its obligations. Credit policies and procedures, administered by TECO Energy, attempt to limit overall credit risk. The credit procedures include a thorough review of potential counterparties' financial position, collateral requirements under certain circumstances, monitoring net exposure to each counterparty and the use of standardized agreements.

Significant factors that could influence results at TWG include energy prices in its markets, weather, domestic economic conditions and commodity price changes. (See the **Investment Considerations** section.)

Union and Gila River Power Stations

In February 2004, we announced our decision to exit from our ownership of the Union and Gila River projects and to cease further funding of these plants. We, as the equity investor, and the project companies that own the two large plants have entered into a non-binding letter of intent containing a binding settlement agreement with the lenders that provided the non-recourse project financing for these projects that contemplates negotiation of an agreement for the purchase and sale or other agreement to transfer ownership of the plants to these banks. As part of the contemplated transaction, the outstanding non-recourse project debt (owed by the project companies) would be satisfied. The decision to end the ownership of the plants and cease further funding is not, however, dependent on reaching final agreement with the lenders for a consensual transfer. Even without such an agreement, the project companies, which are currently indirect subsidiaries of TECO Energy, could pursue other disposition alternatives that would ultimately end TECO Energy's ownership of the plants.

Letter of Intent

The lending group for the Union and Gila River projects approved a non-binding letter of intent containing a binding settlement agreement on Feb. 5, 2004. Under the agreement, we and the project companies will work toward a definitive agreement with the lenders for a purchase and sale or other agreement to transfer of the ownership of the projects to the lenders in exchange for a release of all obligations under the project loan agreements. The letter of intent specifies target dates for a definitive agreement by Jun. 30, 2004 and for closing by Sep. 30, 2004. The settlement agreement provides for the treatment of the $66 million of letters of credit posted by us under the Construction Undertaking, with $35 million drawn in February 2004 for the benefit of the project companies and the remaining $31 million of letters of credit to be cancelled and returned to us. Under the letter of intent, all parties have specified a target completion of due diligence for final acceptance under the construction and undertaking contracts for both projects within 45 days from Feb. 6, 2004; however, we and the project companies will remain responsible to address certain permit issues at the Gila River project. We will make no new investment in the projects. Since the projects have achieved commercial operation on all facilities at Union and Gila River, we believe that we have met all but limited warranty and final acceptance responsibilities to the project companies. We and certain of our subsidiaries plan to continue to provide services and continue to provide expertise and operating support to help the project companies operate the facilities consistent with past practices at least through the completion of the transfer of ownership. The lenders and we and our affiliates have reserved the right to assert certain claims against one another until a definitive agreement is reached.

Expiration of Suspension / Standstill Agreement

The letter of intent permits the parties to reserve their rights against each other, including with respect to our failure to comply with the 3.0 times EBITDA-to-interest ratio coverage requirement in our Construction Undertakings for the quarters ending Sep. 30 and Dec. 31, 2003 (a cross default to the non-recourse credit agreements) that were covered by the Suspension Agreement, which has expired, and the failure of the project companies to make interest payments on the non-recourse project debt and payments under interest rate swap agreements due Dec. 31, 2003 when the project lenders declined to fund the debt service reserve.

As a result, the lending group could seek to exercise remedies against the project companies due to defaults in connection with the non-recourse project debt, including accelerating the non-recourse debt, foreclosing on the project collateral and suspending further funding; subject to the defenses we may have. While there can be no assurance that the lenders group will not exercise these rights, we believe that the lenders would prefer to effect a consensual transfer of the projects in accordance with the letter of intent.

Accounting Treatment

Based on our short-term view of these projects and the efforts to dispose of them, our consolidated financial results include, as of Dec. 31, 2003, an asset impairment of $762 million, after tax, for previous investments to reflect adjustments to the value of the subsidiaries that own the interests in the two plants. These after-tax impairment charges include the asset valuation adjustments resulting in the write off of the full equity investment in the facilities, costs related to the related accelerated impact of the change in hedge accounting for interest rate swaps and a related valuation allowance for certain state tax benefits. The Union and Gila River power stations are considered "Held for Sale" and are included in discontinued operations for income statement purposes, and the assets and liabilities are separately stated as "Held for Sale" on the balance sheet. This accounting treatment could be affected in future periods, depending on the ultimate disposition of our ownership in the plants.

TECO Transport

Net income in 2003 was $15.3 million, before a $0.8 million charge for a change in accounting principle, compared with $21 million in 2002. The decrease was primarily due to lower tonnage for Tampa Electric due to the conversion of the Gannon Station from coal to the natural gas fired Bayside Station, continued weak results from the river transportation and terminal businesses due to lower northbound shipments and a very competitive pricing environment, higher labor and repair costs, and a $1.0 million after tax restructuring charge. Results for 2003 also include a $3.5 million after-tax gain associated with the disposition of ocean-going assets no longer used by TECO Ocean Shipping and scrap river barges at TECO Barge Line.

In 2002, net income declined 24 percent from 2001. 2002 results reflected continued weakness in the U.S. economy as low levels of imported raw materials reduced northbound river shipments and drove pricing lower for all river shipments. These conditions also reduced volumes of petroleum coke and steel-related product volumes through the transfer terminal. These conditions combined to more than offset increased ocean-going phosphate shipments and lower repair and fuel costs.

Northbound river shipments of steel-related raw materials did not improve in 2003 as expected due to continued weakness in the U.S. economy and production problems for furnace coke, which is imported from China for domestic steel production. Additionally, northbound petroleum coke shipments were reduced for six months due to production problems at a major producer. Southbound river shipments of grain products increased in 2003, with much better pricing during the fall grain shipping season. The recovery of the U.S. economy is expected to increase the volumes in 2004 at the same time that consolidation in the river shipping business is expected to reduce capacity. This combination is expected to improve pricing slightly.

The phosphate fertilizer industry, an important business segment for TECO Ocean Shipping, continued its efforts to balance supply and demand to support prices in 2003. TECO Ocean Shipping expects phosphate shipments to be at 2003 levels in 2004.

TECO Transport operating companies expect to be impacted by lower shipments for Tampa Electric, but expect to replace a portion of this tonnage with increased third-party business, as well as lower operations and maintenance expenses in 2004.

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 Transport has two operating leases with an aggregate value of about $100 million as a result of sale-leaseback transactions entered into in 2001 and 2002 that provide for a cross-default in the event TECO Energy or any of its affiliates defaults in the payment of certain obligations. The failure of the Union and Gila River project companies to make payments on the non-recourse project debt, could result in a cross default entitling the lessors to terminate the leases and recover certain amounts. However, we have reached agreement in principle, subject to definitive agreements being executed, with the lessors on amendments to the leases that would eliminate this possible cross-default.

TECO Coal

In 2003, net income increased slightly to $77.1 million before a $0.3 million after-tax charge for a change in accounting principle on total coal sales of almost 9.2 million tons. These results were driven by expensing $7.0 million after tax for the loss of unutilized Section 29 tax credits, lower volumes and prices for conventional coals and higher mining costs due to the use of marginal and waste coals for the production of synthetic fuel, which were more than offset by higher volumes of synthetic fuel production and sales and the sale of a 49.5% interest in the synthetic fuel production facilities. The loss of the tax credits is due to generating tax credits in excess of the company's current regular income tax expense as the tax rules only qualify synthetic fuel tax credits up to a taxpayer's current regular income tax expense.

Synthetic fuel production and sales increased to 5.8 million tons in 2003 from 3.8 million tons and 3.2 million tons in 2002 and 2001, respectively. In April 2003, TECO Coal sold a 49.5% interest in its synthetic fuel production facilities. Under this transaction, TECO Coal is paid to provide feedstock, operate the synthetic fuel production facilities and sell the output while the purchaser has the risks and rewards of ownership including being allocated 49.5% of the tax credits and operating costs. In addition to funding the operating costs of the 49.5% share, TECO Coal recognizes a gain on the sale of the facilities for each installment sale payment. The net income for the year includes $55.8 million of gain from this sale.

Net income was $76.4 million in 2002 compared with $59.0 million in 2001. The 30% increase was driven primarily by better margins and higher synthetic fuel (synfuel) production and sales and the resulting higher Section 29 tax credits. Total coal sales, including synthetic fuel, were 9.3 million tons in 2002. Synthetic fuel production displaced some of the conventional coal production in all years.

In 2004, total coal sales and synthetic fuel production are expected to remain at about 2003 levels, with virtually all planned production sold forward under a variety of contracts of varying terms. Coal prices for 2004 have improved after declining in 2003 and 2002. Higher prices for competing fuels, better balance in supply and demand, lower producer inventories and consolidation in the mining industry are contributing to the improved prices. Late in 2003 and early 2004 spot coal prices increased sharply. TECO Coal contracts much of its coal production for the coming year in the preceding year and is less affected by the rapid price changes, both upward and downward than those companies that sell a higher percentage in the spot markets.

In January 2000, TECO Coal purchased synthetic fuel 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 synthetic fuel from coal, coal fines and waste coal using a technology licensed from Headwaters. The facilities were subsequently sited at all three of TECO Coal's complexes.

TECO Coal has received private letter rulings (PLRs) from the Internal Revenue Service regarding the qualification of synthetic fuel production from its facilities. The PLRs confirm that the facilities are located appropriately and produce a qualified fuel eligible for Section 29 tax credits which are available for the production of such non-conventional fuels through 2007.

In June 2003, the Internal Revenue Service (IRS) suspended the issuance of PLRs to taxpayers seeking certainty regarding the use of the Section 29 tax credits for the production of synthetic fuel from coal. The suspension was due to questions raised within the IRS regarding the validity of the production of a significant chemical change in the production of synthetic fuel as required under Section 29. TECO Coal's sale of the 49.5% interest of its production facilities required an updated PLR. During the suspension period, all cash paid to TECO Coal by the purchaser was held in escrow pending resolution of the PLR issue. In October 2003, the IRS concluded its review and resumed issuing PLRs. TECO Coal received a PLR from the IRS on Oct. 31, 2003 that resolved any uncertainty related to the sale, triggered the release of $70.7 million of cash held in escrow and confirmed that the synthetic fuel produced by TECO Coal is eligible for Section 29 tax credits and that its test procedures are in compliance with the requirements of the IRS.

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 synthetic fuel 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

Independent Power Project Summary

Project	*Location*	*Size MW*	*Economic Interest*	*Net Size MW*	*In Service/ Participation Date* (1)
Alborada Power Station	Guatemala	78	96%	75	9/95
Empresa Eléctrica de Guatemala S.A.(EEGSA) (a distribution utility)	Guatemala		24%		9/98 (2)
San José Power Station	Guatemala	120	100%	120	1/00
Hamakua Energy Project	Hawaii	60	50%	30	8/00, 12/00
Total non-merchant		258		225	

(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.
(2) Dates on which TWG acquired its economic interest in the project.

We now include the non-merchant independent power operations in our Other Unregulated Companies segment for financial reporting purposes. These include the San José and Alborada power stations in Guatemala, our ownership interest in EEGSA, the Guatemalan distribution utility, our 50 percent ownership of the Hamakua Power Station in Hawaii, and HPP, which was sold in October 2003. Other unregulated companies include, TECO Solutions, TECO Partners and TECO Investments.

In 2003, the other unregulated companies reported a loss of $5.4 million, which included $67.7 million of after-tax charges previously discussed partially offset by the $34.6 million after-tax gain on the sale of HPP. (See the **Earning Summary** section.) Excluding charges, gains and $9.0 million of net income from nine months of operations at HPP, net income was $18.7 million which included $24.7 million from the independent power operations and a $7.0 million loss at TECO Solutions. The loss at TECO Solutions was driven primarily by project losses. Results from the independent power operations reflect higher net income from EEGSA from increased energy sales at higher prices and favorable currency translation gains, more than offset by unfavorable tax adjustments on the Guatemalan assets and increased maintenance costs for scheduled maintenance at the San José Power Station.

Many of the other unregulated companies were formed or acquired during the early stages of Florida's proposed electric industry restructuring, as a vehicle through which we could potentially expand our services to other parts of the state. The subsequent rollback of the proposed deregulation and our refocus on our core utility operations has caused us to reexamine our continued participation in these lines of business. As a result of this reexamination, in the third quarter we sold TECO Gas Services' book of business; in November we announced the sale of our interest in TECO Propane Ventures (TPV) which closed in January 2004 (see below); in December we entered into an agreement to sell our end use gas marketing company Prior Energy and closing was completed in February 2004; and, in January 2004 we sold TECO Energy Services (formerly TECO BGA) to an employee group.

TPV held 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. In January 2004, U.S. Propane completed the sale of its direct and indirect equity investments in Heritage Propane Partners, L.P. (Heritage). The sale, part of a larger transaction that involved the merging of privately held Energy Transfer Company with Heritage, was announced in November 2003. Our portion of the sale generated $49.4 million of cash and a $17.2 million pre-tax book gain.

Liquidity, Capital Resources

At Dec. 31, 2003, we had cash and cash equivalents of $108.2 million, excluding all restricted cash, and $590.1 million of availability under our bank credit facilities, net of letters of credit of $109.9 million outstanding under these facilities. The availability under the bank credit facilities included the $250 million undrawn Tampa Electric facility; the undrawn Merrill Lynch facility; and the $350 million TECO Energy multi-year facility, undrawn except for the $110.1 million of outstanding letters of credit.

Restricted cash is comprised of $15.4 million of cash held in escrow under the sale agreement for the 49.5% interest of TECO Coal's synthetic fuel production facilities to provide credit support for the company's obligations under the sale agreement due to the company's current credit rating, and $36.0 million held in escrow from the sale of Hardee Power Partners. In February 2004, $29.0 million of the Hardee escrow amounts were returned as expected.

2003 sources of cash included cash from operations of $329 million, net cash proceeds from asset sales of $245 million, and proceeds from debt and equity sales of $792 million. Cash was used to fund $638 million of capital investing, long term debt repayments of $526 million, short term debt reduction of $323 million and common dividends of $165 million.

TECO Energy met 2002 cash needs with a mix of externally and internally generated funds. Cash from operations was $656 million, and proceeds from the sale of debt and equity were $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.

Cash from Operations

In 2003, cash flow from operations was affected by the accounting for the sale of interests in the synthetic fuel production facilities at TECO Coal, the benefits of which are recorded in financing and investing activities as described more fully below, the payment of taxes associated with asset sales in 2002 and 2003, the under recovery of fuel expense at Tampa Electric, and the impact on working capital due to the consolidation of the Union and Gila River power projects, which were previously recorded as unconsolidated joint ventures. The substantial charges for asset and goodwill impairments, loss on the Panda joint venture termination and the TWG arbitration reserve did not affect cash from operations.

In April 2003, TECO Coal sold a 49.5% interest in its synthetic fuel production facilities located at its operations in eastern

Kentucky. Cash flow from operations includes the operating losses of $9.00 - $11.00 per ton (pre-tax) associated with the production of synthetic fuel, while the cash benefits from the sale of the synthetic fuel production facilities of approximately $30 per ton (pre-tax) are included in the investing and financing activities on the Consolidated Statement of Cash Flows. Investing activity includes cash from the gain on the sale of the synthetic fuel facilities. The company expects to record a quarterly gain associated with the sale of the assets through the life of the contract. The cash paid by the owner for its portion of the operating loss from the production of synthetic fuel is included in Financing Activities as a minority interest.

TES and Prior Energy were required to post collateral to contract counterparties due to the downgrade of TECO Energy's credit rating to non-investment grade in April 2003. As of Dec. 31, 2003, collateral posted of $12 million is included in working capital as a prepaid item.

Cash from operations in 2004 will be affected by lower cash payments of income taxes and collection by Tampa Electric of the under-recovered fuel expense from 2003, offset in part by greater operating losses associated with synthetic fuel. We anticipate selling additional interests in our synthetic fuel facilities in 2004 which, as described previously, will decrease cash from operations but substantially benefit cash from investing and financing.

We have not made a contribution to our defined benefit pension plan since the 1995 plan year because investment returns had been more than sufficient to cover liability growth. Negative stock market returns in 2001 and 2002 reduced the overfunding of the plan and, based on plan asset values at Jan. 1, 2003 and 2004, it is estimated that TECO Energy will be required to make a $14.2 million contribution to its defined benefit plan in September 2004 and a cash contribution of a similar amount in 2005. (See **Note 16** to the **Consolidated Financial Statements**.)

Cash from Investing Activities

Investing activities of $393 million in 2003 included capital investments totaling $638 million, reduced by net asset sales proceeds of $245 million. Asset sales included $98 million from the second installment on the sale of our coalbed methane gas production assets, $72 million from the sale of Hardee Power Partners (net of cash escrows), and installments of $35 million (net of escrows) from the sale of the 49.5% interest in TECO Coal's synthetic fuel facilities.

Capital spending in 2003 represented the completion of a substantial capital investment program both for TWG's merchant power facilities and for Tampa Electric's Bayside Station. In 2004 and for the next several years, we expect capital spending at a "maintenance" level supporting customer growth, safety and reliability, and renewal and replacement of capital. (See **Capital Investment** section.) In January 2004 we sold TECO Propane Ventures, realizing $49.4 million of proceeds, and also received $29 million from the release of escrow in February 2004 from the Hardee sale. We also closed the sale of Prior Energy in February 2004 and received total proceeds of $30 million, including payment for the value of gas inventory.

Cash from Financing Activities

Cash proceeds from long-term debt in 2003 included a $250 million Tampa Electric note issue, a $300 million TECO Energy note issue, and draws of $111 million under the Union and Gila River non-recourse bank facilities. We raised $137 million from the sale of common stock consisting primarily of the direct placement of 11 million shares to Franklin Advisors in September 2003. Debt repayments included the $375 million equity bridge loan for the Union and Gila River power projects, Tampa Electric's $75 million mortgage bond maturity, a $25 million Transport capital lease maturity, and scheduled principal installments of PGS debt and non-recourse project debt. We also reduced short-term borrowings by $323 million in 2003, including the November repayment of a $350 million bank term loan maturity.

We have no significant corporate debt maturities until 2007. Long-term debt maturities in 2004 are $31.6 million, consisting primarily of installment payments of non-recourse project debt, but excluding the project debt of the Union and Gila River power stations. (See **Note 7** to the **Consolidated Financial Statements.**) Our $37.5 million drawn credit facility was repaid in February 2004. We do not expect to issue debt in 2004, except for the planned refinancing of the San José non-recourse project debt in Guatemala, expected to provide net cash proceeds of $40 million and a planned refinancing of $75 million of Tampa Electric First Mortgage Bonds with a 7.75% coupon.

Liquidity Outlook

In 2002 and 2003, our cash and liquidity needs were significant as we faced the funding obligations associated with large construction programs at TWG and Tampa Electric, significant debt maturities, and the liquidity requirements associated with a merchant power business strategy in a difficult power price market. We took significant steps in this time period to meet these needs, including selling assets, raising external capital, reducing capital spending by canceling or delaying for an extended period generation projects, reducing our exposure to merchant power and reducing our common dividend.

Our future liquidity needs will be lower because the major construction programs at TWG and Tampa Electric are now complete, we have no significant upcoming debt maturities, and our business risk will be reduced because of our planned exit from the large Union and Gila River power stations. Tampa Electric currently targets available liquidity (cash plus available undrawn credit lines) of $250 million and, in November, replaced its maturing bank credit facility with new facilities totaling $250 million. While TECO Energy has previously targeted available liquidity of $325 million, we expect to target available liquidity of approximately $200 million in the future, for the reasons described above. We expect that we will replace the expiring $350 million TECO Energy credit facility prior to its expiration with a smaller facility.

Bank Credit Facilities

At Dec. 31, 2003, we had a bank credit facility of $350 million with a maturity date of November 2004 and a $100 million credit facility with Merrill Lynch, and Tampa Electric had bank credit facilities totaling $250 million with maturity dates in November 2004 and November 2006, described below. All were undrawn at Dec. 31, 2003, except for outstanding letters of credit under the $350 million TECO Energy facility. In November 2002, we converted another $350 million bank credit line then in effect into a one-year term loan which was repaid on Nov. 13, 2003.

Our bank credit facility maturing November 2004 includes a $250 million sublimit for letters of credit. At Dec. 31, 2003, $109.9 million of letters of credit were outstanding against that line, of which $66 million related to the construction of the Union and Gila River power stations. These letters of credit represented the remaining amounts of letters of credit posted in May 2003 under the Construction Undertaking posting requirements upon our downgrade to non-investment grade in April 2003. In February 2004, by agreement of the parties, $35 million of these letters of credit were drawn by the lending banks, and the remaining $31 million were cancelled and returned to us. (See the **Covenants in Financing Agreements** section.) In addition, at Dec. 31, 2003, we and our subsidiaries had $0.2 million of letters of credit outside of our bank credit line facility outstanding, and the Union and Gila River project companies had $144.2 million outstanding under the letter of credit facilities included in their non-recourse bank financing.

At TECO Energy, we have not had access to the commercial paper market since the September 2002 downgrade by Standard & Poor's Ratings Service (S&P) of our commercial paper program to A-3. Tampa Electric continued to have access to the commercial paper market until the S&P downgrade in June 2003 of its commercial paper program to A-3. The lack of access to the commercial paper market has caused us to utilize bank credit facilities for short-term borrowing needs.

In April 2003, we entered into a $350 million unsecured credit facility with Merrill Lynch for a term of up to eighteen months. The facility contained certain financial covenants described in the **Covenants in Financing Agreements** Section. In November 2003, we amended this credit facility to allow $100 million of credit capacity to remain in place subsequent to the repayment of the $350 million bank term maturity on Nov. 13, 2003. Under the terms of the original agreement, the facility would have been extinguished upon that repayment. The amendment made the $100 million commitment of undrawn line capacity available through April 8, 2004, at which time the facility can be drawn up to $100 million and remain outstanding to Oct. 8, 2004. The $100 million facility is required to be reduced for certain asset sales and financings. As a result of cash proceeds from asset sales in early 2004, this facility has been reduced to $20.6 million.

On Dec. 19, 2003, TECO Energy and Merrill Lynch further amended the existing credit facility to put in place with Merrill and JP Morgan a contingent credit facility of $200 million. The contingent facility will become effective only if our existing $350 million bank credit facility becomes unavailable because of non-compliance with the 65% debt-to-total-capital covenant or transfer of assets covenant as a result of write-offs or disposition of TWG assets. Upon the occurrence of these certain events, we would pledge the common stock of TECO Transport Corporation as security under the amended credit facility and the commitment available under the facility would be increased to $200 million, all of which would be available for letters of credit or cash draws. If the terms of the facility change as a result of these certain events, the amended facility would mature in December 2004. The contingent facility, if activated, would replace the existing Merrill Lynch facility. See the **Covenants in Financing Agreements** section for a summary of our performance against significant financial covenant requirements.

In June 2003, we entered into a one-year $37.5 million credit facility with four banks, collateralized by 50 percent of the interests in Union and Gila River projects. The proceeds from the credit facility were used in the termination of the joint venture agreement with Panda Energy. The facility was paid in full in February, 2004.

On Nov. 7, 2003, Tampa Electric Company replaced its maturing $300 million credit facility with a $125 million one-year credit facility and a $125 million three-year credit facility maturing in November 2004 and November 2006, respectively. In addition to the financial covenants described in the **Covenants in Financing Agreements** section, the two new facilities include a covenant limiting cumulative distributions after Oct. 31, 2003 and outstanding loans to its parent to an amount representing an accumulation of net income after May 31, 2003 and capital contributions from the parent after Oct. 31, 2003, plus $450 million.

The Tampa Electric bank credit facilities require commitment fees of 20 - 25 basis points, and drawn amounts are charged interest at LIBOR plus 100 - 117.5 basis points at current credit ratings. TECO Energy's $350 million three-year credit facility requires commitment fees of 25 basis points, and drawn amounts incur interest expense at LIBOR plus 55 – 75 basis points at current ratings. The Merrill Lynch credit facility requires commitment fees of 50 basis points and drawn amounts incur interest at LIBOR plus a borrowing spread derived from the borrowing spread of our 7.2% Notes due in 2011.

We expect that the replacement TECO Energy credit facility will be at a higher cost reflecting our current credit ratings, that it will contain restrictive covenants and that it may require security.

Covenants in Financing Agreements

In order to utilize their respective bank credit facilities, TECO Energy and Tampa Electric must meet certain financial tests as defined in the applicable agreements. In addition, TECO Energy, Tampa Electric and other operating companies have certain restrictive covenants in specific agreements and debt issuances. The table below lists the covenants and the performance relative to them at Dec. 31, 2003.

TECO Energy Significant Financial Covenants

(millions, unless otherwise indicated)

Instrument	*Financial Covenant* [1]	*Requirement/Restriction*	*Calculation at Dec. 31, 2003*
Tampa Electric			
Mortgage bond indenture	Dividend restriction	Cumulative distributions cannot exceed cumulative net income plus $4	$5 unrestricted [2]
PGS senior notes	EBIT/interest [3]	Minimum of 2.0 times	3.5 times
	Restricted payments	Shareholder equity at least $500	$1,652
	Funded debt/capital	Cannot exceed 65%	50.5%
	Sale of assets	Less than 20% of total assets	–%
Credit facility	Debt/capital	Cannot exceed 60%	49.2%
	EBITDA/interest [3]	Minimum of 2.5 times	5.8 times
	Restriction on distributions	Limit on cumulative distributions and outstanding affiliate loans [4]	$483 unrestricted
6.25% senior notes	Debt/capital	Cannot exceed 60%	49.2%
	Limit on liens	Cannot exceed $787	$362
TECO Energy			
Credit facilities [5]	Debt/capital	Cannot exceed 65%	61.9%
$37.5 credit facility [6]	EBITDA/interest [3]	Minimum of 2.5 times	2.4 times
	Limit on liens	Cannot exceed 60% of fair value of assets	24.9% [7]
	Debt/capital	Cannot exceed 65%	61.9%
$380 million note indenture	Limit on restricted payments [8]	Cumulative operating cash flow in excess of 1.7 times interest	$284 unrestricted
	Limit on liens	Cannot exceed 5% of tangible assets	$206 unrestricted [9]
	Limit on indebtedness	Interest coverage at least 2.0 times	2.6 times
$300 million note indenture	Limit on liens	Cannot exceed 5% of tangible assets	$206 unrestricted [9]
TPGC guarantees [10]	Debt/capital	Cannot exceed 65%	61.9%
	EBITDA/interest [3]	Minimum of 3.0 times	(11)
TECO Diversified			
Energy management services agreement guarantee	Consolidated tangible net worth	Minimum of $200 net worth	$548
	Consolidated funded debt	Cannot exceed 60%	17.8%
Coal supply agreement guarantee	Dividend restriction	Tangible net worth not less than $200 or $424 (40% of tangible net assets)	$548

(1) As defined in each applicable instrument.
(2) Reflects the determination as of Dec. 31, 2003, after giving effect to $158 million distributed to TECO Energy as a return of capital during 2003. There were $75 million of callable bonds outstanding under the indenture at Dec. 31, 2003.
(3) EBIT generally represents earnings before interest and taxes. EBITDA generally represents EBIT before depreciation and amortization. However, in each circumstance, the term is subject to the definition prescribed under the relevant legal agreements.
(4) Limits cumulative distributions after Oct. 31, 2003 and outstanding affiliate loans to an amount representing an accumulation of net income after May 31, 2003 and capital contributions from the parent after Oct. 31, 2003, plus $450 million.
(5) One of TECO Energy's credit facilities, if drawn upon, can limit payment of dividends each quarter to $40 million, unless the company provides the lender with satisfactory liquidity projections demonstrating the company's ability to pay both the dividends contemplated and each of the three quarterly dividends next scheduled to be paid.
(6) This facility was repaid in full in February 2004 prior to a default under the agreements. (See the **Bank Credit Facilities** section.)
(7) The fair market value of the assets has not been calculated. This calculation represents total collateralized debt, including TWG non-recourse debt, divided by the book value of total assets.
(8) The limitation on restricted payments restricts the company from paying dividends or making distributions or certain investments unless there is sufficient cumulative operating cash flow, as defined, in excess of 1.7 times interest to make such distribution or investment. The operating cash flow and restricted payments are calculated on a cumulative basis since the issuance of the 10.5% Notes in the fourth quarter of 2002. This calculation, at Dec. 31, 2003, reflects the amount accumulated and available for future restricted payments, representing the accumulation of four quarters' activities.
(9) The repayment of the collateralized $37.5 million credit facility in early 2004 (see the **Bank Credit Facilities** section) increases this unrestricted amount to $244 million.
(10) Includes the Construction Undertaking Guarantees related to the TPGC projects.
(11) This calculation was not required for Sep. 30 or Dec. 31, 2003, as provided by the terms of the Suspension Agreement entered into between the lenders, the project companies and TECO Energy, as discussed in the **TECO Wholesale Generation** section. (See the **Investment Considerations, Financing Risks** section.)

Credit Ratings/Senior Unsecured Debt

(As of Feb. 10, 2004)	*Fitch*	*Moody's*	*Standard & Poor's*
Tampa Electric	BBB+	Baa2	BBB-
TECO Energy / TECO Finance	BB+	Ba2	BB+

In February 2004, Moody's lowered the ratings on TECO Energy's senior unsecured debt securities, and those of TECO Finance and Tampa Electric. The ratings assigned to TECO Energy and TECO Finance were below investment grade, while the rating assigned to Tampa Electric remained investment grade. These ratings changes followed actions taken by Moody's, S&P and Fitch in April and May 2003. The outlook assigned by all of the rating agencies to both TECO Energy and Tampa Electric is negative. 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 TWG, as well as the required capital outlays of Tampa Electric, the outlook for low power prices in the merchant energy sector and the resulting 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 2002 and 2001 by all of the rating agencies due to the changing risk profile of TECO Energy related to the increased emphasis on merchant power.

The reduction in credit ratings below investment grade by Moody's in April 2003 accelerated the repayment of the outstanding $250 million balance on the equity bridge loan associated with the construction of the TPGC projects and the requirement to post letters of credit satisfactory to the lending banks under the Construction Undertaking guarantees. The company and the banks agreed that the amount of security to be posted for the remaining construction, liquidated damages for delay and performance shortfalls was $172 million. This amount was subsequently reduced to $66 million following the successful commercial operation of both power plants. (See the **Liquidity, Capital Resources** section.)

In November 2003, S&P affirmed TECO Energy's current credit ratings and removed the ratings from CreditWatch with negative implications following the resolution of the Private Letter Ruling issues related to the production of synthetic fuel at TECO Coal. (See the **TECO Coal** section.) At that time, S&P stated that future ratings stability was directly correlated with TECO Energy's exit from the merchant energy business and the use of future cash flows to reduce debt. S&P went on to state that a failure to exit the Union and Gila River power projects would result in credit rating downgrades. Such downgrades by S&P could result in Tampa Electric's S&P credit rating falling below investment grade. In February 2004, S&P stated that our announcement to exit the Union and Gila River projects was favorable for credit quality but took no ratings action and maintained its negative outlook.

