FirstEnergy.

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April 4, 2003

PY-CEI/NRR-2699L
DB-No.-2948
BV-No. L-03-045

Mr. Ira Dinitz
U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, D.C. 20555

Dear Mr. Dinitz;

Re: Docket Nos. 50-346, 50-440, 50-412, 50-334
Retrospective Premium Guarantee

Enclosed you will find the 2002 FirstEnergy Corp. Annual Report. This is in addition to the 2003 Internal Cash Flow Projection sent March 6, 2003 and completes the requirements for the Retrospective Premium Guarantee.

Very truly yours,

Randy Scilla

sb
Enclosures

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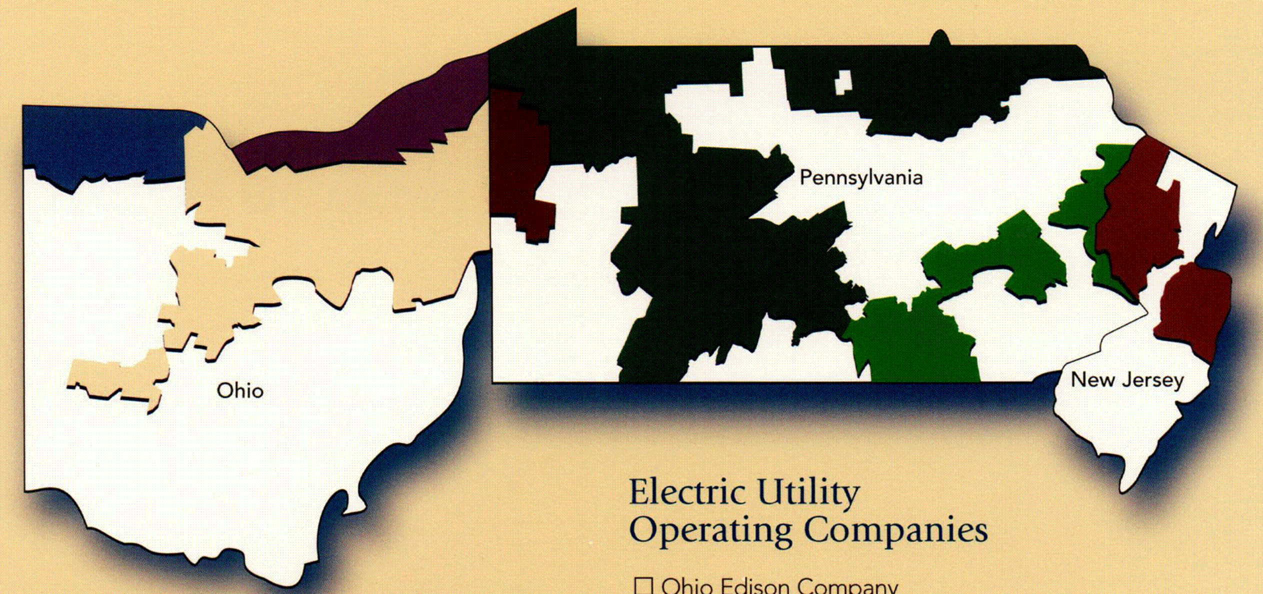
2002 Annual Report

FirstEnergy®



Electric Utility Operating Companies

- ☐ Ohio Edison Company
- ■ Cleveland Electric Illuminating Company
- ■ Toledo Edison Company
- ■ Pennsylvania Power Company
- ■ Pennsylvania Electric Company
- ■ Metropolitan Edison Company
- ■ Jersey Central Power & Light Company

Corporate Profile

FirstEnergy Corp. is a registered public utility holding company headquartered in Akron, Ohio. FirstEnergy subsidiaries and affiliates – which produce approximately $12 billion in annual revenues and own nearly $34 billion in assets – are involved in the generation, transmission and distribution of electricity; exploration and production of oil and natural gas; transmission and marketing of natural gas; energy management and other energy-related services.

FirstEnergy's seven electric utility operating companies comprise the nation's fourth largest investor-owned electric system, based on 4.3 million customers served within a 36,100-square-mile area that stretches from the Ohio-Indiana border to the New Jersey shore.