Any downgrades in credit ratings 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.

Contractual Obligations

		Payments Due by Period			
(millions)	*Total*	*2004*	*2005*	*2006-2008*	*After 2008*
Long-term debt:					
Recourse	$ 3,666.4	$ 6.1	$ 5.5	$ 958.3	$ 2,696.5
Non-recourse (1)	108.7	25.5	20.7	51.6	10.9
Preferred security	649.1	–	–	449.1	200.0
Operating leases/rentals (2)	169.5	24.1	21.3	44.9	79.2
Purchase obligations/commitments	9.4	9.4	–	–	–
Total contractual obligations	$ 4,603.1	$ 65.1	$ 47.5	$ 1,503.9	$ 2,986.6

(1) Excludes the non-recourse debt associated with the Union and Gila River projects which is included in liabilities associated with assets held for sale.
(2) Includes payments under the two TECO Transport operating leases discussed in the **TECO Transport** 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.

			Commitment Expiration			
(millions)		*Total (2)*	*2004*	*2005*	*2006-2008*	*After 2008*
Letters of Credit (1)		$ 110.1	$ 78.7 (3)	$ –	$ 4.7	$ 26.7
Guarantees:	Debt related	24.5	–	–	–	24.5
	Fuel purchase/energy management (4)	363.9	183.2 (5)	–	–	180.7
	Other	8.8	5.0	–	–	3.8

(1) Expected final expiration date with annual renewals.
(2) Expected maximum exposure.
(3) In February 2004, by agreement of the parties, $35 million of these letters of credit were drawn by the Union and Gila River non-recourse lending bank group, and the remaining $31 million cancelled and returned to TECO Energy. (See the **TWG, Union and Gila River** section.)
(4) These guarantee amounts renew annually and are shown on the basis they will continue to renew beyond 2007.
(5) As a result of the sale of Prior Energy in February 2004, $173.2 million of guarantees are expected to be eliminated in early 2004.

Capital Investments

Capital Investments

$ (millions)	Actual 2003	Forecast 2004	2005	2006-2008	2004-2008 Total
Florida Operations	$ 337	$224	$ 255	$ 916	$ 1,395
Independent Power	276	14	25	75	114
Transportation	20	20	20	60	100
Other	21	21	19	53	93
Total	$ 654	$279	$ 319	$ 1,104	$ 1,702

TECO Energy's 2003 capital investments of $654 million (without reduction for asset and business sale proceeds) included $289 million for Tampa Electric (including $27 million of AFUDC), $43 million for PGS and $5 million for the unregulated Florida operations. Tampa Electric's electric division capital investments in 2003 were $152 million for equipment and facilities to meet its growing customer base and generating equipment maintenance and $137 million for the repowering and conversion of the coal-fired Gannon Station to the natural gas-fired Bayside Station (see the **Environmental Compliance** section). Capital expenditures for PGS were approximately $28 million for system expansion and approximately $15 million for maintenance of the existing system. TECO Transport invested $20 million in 2003 for river barge replacements and capitalized maintenance of ocean-going vessels. TECO Coal's capital expenditures included $7 million for normal mining expansions and equipment replacements. TWG's capital investments totaled $276 million, net of $31 million received from the sale of its Enron bankruptcy claims (see the **Enron Related Matters** in the **TWG** section), primarily related to the Union and Gila River power stations. This $276 million includes $33 million classified as Other Non-Current Investments, representing the costs associated with the Panda Energy joint venture termination for Union and Gila River and $29 million classified as investment in Unconsolidated Affiliates representing the cost associated with the buyout of Panda's interest in the TIE projects (see the **Transactions With Related and Certain Other Parties** section).

Asset sale proceeds in 2003 were $245 million net of cash escrows of $51 million. Proceeds included the sale of TECO Coalbed Methane's assets, the sale of Hardee Power Partners, TECO Transport's sale of equipment no longer used at TECO Ocean Shipping, the sale of interest in the ECK Generating project in the Czech Republic, and a portion of the proceeds from TECO Coal's sale of a 49.5% interest in its synthetic fuel production facilities. (See the **TECO Coal** and **Liquidity, Capital Resources** sections.)

TECO Energy estimates capital spending for ongoing operations, without reduction for proceeds from asset sales, to be $279 million for 2004, $319 million for 2005 and $1,104 million during the 2006-2008 period.

For 2004, Tampa Electric's electric division expects to spend $183 million, consisting of $9 million for the completion of the repowering project at the Bayside Station and $174 million to support system growth and generation reliability. At the end of 2003, Tampa Electric had outstanding commitments of about $9 million for the Bayside Station repowering project. Tampa Electric's total capital expenditures over the 2005-2008 period are projected to be $1,006 million, including $221 million for compliance with the Environmental Consent Decree. The environmental compliance expenditures are eligible for recovery of depreciation and a return on investment through the Environmental Cost Recovery Clause. (See the **Environmental Compliance** section.)

Capital expenditures for PGS are expected to be about $40 million in 2004 and $160 million during the 2005-2008 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.

TWG expects to invest $14 million in 2004 for capitalized maintenance, and $100 million in the 2005-2008 period for the completion of the Dell and McAdams power stations when market conditions justify the expenditures. (See the **TECO Wholesale Generation** section.)

The other unregulated companies expect to invest $42 million in 2004 and $156 million during the 2005-2008 period. Included in these amounts is normal renewal and replacement capital, including coal mining equipment and river barge replacements.

Financing Activity

Our 2003 year-end capital structure, excluding the effect of unearned compensation, was 71.6 percent senior debt, 7.9 percent company preferred securities and 20.5 percent common equity. TWG has typically financed its power projects with non-recourse project debt. Excluding this non-recourse debt of $2,196 million, the year-end capital structure was 61.3 percent debt, 10.7 percent company preferred securities and 28.0 percent common equity. The debt-to-total-capital ratio increased from last year primarily due to the impairment charges taken in 2003 associated with our investments in merchant power.

In 2003, we accessed the debt and equity markets on three occasions raising $792 million to provide funds for general liquidity purposes, to repay $526 million of long-term debt, and reduce short-term debt balances by $323 million. In addition, debt proceeds in 2003 included non-recourse proceeds of $111 million associated with the Union and Gila River power projects.

In 2002, we were 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.

In 2004, TECO Energy plans to remarket the Trust Preferred debt securities within TECO Capital Trust II, as required. We have been advised that other companies remarketing similar securities have not been successful due to changing company specific and market conditions. In addition, there is expected to be a large number of other issuers seeking to remarket similar securities at the same time. In the event that these securities cannot be successfully remarketed, a possible consequence could be the loss of the tax deductibility of the interest payments made on these securities retroactive to the time of issue in January 2002. The loss of this tax deduction to TECO Energy could result in a non-cash reduction in earnings of approximately $9 million for the year 2002, but due to the level of taxable income, any earnings reduction in 2003 is expected to be significantly lower. We are exploring various remarketing strategies to avoid the loss of the tax deductibility of these payments.

The following table provides details of the financing activities for the years 2003, 2002 and 2001.

Date	Security	Company	Net Proceeds (millions)	Coupon	Use
Sep. 2003	Common equity	TECO Energy	$129	–	Repay short-term debt, and general corporate purposes
Jun. 2003	7-year notes	TECO Energy	$293	7.5%	Repay short-term debt, and general corporate purposes
Apr. 2003	13-year notes	Tampa Electric	$250	6.25%	Repay maturing short-term debt, and general corporate purposes
Dec. 2002	7-year non-recourse bank loan	TECO Wholesale Generation	$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
Sep. 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
Jun. 2001	2-year equity bridge facility	Union & Gila River	$500	LIBOR + 162.5 BP	Construction of the Union and Gila River power stations
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 with a 50% ownership interest or less have project debt balances as follows at Dec. 31, 2003. TECO Energy has no debt payment obligations with respect to these financings, except as indicated by the maximum potential obligation under a related guarantee issued by TECO Energy or its consolidated subsidiaries. Although TECO Energy is not directly obligated on the debt, TECO Energy's equity interest in those unconsolidated affiliates and its commitments with respect to those projects are at risk if those projects are not successfully developed or operated.

Affiliate	*Long-term Debt (millions)*	*Indirect Maximum Guarantee*	*Indirect Ownership Interest*
TIE	$ 545.4	$ –	50%
EEGSA	$ 234.6	$ 15.0 (1)	24%
Hamakua	$ 86.0	$ –	50%

(1) Represents a subsidiary of TECO Energy's 30% ownership interest in the guarantor.

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. On Dec. 24, 2003, the FASB published a revision to FIN 46 (FIN 46R), to clarify some of the provisions of FIN 46 and exempt certain entities from its requirements. TECO Energy believes it is reasonably possible that FIN 46R may impact the accounting for certain unconsolidated affiliates. (See the **Other Accounting Standards – Variable Interest Entities** section.)

Critical Accounting Policies and Estimates

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

(See **Note 1** to the **Consolidated Financial Statements** for a description of our significant accounting policies and the estimates and assumptions used in the preparation of the consolidated financial statements.)

Asset Impairments

We and our subsidiaries periodically evaluate whether there has been a permanent impairment of an asset as follows:

- Long-lived assets, when indicators of impairment exist or an asset group is held for sale, in accordance with Financial Accounting Standard (FAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (see the **Long-Lived Assets** section); and
- Recognized goodwill and other intangible assets with indefinite lives, at least annually, in accordance with FAS 142, *Goodwill and Other Intangible Assets* (see the **Goodwill and Other Intangible Assets** section); and
- Equity investments, when a decline in fair value below the carrying value is determined to be other than temporary, in accordance with Accounting Principles Board Opinion (APB) No. 18, *The Equity Method of Accounting for Investments in Common Stock*.

We believe 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 uncertainty with respect to market fundamentals; 3) the ongoing expectations of management regarding probable future uses and holding periods of assets; and 4) the impact of an impairment on reported assets and earnings would be material. Our 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. Management's expectations regarding uses and holding periods of assets are based on internal long-term budgets and strategic plans, which give consideration to external factors and market forces, as of the end of each reporting period. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities. (See **Notes 1, 3** and **10** to the **Consolidated Financial Statements**.)

Long-Lived Assets

Effective Jan. 1, 2002, we and our subsidiaries adopted FAS 144, which superseded 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 or component of a business.

In accordance with FAS 144, we assess whether there has been an other-than-temporary impairment of our long-lived assets and certain intangibles held and used by us when such indicators exist. When specific criteria are met, a disposal group, comprised of assets and liabilities expected to be transferred in a sale within one year, is classified as assets and liabilities, respectively, held for sale. Furthermore, the income associated with a disposal group may, if additional criteria are met, be presented as discontinued operations in the statement of income. Under FAS 144, the company records an asset impairment charge associated with a disposal group when the estimated fair value, less costs to sell, is less than the net carrying value of the related assets and liabilities. We recognized impairments associated with certain long-lived assets held for use and a disposal group, comprised of the assets and liabilities associated with the Union and Gila River projects. (See **Notes 1** and **10** to the **Consolidated Financial Statements**.)

Goodwill and Other Intangible Assets

In accordance with FAS 142, we continue to review goodwill and intangibles at least annually for each reporting unit. 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 annual assessment date, except as indicated below. 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. During the year ended Dec. 31, 2003, a $74.0 million after-tax ($113.9 million pre-tax) impairment charge was recorded to write off all goodwill associated with the Frontera and Commonwealth Chesapeake power stations and reduce the goodwill associated with BCH Mechanical. (See **Note 3** to the **Consolidated Financial Statements**.)

Equity Investments

We only record an impairment of an equity investment when a decline in the fair value below the carrying value of the investment is determined to be other than temporary. Management assesses other than temporary based on: 1) the magnitude of the difference of the fair value below the carrying value; 2) the period of time in which the decline in the fair value is less than the carrying value; and 3) other reasonably available qualitative or quantitative information that provides evidence to indicate that a decline in fair value is temporary. As of Dec. 31, 2003, the company did not record an other-than-temporary impairment of an equity investment.

Asset Retirement Obligations

On Jan. 1, 2003, we adopted 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 an existing or enacted law or statute, a written or oral contract, or by legal construction under the doctrine of promissory estoppel. Retirement obligations are 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 was effective for fiscal years beginning after June 15, 2002.

Asset retirement obligations are comprised of significant estimates which, if different, could materially impact our results. We believe 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. In connection with the adoption of the guidance on Jan. 1, 2003, we and our affiliates maintain and periodically review all new legal arrangements and contractual commitments to ensure that any new potential asset retirement obligations are reviewed and recognized as appropriate. (See **Note 5** to the **Consolidated Financial Statements**.)

Employee Postretirement Benefits

We have a funded non-contributory defined benefit retirement plan covering substantially all employees. Our 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 Internal Revenue Service (IRS). Plan assets are invested in a mix of equity and fixed income securities. In addition, we and our 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, we have 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 assure the consistency with our actual experience.

The assumed health care cost trend rate for medical costs was 11.5% in 2003 and decreases to 5.0% in 2013 and thereafter.

A 100 basis point increase in the medical trend rates would produce a 4 percent ($0.6 million) increase in the aggregate service and interest cost for 2003 and a 4 percent ($7.5 million) increase in the accumulated postretirement benefit obligation as of Sep. 30, 2003.

A 100 basis point decrease in the medical trend rates would produce a 3 percent ($0.4 million) decrease in the aggregate service and interest cost for 2003 and a 3 percent ($5.3 million) decrease in the accumulated postretirement benefit obligation as of Sep. 30, 2003.

Deferred Income Taxes

We use the liability method in the measurement of deferred income taxes. Under the liability method, we estimate our current tax exposure and 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. Management reviews all reasonably available current and historical information, including forward-looking information, to determine if it is more likely than not that some or all of the deferred tax asset will not be realized. If we determine that it is likely that some or all of a deferred tax asset will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized.

At Dec. 31, 2003, we had net deferred income tax assets of $1,051.5 million attributable primarily to property-related items and an alternative minimum tax credit carryover of Section 29 non-conventional fuel tax credits. Based primarily on historical income levels and the steady-growth expectations for future earnings of the company's core utility operations, management has determined that the net deferred tax assets recorded at Dec. 31, 2003 will be realized in future periods.

We believe that the accounting estimate related to deferred income taxes, and any related valuation allowance, is a critical estimate for the following reasons: 1) administrative actions of the IRS or the U.S. Treasury or changes in law or regulation could eliminate or reduce the availability of alternative minimum tax credits arising from Section 29 tax credits; 2) realization of the deferred tax asset is dependent upon the generation of sufficient taxable income in future periods; and 3) a change in the estimated valuation reserves could have a material impact on reported assets and results of operations. (See **Note 13** to the **Consolidated Financial Statements**.)

Cost Capitalization

During 2003, our subsidiaries devoted resources to the completion and construction of additional generation capacity at Tampa Electric and TWG, extension of the transmission network and enhancement to the system's reliability at Tampa Electric, expansion of the pipeline distribution infrastructure at PGS, normal ocean equipment improvements at TECO Transport and expansion of production capacity at TECO Coal. (See the **Capital Investments** section.) The cost of additions, including improvements and replacements of property, is charged to plant. We capitalize 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. 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, our 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 are expensed as a component of depreciation when the assets are placed in service. (See **Note 1** to the **Consolidated Financial Statements**.)

Depreciation Expense

We provide 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 4.5% and 4.2% for the years ended Dec. 31, 2003 and 2002. We believe the estimated service life corresponds to the anticipated physical life for most assets. However, our 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, we have 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 1** 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. 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.

We periodically assess 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 1** and **4** to the **Consolidated Financial Statements**.)

Revenue Recognition

We and our 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.

The percentage of completion method is used to recognize revenues for certain transportation services at TECO Transport and for long-term construction-type contracts. 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 BCH Mechanical. 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 merchant power sales and expenses for fuel purchases at TWG are reported on a gross basis, except for derivative gains or losses related to hedge accounting, which are reported net of the hedged item or transaction. Likewise, expenses arising from purchased power or revenues arising from fuel sales at TWG are reported net of power revenues and fuel expense, respectively.

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

Recently Issued Accounting Standards

In accordance with recently issued accounting pronouncements, we will be required to comply with certain changes in accounting rules and regulations. (See **Note 22** to the **Consolidated Financial Statements**.)

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. The adoption of the measurement provisions on Jan. 1, 2003 did not have a material impact. (See **Note 14** to the **Consolidated Financial Statements** for additional details of amounts presented on a net basis.)

Consolidation of Variable Interest Entities

The equity method of accounting is generally used to account for significant investments in arrangements in which we or our subsidiary companies do not have a majority ownership interest or exercise control. On Jan. 17, 2003, the FASB issued FIN 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. On Dec. 24, 2003, the FASB published a revision to FIN 46 (FIN 46R), to clarify some of the provisions of FIN 46 and exempt certain entities from its requirements.

Under FIN 46R, a legal entity is considered a VIE, with some exemptions if specific criteria are met, if it does not have sufficient equity at risk to finance its own activities without relying on financial support from other parties. Additional criteria must be applied to determine if this condition is met or if the equity holders, as a group, lack any one of three stipulated characteristics of a controlling financial interest. If the legal entity is a VIE, then the reporting entity determined to be the primary beneficiary of the VIE must consolidate it. Even if a reporting entity is not obligated to consolidate a VIE, then certain disclosures must be made about the VIE if the reporting entity has a significant variable interest. Certain transition disclosures are required for all financial statements issued after Jan. 31, 2003. The effective date of the interpretation was modified under FIN 46R. A reporting entity is required to apply the provisions of FIN 46R to all VIEs that previously were subject to certain previously issued special purpose entity, or SPE, accounting pronouncements for all reporting periods ending after Dec. 15, 2003. For all other VIEs, a reporting entity is required to adopt the provisions of FIN 46R for all reporting periods after Mar. 15, 2004.

Based on its review under the existing approved guidance, we believe that FIN 46R will impact the accounting for certain unconsolidated affiliates. Below is a discussion of the legal entities as of Dec. 31, 2003 that we believe will be subject to either additional disclosure requirements or consolidation by the company, in accordance with FIN 46R.

In November 2000 and January 2002, respectively, we established TECO Funding I, LLC and TECO Funding II, LLC. Each of these limited-liability companies are wholly-owned subsidiaries of TECO Energy. These companies sold preferred securities to Capital Trust I and Capital Trust II, respectively. The funding companies used the proceeds to purchase subordinated notes from us. The subordinated notes are not secured by specific assets of the company. The terms of these notes are similar to the terms of the preferred securities. The funding companies are expected to be considered VIEs in accordance with FIN 46R. As of Dec. 31, 2003, management expects the potential impact of the adoption of FIN 46R to not be material for the funding companies.

Pike Letcher Synfuel, LLC was established as part of the Apr. 1, 2003, sale of TECO Coal's synthetic fuel production facilities. TECO Energy's maximum loss exposure in this entity is its equity investment of approximately $10.9 million and losses related to the production costs for the future production of synthetic fuel, in the event that such production creates Section 29 non-conventional fuel tax credits in excess of our capacity to generate sufficient taxable income to use such credits.

TECO Transport entered into two separate sale-leaseback transactions for certain vessels which were recognized as sales in December 2001 and December 2002, and are currently recognized as operating leases for the assets. The sale-leaseback transactions were entered into with separate third parties that the company believes meet the definition of a VIE. TECO Transport currently leases two ocean-going tugboats, four ocean-going barges, five river towboats and 49 river barges through these two trusts. The estimated maximum loss exposure faced by TECO Transport is the incremental cost of obtaining suitable equipment to meet the company's contractual shipping obligations. The company does not expect to consolidate upon the effective date of FIN 46R because TECO Transport is not the primary beneficiary of the trusts.

TECO Properties formed a limited liability company with a project developer which meets 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. TECO Properties has provided subordinated financial support in the form of a guarantee on behalf of the limited liability company. Hernando Oaks, LLC had total assets at Dec. 31, 2003 of $21.6 million. TECO Properties' estimated maximum loss exposure in this project is approximately $10.6 million. The company expects to consolidate Hernando Oaks, LLC for all financial reporting periods ending after Mar. 15, 2004.

TECO Solutions owns a partnership formed to construct, own and operate a water cooling plant to produce and distribute chilled water to customers via a local distribution loop primarily for use in air conditioning systems. The partnership, TECO AGC, Ltd., meets the definition of a VIE. The company is the primary beneficiary, in accordance with FIN 46R, due to subordinated financing of $3.3 million provided to the partnership as of Dec. 31, 2003, in addition to the company's equity investment. This note receivable from the partnership is collateralized by the assets in the partnership. The estimated maximum loss exposure associated with this partnership is approximately $3.8 million as of Dec. 31, 2003, representing substantially all of the assets of the partnership. The company expects to consolidate TECO AGC, Ltd. for all financial reporting periods ending after Mar. 15, 2004.

Amendment to Derivatives Accounting

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

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

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

Financial Instruments with Characteristics of Both Liabilities and Equity

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

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

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

This standard is effective for all financial instruments entered into or modified after May 31, 2003, and for all other financial instruments, at the beginning of the first interim period beginning after June 15, 2003. (See **Note 7** to the **Consolidated Financial Statements** for a discussion of the impact of the adoption of this standard on July 1, 2003.)

Disclosures About Market Risk

Risk Management Infrastructure

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

Our Risk Management Policy (Policy) governs all energy transacting activity at the TECO Energy group of companies. The Policy is approved by our Board of Directors and administered by a Risk Authorizing Committee (RAC) that is comprised of senior management, 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, derivative transaction volumes are limited to the anticipated volume for customer sales or supplier procurement activities.

The TECO Energy Authorizing Committee, 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 members of the TECO Energy group of companies enter into futures, forwards, swaps and option contracts for the following purposes:

- To limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric and PGS, and prior to their dispositions, 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 TWG; and
- To limit the exposure to price fluctuations for physical purchases of fuel at TECO Transport.

The TECO Energy group of companies use derivatives only to reduce normal operating and market risks, not for speculative purposes. The company's primary objective in using derivative instruments for regulated operations is to reduce the impact of market price volatility on ratepayers. For unregulated operations, the companies use derivative instruments primarily to optimize the value of physical assets, primarily generation capacity and natural gas delivery.

Derivatives and Hedge Accounting

Effective Jan. 1, 2001, we adopted FAS 133, *Accounting for Derivative Instruments and Hedging Activities,* as subsequently amended and interpreted. FAS 133 requires us and our affiliates to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as 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.

Designation of a hedging relationship requires management to make assumptions about the future probability of the timing and amount of the hedged transaction, and the future effectiveness of the derivative instrument in offsetting the change in fair value or cash flows of the hedged item or transaction. The determination of fair value is dependent upon certain assumptions and judgments, as described more fully below. (See **Unregulated Companies** section below, and **Note 2** to the **Consolidated Financial Statements**.)

Interest Rate Risk

We and our affiliates are exposed to changes in interest rates, primarily as a result of our borrowing activities. We or our 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, 2003, a hypothetical 10% increase in the consolidated group's weighted average interest rate on its variable rate debt during 2004, as compared to 2003, would not result in a material impact on pre-tax earnings. Comparatively, as of Dec. 31, 2002, a hypothetical 10% increase in the consolidated group's weighted average interest rate on its variable rate debt during 2003, as compared to 2002, would not have resulted in a material impact on pre-tax earnings. These amounts were determined based on the variable rate obligations existing on the indicated dates at TECO Energy and its subsidiaries. Due to the uncertainty of future events, as discussed in the **Investment Considerations** section, and our responses to those events, the above sensitivities assume no changes to our financial structure or our affiliates. A hypothetical 10% decrease in interest rates would increase the fair value of long-term debt by approximately 3.1 percent and 5.6 percent at Dec. 31, 2003 and 2002, respectively. (See Financing Activity section, and **Notes 6** and **7** to the **Consolidated Financial Statements**.)

Credit Risk

We have adopted a rigorous process for the establishment of new trading counterparties. This process includes an evaluation of each counterparty's financial statements, with particular attention paid to liquidity and capital resources, establishment of counterparty-specific credit limits, optimization of credit terms, and execution of standardized enabling agreements. Our Credit Guidelines require transactions with counterparties below investment grade to be collateralized. 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 affiliated with the same counterparty are consolidated and managed as appropriate, considering the legal structure and any netting agreements in place. The following is a summary of the TECO Energy group of companies credit risk exposure on energy contracts related to merchant generation activities at Dec. 31, 2003.

(millions) *Rating* [(1)]	*Exposure Before Credit Collateral* [(2)]	*Credit Collateral* [(3)]	*Net Exposure*	*Number of Counterparties >10%* [(4)]	*Net Exposure Counterparties >10%* [(4)]
Investment grade	$ 24.4	$ –	$ 24.4	1	$ 7.4
Split rating	8.4	–	8.4	1	8.4
Non-investment grade	–	–	–	–	–
No external ratings (internally rated)					
Investment grade	0.8	–	0.8	–	–
Non-investment grade	–	–	–	–	–
Total	$ 33.6	$ –	$ 33.6	2	$15.8

(1) 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.
(2) Exposure before credit collateral includes the fair value of net energy contract assets for open positions and the net accounts receivable for realized energy contracts. Exposures are offset by a legal counterparty where legally enforceable netting and set-off arrangements are in place.
(3) Credit collateral is required from time-to-time based on contractual provisions and may generally include cash deposits and letters of credit.
(4) 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

We and our affiliates face varying degrees of exposure to commodity risks—including coal, natural gas, fuel oil and other energy commodity prices. Any changes in prices could affect the prices these businesses charge, their operating costs and the competitive position of their products and services. We assess and monitor risk using a variety of 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 have been affected primarily by the cost of coal and, to a lesser degree, the cost of natural gas. With the completion of the repowering of the Bayside Power Station to natural gas, the use of natural gas, with its more volatile pricing, increased in 2003 and is expected to increase again in 2004. (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, 2003 and 2002, 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, and TWG. The unregulated companies do not speculate using derivative instruments. However, not all derivative instruments receive hedge accounting treatment due to the strict requirements and narrow applicability of the accounting rules to dynamic transactions.

TECO Coal is exposed to commodity price risk through coal sales as a part of its daily operations. Fixed-price sales agreements are used, where possible and economical, to mitigate the variability in coal prices. At Dec. 31, 2003 and 2002, a hypothetical 10% increase in the average annual market price of coal for each year would have resulted in a decrease to pre-tax earnings of approximately $1 million and $5 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. The projected fuel price risk for 2004 was reduced via price adjustment clauses. As a result, as of Dec. 31, 2003, a hypothetical 10% change in the average annual market price of fuel would result in an estimated impact on pre-tax earnings in 2004 of approximately $2.1 million. As of Dec. 31, 2002, the impact of a hypothetical 10% change in the average annual market price of fuel would not have had a material impact due to price adjustment clauses and derivative instruments used to significantly reduce the risk of price variability of anticipated fuel purchases in excess of fuel purchases subject to fuel adjustment clauses.

For TWG, 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. TWG 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, 2003 and Dec. 31, 2002.

Sensitivity of the Fair Value of Merchant Energy Derivative Contracts

(millions) Dec. 31,	*2003*	*2002*
Change in Fair Value due to a 10%: [(1)]		
Decrease in natural gas prices	**$ (3.2)**	$ (16.9)
Increase in electricity prices	**(4.3)**	(24.4)
Increase in electricity and natural gas prices	**(7.5)**	(7.5)

(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.

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

Estimated Merchant Plant Hedging Information

	2004	*2005*
Forecasted plant output and fuel requirements hedged	**15%**	13%

The following tables summarize the changes in and the fair value balances of energy derivative assets (liabilities) for the year ended Dec. 31, 2003:

Changes in Fair Value of Energy Derivatives (millions)

Net fair value of derivatives as of Dec. 31, 2002	$ 8.4
Net change in unrealized fair value of derivatives	1.7
Changes in valuation techniques and assumptions	–
Realized net settlement of derivatives	(1.0)
Net fair value of energy derivatives as of Dec. 31, 2003	$ 9.1

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

Total energy derivative net assets (liabilities) as of Dec. 31, 2002	$ 8.4
Change in fair value of net derivative assets (liabilities):	
Recorded in OCI	12.8
Recorded in earnings	(15.5)
Net option premium payments	10.2
Net purchase (sale) of existing contracts	(6.8)
Net fair value of energy derivatives as of Dec. 31, 2003	$ 9.1

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. We use 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 and estimates for and between commodities. Mathematical approaches are applied on a frequent basis to validate and corroborate the results of valuation calculations.

The following is a summary table of sources of fair value, by maturity period, for energy derivative contracts at Dec. 31, 2003.

Maturity and Source of Energy Derivative Contracts Net Assets (Liabilities) at Dec. 31, 2003

Contracts Maturing in	*Current*	*Non-current*	*Total Fair Value*
Source of fair value (millions)			
Actively quoted prices	$ 13.8	$ –	$ 13.8
Other external sources [1]	(4.9)	–	(4.9)
Model prices [2]	2.0	(1.8)	0.2
Total	$ 10.9	$ (1.8)	$ 9.1

(1) Information from external sources includes information obtained from OTC 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.

Other Items Impacting Net Income

2003 Items

In 2003, our results from continuing operations included $223.1 million of charges related to valuation adjustments, project cancellation costs, turbine valuation adjustments, tax credit reversals and corporate restructuring at the various operating companies and $43.6 million related to the sale of HPP and its operating net income through the date of the sale. (See the **Earnings Summary** section.) In addition, we recognized $1.1 million in after-tax charges related a change in accounting principle for the implementation of FAS 143, *Accounting for Asset Retirement Obligations,* and a $3.2 million after-tax charge for the implementation FAS 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity.*

2002 Items

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

2001 Items

In 2001, our results included charges to adjust asset valuations totaling $7.2 million after-tax. The adjustments included a $6.1 million after-tax charge related to the sale of a minority interest 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.

Discontinued Operations

Discontinued operations include the operational losses and charges for the Union and Gila River power stations and operations of Prior Energy and TECO Gas Services.

The 2003 loss from discontinued operations of $890.4 million reflects primarily the $762.0 million after-tax impairment charges for the Union and Gila River power stations and their $62.0 million operating losses, partially offset by net income of $5.5 million from Prior Energy and TECO Gas Services and a $23.5 million after-tax gain on the final installment of the TECO Coalbed Methane sale in January 2003.

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 reflected 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.

Production from TECO Coalbed Methane's reserves was eligible for Section 29 non-conventional fuels tax credits through 2002. The credit was $1.09 per million Btu for 2002 and $1.08 per million Btu in 2001. This rate escalated with inflation and could have been limited by domestic oil prices. In 2002, domestic oil prices would have had to exceed $50 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 2003, Other Income (Expense) of $101.9 million reflects the income related to the gain on the sale of Hardee Power Partners and the sale of the 49.5% interest in the synthetic fuel production facilities at TECO Coal, partially offset by an arbitration reserve established for TMDP, the indirect owner of the Commonwealth Chesapeake Power Station, and lower AFUDC Equity at Tampa Electric. Results in 2002 included income from loans to Panda Energy for the TIE projects which converted to an equity ownership position in January 2003. (See the **TWG** section.)

In 2002, Other Income (Expense) of $15.2 million included $60.7 million from construction-related and loan agreements with Panda Energy and earnings on the equity investment in EEGSA at TWG, and income from the investment in TPV, partially offset by the $9.4 million pre-tax ($5.8 million after-tax) asset valuation charge for TWG's sale of its minority interest in generating facilities in the Czech Republic and a $34.1 million ($20.9 million after-tax) pre-tax charge related to a TECO Energy debt refinancing completed in 2002.

In 2001, Other Income (Expense) of $38.7 million included income from loan agreements with Panda Energy related to the TIE projects and earnings on the equity investment in EEGSA , and income from the investment in TPV, partially offset by a $9.9 million pre-tax ($6.1 million after-tax) charge for TWG's sale of its minority interest in EGI.

AFUDC equity at Tampa Electric, which is included in Other Income, was $19.8 million in 2003, $24.9 million in 2002 and $6.6 million in 2001. AFUDC is expected to drop to almost zero in 2004, with the completion of Tampa Electric's Bayside repowering.

Interest Charges

Interest expense was $288.4 million in 2003, compared with $142.3 million in 2002 and $164.1 million in 2001. Interest expense increased in 2003 reflecting higher debt balances at both Tampa Electric and TECO Energy associated with the completion of major construction programs. In addition, $45 million less interest was capitalized in 2003, because of the completion of the Union and Gila River construction and the suspension of construction of Dell and McAdams. 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.

Income Taxes

Income taxes decreased in 2003 as the result of a loss from continuing operations, continuing non-taxable AFUDC equity, and substantial tax credits associated with the production of non-conventional fuels. Income tax expense decreased in 2002, reflecting greater 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 90.2 percent in 2003, -22.9 percent in 2002, and -2.8 percent in 2001. During 2004, we expect the effective tax rate to be in the range of 35-40%.

The cash payment for income taxes, as required by the Alternative Minimum Tax Rules, was $58.8 million, $71.9 million, and $52.4 million in 2003, 2002, and 2001, respectively.

Total income tax expense was reduced by the Federal tax credits related to the production of non-conventional fuels, under Section 29 of the Internal Revenue Code. This tax credit totaled $66.0 million in 2003, $107.3 million in 2002, and $86.2 in 2001. 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 Sec. 29 tax credits. (See the **TECO Coal** section.)

The tax credit is determined annually and is estimated to be $1.11 per million Btu for 2003 and was $1.09 per million Btu in 2002 and $1.08 per million Btu in 2001. This rate escalates with inflation but could be limited by domestic oil prices. In 2003, domestic oil prices would have had to exceed $50 per barrel for this limitation to have been effective.

In 2003, 2002, and 2001, 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 $12.3 million, $8.1 million, and $7.2 million for 2003, 2002, and 2001, respectively.

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

Enron Related Matters

TWG filed a claim in the Enron bankruptcy proceeding associated with the NEPCO "swept cash" for the four projects in the amount of $214 million. TWG and others have filed adversary proceedings in the bankruptcy to try to establish a constructive trust with respect to the cash used by Enron that belonged to its subsidiary, NEPCO, the engineering, procurement and construction contractor of four TWG projects.

In 2003, TWG sold its bankruptcy claims for approximately 15.5 cents on the dollar which amounted to a recovery of about $42 million. There was a holdback of 20% to be released at the time of payment by Enron to the purchaser. The cash received in excess of the holdback was approximately $33.4 million. Under the arrangement, the pending adversary proceedings would still be prosecuted to the extent practicable with the excess recovery, if any, shared by us and the purchaser. This recovery would primarily offset increases in construction costs associated with the effect of Enron's bankruptcy on its subsidiary NEPCO.

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 to dramatically decrease emissions from its power plants.

The emission reduction requirements included specific detail with respect to the availability of flue gas desulfurization systems (scrubbers) to help reduce sulfur dioxide (SO_2), 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. The commercial operation dates for the two repowered Bayside units were on April 24, 2003 and Jan. 15, 2004. The completed station has total station capacity of about 1,800 megawatts (nominal) of natural gas-fueled electric generation. 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 June 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 through 2008 period for compliance with the NOx SO2 and particulate matter reduction requirements.

Emission Reductions

Since 1998, Tampa Electric has reduced annual SO2, NOx, and particulate matter (PM) emissions from its facilities by 129,430 tons, 27,630 tons, and 2,865 tons, respectively.

Reductions in SO2 emissions were accomplished through the installation of scrubber systems on Big Bend Units 1 and 2 in 1999. Big Bend Unit 4 was originally constructed with a scrubber. The Big Bend Unit 4 scrubber system was modified in 1994 to allow it to scrub emissions from Big Bend Unit 3. Currently, the scrubbers at Big Bend Station remove more than 95 percent of the SO2 emissions from the flue gas streams.

In addition, Consent Decree and Consent Final Judgment related projects will result in significant reductions in emissions. Reductions have already resulted from the completion of the repowering of Gannon Station to Bayside Power Station in April 2003 (Bayside Unit 1) and January 2004 (Bayside Unit 2). Should Tampa Electric decide to continue to burn coal, the installation of additional NOx emissions controls on all Big Bend Units will result in the further reduction of emissions. By 2010, these projects will result in the additional phased reduction of SO2 by 156,501 tons per year, NOx by 61,549 tons per year, and PM by 3,626 tons per year from 1998 levels. In total, Tampa Electric's emission reduction initiatives will result in the reduction of SO2, NOx, and PM emissions by 90 percent, 89 percent, and 70 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.

Due to pollution control co-benefits from the Consent Final Judgment and Consent Decree, reductions in mercury emissions have occurred due to the re-powering of Gannon Station to Bayside Station. At Bayside, where mercury levels have decreased 44 percent below 1998 levels, there are virtually zero mercury emissions. Additional mercury reductions are also anticipated from the installation of NOx controls at Big Bend Station, which would lead to a mercury removal efficiency of approximately 70 percent. Depending on the NOx control technology selected for Big Bend, the mercury reductions may vary and lead to lower than anticipated mercury removal efficiencies.

The repowering of Gannon Station to Bayside Station will also lead to a significant reduction in carbon dioxide (CO2) emissions. It is expected, that by 2005, the repowering will bring an approximate 5.2 million ton decrease in CO2 emissions below 1998 levels. This reduction will result in the Tampa Electric system CO2 emissions being in line with its 1990 CO2 emission levels.

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, 2003, 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 Tampa Electric Company's experience with similar work adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

Allocation of the responsibility for remediation costs among Tampa Electric Company and other 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 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.

Regulation

Tampa Electric Rate Strategy

In 1996, during the construction of Polk Unit one, Tampa Electric entered into a series of agreements with Florida's Office of Public Counsel (OPC) and the Florida Industrial Power Users Group (FIPUG), which were approved by the FPSC to stabilize prices while securing fair earnings opportunities through 1999.

Since the expiration of the agreements, Tampa Electric's 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 even with the rate base additions associated with the repowering of the Bayside Power Station.

Tampa Electric has not sought a base rate increase to recover the investment in the Bayside Power Station which entered service in two phases, with the first in April 2003 and the second in January 2004.

Cost Recovery Clauses – Tampa Electric

In February 2003, Tampa Electric filed a request for an additional fuel cost adjustment of almost $61 million due to continued increase in the cost of natural gas and oil. The request also reflected Tampa Electric's operational plan to phase out Gannon Units 1 through 4 in 2003. In March 2003, the FPSC approved Tampa Electric's new fuel rates as well as new fuel rates for the other peninsular Florida investor-owned utilities.

In September 2003, 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 2004. In November, the FPSC approved Tampa Electric's requested changes. The resulting rates include the impacts of increased use of natural gas at the Bayside Power Station and the collection of $91 million for under recovery of fuel expense for 2002 and 2003. The filing also included estimated waterborne transportation rates for coal transportation services, discussed below. The FPSC did not allow the recovery of $8.4 million it characterized as "savings" from shutting down the Gannon Station earlier than originally planned which the FPSC deemed generated operations and maintenance savings. Accordingly, Tampa Electric's residential customer rate per 1,000-kilowatt hours increased to $99.01. The rates include projected costs associated with environmental projects required under the EPA Consent Decree and the FDEP Consent Final Judgment.

Tampa Electric filed its objection to the disallowance of the recovery of the $8.4 million and a motion asking the FPSC to reconsider its decision because all facts and law were not taken into account. The motion was filed on Jan. 6, 2004, and a decision on this matter is expected in the first quarter of 2004.

Coal Transportation Contract

Tampa Electric's contract for coal transportation and storage services with TECO Transport expired on Dec. 31, 2003. TECO Transport had been providing river, cross-gulf transportation services and storage services under that contract since 1999 and under a series of contracts for more than 40 years. In June, Tampa Electric issued a Request For Proposal (RFP) to potential providers requesting services for the next five years. The result of the RFP process was the execution of a new contract between Tampa Electric and TECO Transport, effective Jan. 1, 2004, with market rates supported by the results of the RFP and an independent expert in maritime transportation matters. The prudence of the RFP process and final contract were originally scheduled to be reviewed by the FPSC in the course of the normal fuel cost recovery hearings in November 2003. That hearing was deferred due to protests from other parties seeking more time to evaluate the contract information. The matter is scheduled to be heard by the FPSC in May 2004 with a decision expected in July 2004.

In the meantime, Tampa Electric is recovering fuel transportation costs at the rates from the now expired contract, which are slightly higher than those in the contract effective Jan. 1, 2004.

Cost Recovery Clauses – Peoples Gas

In November 2003, the FPSC approved rates under Peoples' Gas Purchased Gas Adjustment (PGA) cap factor for the period January 2004 through December 2004. The PGA is a factor that can vary monthly due to changes in actual fuel costs but is not anticipated to exceed the annual cap. The approved cap includes an under-recovery of $7.5 million for 2002 and a projected over–recovery of $10.3 million in 2003.

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

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

Transmission Rates

In October 2002, Tampa Electric submitted a FERC filing to increase 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 that began in January 2003 resulted in a settlement agreement that approved increased rates and resolved all disputed issues and was certified by the FERC in June 2003. In compliance with the FERC order approving the settlement, Tampa Electric made timely refunds, plus interest, for amount collected in excess of the settlement rates.

Regional Transmission Organization (RTO)

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

In May 2001, the FPSC questioned the prudence of the three filing utilities joining GridFlorida. After an October 2001 hearing, the FPSC found that the companies were prudent in forming GridFlorida, but ordered the companies to modify their proposal to develop a non-transmission owning RTO model. An updated filing was submitted to the FPSC. In August 2002, the FPSC voted to approve many of the compliance changes submitted, but set an October 2002 hearing on the market design changes proposed in the updated filing.

In October 2002, the process was delayed when the OPC filed an appeal with the Florida Supreme Court asserting that the FPSC could not relinquish its jurisdictional responsibility to regulate the IOUs and, by approving GridFlorida, they were doing just that. Oral arguments occurred in May 2003, and the Florida Supreme Court dismissed the OPC appeal citing that it was premature because certain portions of the FPSC GridFlorida order are not final.

In September 2003, a joint meeting of the FERC and FPSC took place to discuss wholesale market and RTO issues related to GridFlorida and in particular federal/state interactions. The FPSC has scheduled a series of collaborative meetings with all interested parties and, upon their conclusion, will set items for hearing and a hearing schedule. This is expected to occur throughout 2004.

Peoples Gas Rate Proceeding

On Jun. 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 Commission 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 allowed ROE range from 10.25 percent to 12.25 with an 11.25 percent midpoint and a capital structure with 57.43 percent equity and were effective after Jan. 16, 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, PGS has developed various programs, including the provision of transportation services at discounted rates.

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

TWG Federal and State Regulatory and Legislative Involvement

Along with TECO Energy's active involvement in restructuring initiatives, TWG 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 of retail deregulation rules and laws in Arkansas and restructured regulatory rules regarding the settlement agreement that governs retail and wholesale competition in Arizona.

TWG was an active intervener in Arizona Public Service Company's (APS) regulatory proceedings regarding a request to 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 instead to purchase almost all of its load requirements from its unregulated affiliate, Pinnacle West Energy Corporation. Tucson Electric Power Company (TEP) filed a similar variance request with the Arizona Corporate Commission, although it only sought a postponement of the implementation date. As a result, in early 2003 APS and TEP were required to competitively procure their unmet needs through separate RFP processes, which were held during the spring. During those competitive solicitations, Gila River Power Station was selected to provide power to both of these entities for three years. Power deliveries began under the agreements last year.

During the 2003 regular legislative session, the Arkansas Legislature repealed its earlier legislation, which was to initiate retail electric deregulation in Arkansas sometime between October 2003 and October 2005. TWG and other independent power producers, embarked on a strategy that would displace the region's older, less efficient, more polluting generating units so that state-of-the-art, gas-fired, combined-cycle units, such as the Union Power Station, could serve the growing needs of the area. This is a strategy that TWG has advanced at the federal level and within other markets it serves. As a result, the Louisiana Public Service Commission ordered its Staff to conduct a unit displacement/retirement study to achieve the identified economic and environmental benefits. This study should be completed during the first half of 2004.

TWG is working on behalf of both the Frontera and TIE facilities to effectuate change at ERCOT, (Electric Reliability Council of Texas) the Public Utility Commission of Texas (PUCT) and Legislature on matters of common interest for the two facilities. Despite the advent of competition in Texas, the market design does not yet result in the dispatch of the region's most economical resources namely, newer, more-efficient, gas-fired capacity.

TWG has taken an active role on ERCOT committees, in proceedings at the PUCT and in the Legislature, whose next session begins in mid-January 2005. Transmission congestion remains a major concern in the ERCOT market, and has 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, and fundamental market redesign issues.

In the meantime until market changes are implemented, local congestion remains a significant issue for the load-serving entities and generation facilities within ERCOT. The new market design will directly assign congestion costs to those who cause the transmission system congestion. TWG is advocating interim market solutions that would eliminate Reliability-Must-Run (RMR) contracts and provide adequate compensation for Frontera when called upon by ERCOT to alleviate congestion in the Rio Grande Valley.

Corporate Governance

In the last several years, the Congress, the Securities and Exchange Commission (SEC), the New York Stock Exchange (NYSE), and other interested groups have focused extensively on improving corporate accountability and corporate governance in an effort to restore investor confidence. The rules passed by the SEC, as well as the listing standards adopted by the NYSE that become effective after the 2004 Annual Meeting of Shareholders, are already a part of our corporate culture and we have been voluntarily complying with them. These rules require, among other things, independence by the Board of Directors and various Board committees, a statement of governance guidelines and detailed committee charters, an internal audit function, a code of ethics for the CEO, senior financial officers and directors, adequate internal controls to detect fraud, increased oversight of financial disclosure by the Audit Committee, and certification by the CEO and CFO of the financial results.

For many years, the vast majority of our Board of Directors have been independent, and the required independent Board committees have been in place. In addition, we have had a rigorous internal audit and compliance function, including an anonymous reporting system which now has been expanded to cover matters required to be disclosed to the Audit Committee and the non-management directors, and a code of ethics for all employees and officers, the *Standards of Integrity*. The code was expanded in 2002 to include directors and is posted on the company's website. Our long-standing controls for full and complete financial reporting and disclosure have been formalized and are reviewed quarterly for effectiveness. The CEO and CFO have filed sworn statements with the SEC quarterly, as required by law, to certify without exception the accuracy of the financial results, and the CEO will be signing the required certification as to compliance with the NYSE's corporate governance listing standards following the next annual meeting.

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

Transactions with Related and Certain Other Parties

We and our subsidiaries had certain transactions, in the ordinary course of business, with entities in which directors of the company had interests that are reported in our 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, 2003, 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. We have interests in unconsolidated affiliates, which are discussed in the **TECO Wholesale Generation**, **Other Unregulated Companies** and **Off-Balance Sheet Financing** sections.

In October 2003, Tampa Electric signed a five-year contract renewal with an affiliate company, TECO Transport Corporation, for integrated waterborne fuel transportation services effective Jan. 1, 2004. The contract calls for inland river and ocean transportation along with river terminal storage and blending services for up to 5.5 million tons of coal annually through 2008.

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

TWG's 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. In September 2003, TWG completed the foreclosure on Panda's interest in TIE for a default on a $23 million note receivable which resulted in TWG becoming a 50-percent owner in the plants and a total investment in TIE of $160 million. In 2003, improved peak season power prices and a new power and gas manager retained to increase the energy sales from these plants resulted in improved financial performance, however; the plants still had a negative impact on earnings. The interest earned on the loans to TIE was reflected in 2002 and 2001 earnings.

In February 2002, the TWG and Panda affiliates that comprised the joint venture that owned the Union and Gila River projects entered into an arrangement obligating TWG to purchase and Panda to sell Panda's interest in the joint venture in 2007 for $60 million. In July 2003, TWG acquired Panda's interest in these plants through a modification of the Purchase Agreement and termination of the joint venture.

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

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

In recent years, we have significantly increased our indebtedness which has resulted in an increase in the amount of fixed charges we are obligated to pay. The level of our indebtedness and restrictive covenants contained in our debt obligations could limit our ability to obtain additional financing or refinance existing debt and could prevent the repayment of subordinated debt and the payment of dividends if those payments would cause a violation of the covenants.

In order for us to use our credit facilities, we must meet certain financial tests. Our credit facilities require that at the end of each quarter our debt-to-capital ratio, as defined in the applicable agreements, not exceed 65%. Tampa Electric Company's credit facility requires that at the end of each quarter Tampa Electric Company's debt-to-capital ratio, as defined in the agreement, not exceed 60% and its earnings before interest, taxes, depreciation and amortization (EBITDA) to interest coverage ratio, as defined in the applicable agreement, not be less than 2.5 times. At Dec. 31, 2003, our debt-to-capital ratio was 61.9% and Tampa Electric Company's debt-to-capital ratio was 49.2% and its interest coverage ratio was 5.8 times. Similarly, certain long-term debt at Tampa Electric Company's Peoples Gas System division contains a prohibition on the incurrence of funded debt if Tampa Electric Company's debt-to-capital ratio, as defined in the applicable agreement, exceeds 65%. The Tampa Electric Company debt related to Peoples Gas also carries a requirement that Tampa Electric Company's interest coverage ratio, as defined in the applicable agreement, be 2.0 times or greater for four consecutive quarters.

Our construction undertaking obligations associated with TWG's Gila River and Union Power Projects, in effect until twelve months after commercial operation, require our consolidated EBITDA to interest coverage ratio, as defined in the applicable agreement, to equal or exceed 3.0 times for the twelve-month period ended each quarter and a debt-to-capital ratio not to exceed 65% at the end of each fiscal quarter. Under the suspension agreement between TECO Energy, the project companies and the lenders, TECO Energy was not required to calculate the EBITDA to interest coverage ratio required in the undertaking for the quarters ended Sep. 30, 2003 and Dec. 31, 2003 until Feb. 1, 2004 which was orally extended until Feb. 5, 2005. On that date, the calculations were made resulting in 2.7 and 2.4 times for the two quarters, respectively. Non-compliance with this covenant could accelerate the $1.395 billion of non-recourse construction debt absent the sale of the projects to the lenders. (See **TECO Wholesale Generation – Letter of Intent** section.)

Our 10.5% Notes due 2007 issued in November 2002, contain covenants that limit our ability to incur additional liens and require us to achieve certain interest coverage levels in order to pay dividends, make distributions or certain investments, or issue additional indebtedness. The 7.5% Notes issued in June 2003 contain the same limitation on liens covenant. 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 level required by the equity bridge loan and Union and Gila River Construction Undertaking while those obligations are outstanding. The covenants became applicable upon Moody's downgrade of TECO Energy's senior unsecured debt in April 2003. The limitation on restricted payments restricts us from paying dividends or making distributions or certain investments unless there is sufficient cumulative operating cash flow, as defined in the agreement applicable to the 10.5% Notes, in excess of 1.7 times interest coverage to make contemplated dividend payments, distributions or investments. Our operating cash flow, restricted payments and interest coverage are calculated on a cumulative basis from the issuance of the 10.5% Notes in November 2002. As of Dec. 31, 2003, $285 million was accumulated and available for future restricted payments, representing a four quarter accumulation. Further, we are not permitted, with certain exceptions as stated in that agreement, to create any lien upon any of our property in excess of 5% of consolidated net tangible assets as defined, without equally and ratably securing the 10.5% Notes. As of Dec. 31, 2003 this limitation would apply to the creation of covered liens exceeding $206 million. Finally, our operating cash flow to interest coverage ratio, as defined in that agreement, for the immediate preceding four quarters must exceed 2.0 times for us to be able to issue additional indebtedness, with certain exceptions as provided in that agreement. As of Dec. 31, 2003, our operating cash flow to interest coverage ratio for the immediate preceding four quarters, with pro forma adjustments as provided in the agreement, was 2.6 times.

Tampa Electric Company's 6.25% Senior Notes Due 2016 contain covenants that require Tampa Electric Company to maintain, as of the last day of each fiscal quarter, a debt-to-capital ratio, as defined in the agreement, that does not exceed 60%, and prohibit the creation of any covered lien on any of its property in excess of $787 million, with certain exceptions as defined in the agreement, without equally and ratably securing the 6.25% Senior Notes.

Finally, in addition to our debt-to-capital ratio requirement discussed above, our credit facility with an affiliate of Merrill Lynch has covenants that, if the facility is drawn, could limit the payment of dividends exceeding $40 million in any quarter unless, prior to the payment of any dividends, we deliver to Merrill Lynch liquidity projections demonstrating that we will have sufficient cash or cash equivalents to pay both the dividends contemplated and each of the three quarterly dividends next scheduled to be paid on our common stock.

We cannot assure you that we will be in compliance with these financial covenants in the future. Our failure to comply with any of these covenants or to meet our payment obligations could result in an event of default which, if not cured or waived, could result in the acceleration of other outstanding debt obligations. We may not have sufficient working capital or liquidity to satisfy our debt obligations in the event of an acceleration of all or a portion of our outstanding obligations. In addition, if we had to defer interest payments on our subordinated notes that support the distributions on our outstanding trust preferred securities, we would be prohibited from paying cash dividends on our common stock until all unpaid distributions on those subordinated notes were made.

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

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

In February 2004, Moody's Investor Service, Inc. lowered the ratings on our senior unsecured debt to Ba2 with a negative outlook. This followed actions in April 2003, when Moody's and Fitch Ratings lowered their ratings on our senior unsecured debt to Ba1 and BB+, respectively, both with a negative outlook. In May 2003, Standard & Poor's Ratings Services lowered the ratings on our senior unsecured debt to BB+ with a negative outlook. These agencies also lowered the ratings on other of our securities, as well as those of TECO Finance and Tampa Electric. Tampa Electric Company's senior secured and unsecured debt ratings were lowered to Baa1 and Baa2, respectively, by Moody's, to A- and BBB+, respectively, by Fitch and to BBB- for both senior secured and unsecured debt by Standard & Poor's. Currently the outlook for Tampa Electric, TECO Energy and TECO Finance at all of the credit rating agencies is negative. The 2003 and 2004 downgrades and any future downgrades may affect our ability to borrow and may increase our financing costs, which may decrease our earnings. We are also likely to experience greater interest expense than we may have otherwise if, in future periods, we replace maturing debt with new debt bearing higher interest rates due to our lower credit ratings. In addition, such downgrades could adversely affect our relationships with customers and counterparties.

In addition, as a result of the 2003 ratings actions, TES, Prior Energy and TECO Gas Services were required to post collateral with counterparties in order to continue to transact in the forward markets for electricity and natural gas. Collateral or margin postings may fluctuate based on either the fair value of open forward positions or credit assurance assessments negotiated with counterparties. Based on the fair value of existing contractual obligations as of Dec. 31, 2003, the maximum collateral obligation, if all counterparties exercised their full rights, would be approximately $16 million. Counterparties with the right to call for collateral or margin postings are not obligated to do so. Based on our analysis of the rights of those counterparties that have the right to call for collateral or margin postings, we believe the maximum collateral obligation would be approximately $16.0 million (including actual collateral posted of $11.8 million).

In November 2003, S&P affirmed TECO Energy's current credit ratings and removed the ratings from Credit Watch with negative implications following the resolution of the Private Letter Ruling issues related to the production of synthetic fuel at TECO Coal, (see the TECO Coal section). At that time, S&P stated that future ratings stability was directly correlated with TECO Energy's exit from the merchant energy business and the use of future cash flows to reduce debt. S&P went on to state that a failure to exit the merchant energy business would likely result in addition credit rating reductions. Such reductions could result in Tampa Electric's credit rating falling below investment grade. In February 2004, S&P stated that the announcement to exit the Union and Gila River projects was favorable to credit quality but took no ratings action and maintained its negative outlook.

If we are unable to limit capital expenditure levels as forecasted or successfully complete planned facility sales to the extent anticipated, our financial condition and results could be adversely affected.

Part of our plans includes capital expenditures at the operating companies at maintenance levels for the next several years. We cannot be sure that we will be successful in limiting capital expenditures to the planned amount. Our plan also includes the sale of an additional 40% portion of our interest in facilities that produce synthetic fuel which qualifies for Section 29 tax credits at TECO Coal. We cannot be certain, however, that we will find purchasers or be able to sell these synthetic fuel production facilities at the prices we expect. If we are unable to limit capital expenditures to the forecasted levels or to sell the synthetic fuel production facilities at the prices we expect or at all, we may need to draw on credit facilities or access the capital markets on unfavorable terms or ultimately sell additional assets to improve our financial position. We cannot be sure that we will be able to obtain additional financings or sell such assets, in which case our financial position, earnings and credit ratings could be adversely affected.

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

We are a holding company and dependent on cash flow from our subsidiaries to meet our cash requirements that are not satisfied from external funding sources. Some of our subsidiaries have indebtedness containing restrictive covenants which, if violated, would prevent them from making cash distributions to us. In particular, Tampa Electric Company's first mortgage bonds indenture contains restrictions on distributions on its common stock, and certain long-term debt at Tampa Electric Company's Peoples Gas System division prohibits payment of dividends to us if Tampa Electric Company's consolidated shareholders' equity is not at least $500 million. At Dec. 31, 2003, Tampa Electric Company's unrestricted retained earnings available for dividends on its common stock were approximately $5 million and its consolidated shareholders' equity was approximately $1.7 billion. Also, our 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 by TECO Diversified to us.

Various factors could affect our ability to sustain our dividend.

Our ability to pay a dividend or sustain it at current levels could be affected by such factors as (i) the level of our earnings and therefore our dividend payout ratio, (ii) the level of our retained earnings could be affected by payment of dividends in excess of earnings and further write-offs of our merchant generation investments or other assets, (iii) pressures on our liquidity needs, including unplanned debt repayments, unexpected capital needs and shortfalls in operating cash flow and (iv) a breach of our 65% debt-to-total capital financial covenant, which could occur in the event of further erosion of our retained earnings without infusion of additional capital. These are in addition to any restrictions on dividends from our subsidiaries to us discussed above.

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

Changes in interest rates and capital markets generally affect our cost of borrowing and access to these markets. We cannot be sure that we will be able to accurately predict the effect those changes will have on our cost of borrowing or access to capital markets.

Merchant Power Project Risks

We and the project companies have not yet reached a definitive agreement with the non-recourse project lending banks for the transfer of our ownership of the Union and Gila River projects through a purchase and sale or other agreement to the lending group.

Our decision to exit from the ownership of the projects is not conditioned on reaching a consensual agreement with the lenders for the sale of the projects. If a definitive agreement cannot be reached, however, there could be a delay in the ultimate forgiveness of the non-recourse debt and there could be a change in the accounting treatment from discontinued operations back to continuing operations in a future period.

Under the letter of intent, the parties have retained the right to assert certain claims they may have against one another until a definitive agreement is reached. Assertion of such claims and defense against them could be time consuming and costly and delay the ultimate disposition of our interest in the projects.

The failure of the project companies to make interest payment on the project debt, which they failed to do beginning December 31, 2003, could permit a claim of a cross default under two leases of TECO Transport. (See the **TECO Transport** section.)

TECO Wholesale Generation's (TWG) power plants are affected by market conditions, and they may not be able to sell power at prices that enable it to recover its investments in the plants.

The TWG power plants that are in operation currently sell most of their power based on market conditions at the time of sale, so TWG 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 Federal Energy Regulatory Commission (FERC) or state regulatory bodies or reimposition of regulation in power markets;
- the demand for power in a market served by TWG's plants relative to available supply;
- the availability of transmission to accommodate the sale of power; or
- whether TWG 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. The excess supply is partially due to the slowdown of electric deregulation in many states, or the outright repeal of electric competition legislation as occurred in Arkansas in 2003 (where the Dell and Union power stations are sited or located). This has allowed incumbent utilities to continue to operate older, less efficient generating facilities in lieu of purchasing power from newer, more efficient independent power plants. Consequently, only a small portion of the output of TWG's plants has been sold forward, or hedged, under short-term agreements. TWG's results could be adversely affected if it is unable to sufficiently sell the output of its plants under longer-term contracts or at a premium to forward curve prices for short-term sales or if we need to write off any of the capital already invested in the projects.

Our outlook assumes that TWG will manage these risks by:

- optimizing among 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 continue to defer, where advisable, construction of output capacity in a market that has become oversupplied.

However, we cannot be sure how successfully TWG will be able to implement these risk management measures. For instance, in oversupplied markets, entering into long-term contracts could be difficult.

TWG may be unable to successfully complete current projects on schedule or within budget, and the book value of uncompleted projects could be impaired.

TWG currently has new power generating facilities where construction has been suspended. The construction and maintenance of these facilities 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. Any of these events could delay a project's construction schedule or increase its costs, which may impact TWG's ability to generate sufficient cash flow. In addition, if these projects remain suspended beyond the currently anticipated time frame, the book value of those projects would likely be impaired.

Asset valuation adjustments or sales of these facilities at prices below the book value would reduce our equity levels and could potentially result in a breach of our 65 percent debt-to-total capital covenant in our bank credit facility.

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

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

TWG's and its affiliates' 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, it 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 our businesses.

Our businesses are affected by general economic conditions. In particular, the projected growth in Tampa Electric's service area and in Florida is important to the realization of Tampa Electric's and Peoples Gas System's forecasts for annual energy sales growth. An unanticipated downturn in the local area's or Florida's economy could adversely affect Tampa Electric's or Peoples Gas System's expected performance.