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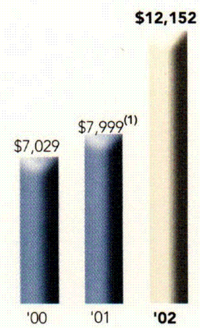
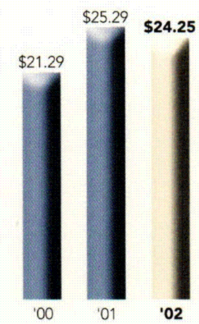


Total Revenues (Millions)



Book Value Per Common Share

Financial Highlights

	2002	2001[1]
(Dollars in thousands, except per share amounts)		
Total revenues	**$12,151,997**	$7,999,362
Income before cumulative effect of accounting changes[2]	**$686,401**	$654,946
Net income	**$629,280**	$646,447
Basic earnings per common share:		
Before cumulative effect of accounting changes	**$2.34**	$2.85
After cumulative effect of accounting changes	**$2.15**	$2.82
Diluted earnings per common share:		
Before cumulative effect of accounting changes	**$2.33**	$2.84
After cumulative effect of accounting changes	**$2.14**	$2.81
Dividends per common share	**$1.50**	$1.50
Book value per common share	**$24.25**	$25.29
Net cash from operations	**$1,915,287**	$1,281,684

[1] *Includes results from the former GPU, Inc., companies from November 7, 2001 - the effective date of the merger - through December 31, 2001.*

[2] *The 2002 accounting changes are described in Note 3 to the Consolidated Financial Statements under International Operations. The 2001 accounting change is described in Note 2(J) to the Consolidated Financial Statements.*

The following analysis reconciles basic earnings per share in 2002 and 2001 computed under generally accepted accounting principles (GAAP) to adjusted basic earnings per share excluding unusual charges in both years.

	2002	2001
Adjusted basic earnings per share:		
Basic earnings per share (GAAP)	**$2.15**	$2.82
Cumulative effect of accounting changes	**0.19**	0.03
Davis-Besse extended outage impacts	**0.47**	—
Asset impairments	**0.33**	—
Retaining generating units planned for sale	**0.15**	—
Other unusual items (see Management's Discussion)	**0.13**	0.04
Adjusted basic earnings per share	**$3.42**	$2.89

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Message to

Shareholders

2002 was a challenging year for your Company, particularly related to costs associated with restart efforts at the Davis-Besse Nuclear Power Station and other unusual charges.

As a result, we did not realize our earnings growth targets. However, we achieved solid results, including continued debt reduction and record performance by our generating fleet, that are helping us realize our vision of being the leading retail energy and related services supplier in the northeastern United States.

For the year, basic earnings were $2.15 per share, reflecting the $0 47 impact of Davis-Besse; $0.19 in charges related to planned sales of two international assets that weren't completed; $0.15 for depreciation and transaction expenses associated with our decision to retain four coal-fired plants in Ohio; and $0 46 in other non-recurring charges, described in this report.

Excluding these items, basic earnings were $3 42 per share, underscoring that our foundation for growth is strong. With the resolve of our employees and a sound and focused business strategy, we're confident that we'll deliver stronger performance in 2003.

"With the resolve of our employees and a sound and focused business strategy, we're confident that we'll deliver stronger performance in 2003."

H. Peter Burg,
Chairman and CEO

Overcoming the Challenges at Davis-Besse

A comprehensive inspection of Davis-Besse's reactor vessel head during a refueling outage in March of 2002 revealed areas of corrosion caused by boric acid that had leaked through cracks in control rod drive mechanism nozzles, which pass through the head.

Based on key industry measures, Davis-Besse had been a strong performer. However, as our own investigation showed, former plant management did not fully identify and address issues that we know, in hindsight, led to the corrosion problem at the plant. We're taking the steps necessary to help ensure that this never happens again And we're encouraged by the progress we're making in preparing Davis-Besse to return to safe and reliable service so that it can provide long-term value to our Company.

Recognizing that our success will depend as much on human performance as it will on equipment performance, we've strengthened our nuclear management team and oversight structure. We're taking significant steps to enhance the plant's safety culture by rigorously implementing a new safety policy and related programs and procedures. And, we've made key operational and system improvements, including replacement of the damaged reactor head.

Physical work required for restart is currently expected to be completed this spring, but the final determination of when Davis-Besse can return to service will be made by the Nuclear Regulatory Commission. Your Board of Directors is fully engaged in restart efforts, and continues to closely monitor changes we're making at the plant and throughout our FirstEnergy Nuclear Operating Company. And, I have personally delivered to all nuclear employees the message that safety is our top priority, and it must never be compromised for the sake of production.

For the year 2002, incremental operating and maintenance costs necessary to prepare the plant for restart, plus replacement power costs, totaled $235 million. And, we incurred $63 million in incremental capital costs, primarily for the reactor head replacement.

The impact of Davis-Besse, which accounts for seven percent of our generating capacity, has been significant. But we have not allowed the problems that occurred at the plant to define our organization.