Our unregulated businesses, particularly TWG, TECO Transport and TECO Coal, are also affected by general economic conditions in the industries and geographic areas they serve, both nationally and internationally.

Potential competitive changes may adversely affect our 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 Peoples Gas System are now unbundled for all non-residential customers. Because Peoples Gas System earns margins on distribution of gas, but not on the commodity itself, unbundling has not negatively impacted Peoples Gas System's results. However, future structural changes that we cannot predict could adversely affect Peoples Gas System.

Our gas and electricity businesses are highly regulated, and any changes in regulatory structures could lower revenues or increase costs or competition.

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

Tampa Electric is seeking regulatory approval for the costs associated with a new contract for coal transportation services.

Tampa Electric has executed a new 5-year contract for coal transportation services with TECO Transport. These services have been provided by TECO Transport historically and represent about 40% of TECO Transport's revenues. The costs associated with the transportation services are subject to FPSC review and a number of parties, including alternative transportation providers have intervened in the proceedings, which are scheduled for hearings in April 2004. Failure to gain regulatory approval for the recovery of the costs associated with these services could adversely impact Tampa Electric's financial results.

Our businesses are sensitive to variations in weather and have seasonal variations.

Most of our businesses are affected by variations in general weather conditions and unusually severe weather. Tampa Electric's, Peoples Gas System's and TWG's energy sales are particularly sensitive to variations in weather conditions. Those companies forecast energy sales on the basis of normal weather, which represents a long-term historical average. 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.

Peoples Gas System, 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 Peoples Gas System.

Variations in weather conditions also affect the demand and prices for the commodities sold by TECO Coal, as well as electric power sales from TECO Wholesale Generation's 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, our 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 we operate and the terms under which we sell electricity.

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

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

In the case of Tampa Electric, fuel costs used for generation have been affected primarily by the cost of coal. Tampa Electric's fuel costs will be increasingly impacted by the cost of natural gas with the completion of the Bayside repowering. 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 affected by the cost of fuel to Tampa Electric, particularly as it compares to the costs of other power producers.

In the case of TECO Wholesale Generation, results are impacted by changes in the cost of fuel and the market price for electricity. The profitability of merchant power plants is heavily dependent on the price for power in the markets 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 Peoples Gas System, 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 Peoples Gas System relative to electricity, other forms of energy and other gas suppliers.

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

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

The FERC has issued regulations that require wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. Although these regulations are designed to encourage competition in wholesale market transactions for electricity, there is the potential that fair and equal access to transmission systems will not be available or that sufficient transmission capacity will not be available to transmit electric power as we desire. We cannot predict the timing of industry changes as a result of these initiatives or the adequacy of transmission facilities 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 our wholesale power marketing business.

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

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

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

We derive a portion of our net income from Section 29 tax credits related to the production of non-conventional fuels. Although we sold a significant portion of our interest in the production facilities in April 2003 and plan to sell the majority of our remaining interest in the production capacity, until and unless we successfully do so, our use of these tax credits is dependent on our generating sufficient taxable income against which to use the credits. The future results of this business could be negatively impacted by administrative actions of the Internal Revenue Service or the U.S. Treasury or changes in law, regulation or administration.

Problems with operations could cause us to incur substantial costs.

Each of our 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 TECO Wholesale Generation 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. Our outlook assumes normal operations and normal maintenance periods for our subsidiaries' facilities.

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

Our subsidiaries are involved in certain 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. The international subsidiaries attempt to manage these risks through a variety of risk mitigation measures, including specific contractual provisions, obtaining non-recourse financing and obtaining political risk insurance where appropriate.

TECO Transport 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 Transport attempts to manage these risks through a variety of risk mitigation measures, including retaining agents with local knowledge and experience in successfully discharging cargoes and vessels similar to those used.

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

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

Consolidated Balance Sheets

Assets *(millions, except share amounts) Dec. 31,*	*2003*	*2002*
Current assets		
Cash and cash equivalents	**$ 108.2**	$ 411.1
Restricted cash	**51.4**	1.6
Receivables, less allowance for uncollectibles of $4.5 and $6.6 at Dec. 31, 2003 and 2002, respectively	**280.4**	422.7
Current notes receivable	**–**	235.1
Current derivative assets	**21.1**	12.5
Inventories, at average cost		
Fuel	**88.2**	113.7
Materials and supplies	**82.5**	96.1
Prepayments and other current assets	**68.6**	30.4
Assets held for sale	**169.4**	–
Total current assets	**869.8**	1,323.2
Property, plant and equipment		
Utility plant in service		
Electric	**5,245.6**	5,054.4
Gas	**778.1**	746.7
Construction work in progress	**1,193.3**	1,556.8
Other property	**823.2**	857.4
Property, plant and equipment, at original cost	**8,040.2**	8,215.3
Accumulated depreciation	**(2,361.2)**	(2,310.7)
Total property, plant and equipment (net)	**5,679.0**	5,904.6
Other assets		
Deferred income taxes	**1,051.5**	340.2
Other investments	**16.5**	845.3
Regulatory assets	**188.3**	163.2
Investment in unconsolidated affiliates	**343.5**	149.2
Goodwill	**71.2**	193.7
Deferred charges and other assets	**165.1**	159.0
Assets held for sale	**2,077.4**	-
Total other assets	**3,913.5**	1,850.6
Total assets	**$10,462.3**	$ 9,078.4

Liabilities and capital *(millions, except share amounts) Dec. 31,*	*2003*	*2002*
Current liabilities		
Long-term debt due within one year		
Recourse	**$ 6.1**	$ 106.3
Non-recourse	**25.5**	20.8
Notes payable	**37.5**	360.5
Accounts payable	**313.8**	377.4
Customer deposits	**101.4**	94.6
Current derivative liabilities	**12.0**	3.9
Interest accrued	**56.6**	49.8
Taxes accrued	**149.9**	95.9
Liabilities associated with assets held for sale	**1,544.4**	–
Total current liabilities	**2,247.2**	1,109.2
Other liabilities		
Deferred income taxes	**498.0**	495.0
Investment tax credits	**22.8**	27.5
Regulatory liabilities	**560.2**	538.7
Deferred credits and other liabilities	**364.1**	321.7
Liabilities associated with assets held for sale	**697.8**	–
Long-term debt, less amount due within one year		
Recourse	**3,660.3**	3,112.7
Non-recourse	**83.2**	211.6
Preferred securities	**649.1**	–
Minority interest	**1.9**	1.2
Total other liabilities	**6,537.4**	4,708.4
Commitments and contingencies	**–**	–
Preferred securities	**–**	649.1
Capital		
Common equity (400 million shares authorized; par value $1; 187.8 million shares and 175.8 million shares outstanding at Dec. 31, 2003 and 2002, respectively)	**187.8**	175.8
Additional paid in capital	**1,220.8**	1,094.5
Retained earnings	**339.5**	1,413.7
Accumulated other comprehensive income	**(55.8)**	(41.2)
Common equity	**1,692.3**	2,642.8
Unearned compensation	**(14.6)**	(31.1)
Total capital	**1,677.7**	2,611.7
Total liabilities and capital	**$10,462.3**	$ 9,078.4

Consolidated Statements of Income

(millions, except per share amounts)

For the years ended Dec. 31,		*2003*	*2002*	*2001*
Revenues	Regulated electric and gas (includes franchise fees and gross receipts taxes of $77.7 million in 2003, $73.8 million in 2002 and $71.1 million in 2001)	**$ 1,991.1**	$ 1,867.0	$ 1,733.0
	Unregulated	**748.9**	797.9	750.3
	Total revenues	**2,740.0**	2,664.9	2,483.3
Expenses	Regulated operations			
	Fuel	**344.9**	312.7	218.2
	Purchased power	**184.8**	202.3	144.7
	Cost of natural gas sold	**224.0**	149.0	186.4
	Other	**258.4**	257.2	250.0
	Other operations	**761.8**	705.7	688.8
	Maintenance	**152.4**	162.1	151.4
	Depreciation	**326.0**	303.2	284.6
	Asset impairment	**145.1**	–	–
	Goodwill and intangible asset impairment	**122.7**	–	–
	Restructuring charges	**24.6**	17.8	–
	Taxes, other than income	**175.2**	173.1	161.3
	Total expenses	**2,719.9**	2,283.1	2,085.4
Income (loss) from operations		**20.1**	381.8	397.9
Other income (expense)	Allowance for other funds used during construction	**19.8**	24.9	6.6
	Other income	**114.5**	19.0	23.1
	Loss on debt extinguishment	**–**	(34.1)	–
	Contingent arbitration reserve	**(32.0)**	–	–
	Earnings (loss) from equity investments	**(0.4)**	5.5	9.1
	Total other income (expense)	**101.9**	15.3	38.8
Interest charges	Interest expense	**288.4**	142.3	164.1
	Distribution on preferred securities	**39.9**	38.9	17.0
	Allowance for borrowed funds used during construction	**(7.6)**	(9.6)	(2.6)
	Total interest charges	**320.7**	171.6	178.5
(Loss) income from continuing operations before provision for income taxes		**(198.7)**	225.5	258.2
(Benefit) for income taxes		**(135.2)**	(51.7)	(7.3)
Net (loss) income from continuing operations before minority interests		**(63.5)**	277.2	265.5
Minority interest		**48.8**	–	–
Net (loss) income from continuing operations		**(14.7)**	277.2	265.5
Discontinued operations	Income (loss) from discontinued operations	**(1,394.6)**	60.3	35.4
	Income tax (benefit) provision	**(504.2)**	7.4	(2.8)
	Total discontinued operations	**(890.4)**	52.9	38.2
Cumulative effect of change in accounting principle, net of tax		**(4.3)**	–	–
Net (loss) income		**$ (909.4)**	$ 330.1	$ 303.7
Average common shares outstanding				
	Basic	**179.9**	153.2	134.5
	Diluted	**179.9**	153.3	135.4
Earnings per share from continuing operations				
	Basic	**$ (0.08)**	$ 1.81	$ 1.98
	Diluted	**$ (0.08)**	$ 1.81	$ 1.96
Earnings per share				
	Basic	**$ (5.05)**	$ 2.15	$ 2.26
	Diluted	**$ (5.05)**	$ 2.15	$ 2.24
Dividends paid per common share outstanding		**$ 0.925**	$ 1.41	$ 1.37

Consolidated Statements of Comprehensive Income

(millions)

For the years ended Dec. 31,		*2003*	*2002*	*2001*
Net (loss) income		**$ (909.4)**	$ 330.1	$ 303.7
Other comprehensive loss, net of tax				
	Foreign currency translation adjustments	**1.2**	(1.2)	–
	Net unrealized gains (losses) on cash flow hedges	**28.1**	(13.2)	(19.2)
	Minimum pension liability adjustments	**(43.9)**	(4.4)	0.3
	Other comprehensive loss, net of tax	**(14.6)**	(18.8)	(18.9)
Comprehensive (loss) income		**$ (924.0)**	$ 311.3	$ 284.8

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

Consolidated Statements of Cash Flows

(millions) *For the years ended Dec. 31,*	*2003*	*2002*	*2001*
Cash flows from operating activities			
Net (loss) income	**$ (909.4)**	$ 330.1	$ 303.7
Adjustments to reconcile net (loss) income to net cash from operating activities:			
Depreciation	**382.0**	303.2	284.6
Deferred income taxes	**(709.4)**	(96.5)	(102.9)
Investment tax credits, net	**(4.7)**	(4.8)	(4.9)
Allowance for funds used during construction	**(27.4)**	(34.5)	(9.2)
Amortization of unearned compensation	**18.3**	13.9	9.7
Cumulative effect of change in accounting principle, pre-tax	**7.1**	–	–
Gain on sales of business/assets, pre-tax	**(147.5)**	(15.1)	–
Equity in earnings of unconsolidated affiliates	**13.8**	15.3	(3.1)
Minority loss	**(48.8)**	–	–
Asset impairment, pre-tax	**1,330.8**	–	–
Goodwill and intangible asset impairment, pre-tax	**122.7**	–	–
Loss on joint venture termination, pre-tax	**153.9**	–	–
Contingent arbitration reserve	**32.0**	–	–
Deferred recovery clause	**(27.3)**	72.2	(19.0)
Refunded to customers	**–**	(6.4)	–
Receivables, less allowance for uncollectibles	**96.4**	(64.1)	57.1
Inventories	**7.0**	(39.4)	(22.8)
Prepayments and other deposits	**(16.5)**	6.3	(14.3)
Taxes accrued	**34.5**	24.1	16.4
Interest accrued	**(60.7)**	14.2	(6.3)
Accounts payable	**(17.5)**	98.3	(51.3)
Other	**99.3**	38.9	65.0
Cash flows from operating activities	**328.6**	655.7	502.7
Cash flows from investing activities			
Capital expenditures	**(590.6)**	(1,065.2)	(965.9)
Allowance for funds used during construction	**27.4**	34.5	9.2
Purchase of minority interest	**–**	(9.9)	–
Net proceeds from sales of business/assets	**296.5**	103.3	(272.6)
Restricted cash	**(63.5)**	–	–
Investment in unconsolidated affiliates	**(30.6)**	(7.6)	27.6
Other non-current investments	**(32.4)**	(715.6)	95.7
Cash flows from investing activities	**(393.2)**	(1,660.5)	(1,106.0)
Cash flows from financing activities			
Dividends	**(165.2)**	(215.8)	(184.2)
Common stock	**136.6**	572.6	348.4
Proceeds from long-term debt	**655.1**	1,758.4	1,255.9
Minority interest	**44.4**	–	–
Restricted cash	**(5.9)**	–	–
Repayment of long-term debt	**(526.5)**	(949.7)	(236.5)
Settlement of joint venture termination obligation	**(33.5)**	–	
Net decrease in short-term debt	**(323.0)**	(278.4)	(570.0)
Issuance of preferred securities	**–**	435.6	–
Equity contract adjustment payments	**(20.3)**	(15.3)	–
Cash flows from financing activities	**(238.3)**	1,307.4	613.6
Net (decrease) increase in cash and cash equivalents	**(302.9)**	302.6	10.3
Cash and cash equivalents at beginning of year	**411.1**	108.5	98.2
Cash and cash equivalents at end of year	**$ 108.2**	$ 411.1	$ 108.5

Supplemental disclosure of cash flow information			
Cash paid during the year for:			
Interest (net of amounts capitalized) [(1)]	**$ 493.1**	$ 160.2	$ 178.1
Income taxes	**$ 58.8**	$ 71.9	$ 52.4

(1) Included in interest paid during the year is interest paid on debt obligations for discontinued operations of $166.6 million for 2003. There was no interest paid on debt obligations for discontinued operations in 2002 or 2001.

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, 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, after tax						(18.9)		(18.9)
Common stock issued	13.3	6.3	203.2	144.7			(5.8)	348.4
Cash dividends declared					(184.2)			(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, 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
Net (loss) for 2003					(909.4)			(909.4)
Other comprehensive loss, after tax						(14.6)		(14.6)
Common stock issued	12.0	12.0	125.0				(0.4)	136.6
Cash dividends declared					(165.2)			(165.2)
Amortization of unearned compensation							18.3	18.3
Tax benefits - ESOP dividends and stock options			1.3		0.4			1.7
Performance shares							(1.4)	(1.4)
Balance, Dec. 31, 2003	**187.8**	**$187.8**	**$ 1,220.8**	**$ –**	**$ 339.5**	**$(55.8)**	**$ (14.6)**	**$1,677.7**

(1) TECO Energy had 400 million shares of $1 par value common stock authorized in 2003, 2002 and 2001.
The accompanying notes are an integral part of the consolidated financial statements.

1. Significant Accounting Policies

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

Principles of Consolidation

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

Results of operations for the proportional share of expenses, revenues and assets reflecting TECO Coalbed Methane's undivided interest in joint venture property are included in the consolidated financial statements through Dec. 31, 2002.

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

Revised Segment Reporting

As more fully described in **Note 14**, the Union and Gila River projects' results have been reflected in discontinued operations. This reclassification, as well as other changes described below, significantly revised operating segments used for decision-making purposes.

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

The non-merchant operations, formerly included in the TECO Power Services operating segment, are comprised of the results from Hardee Power Partners, Ltd. (HPP), up to the date of the sale (see **Note 21** for details), the Hamakua power plant in Hawaii, the Guatemalan operations which include the San José and Alborada power plants and an equity investment in the Guatemalan distribution company, EEGSA, and other non-merchant activities. These non-merchant operations are reported in the Other Unregulated segment (see **Note 19**).

Cash Equivalents

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

Restricted Cash

Restricted cash at Dec. 31, 2003 is comprised of $15.4 million of cash accumulated in escrow under the sale agreement of the 49.5-percent interest of TECO Coal's synthetic fuel production facilities to provide credit support for the company's obligation under the sale agreement due to the company's current credit rating, and $36.0 million held in escrow from the sale HPP (see **Note 21**). Over time, up to $50 million of cash from the synthetic fuel facility sale will accumulate in escrow to support the company's obligation under the sale agreement due to the company's current credit rating.

Cost Capitalization

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

Debt issuance costs – The company capitalizes the external costs of obtaining debt financing and amortizes such costs over the life of the related debt.

Capitalized interest expense – Interest costs for the construction of non-utility facilities are capitalized and depreciated over the service lives of the related property. TECO Energy capitalized $17.3 million, $63.2 million, and $23.0 million of interest costs in 2003, 2002 and 2001, 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, Peoples Gas System (PGS) and TWG expense major maintenance costs as incurred. For Tampa Electric and PGS, concurrent with a planned major maintenance outage, the cost of adding or replacing retirement units-of-property is capitalized in conformity with Florida Public Service Commission (FPSC) and Federal Energy Regulatory Commission (FERC) regulations.

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

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 2003, 2002 and 2001. Total AFUDC for 2003, 2002 and 2001 was $27.4 million, $34.5 million, and $9.2 million, respectively. The base on which AFUDC is calculated excludes construction work-in-progress which has been included in rate base.

Other Investments

Other investments, which include longer-term passive investments, at Dec. 31, 2003 and 2002 were as follows:

Other Investments

(millions) Dec. 31,	*Rate*	*Due Date*	*2003*	*2002*
Notes receivable from:				
Panda Energy (1)	14.00%	1/3/03	**$ –**	$ 137.0
EEGSA	6.14%(2)	9/11/07	**8.1**	11.1
TECO-Panda Generating Company, L.P. (TPGC) (4)	7.79%(3)	11/30/04	**–**	369.5
TECO-Panda Generating Company, L.P. (4)	6.58%(3)	11/30/04	**–**	426.3
Municipal Gas Authority of Georgia (5)	1.38%	3/31/03	**–**	98.1
Continuing investments in leveraged leases	–	–	**8.4**	9.4
Other investments	–	–	**–**	29.0
			16.5	1,080.4
Current notes receivable			**–**	235.1
Other non-current investments			**$16.5**	$ 845.3

(1) On Jan. 3, 2003, this note receivable was converted to an ownership interest (see **Note 21**).
(2) Current rate at Dec. 31, 2003.
(3) Current rate at Dec. 31, 2002.
(4) As of Apr. 1, 2003, TPGC was consolidated as part of the TWG consolidated group. See **Note 12** for additional details regarding the consolidation.
(5) Received payment of this note receivable, relating to the sale of TECO Coalbed Methane, on Jan. 30, 2003 (see **Note 21**).

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.

Investments in Unconsolidated Affiliates

Investments in unconsolidated affiliates are accounted for using the equity method of accounting. The percentage ownership interest for each investment at Dec. 31, 2003 and 2002 is presented in the following table:

TECO Energy and Subsidiaries' Percent Ownership in Unconsolidated Affiliates

Dec. 31,	*2003*	*2002*
TECO Wholesale Generation (TWG)		
TPGC (1)	**100%**	50%
Texas Independent Energy, L.P. (TIE) (2)	**50**	–
Other unregulated		
Empresa Eléctrica de Guatemala, S.A. (EEGSA)	**24%**	24%
Hamakua Energy Partners, L.P.	**50**	50
Hamakua Land Partnership, LLP	**50**	50
US Propane, LLC (3)	**38**	38
TECO AGC, Ltd.	**50**	50
Litestream Technologies, LLC	**36**	65
Hernando Oaks, LLC	**50**	50
Brandon Properties Partners, Ltd.	**50**	50
Walden Woods Business Center, Ltd.	**50**	50
B-T One, LLC (4)	**80**	50

(1) TWG consolidated TPGC effective Apr. 1, 2003 and received Panda's 50-percent interest in June 2003. See **Note 12** for a detailed discussion.
(2) The TIE investment is held by PLC Development Holdings, LLC (PLC). TWG indirectly obtained 50-percent of PLC in January 2003 and the remaining ownership interests outstanding in September 2003. See **Notes 12, 17** and **21** for a complete description of these transactions.
(3) See **Note 23** for information regarding the recent sale of interests held by US Propane.
(4) During April 2003, the company renegotiated the terms of the partnership agreement of B-T One, LLC, to reflect the economic interests of the partners. Effective Apr. 1, 2003, the company indirectly owns an 80-percent interest in the partnership.

Deferred Income Taxes

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

Investment Tax Credits

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

Revenue Recognition

TECO Energy recognizes revenues consistent with the Securities and Exchange Commission's Staff Accounting Bulletin (SAB) 104, *Revenue Recognition in Financial Statements*. The interpretive criteria outlined in SAB 104 are that 1) there is persuasive evidence that an arrangement exists; 2) delivery has occurred or services have been rendered; 3) the fee is fixed and determinable; and 4) collectibility is reasonably assured. Except as discussed below, TECO Energy and its subsidiaries recognize revenues on a gross basis when earned for the physical delivery of products or services and the risks and rewards of ownership have transferred to the buyer. Revenues for any financial or hedge transactions that do not result in physical delivery are reported on a net basis.

The regulated utilities' (Tampa Electric and PGS) retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by FERC. See **Note 4** for a discussion of significant regulatory matters and the applicability of Financial Accounting Standard No. (FAS) 71, *Accounting for the Effects of Certain Types of Regulation*, to the company.

Revenues 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 BCH Mechanical (formerly part of TECO Energy Services) are recognized under the same method, which includes estimates of the total costs for the project compared to the estimated progress of the work required to complete the contract.

Revenues and Fuel Costs

Revenues include amounts resulting from cost recovery clauses which provide for monthly billing charges to reflect increases or decreases in fuel, purchased power, conservation and environmental costs for Tampa Electric and purchased gas, interstate pipeline capacity and conservation costs for PGS. These adjustment factors are based on costs incurred and projected for a specific recovery period. Any over-recovery or under-recovery of costs plus an interest factor are taken into account in the process of setting adjustment factors for subsequent recovery periods. Over-recoveries of costs are recorded as deferred credits, and under-recoveries of costs are recorded as deferred charges.

Certain other costs incurred by the regulated utilities are allowed to be recovered from customers through prices approved in the regulatory process. These costs are recognized as the associated revenues are billed. The regulated utilities accrue base revenues for services rendered but unbilled to provide a closer matching of revenues and expenses. See **Note 4**.

As of Dec. 31, 2003 and 2002, unbilled revenues of $45.7 million and $41.3 million, respectively, are included in the "Receivables" line item on the balance sheet.

Purchased Power

Tampa Electric purchases power on a regular basis primarily to meet the needs of its retail customers. As a result of the sale of HPP in 2003 (see **Notes 14** and **21**), power purchases from HPP, subsequent to the sale, are reflected as non-affiliate purchases by Tampa Electric. Tampa Electric's long-term power purchase agreement from HPP was not affected by the sale of HPP. Under the existing agreement, which has been approved by the FPSC, Tampa Electric has the right to purchase, on average, approximately 52% of the total output of the Hardee power station. Tampa Electric purchased power from non-TECO Energy affiliates, including purchases from HPP, at a cost of $234.9 million, $253.7 million, and $209.7 million, respectively, for the years ended Dec. 31, 2003, 2002 and 2001. The associated revenue at HPP from power sold to Tampa Electric of $50.1 million, $51.4 million and $65.0 million for 2003, 2002 and 2001, respectively, is offset against "Regulated operations – Purchased power" in the income statement. The purchased power costs at Tampa Electric are recoverable through an FPSC-approved cost recovery clause.

In order to meet firm commitments or maintain acceptable operating conditions, TWG's power plants may also purchase power in the ordinary course of business. Total unregulated purchases of power at TWG for continuing operations, for the years ended Dec. 31, 2003, 2002 and 2001, were $26.6 million, $20.2 million, and $4.2 million, respectively. Unregulated power purchases are reported in "Other operations" in the income statement.

Depreciation

TECO Energy provides for depreciation primarily by the straight-line method at annual rates that amortize the original cost, less net salvage value, of depreciable property over its estimated service life. Unregulated electric generating, pipeline and transmission facilities are depreciated over the expected useful lives of the related equipment, a period of up to 40 years. The provision for total regulated and unregulated plant in service, expressed as a percentage of the original cost of depreciable property, was 4.5% for 2003 and 4.2% for 2002 and 2001. For the year ended Dec. 31, 2003, Tampa Electric recognized depreciation expense of $36.6 million related to accelerated depreciation of certain Gannon power station coal-fired assets, in accordance with a regulatory order issued by the FPSC. Construction work-in-progress is not depreciated until the asset is completed or placed in service.

The implementation of FAS 143, *Accounting for Asset Retirement Obligations*, in 2003 resulted in an increase in the carrying amount of long-lived assets and the reclassification of the accumulated reserve for cost of removal from accumulated depreciation to "Regulatory liabilities" for all periods presented. The adjusted capitalized amount is depreciated over the remaining useful life of the asset. See **Note 5**.

Accounting for Excise Taxes, Franchise Fees and Gross Receipts

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

The regulated utilities are allowed to recover certain costs incurred from customers through prices approved by the FPSC. The amounts included in customers' bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Statements of Income. These amounts totaled $77.7 million, $73.8 million and $71.1 million for the years ended Dec. 31, 2003, 2002 and 2001, respectively. Franchise fees and gross receipt taxes payable by the regulated utilities are included as an expense on the Consolidated Statements of Income in "Taxes, other than income." For the years ended Dec. 31, 2003, 2002 and 2001, these totaled $77.5 million, $73.7 million and $71.0 million, respectively.

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 superseded FAS 121, *Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of*. FAS 144 addresses accounting and reporting for the impairment or disposal of long-lived assets, including the disposal of a component of a business.

In accordance with FAS 144, the company assesses whether there has been an impairment of its long-lived assets and certain intangibles held and used by the company when such impairment indicators exist. During 2003, certain events, including market conditions, third-party actions, operating results and changes in the company's long-term strategic plan have occurred, requiring management to assess the likelihood of an impairment for certain long-lived assets and certain intangibles held and used by the company. Indicators of impairment existed for certain asset groups, including long-term turbine purchase contracts, finite-lived intangible assets and merchant power plants, triggering a requirement to ascertain the recoverability of these assets using undiscounted cash flows before interest expense. See **Note 10** for specific details regarding the results of these assessments.

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.

Stock-Based Compensation

TECO Energy has adopted the disclosure-only provisions of FAS 123, *Accounting for Stock-Based Compensation*, but applies Accounting Principles Board Opinion No. (APB) 25, *Accounting for Stock Issued to Employees*, and related interpretations in accounting for its stock-based compensation plans. See **Note 9** for the pro forma impact that the application of the recognition provisions of FAS 123 would have on reported net income and earnings per share.

Effective Jan. 1, 2003, the company adopted FAS 148, *Accounting for Stock-Based Compensation–Transition and Disclosure, an amendment of FASB Statement No. 123*. This standard amends FAS 123 to provide 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 adoption of the disclosure provisions of this standard did not have a material impact on the company's financial position.

Restrictions on Dividend Payments and Transfer of Assets

Dividends on TECO Energy's common stock are declared and paid at the discretion of its Board of Directors. The primary sources of funds to pay dividends on TECO Energy's common stock are dividends and other distributions from its operating companies. TECO Energy's $380 million note indenture contains a covenant that requires the company to achieve certain interest coverage levels in order to pay dividends. TECO Energy's Merrill Lynch credit facility contains a covenant that could limit the payment of dividends exceeding $40 million in any quarter under certain circumstances if the facility is drawn. Tampa Electric's first mortgage bond indenture and certain long-term debt at PGS contain restrictions that limit the payment of dividends and distributions on the common stock of Tampa Electric. Tampa Electric's first mortgage bond indenture does not limit loans or advances. As of Dec. 31, 2003 and 2002, the balances restricted as to transfers from Tampa Electric to TECO Energy under the first mortgage bonds were 3% and 20%, respectively, of consolidated common equity. Tampa Electric's new credit facilities include a covenant limiting cumulative distributions and outstanding affiliate loans.

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

See **Notes 6, 7** and **20** for a more detailed description of significant financial covenants.

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

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 2003, 2002 and 2001 were not significant. The foreign investments are generally protected from any significant currency gains or losses by the terms of the power sales agreements and other related contracts, in which payments are defined in U.S. dollars.

Reclassifications

Certain prior year amounts were reclassified to conform with the current year presentation. Results for all prior periods have been reclassified from continuing operations to discontinued operations as appropriate for each of the entities as discussed in **Note 14**.

2. Derivatives and Hedging

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

- To limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric and PGS;
- To limit the exposure to interest rate fluctuations on debt 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 TWG; and
- To limit the exposure to price fluctuations for physical purchases of fuel at TECO Transport.

TECO Energy and its affiliates use derivatives only to reduce normal operating and market risks, not for speculative purposes. The company's primary objective in using derivative instruments for regulated operations is to reduce the impact of market price volatility on ratepayers. 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 and other relevant metrics are performed by a centralized risk management group which is independent of all operating companies.

The company applies the provisions of FAS 133, *Accounting for Derivative Instruments and Hedging Activities*. The 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 deferred in OCI related to an effective designated cash flow hedge must be reclassified to current earnings if the anticipated hedged transaction is no longer probable of occurring. At adoption on Jan. 1, 2001, 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. TECO Coalbed Methane was subsequently reclassified to discontinued operations, reflecting the December 2002 sale of the company's investment in the entity, as discussed in **Notes 14** and **21**.