Enhancing Corporate Governance

Your Company understands the importance of achieving success with a steadfast commitment to ethics and integrity – cornerstones of good corporate governance.

As we all know, some businesses lost sight of this important issue in recent years, resulting in the financial collapse of several companies once considered leaders in their industries.

We support recent changes to federal disclosure and corporate governance requirements designed to prevent unethical business practices. We've taken a number of steps to enhance corporate governance policies and practices throughout our organization.

For example, we've revised and enhanced Board committee charters and policies – now available on our Web site, *www.firstenergycorp.com/ir* – to ensure your Company meets the highest standards for independent Board oversight. We have a chief ethics officer and an ethics policy in place, in addition to codes of business conduct that all employees must follow. And, we remain vigilant in our commitment to ensure that you have accurate and complete information regarding the performance of your Company.

Recognizing the Value of Our Strategy

This past year certainly was a difficult one for our industry as companies continued to change their strategies for success in the evolving energy marketplace. We remain confident that we've chosen the right strategy for FirstEnergy.

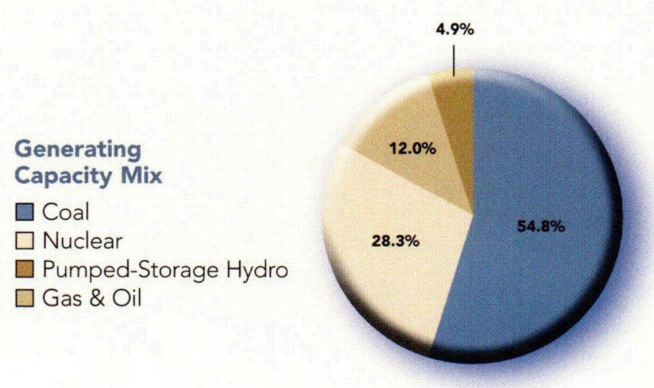
We continue to be committed to the generation, transmission and distribution of electricity and related services. Our business model provides for strong cash flow and financial flexibility, with approximately 75 percent of our revenues derived from our regulated businesses and a diversified sales mix.

Our integrated approach gives us the distinct competitive advantage of being better positioned to manage risks and unexpected developments, and to improve the value of your investment. While 2002 was a tough year for utility stocks, FirstEnergy remains a solid long-term investment. For example, at year end, our three-year annualized total shareholder return – the market appreciation of common stock, including the reinvestment of dividends – of 19 percent ranked us ninth among the 65 U.S. investor-owned electric utility companies that comprise the Edison Electric Institute Index.

Delivering Results

Enhancing our financial flexibility remains a key element of our strategy, and we delivered solid results in this important area in 2002. We retired, refinanced or repriced $2.6 billion in long-term debt and preferred stock, which will produce $125 million in annual savings. Our debt reduction activity should help lower our debt ratio to about 50 percent by the end of 2005. To help reach that goal, we'll continue reducing costs where appropriate and maximizing cash flow. In 2002, we made steady progress toward those ends.

We're on track to achieve our goal of $150 million in annual merger-related savings by the end of 2004. By that time, we also expect to save another $135 million annually through a cost reduction initiative we began implementing in 2002. Cost reductions are important, particularly as we – like other companies – face rising health care and pension and other post-employment benefit costs.



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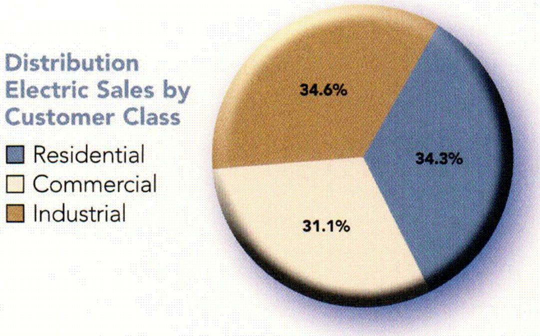
Distribution Electric Sales by Customer Class



Reducing costs also is important to our ongoing efforts to maximize our free cash flow – cash flow after the payment of common stock dividends and capital expenditures. Free cash flow, which totaled about $340 million in 2002, is projected to exceed $700 million in 2003. The increase is based on Davis-Besse's anticipated return to service, expected growth and improvements in our core electric business, a reduction in capital expenditures, and ongoing merger-related and financing cost savings.

"More than 60 percent of customers surveyed rated us a 9 or 10 on a 10-point scale..."

Continued savings and debt reduction are key to our commitment to maintaining the investment grade ratings held by our holding company and all seven of its operating companies. These ratings are important because they improve our access to capital markets and reduce the cost of borrowing.