At Dec. 31, 2003 and 2002, respectively, TECO Energy and its affiliates had derivative assets (current and non-current) totaling $21.1 million and $12.6 million, and liabilities (current and non-current) totaling $12.0 million and $4.1 million. At Dec. 31, 2003 and 2002, accumulated other comprehensive income (OCI) included $4.3 million and $32.4 million, respectively, of unrealized after-tax losses, representing the fair value of cash flow hedges whose transactions will occur in the future. Included in OCI at Dec. 31, 2003 is an unrealized after-tax loss of $14.6 million on interest rate swaps designated as cash flow hedges, reflecting the remaining amount included in OCI related to cash flow hedges for the period preceding the expected disposition of TPGC (see **Note 14**). At Dec. 31, 2002 the unrealized after-tax loss of $37.3 million, included in OCI, represented the company's proportionate share of OCI at TPGC, in accordance with the equity method of accounting. Amounts recorded in OCI reflect the estimated fair value of derivative instruments designated as hedges, based on market prices as of the balance sheet date. These amounts are expected to fluctuate with movements in market prices and may or may not be realized as a loss upon future reclassification from OCI.

For the years ended Dec. 31, 2003, 2002 and 2001, TECO Energy and its affiliates reclassified amounts from OCI (excluding certain reclassifications for interest rate swaps described below) and recognized net pre-tax losses of $12.6 million, $29.0 million and $19.7 million, respectively. 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 or received for spot purchases of natural gas or decreased revenue from sales of electricity. Conversely, reclassification of a gain from OCI to earnings is offset by the increased cost of spot purchases of natural gas or sales of electricity.

As a result of 1) the suspension of construction on the Dell and McAdams power plants at TWG in 2003 and 2) the maintenance activity on the Frontera Power Station at TWG in early 2003, the company discontinued hedge accounting for purchases of natural gas and sales of electricity which were no longer anticipated to take place within two months of the originally designated time period for delivery. The discontinuation of hedge accounting resulted in a reclassification of a pre-tax 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 pre-tax loss reported above for 2002. In addition, as a result of the designation of TPGC as an asset held for sale, the company concluded that the hedged interest expense for periods beyond the expected disposition date are no longer probable. As a result, the company reclassified a pre-tax loss of $63.8 million ($41.5 million after tax) from OCI to income from discontinued operations (see **Note 14**). Gains and losses on these derivative instruments, subsequent to the discontinuation of hedge accounting treatment, were recorded in earnings.

Based on the fair value of cash flow hedges at Dec. 31, 2003, pre-tax losses of $9.0 million are expected to be reversed from OCI to the Consolidated Statements of Income within the next twelve months. However, these losses and other future reclassifications from OCI will fluctuate with movements in the underlying market price of the derivative instruments. The company does not currently have any cash flow hedges for transactions forecasted to take place in periods subsequent to 2006.

At Dec. 31, 2003, Prior Energy, a subsidiary of TECO Energy, had transactions in place to hedge gas storage inventory that qualify for fair value hedge accounting treatment under FAS 133. During the years ended Dec. 31, 2003, 2002 and 2001, respectively, the company recognized pre-tax gains (losses) of $(1.3) million, $0.7 million and $0.1 million, respectively. These gains and losses are included in discontinued operations as a result of the expected sale of Prior Energy (see **Notes 14** and **21**). See **Note 23** for details regarding the subsequent sale of Prior Energy. For the years ended Dec. 31, 2003, 2002 and 2001, respectively, the company also recognized pre-tax losses of $6.5 million, $2.4 million and $1.5 million, relating to derivatives that were not designated as either a cash flow or fair value hedge.

3. 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 and intangible assets, with an indefinite life, are subject to an annual assessment for impairment by applying a fair-value-based test. Intangible assets with a measurable useful life are required to be amortized.

As required under FAS 142, *Goodwill and Other Intangible Assets*, TECO Energy reviews recorded goodwill and intangible assets at least annually for each reporting unit. Reporting units are generally determined as one level below the operating segment level; reporting units with similar characteristics are grouped for the purpose of determining the impairment, if any, of goodwill and other intangible assets. The fair value for the reporting units evaluated is generally determined using discounted cash flows appropriate for the business model of each significant group of assets within each reporting unit. The models incorporate assumptions relating to future results of operations that are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. Management periodically reviews and adjusts the assumptions, as necessary, to reflect current market conditions and observable activity. If a sale is expected in the near term or a similar transaction can be readily observed in the marketplace, then this information is used by management to estimate the fair value of the reporting unit.

As a result of the consolidation of TPGC, effective Apr. 1, 2003 (see **Note 12**), the completion and commercial operation of the Union Power Partners (UPP) plant in June 2003, and the termination of the partnership with Panda Energy in June 2003, management initiated an interim review for the possible impairment of goodwill associated with TWG's reporting units. This evaluation indicated that an impairment of goodwill existed. Accordingly, the fair value of the reporting unit was determined, in accordance with the policy described above, to calculate the goodwill impairment. Consequently, the company recorded a pre-tax impairment charge in June 2003 of $95.2 million to write off all of the goodwill previously recorded at these reporting units based on the implied fair value of the goodwill for each respective reporting unit. This goodwill arose from the previous acquisitions of the Commonwealth Chesapeake power station in Virginia and the Frontera power station in Texas. TWG has no remaining goodwill.

In connection with the annual goodwill assessment, the company determined that the goodwill recognized and associated with TECO Energy Services, relating to BCH Mechanical and BGA, was impaired. The company recognized a goodwill impairment pre-tax loss of $19.4 million. Additionally, goodwill of $9.6 million related to Prior Energy has been reclassified to "Assets held for sale" (see **Notes 14** and **23**).

The amount of intangible assets recorded in "Other assets" at Dec. 31, 2003 and 2002 was $4.9 million and $12.6 million, respectively (net of accumulated amortization in 2002 of $13.3 million). For the years ended Dec. 31, 2003 and 2002, the company recognized amortization expense of $4.7 million and $23.1 million, respectively. TECO Energy expects to recognize amortization expense of $0.2 million each year for 2004-2009.

Intangible assets at Dec. 31, 2002 included $8.1 million relating to an indefinite-lived intangible asset arising from gasification technology licenses held by TWG and a long-term customer arrangement at BGA. However, in 2003, due to changes in management's long-term strategic plan and the expected disposal of BGA, a pre-tax impairment charge of $8.1 million was recognized to write off the value of these intangible assets.

The pro forma reconciliation of reported net income and earnings per share to adjusted net income excluding goodwill amortization expense for the years ended Dec. 31, 2003, 2002 and 2001 follows:

Pro Forma Effect of FAS 142 Adoption

(millions, except per share amounts)	*2003*	*2002*	*2001*
Net (loss) income:			
As reported	**$(909.4)**	$ 330.1	$ 303.7
Add: Goodwill amortized, net of tax	–	–	3.7
Adjusted net (loss) income	**$(909.4)**	$ 330.1	$ 307.4
Earnings per share – basic:			
As reported	**$ (5.05)**	$ 2.15	$ 2.26
Add: Goodwill amortized, net of tax	–	–	0.03
Adjusted basic earnings per share	**$ (5.05)**	$ 2.15	$ 2.29
Earnings per share – diluted:			
As reported	**$ (5.05)**	$ 2.15	$ 2.24
Add: Goodwill amortized, net of tax	–	–	0.03
Adjusted diluted earnings per share	**$ (5.05)**	$ 2.15	$ 2.27

4. Regulatory

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

Base Rate – Tampa Electric

Since the expiration, in 1999, 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, Tampa Electric is not under a new stipulation to stabilize prices while securing fair earnings opportunities. Tampa Electric's 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.

Tampa Electric has not sought a base rate increase to recover the investment in the Bayside Power Station, of which phase one entered service in April 2003.

Cost Recovery – Tampa Electric

2003 Proceedings

In February 2003, Tampa Electric filed a request for an additional fuel cost adjustment of almost $61 million due to continued increases in the cost of natural gas and oil and the plan to phase out Gannon Units 1 through 4 in 2003. In March 2003, the FPSC approved Tampa Electric's new fuel rates as well as new fuel rates for the other peninsular Florida investor-owned utilities.

In September 2003, 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 2004. In November 2003, the FPSC approved Tampa Electric's requested changes. The resulting rates included the impact of increased use of natural gas at the Bayside Power Station, the collection of approximately $91 million for under-recovery of fuel expense for 2002 and 2003, and estimated waterborne transportation rates for coal transportation services (see **Note 17**). The FPSC did not allow recovery of $8.4 million it characterized as savings from shutting down the Gannon Station earlier than originally planned, which the FPSC asserted generated operations and maintenance savings. The rates include projected costs associated with environmental projects required under the Environmental Protection Agency (EPA) Consent Decree and the Florida Department of Environmental Protection (FDEP) Consent Final Judgment (see **Note 20** for additional details regarding these environmental matters). The costs associated with this disallowance were recognized in 2003.

Tampa Electric filed its objection to the disallowance of the recovery of the $8.4 million and a motion asking the FPSC to reconsider its decision because all facts and law were not taken into account. The motion was filed on Jan. 6, 2004, and a decision on this matter is expected in the first quarter of 2004.

As part of the regulatory process, it is reasonably likely that third parties may intervene on this or similar matters in the future. The company is unable to predict the timing, nature or impact of such future actions.

Base Rate – Peoples Gas

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.

Cost Recovery – Peoples Gas

In November 2003, the FPSC approved rates under Peoples' Gas Purchased Gas Adjustment (PGA) cap factor for the period January 2004 through December 2004. The PGA is a factor that can vary monthly due to changes in actual fuel costs but is not anticipated to exceed the annual cap.

Other Items

Coal Transportation Contract

Tampa Electric's contract for coal transportation and storage services with TECO Transport expired on Dec. 31, 2003. In June 2003, Tampa Electric issued a Request For Proposal (RFP) to potential providers requesting services for the next five years. The result of the RFP process was the execution of a new contract between Tampa Electric and TECO Transport with market rates supported by the results of the RFP and an independent consultant in maritime transportation matters. The prudence of the RFP process and final contract is expected to be reviewed by the FPSC in May 2004, with a decision expected in July 2004.

Regional Transmission Organization (RTO)

In October 2002, the RTO process involving the proposed formation of GridFlorida LLC, as initiated in response to the Federal Regulatory Commission's (FERC's) continuing effort to affect open access to transmission facilities in large regional markets, was delayed when the OPC filed an appeal with the Florida Supreme Court asserting that the FPSC could not relinquish its jurisdictional responsibility to regulate the IOUs and the approval of GridFlorida would result in such a relinquishment. Oral arguments occurred in May 2003, and the Florida Supreme Court dismissed the OPC appeal citing that it was premature because certain portions of the FPSC GridFlorida order are not final.

In September 2003, a joint meeting of the FERC and FPSC took place to discuss wholesale market and RTO issues related to GridFlorida and in particular federal/state interactions. The FPSC has scheduled a series of collaborative meetings with all interested parties and upon their conclusion, will set items for hearing and a hearing schedule. This is expected to occur throughout 2004.

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 charges to reflect increases or decreases in fuel; purchased power, conservation and environmental costs; and deferral of costs as regulatory assets, when cost recovery is ordered over a period longer than a fiscal year, to the period that the regulatory agency recognizes them. Details of the regulatory assets and liabilities as of Dec. 31, 2003 and 2002 are presented in the following table:

Regulatory Assets and Liabilities *(millions)*

Dec. 31,	*2003*	*2002*
Regulatory assets:		
Regulatory tax asset [(1)]	**$ 63.3**	$ 54.9
Other:		
Cost recovery clauses	**59.7**	34.7
Coal contract buy-out [(2)]	**2.7**	5.4
Deferred bond refinancing costs [(3)]	**32.2**	35.9
Environmental remediation	**20.7**	20.3
Competitive rate adjustment	**5.3**	7.4
Other	**4.4**	4.6
	125.0	108.3
Total regulatory assets	**$ 188.3**	$ 163.2
Regulatory liabilities:		
Regulatory tax liability [(1)]	**$ 29.9**	$ 36.6
Other:		
Deferred allowance auction credits	**1.9**	2.1
Recovery clause related	**–**	2.2
Environmental remediation	**20.7**	20.3
Transmission and distribution storm reserve	**40.0**	36.0
Deferred gain on property sales [(4)]	**1.9**	0.9
Accumulated reserve – cost of removal	**462.2**	440.6
Other	**3.6**	–
	530.3	502.1
Total regulatory liabilities	**$ 560.2**	$ 538.7

(1) Related primarily to plant life. Includes $17.0 million and $20.9 million of excess deferred taxes as of Dec. 31, 2003 and 2002, respectively.
(2) Amortized over a 10-year period ending December 2004.
(3) Unamortized refinancing costs:

Related to debt transactions as follows (millions):	Amortized until:
$ 50.0	2004
$ 51.6	2005
$ 22.1	2007
$ 25.0	2011
$ 50.0	2011
$ 150.0	2012
$ 150.0	2012
$ 85.9	2014
$ 25.0	2021
$ 100.0	2022

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

5. Asset Retirement Obligations

On Jan. 1, 2003, TECO Energy adopted FAS 143, *Accounting for Asset Retirement Obligations*. The company recognized liabilities for retirement obligations associated with certain long-lived assets, in accordance with the relevant accounting guidance. An asset retirement obligation for a long-lived asset is recognized at fair value at inception of the obligation if there is a legal obligation under an existing or enacted law or statute, a written or oral contract, or by legal construction under the doctrine of promissory estoppel. Retirement obligations are recognized only if the legal obligation exists in connection with or as a result of the permanent retirement, abandonment or sale of a long-lived asset.

When the liability is initially recorded, the carrying amount of the related long-lived asset is correspondingly increased. Over time, the liability is accreted to its future value. The corresponding amount capitalized at inception is depreciated over the remaining useful life of the asset. The liability must be revalued each period based on current market prices.

TECO Energy has recognized asset retirement obligations for reclamation and site restoration obligations principally associated with coal mining, storage and transfer facilities. The majority of obligations arise from environmental remediation and restoration activities for coal-related operations. Prior to the adoption of FAS 143, TECO Coal accrued reclamation costs for such activities. For TECO Coal, the adoption of FAS 143 modifies the valuation and accrual methods used to estimate the fair value of asset retirement obligations.

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

For the year ended Dec. 31, 2003, TECO Energy recognized $1.2 million of accretion expense associated with asset retirement obligations. During this period, no new retirement obligations were incurred and no significant revisions to estimated cash flows used in determining the recognized asset retirement obligations were necessary. FAS 143 was not effective for the years ended Dec. 31, 2002 and 2001.

As regulated utilities, Tampa Electric and PGS must file depreciation and dismantlement studies periodically and receive approval from the FPSC before implementing new depreciation rates. Included in approved depreciation rates is either an implicit net salvage factor or a cost of removal factor, expressed as a percentage. The net salvage factor is principally comprised of two components—a salvage factor and a cost of removal or dismantlement factor. The company uses current cost of removal or dismantlement factors as part of the estimation method to approximate the amount of cost of removal in accumulated depreciation.

Upon adoption of FAS 143 at Jan. 1, 2003, the estimated accumulated cost of removal and dismantlement included in net accumulated depreciation as of Dec. 31, 2003 and 2002 of $462.2 million and $440.6 million, respectively, was reclassified to a regulatory liability for all periods presented (see also **Note 4**). For Tampa Electric and PGS, the original cost of utility plant retired or otherwise disposed of and the cost of removal, or dismantlement, less salvage value is charged to accumulated depreciation and the accumulated cost of removal reserve reported as a regulatory liability, respectively.

6. Short-Term Debt

At Dec. 31, 2003 and 2002, the following credit facilities and related borrowings existed:

Credit Facilities

	Dec. 31, 2003			*Dec. 31, 2002*		
(millions)	*Credit Facilities*	*Borrowings Outstanding*	*Letters of Credit Outstanding*	*Credit Facilities*	*Borrowings Outstanding*	*Letters of Credit Outstanding*
Recourse:						
Tampa Electric:						
1-year facility	**$ 125.0**	**$ –**	**$ –**	$ 300.0	$ –	$ –
3-year facility	**125.0**	**–**	**–**	–	–	–
TECO Energy:						
1-year term loan	**–**	**–**	**–**	350.0	350.0	–
18-month facility [1]	**100.0**	**–**	**–**	–	–	
1-year facility	**37.5**	**37.5**	**–**	–	–	–
3-year facility	**350.0**	**–**	**109.9**	350.0	–	179.8
Total	**$ 737.5**	**$ 37.5**	**$ 109.9**	$ 1,000.0	$ 350.0	$ 179.8

(1) See **Note 23** for details regarding the subsequent reduction of this credit facility.

These credit facilities require commitment fees ranging from 20 to 50 basis points. The weighted average interest rate on outstanding notes payable at Dec. 31, 2003 and 2002 was 6.63% and 1.88%, respectively. At Dec. 31, 2003 and 2002, notes payable consisted of the following:

Notes Payable

(millions) Dec. 31,	*2003*	*2002*
Credit facilities outstanding	**$ 37.5**	$ 350.0
Commercial paper	**–**	10.5
Total notes payable	**$ 37.5**	$ 360.5

Tampa Electric 1-year and 3-year facilities

On Nov. 7, 2003, Tampa Electric Company replaced its maturing $300 million credit facility with a $125 million one-year credit facility and a $125 million three-year credit facility, maturing in November 2004 and November 2006, respectively. In addition to the financial covenants described below and in **Notes 1** and **20**, the two new facilities include a covenant limiting cumulative distributions after Oct. 31, 2003 and outstanding affiliate loans to an amount representing an accumulation of net income after May 31, 2003 and capital contributions from the parent after Oct. 31, 2003, plus $450 million.

TECO Energy 1-year term loan

On Nov. 13, 2003, TECO Energy repaid the $350 million one-year credit facility maturing on that date.

TECO Energy 18-month facility

On Apr. 9, 2003, TECO Energy entered into a $350 million unsecured credit facility with Merrill Lynch for a term of up to eighteen months. The Merrill Lynch credit facility requires TECO Energy's debt-to-capital ratio, as defined in the credit agreement, not to exceed 65%. This facility also has covenants that, if the facility is drawn, could limit the payment of dividends exceeding $40 million in any quarter unless, prior to the payment of any dividends, the company delivers to Merrill Lynch liquidity projections satisfactory to Merrill Lynch demonstrating that the company will have sufficient cash or cash equivalents to pay both the dividends contemplated and each of the three quarterly dividends next scheduled to be paid on its common stock. Current quarterly dividends are $34.8 million.

On Nov. 12, 2003, TECO Energy and Merrill Lynch amended the existing $350 million credit facility to allow $100 million of credit capacity to remain in place subsequent to the repayment of the $350 million bank term maturity on Nov. 13, 2003. Under the terms of the original agreement, the facility would have been extinguished upon that repayment. The amendment made the $100 million commitment of undrawn line capacity available through Apr. 8, 2004, at which time the facility can be drawn up to $100 million and remain outstanding to Oct. 8, 2004. The $100 million facility is required to be reduced for certain asset sales and financings. See **Note 23** for details regarding the subsequent reduction of this facility due to subsequent asset sales.

On Dec. 19, 2003, TECO Energy and Merrill Lynch further amended the existing Merrill Lynch credit facility to put in place with Merrill and JP Morgan a contingent credit facility of $200 million. The contingent facility becomes effective only if the existing $350 million bank credit facility becomes unavailable because of non-compliance with the 65% debt-to-total-capital covenant or transfer of assets covenant as a result of write-offs or the disposition of TWG assets. Upon the occurrence of these particular events, TECO Energy would pledge the common stock of TECO Transport Corporation as security under the amended credit facility and the commitment available under the facility would be increased to $200 million, all of which would be available for letters of credit or cash draws. If the terms of the facility change as a result of these particular events, the amended facility would mature in December 2004. The contingent facility, if activated, would replace the existing $100 million Merrill Lynch facility. See **Note 20** for a summary of performance against significant financial covenant requirements.

TECO Energy 1-year facility

On June 24, 2003, TECO Energy entered into a one-year $37.5 million credit facility with four banks, collateralized by 50% of the Union and Gila River assets. The proceeds from the credit facility were used in the termination of the partnership with Panda. This credit facility has a debt-to-capital covenant similar to those of the other TECO Energy credit facilities, but also includes an earnings before interest, taxes, depreciation and amortization (EBITDA) to interest coverage requirement of 2.5 times, a limitation on liens of not more than 60% of the fair value of assets, and a restriction on the sale of any of the company's interest in the Union and Gila River projects. This loan can be repaid without penalty at any time with three business days' notice. See **Note 20** for a summary of performance against significant financial covenant requirements. Subsequent to Dec. 31, 2003, this obligation was repaid (see **Note 23**).

7. Long-Term Debt

At Dec. 31, 2003, total long-term debt had a carrying amount of $4,392.6 million and an estimated fair market value of $4,503.6 million. The estimated fair market value of long-term debt was based on quoted market prices for the same or similar issues, on the current rates offered for debt of the same remaining maturities, or for long-term debt issues with variable rates that approximate market rates, at carrying amounts. The carrying amount of long-term debt due within one year approximated fair market value because of the short maturity of these instruments.

A substantial part of the tangible assets of Tampa Electric is pledged as collateral to secure 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 2004 through 2008 are as follows:

Long-Term Debt Maturities For Continuing Operations

Dec. 31, 2003 (millions)	*2004*	*2005*	*2006 – 2008*	*Total 2004 – 2008*
TECO Energy				
Debt securities	$ –	$ –	$ 680.0	$ 680.0
Preferred securities (1)	–	–	449.1	449.1
Tampa Electric	0.8	–	125.0	125.8
Peoples Gas	5.3	5.5	42.7	53.5
TWG	–	–	–	–
TECO Transport	–	–	110.6	110.6
TECO Coal	–	–	–	–
Other (2)	25.5	20.7	51.6	97.8
	31.6	26.2	1,459.0	1,516.8
Liabilities associated with assets held for sale	2,087.3	–	–	2,087.3
Total long-term debt maturities	$ 2,118.9	$26.2	$1,459.0	$3,604.1

(1) FAS 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*, which was adopted on July 1, 2003, requires the classification of the preferred securities as debt.

(2) Includes debt maturities for the Guatemalan operations of $17.8 million, $20.7 million, and $51.6 million for 2004, 2005 and 2006-2008, respectively.

Debt

TECO Energy – $300 million 7.5% Senior Unsecured Notes

On June 13, 2003, TECO Energy issued $300 million of 7.5% Senior Unsecured Notes due in 2010. These notes contain a covenant that limits the ability of the company to create any lien upon any of its property in excess of 5% of consolidated tangible net assets, as defined in the agreement, without equally and ratably securing the 7.5% Notes. Net proceeds of $293 million were used to repay short-term debt and for general corporate purposes. See **Note 20** for a summary of performance against significant financial covenant requirements.

TECO Energy – $380 million 10.5% Senior Unsecured Notes

In November 2002, the proceeds from the issuance of TECO Energy notes were used for general corporate purposes and 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.

Tampa Electric – $250 million 6.25% Senior Notes

In April 2003, Tampa Electric issued $250 million of 6.25% Senior Notes due in 2016, in a private placement. Net proceeds of approximately $250 million were used to repay short-term indebtedness and for general corporate purposes at Tampa Electric. The 6.25% Senior Notes contain covenants that (1) require Tampa Electric Company to maintain, as of the last day of each fiscal quarter, a debt-to-capital ratio, as defined in the agreement, that does not exceed 60%, and (2) prohibit the creation of any liens on any of its property in excess of $787 million in the aggregate, with certain exceptions, as defined, without equally and ratably securing the 6.25% Senior Notes.

Preferred Securities

As a result of the adoption of FAS 150, on July 1, 2003, the preferred securities issued by the company were reclassified and presented as long-term debt for external financial reporting purposes only. The cumulative effect of the adoption of FAS 150 was an after-tax loss of $3.2 million ($5.3 million pre-tax), reflecting an adjustment to recognize interest expense ratably over the life of the instruments in accordance with the new guidance. See **Note 22** for a discussion of the estimated impact of new accounting guidance in 2004.

Capital Trust I

In December 2000, TECO Capital Trust I, a trust established for the sole purpose of issuing Trust Preferred Securities (TRuPS) and purchasing company preferred securities, issued 8 million shares of $25 par, 8.5% TRuPS, due 2041, with an aggregate liquidation value of $200 million. Each TRuPS represents an undivided beneficial interest in the assets of the Trust. The TRuPS represent an indirect interest in a corresponding amount of TECO Energy 8.5% junior subordinated notes due 2041. TECO Energy's proceeds from the sale of the junior subordinated notes were used to reduce the commercial paper outstanding and for general corporate purposes. Distributions are payable quarterly in arrears on January 31, Apr. 30, July 31, and October 31 of each year. Distributions were $17.0 million in 2003 and 2002 and $14.6 million in 2001.

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. Upon any liquidation of the company preferred securities, holders of the TRuPS would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends through the date of redemption.

Capital Trust II

In January 2002, TECO Energy sold 17.965 million mandatorily convertible equity security units in the form of 9.5% equity units at $25 per unit resulting in $436 million of net proceeds. Each equity unit consisted of $25 in principal amount of a trust preferred security of TECO Capital Trust II, a Delaware business trust formed for the purpose of issuing these securities, with a stated liquidation amount of $25 and a contract to purchase shares of common stock of TECO Energy in January 2005 at a price per share of between $26.29 and $30.10 based on the market price at that time. If the equity units had been converted as of Dec. 31, 2003, the company would have been required to issue 17.1 million shares of common stock to satisfy the mandatory conversion obligation. This is also the maximum number of shares issuable under the conversion feature. 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.

At Dec. 31, 2003 and 2002, TECO Energy had the following long-term debt outstanding:

Long-Term Debt *(millions) Dec. 31,*		*Due*	*2003*	*2002*
TECO Energy	Notes: 7.2% (effective rate of 7.38%) (1)	2011	**$ 600.0**	$ 600.0
	6.125% (effective rate of 6.31%) (1)	2007	**300.0**	300.0
	7% (effective rate of 7.08%) (1)	2012	**400.0**	400.0
	10.5% (effective rate of 12.37%) (1)(2)	2007	**380.0**	380.0
	7.5% (effective rate of 7.85%) (1)(2)	2010	**300.0**	–
	Preferred securities: 8.50% (3)	2041	**200.0**	–
	9.50% (4)	2007	**449.1**	–
			2,629.1	1,680.0
Tampa Electric	First mortgage bonds (issuable in series):			
	7.75% (effective rate of 7.96%)	2022	**75.0**	75.0
	6.125% (effective rate of 6.61%)	2003	**–**	75.0
	Installment contracts payable: (5)			
	6.25% Refunding bonds (effective rate of 6.81%) (6)	2034	**86.0**	86.0
	5.85% Refunding bonds (effective rate of 5.88%)	2030	**75.0**	75.0
	5.1% Refunding bonds (effective rate of 5.77%) (7)	2013	**60.7**	60.7
	5.5% Refunding bonds (effective rate of 6.34%) (7)	2023	**86.4**	86.4
	4% (effective rate of 4.22%) (8)	2025	**51.6**	51.6
	4% (effective rate of 4.17%) (8)	2018	**54.2**	54.2
	4.25% (effective rate of 4.44%) (8)	2020	**20.0**	20.0
	Notes: 6.875% (effective rate of 6.98%) (1)	2012	**210.0**	210.0
	6.375% (effective rate of 7.35%) (1)	2012	**330.0**	330.0
	5.375% (effective rate of 5.59%) (1)	2007	**125.0**	125.0
	6.25% (effective rate of 6.31%) (1)	2016	**250.0**	–
			1,423.9	1,248.9
Peoples Gas System	Senior Notes: (2) 10.35%	2007	**3.4**	4.2
	10.33%	2008	**4.8**	5.6
	10.3%	2009	**6.4**	7.2
	9.93%	2010	**6.6**	7.4
	8%	2012	**23.3**	25.4
	Notes: 6.875% (effective rate of 6.98%) (1)	2012	**40.0**	40.0
	6.375% (effective rate of 7.35%) (1)	2012	**70.0**	70.0
	5.375% (effective rate of 5.59%) (1)	2007	**25.0**	25.0
			179.5	184.8
TECO Wholesale Generation	Non-recourse secured facility notes, Series A: 7.8%	2003	**–**	111.0
	Non-recourse secured facility notes, variable rate:			
	4.38% for 2003 and 4.36% for 2002 (9)	2004-2007	**36.7**	50.1
	6.63% for 2003 and 6.88% for 2002 (9)	2004-2009	**16.0**	16.0
	4.75% for 2003 and 5.00% for 2002 (9)	2004-2009	**14.0**	14.0
	Non-recourse secured facility notes: 10.1%	2004-2009	**15.3**	16.4
	9.629%	2004-2009	**19.1**	24.8
	Non-recourse secured facility note, variable rate: 3.00% weighted average (9)(10)	2004-2006	**1,395.0**	–
	Non-recourse financing facility - Union County: 7.5% (5) (10)	2004-2021	**692.3**	–
			2,188.4	232.3
Diversified companies	Dock and wharf bonds, 5% (5)	2007	**110.6**	110.6
	Non-recourse mortgage notes: 4.45% (effective rate of 4.62%) (11)	2004	**4.6**	–
	3.95% (effective rate of 4.16%) (11)	2004	**3.0**	–
	Capital lease: implicit rate of 8.5%	2003	**–**	25.3
			118.2	135.9
Unamortized debt premium (discount), net			**(27.6)**	(30.5)
			6,511.5	3,451.4
Less amount due within one year (12)			**31.6**	127.1
Less long-term liabilities held for sale (10)			**2,087.3**	–
Total long-term debt			**$ 4,392.6**	$3,324.3

(1) These notes are subject to redemption in whole or in part, at any time, at the option of the company.
(2) These long-term debt agreements contain various restrictive covenants, such as limitations on restricted payments, liens and indebtedness (see **Note 20**).
(3) These securities may be redeemed in whole or in part, by action of the company on or after Dec. 20, 2005.
(4) These securities are comprised of two components–an equity contract which pays a coupon of 4.39%, adjusted quarterly, and a note obligation which pays a coupon of 5.11% (effective rate of 5.85%). The note obligation is subject to a potential rate reset on Oct. 15, 2004.
(5) Tax-exempt securities.
(6) Proceeds of these bonds were used to refund bonds with an interest rate of 9.9% in February 1995. For accounting purposes, interest expense has been recorded using a blended rate of 6.52% on the original and refunding bonds, consistent with regulatory treatment.
(7) Proceeds of these bonds were used to refund bonds with interest rates of 5.75%-8%.
(8) The interest rate on these bonds was fixed for a five-year term on Aug. 5, 2002.
(9) Composite year-end interest rate.
(10) This obligation is expected to be transferred in the disposition of the Union and Gila River power plants. As a result, the liability has been reclassified to "Liabilities associated with assets held for sale". See **Note 14** for additional details.
(11) These notes represent 100% of the debt for BT-One, LLC, an 80-percent owned unconsolidated affiliate. In total, the company has a $1.0 million guarantee on these notes.
(12) Of the amount due in 2004, $0.8 million may be satisfied by the substitution of property in lieu of cash payments.