Achieving Operational Excellence

We continued to improve our operations in 2002, including the record output of 71.3 million megawatt-hours set by our generating units. Strong performance by our coal-fired plants, as well as our Perry and Beaver Valley nuclear plants, helped offset the decline in power production resulting from the extended outage at Davis-Besse.

We also achieved a 7.9 percent increase in total kilowatt-hour sales, while again demonstrating our commitment to safe operations. Our company-wide Occupational Safety and Health Administration incident rate of 1.56 per 100 utility employees ranks us among our industry's leaders in safety.

In addition, we made solid progress in our efforts to provide superior customer service. More than 60 percent of customers surveyed rated us a 9 or 10 on a 10-point scale measuring our performance in key areas of service reliability and restoration, and employee performance.

Maximizing the Value of our Assets

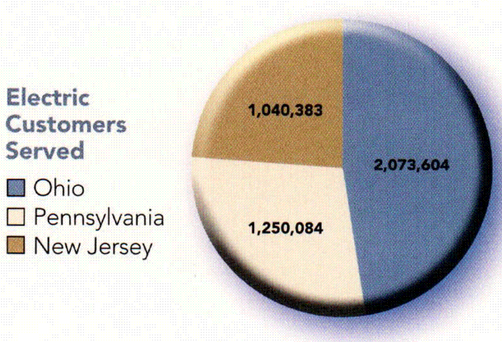
Consistent with our strategy, we remain focused on maximizing the value of our assets and divesting non-core businesses, most of which were acquired through the GPU merger.

As you may recall, we sold 79.9 percent of Avon Energy Partners Holdings in the United Kingdom to Aquila, Inc., in 2002. We continue to evaluate opportunities to sell our remaining 20.1 percent interest. However, we'll likely receive less for our interest in Avon Energy than its original carrying value, and as a result, recorded a $50 million, or $0.11 per share, non-cash charge in 2002.

We also plan to divest Emdersa – a distribution company in Argentina – although difficult economic conditions there have complicated our efforts. Because we were unable to reach a sale agreement within one year of the merger, we could no longer classify it as an asset pending sale. As a result, we recorded in 2002 a one-time, non-cash cumulative effect of an accounting change that reduced net income by $88.8 million, or $0.30 per share.

And, we're continuing to explore opportunities to divest our other remaining international assets, which include interests in four generating plants – one in Colombia and three

Electric Customers Served



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in Bolivia – also acquired through the GPU merger.

With respect to our core assets, in August we canceled an agreement with NRG Energy, Inc., of Minneapolis, Minnesota, and its affiliate (NRG), to sell four coal-fired power plants located along Lake Erie in Ohio for $1.5 billion based on an anticipatory breach by NRG. We've reserved the right to pursue legal action against NRG and its parent, Xcel Energy, and in February, received permission from the U.S. Bankruptcy Court in Minnesota to proceed to arbitration with NRG.

We're also continuing to evaluate the competitiveness of our other generating assets. As a result, we closed four small electric generating units totaling 236 megawatts in Ohio. This decision is consistent with our strategy to focus on larger baseload plants and newer, higher-efficiency peaking units, including our 340-megawatt Sumpter Plant, which went into service in 2002. Enhancing the performance of our generating fleet is critical to meeting customer demand and to effectively managing our commodity supply needs, including those associated with meeting our provider of last resort obligations in the states where we operate.

A 2002 ruling by the Pennsylvania Commonwealth Court denied two of our operating companies the ability to defer costs in excess of capped generation rates incurred to serve customers in that state. As a result, we incurred a $56 million, or $0.11 per share, charge during the year. The Pennsylvania Supreme Court declined to hear our appeal of the Commonwealth Court ruling. However, we remain well-positioned to meet our provider of last resort obligations through a combination of our own generating capacity, which totals more than 13,000 megawatts, and contracted supply.

> "With the steady progress we're making to improve operations, grow cash flow and further reduce debt, we're positioned to build on the many performance gains of our core electric business."

Protecting the Environment

We're delivering on our commitment to protect the environment, while meeting customer needs for reliable and competitively priced electricity. We've spent more than $5 billion on environmental protection efforts since enactment of the Clean Air Act. And through the installation of low-nitrogen-oxide (NOx) burners and other environmental protection systems, we've reduced by more than one-half emissions of NOx and sulfur dioxide since 1990.

We'll achieve further reductions in NOx emissions through state-of-the-art environmental protection systems that will begin operating at our largest coal-fired generating units this summer.