8. Preferred Stock

Preferred stock of TECO Energy – $1 par 10 million shares authorized, none outstanding.

Preference 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.

9. Common Stock

Stock-Based Compensation

In April 1996, the shareholders approved the 1996 Equity Incentive Plan (1996 Plan). The 1996 Plan superseded the 1990 Equity Incentive Plan (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 2003, under the 1996 Plan, 2,828,806 stock options were granted, with a weighted average option price of $11.10 and a maximum term of 10 years. In addition, 561,050 shares of restricted stock were awarded, each with a weighted average fair value of $11.14. Compensation expense recognized for stock grants awarded under the 1996 Plan was $1.6 million, $1.7 million and $2.8 million in 2003, 2002 and 2001, respectively. Approximately half of the stock grants awarded in 2003 and 2002 and all of the stock grants awarded in 2001 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, 2003 and 2002 reflected a $(4.7) million and a $(6.3) million liability, respectively, classified as other deferred credits, for these contingent shares. The remaining stock grants are restricted subject to continued employment generally, with the 2003 and 2002 stock grants vesting in three 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, 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
Granted	2,829	$11.10
Exercised	(14)	$11.09
Cancelled	(306)	$23.35
Balance at Dec. 31, 2003	8,925	$21.35
Exercisable at Dec. 31, 2003	–	–
Available for future grant at Dec. 31, 2003	1,447	

As of Dec. 31, 2003, the 8.9 million options outstanding under the Equity Plans are summarized below.

Stock Options Outstanding at Dec. 31, 2003

Option Shares (thousands)	*Range of Option Prices*	*Weighted Avg. Option Price*	*Weighted Avg. Remaining Contractual Life*
2,783	$11.09 - $11.78	$11.10	9 Years
2,070	$19.44 - $22.48	$21.16	5 Years
535	$23.55 - $25.97	$24.22	4 Years
3,537	$27.56 - $31.58	$29.08	7 Years

In April 1997, the Shareholders approved the 1997 Director Equity Plan (1997 Plan), as an amendment and restatement of the 1991 Director Stock Option Plan (1991 Plan). The 1997 Plan superseded the 1991 Plan, and no additional grants will be made under the 1991 Plan. The rights of the holders of outstanding options under the 1991 Plan will not be affected. The purpose of the 1997 Plan is to attract and retain highly qualified non-employee directors of the company and to encourage them to own shares of TECO Energy common stock. The 1997 Plan is administered by the Board of Directors. The 1997 Plan amended the 1991 Plan to increase the number of shares of common stock subject to grants by 250,000 shares, expanded the types of awards available to be granted and replaced the fixed formula grant by giving the Board discretionary authority to determine the amount and timing of awards under the plan.

In 2003, 40,000 options were granted, with a weighted average option price of $11.73. 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, 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
Granted	40	$11.73
Exercised	–	–
Cancelled	(10)	$23.41
Balance at Dec. 31, 2003	236	$23.08
Exercisable at Dec. 31, 2003	40	$11.72
Available for future grant at Dec. 31, 2003	230	

As of Dec. 31, 2003, the 236,000 options outstanding under the 1997 Plan with option prices of $11.09 – $31.58, had a weighted average option price of $23.08 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*, as amended by FAS 148, 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 the grant date, 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 set forth below:

Pro Forma Stock-Based Compensation Expense

(millions, except per share amounts)		*2003*	*2002*	*2001*
Net (loss) income from continuing operations	As reported	**$ (14.7)**	$ 277.2	$ 265.5
	Pro forma expense [(1)]	**2.7**	5.1	4.3
	Pro forma	**$ (17.4)**	$ 272.1	$ 261.2
Net (loss) income	As reported	**$(909.4)**	$ 330.1	$ 303.7
	Pro forma expense [(1)]	**2.7**	5.1	4.3
	Pro forma	**$(912.1)**	$ 325.0	$ 299.4
Net (loss) income from continuing operations - EPS, basic	As reported	**$ (0.08)**	$ 1.81	$ 1.98
	Pro forma	**$ (0.10)**	$ 1.78	$ 1.95
Net (loss) income from continuing operations - EPS, diluted	As reported	**$ (0.08)**	$ 1.81	$ 1.96
	Pro forma	**$ (0.10)**	$ 1.78	$ 1.93
Net income (loss) - EPS, basic	As reported	**$ (5.05)**	$ 2.15	$ 2.26
	Pro forma	**$ (5.07)**	$ 2.12	$ 2.23
Net income (loss) - EPS, diluted	As reported	**$ (5.05)**	$ 2.15	$ 2.24
	Pro forma	**$ (5.07)**	$ 2.12	$ 2.21
Assumptions				
Risk-free interest rate		**3.52%**	5.09%	4.89%
Expected lives (in years)		**7**	6	6
Expected stock volatility		**32.68%**	25.92%	27.45%
Dividend yield		**6.87%**	5.47%	5.46%

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

Dividend Reinvestment Plan

In 1992, TECO Energy implemented a Dividend Reinvestment and Common Stock Purchase Plan. TECO Energy raised $8.0 million, $11.2 million and $8.6 million of common equity from this plan in 2003, 2002 and 2001, respectively.

Common Stock and Treasury Stock

On Mar. 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 proceeds to the company of approximately $206.8 million, which were used to repay short-term debt.

On Sep. 10, 2003, TECO Energy sold 11 million shares of common stock to funds managed by Franklin Advisers, Inc. of San Mateo, California at a price of $11.76 per share. Net proceeds of approximately $129 million were used to repay short-term indebtedness and for general corporate purposes.

Shareholder Rights Plan

In accordance with the company's Shareholder Rights Plan, a Right to purchase one additional share of the company's common stock at a price of $90 per share is attached to each outstanding share of the company's common stock. The Rights expire in May 2009, subject to extension. The Rights will become exercisable 10 business days after a person acquires 10 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 $21.1 million, $13.6 million and $5.6 million in 2003, 2002 and 2001, 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)	*2003*	*2002*	*2001*
Interest expense	**$ 2.6**	$ 4.3	$ 5.2
Compensation expense	**16.0**	12.2	7.4
Dividends	**(5.3)**	(8.5)	(8.5)
Net ESOP expense	**$ 13.3**	$ 8.0	$ 4.1

Compensation expense was determined by the shares allocated method.

At Dec. 31, 2003, the ESOP had 4.8 million allocated shares, 0.3 million committed-to-be-released shares, and 0.6 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 in 2003 for allocated shares ($1.6 million) is a reduction of income tax expense and for unallocated shares ($0.4 million) is an increase in retained earnings. All ESOP shares are considered outstanding for earnings per share computations.

10. Asset Impairments

In September 2003, as a result of the market conditions for merchant assets, management tested the merchant plants for impairment. This test was performed using undiscounted cash flows based on assumptions which included long-term gross margin projections, long-term forecasts of supply and demand growth rates, and reasonably available information to develop long term expectations. As of Sep. 30, 2003, based on the then-current assumptions and expectations of management, no impairment was indicated based on the undiscounted cash flows of the merchant assets tested, in accordance with FAS 144.

As of Dec. 31, 2003, based on the negotiations with potential buyers, including the project lenders, a change in management's expectations regarding an exit strategy in the near term, and management's designation of the Union and Gila River project companies as held for sale, a pre-tax asset impairment charge of $1,099.3 million was recognized and reflected in discontinued operations, in accordance with FAS 144 (see **Note 14** for additional details). The impairment charge was calculated as the difference between the carrying value of the net assets and liabilities held for sale and the respective estimated fair value of those net assets and liabilities. The fair value was estimated using available market information, corroborated by discounted cash flow analyses. The discounted cash flow analyses included significant assumptions relating to long-term price and economic forecasts, refinancing of the non-recourse debt and an appropriate discount rate.

In December 2003, additional pre-tax asset impairment charges of $41.0 million ($25.6 million after tax) were recognized primarily related to certain steam turbines and licenses, originally planned for use in a cogeneration project, and an estimated pre-tax loss on the disposal of BGA (see **Notes 14** and **23** for additional details of the disposition).

In 2003, TECO Energy recognized a pre-tax asset impairment charge of $104.1 million ($64.2 million after tax) relating to installment payments made and capitalized under turbine purchase commitments in prior periods. As reported previously and in **Note 17**, certain turbine rights had been transferred from Other Unregulated operations to Tampa Electric in 2002 for use in Tampa Electric's generation expansion activities. These cancellations, made in April 2003, fully terminate all turbine purchase obligations for these entities.

11. Restructuring Costs

In September and October of 2003, TECO Energy announced a corporate reorganization to restructure the company along functional lines, consistent with its objectives to grow the core utility operations, maintain liquidity, generate cash and maximize the value in the existing assets. As a result of these actions, the company is now aligned to provide for centralized oversight along functional lines for power plant operations, energy delivery, energy management, terminal operations, human resources and technology/support services. The 2003 actions included the involuntary termination or retirement of 337 employees, including officers and other personnel from operations and support services.

In 2002, TECO Energy initiated a restructuring program that impacted approximately 250 employees across multiple operations and services within, primarily, Tampa Electric. This program included retirements, the elimination of positions and other cost control measures. The total costs associated with this program, included severance, salary continuation and other termination and retirement benefits.

The company recognized a pre-tax expense of $24.6 million and $17.8 million for accrued benefits and other termination and retirement benefits for the years ended Dec. 31, 2003 and 2002, respectively. The company completed these restructuring activities as of Dec. 31, 2003. As of Dec. 31, 2003 and 2002, respectively, no adjustments were made to the benefits initially accrued for and $14.0 million and $17.8 million, respectively, of the accrued benefits were paid or otherwise settled. The table below details the pre-tax expense recognized by the operating segments:

Restructuring Charges

For the year ended Dec. 31, (millions)	*2003*	*2002*
Tampa Electric	**$ 9.9**	$16.6
Peoples Gas	**4.1**	–
TWG	**0.4**	–
TECO Transport	**1.7**	–
TECO Coal	**–**	–
Other Unregulated	**5.9**	1.2
Eliminations and other [(1)]	**2.6**	–
Total TECO Energy	**$24.6**	$17.8

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

12. TPGC Joint Venture Termination

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

On Apr. 9, 2003, the TWG subsidiaries and Panda Energy amended the agreements related to the purchase obligation. The modified terms accelerated the purchase obligation to occur on or before July 1, 2003, and reduced the overall purchase obligation to $58 million. Under the guarantee, TWG became obligated to make interest and certain principal payments to or on behalf of Panda related to the collateralized loan obligation of Panda. The purchase obligation of $58 million included $35 million for Panda Energy's interest in TPGC, and a short-term receivable from Panda, collateralized by Panda's remaining interests in PLC (see **Notes 1** and **17** for additional details on TECO Energy's indirect ownership interest in PLC). Both modifications to the purchase obligation were subject to the condition, which TECO Energy could waive, that bank financing be obtained by TECO Energy. Panda Energy's cancellation right was accelerated to expire on June 16, 2003. TECO Energy's guarantee of the TWG subsidiaries' obligation was modified to reflect the amendments to the purchase obligation. In April 2003, TECO Energy recognized the fair value of the guarantee as a pre-tax loss of $35.0 million ($21.4 million after tax), included in discontinued operations, as a result of the expected disposition of the project companies (see **Note 14**). From April 2003 through June 2003, TECO Energy made and accrued certain principal payments under the guarantee commitment.

As a result of the amendments to these agreements in early April 2003, management believed the exercise of the modified guarantee and the related purchase obligation became highly probable. The likelihood of the exercise of the purchase obligation created a presumption of effective control. When combined with TECO Energy's exposure to the majority of risk of loss under the previously disclosed letters of credit and contractor undertakings, management believed that consolidation of TPGC was appropriate as of the date of the modifications to the agreements. For convenience of reporting periods and accounting cycles, management selected Apr. 1, 2003 as the initial date of consolidation. Prior to Apr. 1, 2003, TWG recognized assets of $839.1 million, liabilities of $48.9 million and an unrealized loss in OCI of $69.0 million, to reflect the equity method of accounting for its investment in TPGC. As a result of the consolidation on Apr. 1, 2003, the company recognized additional assets of $2,446.9 million, primarily relating to utility plant and construction work in progress, additional liabilities of $1,976.8 million (including non-recourse debt), and an additional unrealized loss in OCI of $69.0 million for interest rate swaps designated as hedges. See **Note 14** for a discussion of the subsequent designation of the TPGC projects as assets and liabilities held for sale.

In June 2003, TECO Energy satisfied the bank financing condition resulting in the acceleration of TECO Energy's guarantee obligation and executed a final agreement with Panda to effect the termination of Panda's involvement in the partnership. Proceeds from the bank financing obtained in June 2003, which is more fully discussed in **Note 6**, were used to fund the net termination payment to Panda. Upon acceleration of the guarantee obligation and the resulting partnership termination, TWG indirectly received the 50-percent outstanding partnership interests in TPGC. As previously discussed, under the amended agreements, $35.0 million, pre-tax, had been recognized in April 2003 as the fair value of the guarantee obligation. The remaining amount was recorded as due from Panda and collateralized by Panda's remaining interests in PLC. Foreclosure proceedings were consummated on Panda's remaining interests in PLC in September 2003 (see **Notes 1, 17** and **21** for additional details). As of Dec. 31, 2003 substantially all of the assets and liabilities associated with the TPGC projects (Union and Gila River) were classified as held for sale. All results of operations for these two projects have been reclassified to discontinued operations for all periods presented.

For the year ended Dec. 31, 2003, TWG recorded total pre-tax charges of $249.1 million ($155.9 million after tax) as a direct result of the consolidation of TPGC. Of the total charges recorded, $95.2 million pre-tax ($61.2 million after tax), was recorded in continuing operations to reflect a goodwill impairment discussed in **Note 3**. See **Note 14** for a discussion of the remaining amount recorded in discontinued operations.

13. Income Tax Expense

Income tax expense consists of the following components:

Income Tax Expense

(millions)	*Federal*	*Foreign*	*State*	*Total*
2003				
Continuing operations				
Current payable	**$ 49.7**	**$ 2.2**	**$ 6.3**	**$ 58.2**
Deferred	**(175.4)**	**5.3**	**(18.6)**	**(188.7)**
Amortization of investment tax credits	**(4.7)**	**–**	**–**	**(4.7)**
Income tax benefit from continuing operations	**(130.4)**	**7.5**	**(12.3)**	**(135.2)**
Discontinued operations				
Current payable	**8.4**	**–**	**8.0**	**16.4**
Deferred	**(487.3)**	**–**	**(33.3)**	**(520.6)**
Income tax benefit from discontinued operations	**(478.9)**	**–**	**(25.3)**	**(504.2)**
Total income tax expense (benefit)	**$ (609.3)**	**$ 7.5**	**$ (37.6)**	**$ (639.4)**
2002				
Continuing operations				
Current payable	$ 17.8	$ 1.0	$ 10.4	$ 29.2
Deferred	(70.9)	–	(5.2)	(76.1)
Amortization of investment tax credits	(4.8)	–	–	(4.8)
Income tax benefit from continuing operations	(57.9)	1.0	5.2	(51.7)
Discontinued operations				
Current payable	22.2	–	5.6	27.8
Deferred	(18.2)	–	(2.2)	(20.4)
Income tax benefit from discontinued operations	4.0	–	3.4	7.4
Total income tax expense (benefit)	$ (53.9)	$ 1.0	$ 8.6	$ (44.3)
2001				
Continuing operations				
Current payable	$ 81.3	$ –	$ 17.5	$ 98.8
Deferred	(94.1)	–	(7.1)	(101.2)
Amortization of investment tax credits	(4.9)	–	–	(4.9)
Income tax benefit from continuing operations	(17.7)	–	10.4	(7.3)
Discontinued operations				
Current payable	(3.5)	–	2.4	(1.1)
Deferred	(1.4)	–	(0.3)	(1.7)
Income tax benefit from discontinued operations	(4.9)	–	2.1	(2.8)
Total income tax expense (benefit)	$ (22.6)	$ –	$ 12.5	$ (10.1)

TECO Energy uses the liability method to determine deferred income taxes. Under the liability method, the company estimates its current tax exposure and assesses the temporary differences resulting from differences in the treatment of items, such as depreciation, for financial statement and tax purposes. These differences are reported as deferred taxes, measured at current rates, in the consolidated financial statements. Management reviews all reasonably available current and historical information, including forward-looking information, to determine if it is more likely than not, that some or all of the deferred tax asset will not be realized. If management determines that it is likely that some or all of a deferred tax asset will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized. In accordance with the policy, at Dec. 31, 2003 a valuation reserve of $64.2 million was established and charged to income to reflect the estimated amount of state deferred tax assets which may not be realized due to the lack of future taxable income.

Based primarily on the reversal of deferred income tax liabilities and future earnings of the company's core utility operations, management has determined that the net deferred tax assets recorded at Dec. 31, 2003 will be realized in future periods.

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

Deferred Income Tax Assets and Liabilities

(millions) Dec. 31,	*2003*	*2002*
Deferred income tax assets [1]		
Property related	**$ 578.8**	$ 86.8
Alternative minimum tax credit forward	**224.6**	201.3
Goodwill writedown	**107.5**	–
Other	**204.8**	52.1
Valuation allowance	**(64.2)**	–
Total deferred income tax assets	**$ 1,051.5**	$ 340.2
Deferred income tax liabilities [1]		
Property related	**$ (521.8)**	$ (565.3)
Basis difference in oil and gas properties	**4.4**	(13.9)
Other	**19.4**	84.2
Total deferred income tax liabilities	**$ (498.0)**	$ (495.0)
Net deferred tax assets	**$ 553.5**	$ (154.8)

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

Included in the "Property related" component of the deferred tax asset, as of Dec. 31, 2003, is the impact of the asset impairments and the related effect on hedge accounting discussed in **Notes 2**, **10** and **14**.

Effective Income Tax Rate

(millions) For the years ended Dec. 31,	*2003*	*2002*	*2001*
Net (loss) income from continuing operations before minority interest	**$ (63.5)**	$ 277.2	$ 265.5
Plus: minority interest	**48.8**	–	–
Net (loss) income from continuing operations	**(14.7)**	277.2	265.5
Total income tax provision (benefit)	**(135.2)**	(51.7)	(7.3)
(Loss) income from continuing operations before income taxes	**(149.9)**	225.5	258.2
Income taxes on above at federal statutory rate of 35%	**(52.4)**	78.9	90.4
Increase (decrease) due to			
State income tax, net of federal income tax	**(8.0)**	3.4	6.8
Foreign income taxes	**7.5**	1.0	–
Amortization of investment tax credits	**(4.7)**	(4.8)	(4.9)
Permanent reinvestment – foreign income	**(12.3)**	(8.1)	(7.2)
Non-conventional fuels tax credit	**(66.0)**	(107.3)	(86.2)
AFUDC Equity	**(6.9)**	(8.7)	(2.3)
Other	**7.6**	(6.1)	(3.9)
Total income tax provision from continuing operations	**$(135.2)**	$ (51.7)	$ (7.3)
Provision for income taxes as a percent of income from continuing operations, before income taxes	**90.2%** (1)	-22.9%	-2.8%

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

During 2003, pre-tax losses from continuing operations, Sec. 29 credits and the reclassification of results of operations to discontinued operations as described in **Note 14**, caused variations in the overall effective income tax rate throughout the year and at year-end.

The provision for income taxes as a percent of income from discontinued operations was 36.2%, 12.3% and -8.0%, respectively, in 2003, 2002 and 2001. 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 2003, 2002, and 2001 was $58.8 million, $71.9 million and $52.4 million, respectively.

14. Discontinued Operations and Assets Held for Sale

Union and Gila River Project Companies (TPGC)

In October 2003, the company, the bank financing group and the Union and Gila River project companies entered into a suspension agreement (see **Note 20**) in order to continue discussions regarding the operating budgets and performance of the two power plants. In late December 2003, a stand-still agreement was entered into by the same parties to continue to facilitate the discussions (see **Note 20**). See **Note 23** for a discussion of subsequent events which impact both the suspension and the stand-still agreements. As of Dec. 31, 2003, management was committed to a plan to sell TECO Energy's ownership of the equity or net assets of the project companies. The company expects to complete the transfer of TPGC in 2004. The Union and Gila River project companies comprised part of the TWG operating segment until designated as assets held for sale in December 2003.

See **Note 23** regarding subsequent events relating to the Union and Gila River project companies.

As an asset held for sale, the assets and liabilities that are expected to be transferred as part of the sale, as of Dec. 31, 2003, have been reclassified, respectively, in the balance sheet. Furthermore, the company has determined that TPGC meets the criteria of a discontinued operation. Results from operations for the Union and Gila River project companies have been reclassified to "Discontinued operations" for all periods presented. For the years ended Dec. 31, 2002 and 2001, TPGC was a development stage company. The following table provides selected components of discontinued operations for TPGC.

Components of income from discontinued operations – Union and Gila River Project Companies

(millions) *For the years ended Dec. 31,*	*2003*	*2002*	*2001*
Revenues	**$ 319.4**	$ –	$ –
Asset impairment (1)	**(1,185.7)**	–	–
(Loss) income from operations	**(1,239.8)**	–	–
(Loss) on joint venture termination	**(153.9)**	–	–
(Loss) income before provision for income taxes	**(1,441.4)**	27.4	13.1
(Benefit) provision for income taxes	**(522.7)**	10.6	5.0
Net (loss) income from discontinued operations	**$ (918.7)**	$ 16.8	$ 8.1

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

Asset impairment charge

The pre-tax asset impairment charge of $1,185.7 million ($762.0 million after tax) is comprised of an impairment in long-lived assets and a related charge to reflect the impacts of hedge accounting. The pre-tax asset impairment charge of $1,099.3 million was recognized in accordance with FAS 144. The recognition of the asset impairment effectively accelerated the recognition of previously capitalized interest. As a result, in accordance with cash flow hedge accounting under FAS 133, a reversal from OCI of $22.6 million of pre-tax losses on the interest rate swaps was required to give effect in the income statement to the previously hedged interest which was capitalized during construction.

In addition, the change in future expectations regarding the probability of the company retaining the long-term, non-recourse debt resulted in the reversal of an additional $63.8 million pre-tax losses which were previously deferred in OCI and related to the future recognition of capitalized interest amortization and future interest expense on the non-recourse debt, anticipated to be recognized in periods subsequent to 2004. See **Note 10** for a full description of the asset impairment component and **Note 2** for additional details on the hedge accounting (OCI reversal) components.

Loss on joint venture termination

As discussed in greater detail in **Note 12**, the consolidation of TPGC on Apr. 1, 2003 resulted in the recognition of a pre-tax charge of $153.9 million ($94.7 million after tax) which was recorded in discontinued operations. This pre-tax charge included: $35.0 million ($21.4 million after tax) related to the partnership termination under the guarantee; and $118.9 million ($73.3 million after tax) related to the consolidation of TPGC to reflect the impact of Panda's portion of TPGC's partnership deficit and the elimination of certain related-party liabilities (see **Note 17**).

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

Assets held for sale – Union and Gila River Project Companies

(millions)	*Dec. 31, 2003*
Current assets	$ 72.9
Net property, plant and equipment	1,367.9
Other investments	676.1
Other non-current assets	23.7
Total assets held for sale	$2,140.6

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

(millions)	*Dec. 31, 2003*
Current liabilities	$ 94.0
Long-term debt, non-recourse:	
Secured facility note (1)	1,395.0
Financing facility note	676.1
Other non-current liabilities	21.7
Total liabilities associated with assets held for sale	$2,186.8

(1) As defined in the legal documents.

Current and non-current assets

Current assets include $18.8 million of restricted cash which, under the terms of the lending agreements for the projects, is primarily related to cash to be used for construction-related purposes only. Also included in current assets is $16.2 million, representing the current portion of the investment in Union County bonds, described in Other investments below.

Net property, plant and equipment

Net property, plant and equipment has been reduced by accumulated depreciation of $49.4 million and an asset impairment charge of $1,099.3 million. This impairment charge arose as a result of changes in management's expectations, including its long-term strategic outlook, and is more fully described in **Note 10**. The decline of the fair value of the disposal group (comprised of the assets and liabilities expected to be transferred upon disposition) below the carrying value is directly attributable to the decline in future wholesale power price expectations as a result of the repercussions of the failure of deregulation in California and the Enron bankruptcy; less than economic dispatch in some areas of the country; the U.S. economic slowdown; uncertainty with respect to long-term price recovery; and the significant excess generating capacity in the many areas of the country. The primary triggering event for the recognition of the charge by the company was the significant change in management's expectations regarding the company's long-term future involvement in the Union and Gila River project companies and the decision, during the fourth quarter of 2003, to sell the project companies.

Other investments

Other investments includes industrial revenue bonds from Union County, Arkansas, which were acquired by Union Power Partners, L.P. (UPP), a subsidiary of TPGC, with financing obtained by borrowings from Union County (the County). As of Dec. 31, 2003, UPP's investment in the bonds from the County totaled $692.3 million, which equals the non-recourse financing facility from Union County. Union County's debt service payments on the bonds equal UPP's debt service obligations to the County. This agreement provides an incentive to and a means through which the company can invest in the County. For periods prior to Dec. 31, 2003, TECO Energy did not include TPGC in the Consolidated Balance Sheet (see **Note 12**).

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

Current and non-current liabilities

Included in current liabilities is the current portion of the financing facility due to Union County, described in Other investments above, of $16.2 million and $58.6 million ($26.4 million current and $32.2 million non-current) for interest rate swaps entered into by the Union and Gila River projects in connection with the non-recourse collateralized borrowings.

The purpose of the interest rate swap agreement is to effectively convert a portion of the floating-rate debt to a fixed rate. At Dec. 31, 2003 and 2002, the notional amount of the interest rate swap agreements was $697.5 million and $1,035.0 million, respectively. The interest rate swap agreements have terms ranging from 2 to 5 years with the majority maturing in June 2006. As more fully described in **Note 2**, the designation of the secured facility note as a liability associated with assets held for sale resulted in the prospective loss of hedge accounting for the periods beyond the expected effective date of the sale.

Non-recourse, secured facility note

In 2001, the Union and Gila River project companies obtained construction financing of $1,395.0 million in the form of floating rate, non-recourse senior secured credit facilities from a bank group. The construction loans will convert to term loans upon the completion and full commercial operation of the Union and Gila River projects, however, conversion will not occur during the Suspension Period, as agreed under the Suspension Agreement described in **Note 20**. The Union and Gila River project companies each jointly and severally guarantee and cross-collateralize the loans and debts of the other. The loans are non-recourse to TECO Energy, TWG and its subsidiaries that own the project entities.

Credit Facilities

The Union and Gila River project companies have credit facilities for commercial letters of credit and debt service as part of the non-recourse project financing. These facilities are recourse only to the project companies, and not to TECO Energy or its other subsidiaries. Each project company's commercial letter of credit facility of $100 million is to facilitate gas purchases and power sales. Total aggregate letters of credit outstanding under the two commercial facilities at Dec. 31, 2003 was $144.2 million. Each project company also has a $40 million debt service reserve facility, neither of which has been drawn upon at Dec. 31, 2003. The Union and Gila River project companies' non-recourse project facilities have maturity dates of June 2006.

See **Note 23** regarding subsequent events relating to the Union and Gila River projects companies.

Other transactions

In 2003 and 2002, the company completed several sales transactions and achieved significant milestones towards additional transactions anticipated to be completed, as of Dec. 31, 2003, in 2004. The completed transactions include: the sale of Hardee Power Partners, Ltd. (HPP) in 2003; and the sale of TECO Coalbed Methane in 2002 (see **Note 21**). As a result of the accounting treatment of the sale of HPP, the results from operations of HPP through the date of the sale and for all prior periods presented are included in continuing operations. For all periods presented, the results from operations of TECO Coalbed Methane are presented as discontinued operations on the income statement. As of Dec. 31, 2003, no significant assets or liabilities remained relating to these two entities, with the exception of certain cash proceeds held by TECO Energy which are subject to restriction, as described in **Note 1**.

As of Dec. 31, 2003, management was committed to a plan to sell Prior Energy and BGA (formerly a component of TECO Energy Services). The company expects to complete these sales in early 2004 (see **Note 23** for details of these subsequent transactions). As of the same date, a subsidiary of TECO Energy completed the sale of substantially all of the net assets of TECO Gas Services. These entities comprised part of TECO Energy's Other unregulated businesses segment. In accordance with FAS 144, the assets and liabilities that have yet to be transferred as part of these transactions, as of Dec. 31, 2003, have been reclassified, respectively, in the balance sheet. Results from operations for Prior Energy and TECO Gas Services have been reclassified to "Discontinued operations".

Below is a table which provides selected components of discontinued operations for transactions other than the Union and Gila River projects (TPGC) transaction:

Components of income from discontinued operations – Other

(millions) *For the years ended Dec. 31,*	*2003*	*2002*	*2001*
Revenues	**$ 21.6**	$ 51.5	$ 60.1
Income from operations	**9.1**	22.1	24.6
Gain on sale	**39.7**	12.7	–
Income before provision for income taxes [1]	**46.8**	32.9	22.3
Provision for income taxes	**18.5**	(3.2)	(7.8)
Net income from discontinued operations [1]	**$ 28.3**	$ 36.1	$ 30.1

(1) Includes internal financing costs, allocated prior to discontinued operations designation. Internally allocated costs for 2003, 2002 and 2001 were at pre-tax rates of 8%, 7% and 7%, respectively, based on the average investment in each subsidiary.

Revenues

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 for the years ended Dec. 31, 2003, 2002 and 2001 were $853.4 million, $568.3 million and $105.5 million, respectively.

Gain on sale

As a result of the sale of TECO Coalbed Methane in December 2002, the company recognized pre-tax gains of $39.7 million ($24.1 million after tax) and $12.7 million ($7.7 million after tax) for the years ended Dec. 31, 2003 and 2002, respectively.

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

Assets held for sale – Other

(millions)	*Dec. 31, 2003*
Current assets	**$ 96.5**
Net property, plant and equipment	**1.5**
Other non-current assets	**8.2**
Total assets held for sale	**$106.2**

Liabilities associated with assets held for sale – Other

(millions)	*Dec. 31, 2003*
Current liabilities	**$ 55.4**
Other non-current liabilities	**–**
Total liabilities associated with assets held for sale	**$ 55.4**

15. Other Comprehensive Income

TECO Energy reported the following other comprehensive income (loss) for the years ended Dec. 31, 2003, 2002 and 2001, 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*
2003			
Unrealized (loss) gain on cash flow hedges [1]	**$ (31.8)**	**$ (10.6)**	**$ (21.2)**
Less: Loss (gain) reclassified to net income	**76.4**	**27.1**	**49.3**
Gain (loss) on cash flow hedges	**$ 44.6**	**$ 16.5**	**$ 28.1**
Foreign currency adjustments	**1.2**	**—**	**1.2**
Pension adjustments [2]	**(69.3)**	**(25.4)**	**(43.9)**
Total other comprehensive (loss) income	**$ (23.5)**	**$ (8.9)**	**$ (14.6)**
2002			
Unrealized (loss) gain on cash flow hedges [1]	$ (51.2)	$ (20.4)	$ (30.8)
Less: Loss (gain) reclassified to net income	29.0	11.4	17.6
Gain (loss) on cash flow hedges	$ (22.2)	$ (9.0)	$ (13.2)
Foreign currency adjustments	(1.2)	–	(1.2)
Pension adjustments [2]	(7.2)	(2.8)	(4.4)
Total other comprehensive (loss) income	$ (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 [1]	(32.1)	(12.5)	(19.6)
Less: Loss (gain) reclassified to net income	19.7	7.6	12.1
Gain (loss) on cash flow hedges	$ (31.4)	$ (12.2)	$ (19.2)
Pension adjustments [2]	0.5	0.2	0.3
Total other comprehensive (loss) income	$ (30.9)	$ (12.0)	$ (18.9)

(1) Amounts include interest rate swaps designated as cash flow hedges at TPGC, which was consolidated effective Apr. 1, 2003 as a result of the termination of the partnership. Prior to Apr. 1, 2003, only the company's proportionate share of its equity investee's comprehensive loss was included. See **Notes 12** and **14** for additional details regarding the OCI balances for cash flow hedges.

(2) See **Note 16** for additional details regarding pension adjustments.

16. 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 Apr. 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 $0.8 million in 2001 and a reduction of benefit obligation of $6.2 million at Sep. 30, 2001.

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. In 2004, the company expects to make a contribution of about $14.2 million.

Amounts disclosed for pension benefits also include the unfunded obligations for the supplemental executive retirement plans, non-qualified, non-contributory defined benefit retirement plans available to certain senior management. In 2004, the company expects to make a contribution of about $1.7 million to these plans. TECO Energy reported other comprehensive losses of $43.9 million and $4.4 million in 2003 and 2002, respectively, and other comprehensive income of $0.3 million in 2001, related to adjustments to the minimum pension liability associated with the pension plan and supplemental executive retirement plans.

The asset allocation for the company's pension plan as of Sep. 30, 2003 and 2002, and the target allocation for 2004, by asset category, follows:

Asset Allocation

	Target Allocation for	*Percentage of Plan Assets at Sep. 30,*	
Asset category	*2004*	*2003*	*2002*
Equities	55% – 60%	57%	53%
Fixed income	40% – 45%	43%	47%
Real Estate	–	–	–
Other	–	–	–
Total		100%	100%

The company's investment objective is to obtain above average returns while minimizing volatility of expected returns over the long term. The target equities/fixed income mix is designed to meet investment objectives. The company's strategy is to hire proven managers and allocate assets to reflect a mix of investment styles, emphasize preservation of principal to minimize the impact of declining markets, and stay fully invested except for cash to meet benefit payment obligations and plan expenses.

The assumptions for the expected return on plan assets were developed based on an analysis of historical market returns, the plan's past experience and current market conditions. Estimates of future market returns are lower than actual long-term historical returns of the plan but were factored into the expected return on asset assumptions to generate a conservative forecast.

In 2001, TECO Energy elected to change the measurement date for pension obligations and plan assets from Dec. 31 to Sep. 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 Apr. 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. In 2004, the company expects to make a contribution of about $9.5 million to this program. Postretirement benefit levels are substantially unrelated to salary. The company reserves the right to terminate or modify the plans in whole or in part at any time.

On Dec. 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). Beginning in 2006, the new law adds prescription drug coverage to Medicare, with a 28% tax-free subsidy to encourage employers to retain their prescription drug programs for retirees, along with other key provisions. TECO Energy's current retiree medical program for those eligible for Medicare (generally over age 65) includes coverage for prescription drugs. The company is continuing to analyze the potential impact the Act may have on the company's FAS 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions,* expense and what, if any, plan design changes should be made with respect to the company's retiree medical program in response to the Act.

In 2001, TECO Energy elected to change the measurement date for benefit obligations from Dec. 31 to Sep. 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*		
(millions)	*2003*	*2002*	*2001*	*2003*	*2002*	*2001*
Components of net periodic benefit expense						
Service cost (benefits earned during the period)	**$ 14.3**	$ 11.8	$ 11.2	**$ 4.2**	$ 3.5	$ 3.4
Interest cost on projected benefit obligations	**30.8**	28.7	27.9	**12.5**	11.2	10.9
Expected return on assets	**(42.1)**	(42.9)	(42.0)	**–**	–	–
Amortization of:						
Transition obligation (asset)	**(1.1)**	(1.1)	(1.1)	**2.7**	2.7	2.7
Prior service cost (benefit)	**(0.5)**	(0.5)	(0.5)	**1.8**	1.9	2.0
Actuarial (gain) loss	**1.4**	(3.7)	(4.4)	**1.5**	0.1	0.4
Pension expense (benefit)	**2.8**	(7.7)	(8.9)	**22.7**	19.4	19.4
Special termination benefit charge	**–**	2.7	–	**–**	0.6	–
Additional amounts recognized	**–**	–	–	**0.1**	–	–
Net pension expense (benefit)recognized in the Consolidated Statements of Income	**$ 2.8**	$ (5.0)	$ (8.9)	**$ 22.8**	$ 20.0	$ 19.4
Assumptions used to determine net cost						
Discount rate	**6.75%**	7.50%	7.50%	**6.75%**	7.50%	7.50%
Rate of compensation increase	**4.82%**	4.66%	4.69%	**4.82%**	4.66%	4.69%
Expected return on plan assets	**9.00%**	9.00%	9.00%	**N/A**	N/A	N/A

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

Pension Plans – Projected Obligation Exceeds Plan Assets

(millions) Dec. 31,	*2003*	*2002*
Projected benefit obligation	**$ 554.5**	$ 455.1
Fair value of plan assets	**391.8**	371.9
Projected obligation in excess of plan assets	**$ 162.7**	$ 83.2
Accumulated benefit obligation	**$ 480.0**	$ 400.8

As of Dec. 31, 2003, for the qualified and non-qualified pension plans, the accumulated obligation exceeded the fair value of the plan assets. As of Dec. 31, 2002 the accumulated obligation exceeded the fair value of the plan assets for only the non-qualified pension plan. The table below shows the funded status at the end of 2003 and 2002 for the respective plans:

Pension Plans – Accumulated Obligation Exceeds Plan Assets

(millions) Dec. 31,	*2003*	*2002*[(1)]
Accumulated benefit obligation	**$ 480.0**	$ 32.8
Fair value of plan assets	**391.8**	–
Accumulated obligation in excess of plan assets	**$ 88.2**	$ 32.8
Projected benefit obligation	**$ 554.5**	$ 41.3

(1) In 2002 only the non-qualified plan is presented due to the fact that the fair value of plan assets exceeded the accumulated obligation for the qualified plan.

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

Employee Postretirement Benefits

	Pension Benefits		*Other Postretirement Benefits*	
(millions)	*2003*	*2002*	*2003*	*2002*
Change in benefit obligation				
Net benefit obligation at prior measurement date	**$ 455.1**	$ 382.3	**$ 184.6**	$ 150.2
Service cost	**14.3**	11.8	**4.2**	3.5
Interest cost	**30.8**	28.7	**12.5**	11.2
Plan participants' contributions	**–**	–	**1.4**	1.0
Actuarial loss	**89.7**	58.3	**6.5**	25.6
Plan amendments	**–**	1.1	**–**	–
Special termination benefits	**–**	2.7	**–**	0.6
Curtailment	**(1.9)**	–	**–**	–
Gross benefits paid	**(33.5)**	(29.8)	**(10.5)**	(7.5)
Net benefit obligation at measurement date	**$ 554.5**	$ 455.1	**$ 198.7**	$ 184.6
Change in plan assets				
Fair value of plan assets at prior measurement date	**$ 371.9**	$ 428.0	**$ –**	$ –
Actual return on plan assets	**51.7**	(24.9)	**–**	–
Employer contributions	**1.7**	1.7	**9.1**	6.5
Plan participants' contributions	**–**	–	**1.4**	1.0
Gross benefits paid (including expenses)	**(33.5)**	(32.9)	**(10.5)**	(7.5)
Fair value of plan assets at measurement date	**$ 391.8**	$ 371.9	**$ –**	$ –
Funded status				
Fair value of plan assets	**$ 391.8**	$ 371.9	**$ –**	$ –
Benefit obligation	**554.5**	455.1	**198.7**	184.6
Funded status at measurement date	**(162.7)**	(83.2)	**(198.7)**	(184.6)
Net contributions after measurement date	**6.7**	0.4	**2.4**	1.9
Unrecognized net actuarial loss	**165.6**	88.9	**47.4**	42.4
Unrecognized prior service cost (benefit)	**(6.9)**	(7.4)	**20.5**	22.4
Unrecognized net transition obligation (asset)	**(1.4)**	(2.5)	**24.7**	27.4
Accrued liability at end of year	**$ 1.3**	$ (3.8)	**$(103.7)**	$ (90.5)
Amounts recognized in the statement of financial position				
Prepaid benefit cost	**$ 16.9**	$ 14.8	**$ –**	$ –
Accrued benefit cost	**(15.7)**	(18.5)	**(103.7)**	(90.5)
Additional minimum liability	**(82.7)**	(13.8)	**–**	–
Intangible asset	**1.3**	1.5	**–**	–
Accumulated other comprehensive income	**81.5**	12.2	**–**	–
Net amount recognized at end of year	**$ 1.3**	$ (3.8)	**$(103.7)**	$ (90.5)
Assumptions used in determining benefit obligations, end of year				
Discount rate to determine projected benefit obligation	**6.00%**	6.75%	**6.00%**	6.75%
Rate of increase in compensation levels	**4.25%**	4.82%		

Employer contributions and benefits paid in the above table include both those amounts contributed directly to, and paid directly from both plan assets and directly to plan participants. The assumed health care cost trend rate for medical costs was 11.5% in 2003 and decreases to 5.0% in 2013 and thereafter.

A 100 basis point increase in the medical trend rates would produce a 4 percent ($0.6 million) increase in the aggregate service and interest cost for 2003 and a 4 percent ($7.5 million) increase in the accumulated postretirement benefit obligation as of Sep. 30, 2003.

A 100 basis point decrease in the medical trend rates would produce a 3 percent ($0.4 million) decrease in the aggregate service and interest cost for 2003 and a 3 percent ($5.3 million) decrease in the accumulated postretirement benefit obligation as of Sep. 30, 2003.

17. Related Parties

In February 2002, Tampa Electric and TECO-PANDA Generating Company II (TPGC II) entered into an assignment and assumption agreement under which Tampa Electric obtained TPGC II's rights and interests to four combustion turbines being purchased from General Electric, and assumed the corresponding liabilities and obligations for such equipment. In accordance with the terms of the assignment and assumption agreement, Tampa Electric paid $62.5 million to TPGC II as reimbursement for amounts already paid to General Electric by TPGC II for such equipment. No gain or loss was incurred on the transfer. In the first quarter of 2003, Tampa Electric recorded a $48.9 million after-tax charge related to the cancellation of these turbine purchase commitments (see **Note 10**).

In the second and third quarters of 2003, Tampa Electric returned approximately $158 million of capital to TECO Energy. TECO Energy had previously contributed capital to Tampa Electric in support of Tampa Electric's construction program in the wholesale business, which was subsequently scaled back.

In October 2003, Tampa Electric signed a five-year contract renewal with an affiliate company, TECO Transport Corporation, for integrated waterborne fuel transportation services effective Jan. 1, 2004. The contract calls for inland river and ocean transportation along with river terminal storage and blending services for up to 5.5 million tons of coal annually through 2008. See **Note 4** for additional details.

At Dec. 31, 2002, notes receivable from unconsolidated affiliates included the following: $795.8 million due from TPGC; $137.0 million due from PLC; $1.4 million due from Energeticke Centrum Kladno (ECKG); $13.7 million due from Mosbacher Power Partners L.P.; and $11.1 million due from EEGSA.

As of Dec. 31, 2003, a note receivable of $8.1 million due from EEGSA, an unconsolidated affiliate, bearing a current effective interest rate of 6.14%, was recorded on the balance sheet.

On Jan. 3, 2003, the $137.0 million loan receivable from PLC, a wholly-owned subsidiary of Panda Energy, converted to a 50-percent ownership interest in PLC, leading to a joint venture with Panda Energy. This joint venture holds a 50-percent ownership interest in Texas Independent Energy, L.P. (TIE). The TIE partnership owns and operates the Odessa and Guadalupe power stations in Texas. In September 2003, TWG completed foreclosure proceedings against Panda Energy for their ownership interest in PLC as a result of Panda's default under a $23.0 million note receivable. Consequently, as of Sep. 30, 2003, PLC is fully consolidated and the $23.0 million note receivable was converted to an equity interest. See also **Notes 1, 12** and **21** for additional information regarding PLC.

The company and its subsidiaries had certain transactions, in the ordinary course of business, with entities in which directors of the company had interests. These transactions were not material for the years ended Dec. 31, 2003, 2002 and 2001. No material balances were payable as of Dec. 31, 2003 or 2002.

18. Earnings Per Share

For the years ended Dec. 31, 2003, 2002 and 2001, stock options for 9.2 million shares, 4.5 million shares and 1.2 million shares, respectively, were excluded from the computation of diluted earnings per share due to their antidilutive effect. Additionally, 17.1 million common shares issuable under the purchase contract associated with the mandatorily convertible equity units issued in January 2002 were also excluded from the computation of diluted earnings per share for each of the years ended Dec. 31, 2003 and 2002, due to their antidilutive effect.

Earnings Per Share

(millions, except per share amounts)			*2003*	*2002*	*2001*
Numerator	Net (loss) income from continuing operations, basic and diluted		**$ (14.7)**	$ 277.2	$ 265.5
	Discontinued operations, net of tax		**(890.4)**	52.9	38.2
	Cumulative effect of a change in accounting principle, net		**(4.3)**	–	–
	Net (loss) income, basic and diluted		**$ (909.4)**	$ 330.1	$ 303.7
Denominator	Average number of shares outstanding - basic		**179.9**	153.2	134.5
	Plus: Incremental shares for assumed conversions:				
	Stock options at end of period and contingent performance shares		**–**	2.1	4.2
	Less: Treasury shares which could be purchased		**–**	(2.0)	(3.3)
	Average number of shares outstanding - diluted		**179.9**	153.3	135.4
Earnings per share from continuing operations		Basic	**$ (0.08)**	$ 1.81	$ 1.98
		Diluted	**$ (0.08)**	$ 1.81	$ 1.96
Earnings per share from discontinued operations, net		Basic	**$ (4.95)**	$ 0.34	$ 0.28
		Diluted	**$ (4.95)**	$ 0.34	$ 0.28
Earnings per share from cumulative effect of change in accounting principle, net		Basic	**$ (0.02)**	$ –	$ –
		Diluted	**$ (0.02)**	$ –	$ –
Earnings per share		Basic	**$ (5.05)**	$ 2.15	$ 2.26
		Diluted	**$ (5.05)**	$ 2.15	$ 2.24

19. Segment Information

TECO Energy is an electric and gas utility holding company with significant diversified activities. Segments are determined based on how management evaluates, measures and makes decisions with respect to the operations of the entity. The management of TECO Energy reports segments based on each subsidiary's contribution of revenues, net income and total assets, as required by FAS 131, *Disclosures about Segments of an Enterprise and Related Information.* All significant intercompany transactions are eliminated in the consolidated financial statements of TECO Energy, but are included in determining reportable segments.

As more fully described in **Note 1**, in 2004, the company revised internal reporting information for the purpose of evaluating, measuring and making decisions with respect to the components which previously comprised the TECO Power Services operating segment. The revised operating segment, TECO Wholesale Generation, is comprised of all merchant operations. The non-merchant components are now included in Other Unregulated operations.

The information presented in the following table excludes all discontinued operations. See **Note 14** for additional details of the components of discontinued operations.

Segment Information [1]

(millions)		Tampa Electric	Peoples Gas	TWG Merchant	TECO Transport	TECO Coal	Other Unregulated	Eliminations & Other	Total TECO Energy
2003	Revenues - outsiders	**$ 1,582.7**	**$ 408.4**	**$ 95.9**	**$ 162.2**	**$ 296.3**	**$ 194.0**	**$ 0.5**	**$ 2,740.0**
	Sales to affiliates	**3.4**	**–**	**–**	**98.4**	**–**	**69.5**	**(171.3)**	**–**
	Total revenues	**$ 1,586.1**	**$ 408.4**	**$ 95.9**	**$ 260.6**	**$ 296.3**	**$ 263.5**	**$ (170.8)**	**$ 2,740.0**
	Depreciation	**210.3**	**32.7**	**12.3**	**20.6**	**34.2**	**15.9**	**–**	**326.0**
	Restructuring costs [2]	**9.9**	**4.1**	**0.4**	**1.7**	**–**	**5.9**	**2.6**	**24.6**
	Interest charges [3]	**85.0**	**15.6**	**50.6**	**4.9**	**11.0**	**34.7**	**118.9**	**320.7**
	(Benefit) provision for taxes	**48.1**	**15.2**	**(27.0)** [4]	**9.7**	**(64.4)**	**(85.6)**	**(31.2)**	**(135.2)**
	Net (loss) income from continuing operations [3]	**$ 98.9** [5]	**$ 24.5**	**$ (147.6)** [6]	**$ 15.3**	**$ 77.1**	**$ (5.4)** [7]	**$ (77.5)**	**$ (14.7)**
	Goodwill, net	**–**	**–**	**–**	**–**	**–**	**71.2**	**–**	**71.2**
	Investment in unconsolidated affiliates	**–**	**–**	**158.9**	**–**	**–**	**184.6**	**–**	**343.5**
	Other non-current investments	**–**	**–**	**–**	**–**	**–**	**16.5**	**–**	**16.5**
	Total assets	**4,178.6**	**651.5**	**3,398.7**	**315.8**	**340.8**	**958.7**	**618.2**	**10,462.3**
	Capital expenditures	**289.1**	**42.6**	**194.3**	**19.6**	**20.6**	**24.3**	**0.1**	**590.6**
2002	Revenues - outsiders	$ 1,548.9	$ 318.1	$ 111.1	$ 143.9	$ 316.4	$ 226.5	$ –	$ 2,664.9
	Sales to affiliates	34.3	–	–	110.7	0.7	71.2	(216.9)	–
	Total revenues	$ 1,583.2	$ 318.1	$ 111.1	$ 254.6	$ 317.1	$ 297.7	$ (216.9)	$ 2,664.9
	Depreciation	189.8	30.5	12.0	22.3	31.4	17.2	–	303.2
	Restructuring costs [2]	16.6	–	–	–	–	1.2	–	17.8
	Interest charges [3]	51.5	14.8	24.3	6.3	8.2	37.1	29.4	171.6
	(Benefit) provision for taxes	85.7	14.7	5.8 [4]	10.8	(22.9)	(9.7)	(136.1)	(51.7)
	Net income (loss) from continuing operations [3]	$ 171.8	$ 24.2	$ (7.9)	$ 21.0	$ 76.4	$ 27.8	$ (36.1)	$ 277.2
	Goodwill, net	–	–	95.1	–	–	98.6	–	193.7
	Investment in unconsolidated affiliates	–	–	(38.2)	–	–	187.4	–	149.2
	Other non-current investments	–	–	795.8	–	–	49.2	0.3	845.3
	Total assets	4,119.4	629.9	2,020.1	355.1	283.5	1,167.3	503.1	9,078.4
	Capital expenditures	632.2	53.4	223.1	25.2	48.2	79.9	3.2	1,065.2
2001	Revenues - outsiders	$ 1,380.1	$ 352.9	$ 81.8	$ 151.7	$ 298.4	$ 218.4	$ –	$ 2,483.3
	Sales to affiliates	32.6	–	–	123.2	5.1	80.4	(241.3)	–
	Total revenues	$ 1,412.7	$ 352.9	$ 81.8	$ 274.9	$ 303.5	$ 298.8	$ (241.3)	$ 2,483.3
	Depreciation	173.4	27.9	9.8	24.1	28.3	21.1	–	284.6
	Restructuring costs	–	–	–	–	–	–	–	–
	Interest charges [3]	60.8	14.3	17.3	8.9	7.6	39.1	30.5	178.5
	(Benefit) provision for taxes	83.5	14.2	4.6 [4]	14.2	(19.0)	(6.1)	(98.7)	(7.3)
	Net income (loss) from continuing operations [3]	$ 154.0	$ 23.1	$ 0.5	$ 27.6	$ 59.0	$ 22.1	$ (20.8)	$ 265.5
	Goodwill, net	–	–	70.0	–	–	95.8	–	165.8
	Investment in unconsolidated affiliates	–	–	(14.1)	–	–	187.0	–	172.9
	Other non-current investments	–	–	124.1	–	–	85.7	0.6	210.4
	Total assets	3,674.5	582.6	1,129.7	333.1	258.5	1,101.3	96.5	7,176.2
	Capital expenditures	426.3	73.0	368.4	38.8	25.8	29.0	4.6	965.9

(1) From continuing operations. All periods have been adjusted to reflect the reclassification of results from operations to discontinued operations for: the Union and Gila River projects (formerly part of TWG); and TECO Coalbed Methane, Prior Energy and substantially all of TECO Gas Services (formerly part of Other Unregulated).
(2) See **Note 11** for a discussion of restructuring charges in 2003 and 2002.
(3) Segment net income is reported on a basis that includes internally allocated financing costs. Internally allocated costs for 2003, 2002 and 2001 were at pre-tax rates of 8%, 7% and 7%, respectively, based on the average investment in each subsidiary.
(4) Taxes have been allocated, for segment reporting purposes, to TWG based on the weighted-average tax rates of the TWG components.
(5) Net income for 2003 includes a $48.9 million after-tax ($79.6 million pre-tax) asset impairment charge related to the turbine purchase cancellations (see **Note 10**).
(6) Net income for 2003 includes a $25.9 million after-tax charge ($40.7 million pre-tax) related to a contingent arbitration proceeding (see the **Legal Contingencies** section of **Note 20**), a $61.2 million after-tax charge ($95.2 million pre-tax) for goodwill impairment (see **Note 3**), and a $15.3 million after-tax asset impairment charge ($24.5 million pre-tax) related to the turbine purchase cancellations (see **Note 10**).
(7) Net income for 2003 includes a $40.9 million after-tax asset impairment charge ($65.5 million pre-tax).

Tampa Electric Company provides retail electric utility services to more than 612,000 customers in West Central Florida. Its Peoples Gas System division is engaged in the purchase, distribution and marketing of natural gas for more than 299,000 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. TECO Coal transferred the synthetic fuel operations into a newly formed LLC for the purpose of continuing growth in the production and sale of synthetic fuel. In April 2003, TECO Coal sold a 49.5 percent interest in this entity.

TWG has subsidiaries that have interests in independent power projects in Virginia, Texas, Arkansas, Mississippi and Arizona.

TECO Energy's other unregulated businesses are primarily engaged in energy services, engineering and owning and operating independent power projects with long-term contracts, in Hawaii, Guatemala, and, until the date of the sale of HPP, Florida (see **Note 21**).

Foreign Operations

Other Unregulated includes independent power operations and investments in Guatemala. TECO Energy, 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, 2003, TECO Energy, 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.

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

Total assets at Dec. 31, 2003, 2002 and 2001 included $445.8 million, $415.9 million and $454.2 million, respectively, related to these Guatemalan operations and investments. Revenues included $91.5 million, $88.5 million and $79.9 million for the years ended Dec. 31, 2003, 2002 and 2001, respectively, and operating income included $53.1 million, $33.0 million and $38.0 million for the same periods from these Guatemalan operations and investments.

20. Commitments and Contingencies

Capital Investments

TECO Energy has made certain commitments in connection with its continuing capital expenditure program. At Dec. 31, 2003, these estimated capital investments total approximately $1.7 billion for the years 2004 through 2008 and are summarized as follows:

Forecasted Capital Investments

As of Dec. 31, 2003 *(millions)*	*2004*	*2005*	*2006 – 2008*	*Total 2004 – 2008*
Tampa Electric	$182.9	$213.5	$ 792.9	$1,189.3
Peoples Gas	40.0	40.0	120.0	200.0
TWG	14.9	25.0	75.0	114.9
TECO Transport	19.9	20.0	60.0	99.9
TECO Coal	20.7	19.4	53.3	93.4
Other	1.2	1.0	2.4	4.6
Total capital investments	$279.6	$318.9	$1,103.6	$1,702.1

For 2004, Tampa Electric expects to spend $182.9 million, consisting of $9.4 million (committed as of Dec. 31, 2003) for the completion of the repowering project at the Gannon Station, $18.2 million for environmental expenditures and $155.3 million to support system growth and generation reliability. Tampa Electric's estimated capital expenditures over the 2005-2008 period are projected to be $1,006.4 million, including $323.8 million for environmental expenditures.

Capital expenditures for PGS are expected to be about $40 million in 2004 and $160 million during the 2005-2008 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.

TWG expects to invest $14.9 million in 2004, $6.2 million of ongoing maintenance and warranty related items on the TECO Undertaking for Union and Gila River power stations plus $8.7 million of net contributions to projects of unconsolidated affiliates. Capital expenditures at TWG for 2005 through 2008 are expected to be about $100 million for the completion of the Dell and McAdams power stations. TWG had outstanding commitments of approximately $13.3 million primarily for contributions to projects of unconsolidated affiliates and maintenance projects.

The other unregulated companies expect to invest $41.8 million in 2004 and $156.1 million during 2005 through 2008, mainly for normal renewal and replacement capital.

Legal Contingencies

TM Delmarva Power Arbitration Proceeding

A dispute resulting in an arbitration proceeding was brought against a TWG subsidiary, TM Delmarva Power, L.L.C. (TMDP), by the non-equity member, NCP of Virginia, L.L.C. (NCP), in the Commonwealth Chesapeake Project (CCC). The arbitration panel, in a 2-to-1 decision, found in favor of NCP and issued an interim award on Dec. 17, 2002 and, after several briefing cycles and a reopened hearing, issued its final award in September 2003.

Under the award TMDP is obligated to acquire NCP's voting and other rights, pay NCP interest on the deemed acquisition price from a pre-determined date, and pay NCP's legal fees as prescribed under the final award. The forced acquisition created a pre-tax loss of $32.0 million, representing the excess of the purchase price over the fair value of the interests acquired. TMDP is seeking to vacate the arbitration award in the U.S. District Court for the District of Columbia and has not yet paid the amount of the award. As of Dec. 31, 2003, the company has reserved for the full $46.9 million, representing the maximum payment obligation for the award plus accrued interest. The vacatur proceeding is still pending, and is expected to be completed in the third or fourth quarter of 2004.

Other Actions

In March 2001, TWG (under its former name of TECO Power Services) was served with a lawsuit filed in the Circuit Court for Hillsborough County by a Tampa-based firm called Grupo Interamerica, LLC. ("Grupo") in connection with a potential investment in a power project in Columbia in 1996. Grupo alleges, among other things, that TWG breached an oral contract with Grupo that would have allowed Grupo to acquire up to a 20-percent interest in the Columbian wholesale generation project when TWG declined to invest in such project. Grupo is seeking damages equal to the net present value of the value of 20-percent of the project over its life. TWG disputes the allegations and denies liability since any understanding made regarding the investment in the project was subject to TECO Energy Board approval which was not obtained. A trial date has not been set.

Three lawsuits have been filed in the Circuit Court in Hillsborough County against Tampa Electric, in connection with the location of transmission structures in certain residential areas, by residents in the areas surrounding the structures. The high-voltage power lines are needed by Tampa Electric to move electricity to the northwest part of its service territory where population growth has been experienced. The residents are seeking to remove the poles or to receive monetary damages. Tampa Electric is working with the community to determine the feasibility of alternate routes or structures or some combination.

From time to time TECO Energy and its subsidiaries are involved in various other legal, tax, and regulatory proceedings before various courts, regulatory commissions, and governmental agencies in the ordinary course of its business. Where appropriate, accruals are made in accordance with FAS 5, *Accounting for Contingencies*, to provide for matters that are reasonably likely to result in an estimable, material loss. While the outcome of such proceedings is uncertain, management does not believe that the ultimate resolution of pending matters will have a material adverse effect on the company's results of operations or financial condition.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party 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, 2003, Tampa Electric Company has estimated its ultimate financial liability to be approximately $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 Company. The estimates to perform the work are based on actual estimates obtained from contractors, or Tampa Electric Company's experience with similar work adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

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

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

Long Term Commitments

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

Total rental expense for these operating leases, included in the Consolidated Statements of Income for the years ended Dec. 31, 2003, 2002 and 2001 was $29.5 million, $26.0 million and $20.4 million, respectively. The following is a schedule of future minimum lease payments at Dec. 31, 2003 for all operating leases with noncancelable lease terms in excess of one year:

Future Minimum Lease Payments For Operating Leases

Year ended Dec. 31:	*Amount (millions)*
2004	$ 24.1
2005	21.3
2006	17.6
2007	14.9
2008	12.4
Later Years	79.2
Total minimum lease payments	$ 169.5

In 1994, Tampa Electric bought out a long-term coal supply contract which would have expired in 2004 for a lump sum payment of $25.5 million. In February 1995, the FPSC authorized the recovery of this buy-out amount plus carrying costs through the Fuel and Purchased Power Cost Recovery Clause over the 10-year period beginning Apr. 1, 1995. In each of the years 2003, 2002 and 2001, $2.7 million of buy-out costs were amortized to expense.

Guarantees and Letters of Credit

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

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

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

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

A summary of the face amount or maximum theoretical obligation under TECO Energy's letters of credit and guarantees as of Dec. 31, 2003 are as follows:

Letters of Credit and Guarantees

($ millions)

Letters of Credit and Guarantees for the Benefit of:	*2004*	*2005*	*2006-2008*	*After 2008*	*Total*	*Liabilities Recognized at Dec. 31, 2003*
Tampa Electric						
Letters of credit	$ –	$ –	$ –	$ 0.9	$ 0.9	$ –
Guarantees:						
Fuel purchase/energy management (1)	–	–	–	15.0	15.0	–
	–	–	–	15.9	15.9	–
TECO Wholesale Generation						
Letters of credit (2)	67.2	–	–	–	67.2	–
Guarantees:						
Debt related	–	–	–	–	–	–
Tax related	–	–	–	1.3	1.3	–
Fuel purchase/energy management (1)	10.0	–	–	149.5	159.5	14.6
Construction/Investment related	5.0	–	–	–	5.0	–
	82.2	–	–	150.8	233.0	14.6
TECO Transport						
Letters of credit	–	–	–	1.5	1.5	–
TECO Coal						
Letters of credit	–	–	–	20.0	20.0	–
Guarantees: Fuel purchase related	–	–	–	1.5	1.5	1.5
	–	–	–	21.5	21.5	1.5
Other unregulated subsidiaries						
Letters of credit	11.5	–	4.7	4.3	20.5	–
Guarantees:						
Debt related	–	–	–	24.5	24.5	–
Tax related	–	–	–	2.5	2.5	–
Fuel purchase/energy management (1)	173.2 (3)	–	–	14.7	187.9	33.4
	184.7	–	4.7	46.0	235.4	33.4
Total	$266.9	$ –	$ 4.7	$235.7	$ 507.3	$49.5

(1) These guarantees renew annually and are shown on the basis that they will continue to renew beyond 2008. The amounts shown are the maximum theoretical amount guaranteed under current agreements. Liabilities recognized represent the associated obligation of TECO Energy under these agreements at Dec. 31, 2003. The obligations under these letters of credit and guarantees include net accounts payable and net derivative liabilities.
(2) Primarily includes letters of credit for construction support for the Gila River and Union power stations.
(3) These guarantees will be eliminated as a result of the sale of Prior Energy subsequent to Dec. 31, 2003. See **Note 23**.

TECO Energy and its subsidiaries also enter into commercial agreements in the normal course of business that typically contain standard indemnification clauses. TECO Energy may sometimes agree to make payments to compensate or indemnify the counterparty for legal fees, environmental remediation costs and other similar costs arising from possible future events or changes in laws or regulations. These agreements cover a variety of goods and services, and have varying triggering events dependent on actions by third parties.

TECO Energy is unable to estimate the maximum potential future exposure under these clauses because the events that would obligate TECO Energy have not occurred, or if such event has occurred, TECO Energy has not been notified of any occurrence. As claims are made or changes in laws or regulations indicate, an amount related to the indemnification is reflected in the financial statements.

Financial Covenants

A summary of TECO Energy's significant financial covenants as of Dec. 31, 2003 is as follows:

TECO Energy Significant Financial Covenants

(millions, unless otherwise indicated) *Instrument*	*Financial Covenant* (1)	*Requirement/Restriction*	*Calculation at Dec. 31, 2003*
Tampa Electric			
Mortgage bond indenture	Dividend restriction	Cumulative distributions cannot exceed cumulative net income plus $4	$5 unrestricted (2)
PGS senior notes	EBIT/interest (3)	Minimum of 2.0 times	3.5 times
	Restricted payments	Shareholder equity at least $500	$1,652
	Funded debt/capital	Cannot exceed 65%	50.5%
	Sale of assets	Less than 20% of total assets	–%
Credit facility	Debt/capital	Cannot exceed 60%	49.2%
	EBITDA/interest (3)	Minimum of 2.5 times	5.8 times
	Restriction on distributions	Limit on cumulative distributions and outstanding affiliate loans (4)	$483 unrestricted
6.25% senior notes	Debt/capital	Cannot exceed 60%	49.2%
	Limit on liens	Cannot exceed $787	$362
TECO Energy			
Credit facilities (5)	Debt/capital	Cannot exceed 65%	61.9%
$37.5 credit facility (6)	EBITDA/interest (3)	Minimum of 2.5 times	2.4 times (6)
	Limit on liens	Cannot exceed 60% of fair value of assets	24.9% (7)
	Debt/capital	Cannot exceed 65%	61.9%
$380 million note indenture	Limit on restricted payments (8)	Cumulative operating cash flow in excess of 1.7 times interest	$284 unrestricted
	Limit on liens	Cannot exceed 5% of tangible assets	$206 unrestricted (9)
	Limit on indebtedness	Interest coverage at least 2.0 times	2.6 times
$300 million note indenture	Limit on liens	Cannot exceed 5% of tangible assets	$206 unrestricted (9)
TPGC guarantees (10)	Debt/capital	Cannot exceed 65%	61.9%
	EBITDA/interest (3)	Minimum of 3.0 times	– (11)
TECO Diversified			
Energy management services agreement guarantee	Consolidated tangible net worth	Minimum of $200 net worth	$548
	Consolidated funded debt	Cannot exceed 60%	17.8%
Coal supply agreement guarantee	Dividend restriction	Tangible net worth not less than $200 or $424 (40% of tangible net assets)	$548

(1) As defined in each applicable instrument.
(2) Reflects the determination as of Dec. 31, 2003, after giving effect to $158 million distributed to TECO Energy as a return of capital during 2003. There were $75 million of callable bonds outstanding under the indenture at Dec. 31, 2003.
(3) EBIT generally represents earnings before interest and taxes. EBITDA generally represents EBIT before depreciation and amortization. However, in each circumstance, the term is subject to the definition prescribed under the relevant legal agreements.
(4) Limits cumulative distributions after Oct. 31, 2003 and outstanding affiliate loans to an amount representing an accumulation of net income after May 31, 2003 and capital contributions from the parent after Oct. 31, 2003, plus $450 million.
(5) One of TECO Energy's credit facilities, if drawn upon, can limit payment of dividends each quarter to $40 million, unless the company provides the lender with satisfactory liquidity projections demonstrating the company's ability to pay both the dividends contemplated and each of the three quarterly dividends next scheduled to be paid. See **Note 6** for the details regarding this credit facility.
(6) This facility was repaid in full in February 2004 prior to a declaration of default under the agreements. See **Note 23**.
(7) The fair market value of the assets has not been calculated. This calculation represents total collateralized debt, including TWG non-recourse debt, divided by the book value of total assets.
(8) The limitation on restricted payments restricts the company from paying dividends or making distributions or certain investments unless there is sufficient cumulative operating cash flow, as defined, in excess of 1.7 times interest to make such distribution or investment. The operating cash flow and restricted payments are calculated on a cumulative basis since the issuance of the 10.5% Notes in the fourth quarter of 2002. This calculation, at Dec. 31, 2003, reflects the amount accumulated and available for future restricted payments, representing the accumulation of four quarters' activities.
(9) The repayment of the collateralized $37.5 million credit facility in early 2004 increases this unrestricted amount to $244 million. See **Note 23**.
(10) Includes the Construction Undertaking Guarantees related to the TPGC projects.
(11) This calculation was not required for Sep. 30 or Dec. 31, 2003, as provided by the terms of the Suspension Agreement entered into between the lenders, the project companies and TECO Energy, as discussed below. The related long-term obligation is a component of the disposal group reported as a current liability on the balance sheet in the "Liabilities associated with assets held for sale" line item (see **Note 14**). Also, see **Note 23** for subsequent events relating to this covenant.

In April 2003, Moody's lowered TECO Energy's senior unsecured debt rating to Ba1 with a negative outlook. This debt rating change triggered the payment of the $250 million equity bridge loan balance associated with the construction of the Union and Gila River power projects. In addition, this ratings change required the company to post letters of credit, in an amount satisfactory to the majority of lenders, to secure the projects and project lenders for the remaining potential cost to complete the projects.

Suspension / Standstill Agreement

On Oct. 28, 2003, TECO Energy and the Union and Gila River project companies entered into a Suspension Agreement with the lending group for the Union and Gila River projects to suspend until Feb. 1, 2004 (see **Note 23** – subsequently, orally extended to Feb. 5, 2004) the quarterly calculation of the 3.0 times EBITDA-to-interest coverage ratio covenant included in the "TPGC guarantees" line in the table above. The Suspension Agreement contemplated discussions among TECO Energy, the Union and Gila River project companies and the lending group to reach an understanding regarding the projects' operating budgets and performance before expiration of the suspension period on Jan. 31, 2004. At the end of the suspension period, the Sep. 30 and Dec. 31, 2003 quarterly calculations would be performed.

In December 2003, the Union and Gila River project companies were unable to make interest payments on the non-recourse debt and payments under interest rate swap agreements due Dec. 31, 2003 when the project lenders declined to fund the debt service reserve. On Dec. 31, 2003, TECO Energy and the Union and Gila River project companies entered into a Standstill Agreement with the lending group for the Union and Gila River projects under which the lending group agreed to not exercise its rights or pursue remedies until after Jan. 31, 2004, while preserving such rights and remedies, relating to this payment default.

Subsequent to Dec. 31, 2003, the bank group for the Union and Gila River projects approved a non-binding letter of intent containing a binding Settlement Agreement which impacted these two agreements. See **Note 23** for additional details of these subsequent events and their impact.

21. Mergers, Acquisitions and Dispositions

Hardee Power Partners

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

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

PLC Development/TIE

At Dec. 31, 2002, TWG had a loan receivable of $137 million from PLC, a subsidiary of Panda Energy International. On Jan. 3, 2003, this loan was converted to a partnership interest in PLC. See **Notes 1** and **17** for additional details regarding the conversion of this loan to an equity interest in PLC. Furthermore, in September 2003, the company consummated the foreclosure on Panda Energy's interest in PLC for a default under a $23 million note receivable leading to TWG's 100-percent ownership in PLC which owns 50 percent of TIE (see **Notes 1, 12** and **17**). As of Sep. 30, 2003, TWG consolidated PLC, resulting in a net increase in investment in unconsolidated affiliates of approximately $18 million. For additional details related to this transaction see **Note 12**.

Synthetic Fuel Facilities

Effective Apr. 1, 2003, TECO Coal sold a 49.5-percent interest in its synthetic fuel production facilities located at its operations in eastern Kentucky. No significant gain or loss was recognized at the time of the sale. The company, through its various affiliates, will provide feedstock supply, and operating, sales and management services to the buyer through 2007, the current expiry date for the related Section 29 credit for which the production qualifies. Because the transaction was structured on a "pay-as-you-go" basis typical of similar transactions in the industry, TECO Coal received no significant cash at the time of sale. The sale required receipt of a positive response to a Private Letter Ruling (PLR) request, and the proceeds from this transaction were held in escrow pending resolution of this contingency. On Oct. 31, 2003, TECO Coal received a PLR from the IRS that resolved any uncertainty related to the previous sale of the 49.5-percent interest in its synthetic fuel facilities; triggered the release of certain cash escrows related to this sale; and confirmed that synthetic fuel produced by TECO Coal is eligible for Section 29 credits and that its testing procedures are in compliance with the requirements of the IRS. On Nov. 5, 2003, $58.9 million of restricted cash that had been held in escrow was released following receipt of the PLR.

TECO Coalbed Methane

TECO Coalbed Methane, a subsidiary of TECO Energy, produced natural gas from coal seams in Alabama's Black Warrior Basin. In September 2002, the company announced its intent to sell the TECO Coalbed Methane gas assets. On Dec. 20, 2002, substantially all of TECO Coalbed Methane's assets in Alabama were sold to the Municipal Gas Authority of Georgia. Proceeds from the sale were $140 million, $42 million paid in cash at closing, and a $98 million note receivable which was paid in January 2003. Net income for the year ended Dec. 31, 2003 included a $23.5 million after-tax gain for the final cash installment from the sale of these assets. TECO Coalbed Methane's results are included in discontinued operations for all periods presented (see **Note 14**).

Commonwealth Chesapeake

In May 2002, TWG purchased Mosbacher 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 was initially recorded as an increase in goodwill. The acquisition increased the company's ownership interest in TMPV to 100 percent. In 2003, the goodwill initially recorded was written off. See **Note 3** for additional details.

Prior Energy

In November 2001, TECO Solutions acquired Prior Energy Corporation, a 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 with Nov. 1, 2001 as the acquisition date. 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 initially recorded. 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.

At Dec. 31, 2003, the assets and liabilities expected to be transferred in the disposition of Prior Energy have been presented as held for sale on the balance sheet. The results of operations have been included in discontinued operations for all periods presented (see **Note 14**). See **Note 23** for details regarding the recent sale of Prior Energy.

Frontera Power Station

In March 2001, TWG 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 142 became effective on Jan. 1, 2002 (see **Note 3**). The results of operations of Frontera Power Station are included as part of TWG's results beginning Mar. 16, 2001.

The following pro forma disclosure includes the Frontera Power Station as if it had been included in TECO Energy's financial statements for the year ended Dec. 31, 2001.

Pro Forma Disclosure

(millions, except per share data) *Year ended Dec. 31,*	*Pro Forma* *2001*
Revenues	$2,506.5
Net income from continuing operations	262.2
Earnings per share from continuing operations – basic	$ 1.95

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.

22. New Accounting Pronouncements

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. The adoption of the measurement provisions on Jan. 1, 2003 did not have a material impact. See **Note 14** for additional details of amounts presented on a net basis.

Consolidation of Variable Interest Entities

The equity method of accounting is generally used to account for significant investments in partnership arrangements in which TECO Energy or its subsidiary companies do not have a majority ownership interest or exercise control. On Jan. 17, 2003, the FASB issued FIN 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. On Dec. 24, 2003, the FASB published a revision to FIN 46 (FIN 46R), to clarify some of the provisions of FIN 46 and exempt certain entities from its requirements.

Under FIN 46R, a legal entity is considered a VIE, with some exemptions if specific criteria are met, if it does not have sufficient equity at risk to finance its own activities without relying on financial support from other parties. Additional criteria must be applied to determine if this condition is met or if the equity holders, as a group, lack any one of three stipulated characteristics of a controlling financial interest. If the legal entity is a VIE, then the reporting entity determined to be the primary beneficiary of the VIE must consolidate it. Even if a reporting entity is not obligated to consolidate a VIE, then certain disclosures must be made about the VIE if the reporting entity has a significant variable interest. Certain transition disclosures are required for all financial statements issued after Jan. 31, 2003. The effective date of the interpretation was modified under FIN 46R. A reporting entity is required to apply the provisions of FIN 46R to all VIEs that previously were subject to certain previously issued special purpose entity, or SPE, accounting pronouncements for all reporting periods ending after Dec. 15, 2003. For all other VIEs, a reporting entity is required to adopt the provisions of FIN 46R for all reporting periods after Mar. 15, 2004.

Based on its review under the existing approved guidance, TECO Energy believes that FIN 46R will impact the accounting for certain unconsolidated affiliates. Below is a discussion of the legal entities as of Dec. 31, 2003 that TECO Energy believes will be subject to either additional disclosure requirements or consolidation by the company, in accordance with FIN 46R.

In November 2000 and January 2002, respectively, TECO Energy established TECO Funding I, LLC and TECO Funding II, LLC. Each of these limited-liability companies are wholly-owned subsidiaries of TECO Energy. These companies sold preferred securities to Capital Trust I and Capital Trust II, respectively. The funding companies used the proceeds to purchase subordinated notes from TECO Energy. The subordinated notes are not secured by specific assets of the company. The terms of these notes are similar to the terms of the preferred securities (see **Note 7** for additional details, including the impact of FAS 150 on the preferred securities). The funding companies are expected to be considered VIEs in accordance with FIN 46R. As of Dec. 31, 2003, management expects the potential impact of the adoption of FIN 46R to not be material for the funding companies.

Pike Letcher Synfuel, LLC was established as part of the Apr. 1, 2003 sale of TECO Coal's synthetic fuel production facilities. See **Note 21** for additional details regarding the terms of the sale and purpose of the entity. TECO Energy's maximum loss exposure in this entity is its equity investment of approximately $10.9 million and potential losses related to the production costs for the future production of synthetic fuel, in the event that such production creates Section 29 non-conventional fuel tax credits in excess of TECO Energy's capacity to generate sufficient taxable income to use such credits.

TECO Transport entered into two separate sale-leaseback transactions for certain vessels which were recognized as sales in December 2001 and December 2002, and are currently recognized as operating leases for the assets. The sale-leaseback transactions were entered into with separate third parties that the company believes meet the definition of a VIE. TECO Transport currently leases two ocean-going tugboats, four ocean-going barges, five river towboats and 49 river barges through these two trusts. The estimated maximum loss exposure faced by TECO Transport is the incremental cost of obtaining suitable equipment to meet the company's contractual shipping obligations. The company does not expect to consolidate upon the effective date of FIN 46R.

TECO Properties formed a limited liability company with a project developer which meets 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. The company has provided subordinated financial support in the form of a guarantee on behalf of the limited liability company. Hernando Oaks, LLC had total assets at Dec. 31, 2003 of $21.6 million. TECO Properties' estimated maximum loss exposure in this project is approximately $10.6 million, representing the sum of its guarantee and equity investment. The company expects to consolidate Hernando Oaks, LLC for all financial reporting periods ending after Mar. 15, 2004.

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 primarily for use in air conditioning systems. The partnership, TECO AGC, Ltd., meets the definition of a VIE. The company is the primary beneficiary, in accordance with FIN 46R, due to subordinated financing and other funding of $3.3 million provided to the partnership as of Dec. 31, 2003, in addition to the company's equity investment. This note receivable from the partnership is collateralized by the assets in the partnership. The estimated maximum loss exposure associated with this partnership is approximately $3.8 million as of Dec. 31, 2003, representing substantially all of the assets of the partnership. The company expects to consolidate TECO AGC, Ltd. for all financial reporting periods ending after Mar. 15, 2004.

Amendment to Derivatives Accounting

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

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

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

Financial Instruments with Characteristics of both Liabilities and Equity

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

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

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

This standard is effective for all financial instruments entered into or modified after May 31, 2003, and for all other financial instruments, at the beginning of the first interim period beginning after June 15, 2003. See **Note 7** for a discussion of the impact of the adoption of this standard on July 1, 2003.

23. Subsequent Events

Sale of TECO BGA, Inc. (formerly a component of TECO Energy Services)

Effective Jan. 1, 2004, the company completed the sale of TECO **BGA, Inc.** (formerly a component of TECO Energy Services) to an entity owned by an employee group for a pre-tax loss on disposal of $12.2 million ($7.5 million after tax). This loss was recorded as part of the asset impairment charge reported in the income statement for the year ended Dec. 31, 2003, in accordance with FAS 144 (see **Note 10** and the **Other transactions** section of **Note 14** for additional details relating to this disposition).

Repayment of $37.5 million one-year TECO Energy credit facility

On Jan. 5, 2004, TECO Energy repaid $20 million of the $37.5 million one-year credit facility collateralized by the Union and Gila River assets. On Feb. 4, 2004, TECO Energy repaid the remaining $17.5 million of the one-year credit facility.

Sale of TECO Propane Ventures' Indirect Interest in Heritage Propane Partners, L.P.

On Jan. 20, 2004, US Propane LP, in which TECO Propane Ventures holds a 38% equity interest, completed the sale of its direct and indirect equity investments in Heritage Propane Partners, L.P. (Heritage). The sale, part of a larger transaction that involved the merging of privately held Energy Transfer Company with Heritage, was announced Nov. 7, 2003. TECO Propane Ventures received $49.4 million in cash on Jan. 20, 2004 related to the sale and will record a $17.2 million pre-tax gain.

Recent Agreements Related to the Union and Gila River Project Exit Activities

Letter of Intent

On Feb. 5, 2004, the bank group for the Union and Gila River projects approved a non-binding letter of intent containing a binding Settlement Agreement. Under the agreement, TECO Energy and the project companies will work toward a definitive agreement with the lending banks for a purchase and sale or other agreement to transfer the ownership of the projects to the lending banks in exchange for a release of all obligations under the project loan agreements. The letter of intent specifies target dates for a definitive agreement by Jun. 30, 2004 and for closing by Sep. 30, 2004. The Settlement Agreement provides for the treatment of the $66 million of letters of credit posted by TECO Energy under the Construction Undertaking, with $35 million for the benefit of the project companies (drawn in February 2004) and the remaining $31 million of letters of credit to be cancelled and returned to TECO Energy. Under the letter of intent, all parties have specified a target completion of due diligence for final acceptance under the construction and undertaking contracts for both projects within 45 days; however, TECO Energy and the project companies will remain responsible to address certain permit issues at the Gila River project. No new investment in the projects will be made by TECO Energy. Since the projects have achieved commercial operation on all facilities at Union and Gila River, TECO Energy believes that it has met all but limited warranty and final acceptance responsibilities to the project companies. TECO Energy and various of its subsidiaries plan to continue to provide services and continue to provide expertise and operating support to help the project companies operate the facilities consistent with past practices at least through the completion of the transfer of ownership. The lending banks and TECO Energy and its affiliates have reserved their rights to assert certain claims they may have against one another until a definitive agreement is reached.

Expiration of Suspension / Standstill Agreement

The letter of intent permits the parties to reserve their rights against each other, including with respect to TECO Energy's failure to comply with the 3.0 times EBITDA-to-interest ratio coverage requirement in its Construction Undertakings for the quarters ending Sep. 30 and Dec. 31, 2003 (a cross default to the non-recourse credit agreements) that were covered by the Suspension Agreement, which has expired, and the failure of the project companies to make interest payments on the non-recourse project debt and payments under interest rate swap agreements due Dec. 31, 2003 when the project lenders declined to fund the debt service reserve.

The Construction Undertakings permit TECO Energy to terminate its obligations thereunder, including the requirement to comply with the covenants, by providing a Substitute Guarantor reasonably satisfactory to the lending group. On Sept. 22, 2003, TECO Energy tendered a Substitute Guarantor, which it believes satisfied the requirements of the Construction Undertakings. The lending group declined to accept this tender as being satisfactory. Under the letter of intent, TECO Energy has retained its right to assert that the Construction Undertakings were terminated in the event that the lending group seeks to exercise its rights thereunder based on a violation of the EBITDA-to-interest coverage ratio covenant.

As a result, the lending bank group could seek to exercise remedies against the project companies as a result of defaults in connection with the non-recourse project debt, including accelerating the non-recourse debt, foreclosing on the project collateral and suspending further funding; subject to the defenses that TECO Energy and its affiliates may have.

Under the Suspension Agreement between TECO Energy, the project companies and the lending bank group, TECO Energy was not required to calculate the EBITDA to interest coverage ratio required in the undertaking for the quarters ended Sep. 30, 2003 and Dec. 31, 2003 until Feb. 1, 2004 (orally extended until Feb. 5, 2004). On that date, the calculations were made resulting in a 2.7 and 2.4 times interest coverage ratio for the two quarters, respectively. Due to non-compliance with this covenant, the lenders could accelerate the $1.395 billion of non-recourse construction debt, absent the sale of the projects to the bank group.

Sale of Prior Energy

Effective Feb. 1, 2004, a subsidiary of TECO Energy completed the sale of Prior Energy for net proceeds of approximately $30 million. This sale did not result in a material gain or loss to the company. Outstanding guarantees related to the operations of Prior Energy are expected to be eliminated as a result of this transaction (see **Note 20**). See the **Other transactions** section of **Note 14** for additional details relating to this disposition.

TECO Energy 18-Month Credit Facility

As a result of receipt of cash proceeds from certain asset sales in early 2004, the existing $100 million unsecured credit facility with Merrill Lynch has been reduced to $20.6 million per the terms of the amended facility. The $200 million contingent credit facility with Merrill Lynch and JP Morgan, if activated would replace the existing Merrill Lynch facility. See **Note 6**.

24. Quarterly Data (unaudited)

The results for the three months ended Sep. 30, 2003 have been restated from amounts previously reported in the Form 10-Q for the quarter then ended due to a re-evaluation of the accounting for the HPP sale transaction subsequent to the filing date. The "Restated" column for Sep. 30, 2003 below:

(1) Reflects the results of operations for HPP as a component of continuing operations, rather than discontinued operations, due to a pre-existing long-term power purchase agreement from HPP to Tampa Electric, in accordance with FAS 144 (see the **Purchased Power** section of **Note 1**); and

(2) Reflects in the fourth quarter, rather than the third quarter, the gain on the sale of HPP to a third party, in accordance with SAB 104 (see **Note 21**).

The reclassification of HPP's operating results for the three months ended Sep. 30, 2003, after intercompany eliminations, increased a) revenues by $7.3 million, b) income from operations by $7.1 million and c) net income from continuing operations by $2.8 million. The recognition of the gain on the sale of HPP in the fourth quarter, rather than the third quarter, reduced net income in the third quarter by $34.6 million ($0.19 per share). The $34.6 million after-tax ($56.3 million pre-tax) gain on the sale of HPP was recognized in the fourth quarter. These revisions had no impact on TECO Energy's net loss for the year ended Dec. 31, 2003.

(millions, except per share amounts) *Quarter ended*	*Dec. 31*	*Restated* *Sep. 30*	*Sep. 30* (1)	*June 30* (2)	*Mar. 31* (2)
2003					
Revenues	$ 633.8	$ 759.1	$ 751.8	$ 695.3	$ 651.8
Income from operations	$ (63.8)	$ 92.2	$ 85.1	$ 0.5	$ (8.8)
Net income					
Net income from continuing operations	$ (4.0)	$ 4.6	$ 1.8	$ 5.0	$ (20.3)
Net income	$(790.7)	$ (19.5)	$ 15.0	$ (101.9)	$ 2.7
Earnings per share (EPS) - basic					
EPS from continuing operations	$ (0.02)	$ 0.03	$ 0.01	$ 0.03	$ (0.12)
EPS	$ (4.21)	$ (0.11)	$ 0.08	$ (0.58)	$ 0.02
Earnings per share (EPS) - diluted					
EPS from continuing operations	$ (0.02)	$ 0.03	$ 0.01	$ 0.03	$ (0.12)
EPS	$ (4.21)	$ (0.11)	$ 0.08	$ (0.58)	$ 0.01
Dividends paid per common share (3)	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.355
Stock price per common share (4)					
High	$ 14.85	$ 14.20	$ 14.20	$ 13.69	$ 17.00
Low	$ 11.80	$ 11.50	$ 11.50	$ 10.05	$ 9.47
Close	$ 14.41	$ 13.82	$ 13.82	$ 11.99	$ 10.63

Quarter ended	*Dec. 31*	*Sep. 30*	*June 30*	*Mar. 31*
2002 (5)				
Revenues	$ 665.2	$ 727.2	$ 672.7	$ 599.8
Income from operations	$ 58.0	$ 141.5	$ 95.7	$ 86.6
Net income				
Net income from continuing operations	$ 28.5	$ 106.6	$ 76.0	$ 66.1
Net income	$ 50.1	$ 118.9	$ 85.7	$ 75.4
Earnings per share (EPS) - basic				
EPS from continuing operations	$ 0.17	$ 0.68	$ 0.53	$ 0.47
EPS	$ 0.29	$ 0.76	$ 0.59	$ 0.54
Earnings per share (EPS) - diluted				
EPS from continuing operations	$ 0.17	$ 0.68	$ 0.53	$ 0.47
EPS	$ 0.29	$ 0.76	$ 0.59	$ 0.54
Dividends paid per common share (3)	$ 0.355	$ 0.355	$ 0.355	$ 0.345
Stock price per common share (4)				
High	$ 16.48	$ 24.71	$ 29.05	$ 28.94
Low	$ 10.02	$ 14.20	$ 22.70	$ 23.40
Close	$ 15.47	$ 15.88	$ 24.75	$ 28.63

(1) The amounts which were reported in the Form 10-Q for the quarter ended Sep. 30, 2003 (which amounts were subsequently changed to reflect both the revisions for the HPP sale and the reclassifications for the discontinued operations occurring in the fourth quarter as further discussed in **Note 14**) were as follows: revenues of $940.7 million; income from operations of $74.4 million; net income (loss) from continuing operations of $(19.2) million; net income of $15.0 million; EPS from continuing operations – basic and diluted of $(0.11); and EPS – basic and diluted of $0.08.
(2) Amounts shown reflect reclassifications to reflect discontinued operations as discussed in **Note 14**.
(3) Dividend paid on TECO Energy common stock.
(4) Trading prices for common shares.
(5) Amounts shown for 2002 reflect reclassifications to conform with the current year presentation. In particular, reclassifications have been made from continuing operations to discontinued operations as discussed in **Note 14**.

To 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, 2003 and Dec. 31, 2002, and the results of their operations and their cash flows for each of the three years in the period ended Dec. 31, 2003 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 Note 7 to the consolidated financial statements, the Company changed the manner in which it accounts for mandatorily redeemable securities as of July 1, 2003. As discussed in Note 5 to the consolidated financial statements, the Company changed the manner in which it accounts for asset retirement costs as of Jan. 1, 2003. As discussed in Note 3 to the consolidated financial statements, the Company changed the manner in which it accounts for goodwill and other intangible assets as of Jan. 1, 2002. As discussed in Note 2 to the consolidated financial statements, the Company changed the manner in which it accounts for derivative instruments as of Jan. 1, 2001.

PricewaterhouseCoopers LLP

Tampa, Florida
March 2, 2004

Selected Financial Data

(millions, except per share amounts) *Year ended Dec. 31,*	*2003*	*2002*	*2001*	*2000*	*1999*
Revenues	**$ 2,740.0**	$ 2,664.9	$ 2,483.3	$ 2,223.2	$ 1,932.6
Net (loss) income from continuing operations	**$ (14.7)**	$ 277.2	$ 265.5	$ 225.6	$ 179.2
Net (loss) income from discontinued operations	**(890.4)**	52.9	38.2	25.3	6.9
Cumulative effect of change in accounting principle, net	**(4.3)**	–	–	–	–
Net (loss) income	**$ (909.4)**	$ 330.1	$ 303.7	$ 250.9	$ 186.1
Total assets	**$ 10,462.3**	$ 9,078.4	$ 7,176.2	$ 6,167.8	$ 5,103.2
Long-term debt	**$ 4,392.6**	$ 3,324.3	$ 1,842.5	$ 1,374.6	$ 1,207.8
Earnings per share (EPS) – basic					
From continuing operations	**$ (0.08)**	$ 1.81	$ 1.98	$ 1.79	$ 1.37
From discontinued operations	**(4.95)**	0.34	0.28	0.20	0.05
From cumulative effect of change in accounting principle	**(0.02)**	–	–	–	–
EPS basic	**$ (5.05)**	$ 2.15	$ 2.26	$ 1.99	$ 1.42
Dividends paid per common share	**$ 0.925**	$ 1.41	$ 1.37	$ 1.33	$ 1.285

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

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

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Auditors
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Tampa, FL

Annual Meeting
The Annual Meeting of Shareholders will be held on April 28, 2004, 11:30 a.m. at:
Hilton Tampa Airport Westshore
2225 N. Lois Avenue
Tampa, FL 33607

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

Transfer Agent & Registrar
The Bank of New York
Receive and Deliver Department
P.O. Box 11002
Church Street Station
New York, NY 10286
www.stockbny.com

Dividend Reinvestment
The company offers a Dividend Reinvestment and Common Stock Purchase Plan which allows common shareholders of record to purchase additional shares of common stock at the current market price. All correspondence concerning this Plan should be directed to the Plan Agent:
The Bank of New York
Investment Services Department
P.O. Box 1958
Newark, NJ 07101-9774

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.sec.gov** or through the Investor Relations page at **www.tecoenergy.com**. Requests should be addressed to:
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