Despite our progress, the U.S. Environmental Protection Agency (U.S. EPA) is pursuing installation of additional environmental controls in legal action against our W. H. Sammis Plant and more than 40 power plants in the Midwest and South owned by other utility companies. The U.S. EPA claims that routine maintenance, repairs and replacements at Sammis – common industry practices for decades that the agency was fully aware of – violated provisions of the Clean Air Act, even though capacity and emissions have not increased. The U.S. EPA's allegations were tried before the U.S. District Court in Columbus, Ohio, in February of this year. While a ruling has not been issued, we remain confident that all of our plants, including Sammis, are in compliance.

Committed to Delivering Stronger Performance

Your Company faced many challenges in 2002. However, we view the most significant ones – including those associated with Davis-Besse – primarily as short term. With the steady progress we're making to improve operations, grow cash flow and further reduce debt, we're positioned to build on the many performance gains of our core electric business.

For 2003, our primary goals include further improving the performance of our generating fleet, including returning Davis-Besse to safe and reliable service, and continuing to enhance our credit profile and financial flexibility.

And with a sound corporate strategy, the hard work and dedication of employees and your continued support, we're confident that we'll achieve solid performance in 2003 that will lead to continued success in the years ahead.

Sincerely,

H. Peter Burg
Chairman and
Chief Executive Officer

March 24, 2003

Management Report

The consolidated financial statements were prepared by the management of FirstEnergy Corp., who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, independent public accountants, have expressed an unqualified opinion on the Company's 2002 consolidated financial statements.

The Company's internal auditors, who are responsible to the Audit Committee of the Board of Directors, review the results and performance of operating units within the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

The Audit Committee consists of six nonemployee directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent public accountants and the internal auditors; appointment of independent accountants to conduct the normal annual audit and special purpose audits as may be required; reviewing and approving all services, including any non-audit services, performed for the Company by the independent public accountants and reviewing the related fees; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee reviews the independent accountants' internal quality control procedures and reviews all relationships between the independent accountants and the Company, in order to assess the auditors' independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Audit Committee held nine meetings in 2002.

Richard H. Marsh

Richard H. Marsh, *Senior Vice President and Chief Financial Officer*

Harvey L. Wagner

Harvey L. Wagner, *Vice President, Controller and Chief Accounting Officer*

Report of Independent Public Accountants

To the Stockholders and Board of Directors of FirstEnergy Corp.:

In our opinion, the accompanying consolidated balance sheet and consolidated statement of capitalization and the related consolidated statements of income, common stockholders' equity, preferred stock, cash flows and taxes present fairly, in all material respects, the financial position of FirstEnergy Corp. and subsidiaries as of December 31, 2002, and the results of their operations and their cash flows for the year then ended 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 audit. We conducted our audit 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 audit provides a reasonable basis for our opinion. The consolidated financial statements of FirstEnergy Corp. and subsidiaries as of December 31, 2001 and for each of the two years in the period ended December 31, 2001 were audited by other independent accountants who have ceased operations. Those independent accountants expressed an unqualified opinion on those financial statements, before the revisions described in Notes 2 and 8 to the 2002 consolidated financial statements, in their report dated March 18, 2002.

As discussed in Note 2 to the consolidated financial statements, the Company changed its method of accounting for goodwill in 2002. As discussed in Note 3 to the consolidated financial statements, the Company changed its method of accounting for its investments in Avon Energy Partners Holdings and Emdersa in 2002.

As discussed above, the consolidated financial statements of FirstEnergy Corp. and subsidiaries as of December 31, 2001 and for each of the two years in the period ended December 31, 2001 were audited by other independent accountants who have ceased operations. As described in Note 2 to the consolidated financial statements, revisions have been made to include the transitional disclosures required by Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets*, which was adopted by the Company as of January 1, 2002. In our opinion the transitional disclosures for 2001 and 2000 are appropriate. However, we were not engaged to audit, review, or apply any procedures to the 2001 and 2000 consolidated financial statements of the Company other than with respect to such disclosures and, accordingly, we do not express an opinion or any other form of assurance on the 2001 and 2000 consolidated financial statements taken as a whole. Additionally, as described in Note 8 to the consolidated financial statements, the Company changed the composition of its reportable segments in 2002. Accordingly, the corresponding 2001 and 2000 reportable segments disclosures have been revised to conform to the 2002 presentation. We audited the revisions that were applied to the 2001 and 2000 reportable segments disclosures reflected in Note 8 to the 2002 consolidated financial statements. In our opinion, such revisions are appropriate and have been properly applied.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP Cleveland, OH, February 28, 2003

The following report is a copy of a report previously issued by Arthur Andersen LLP and has not been reissued by Arthur Andersen LLP.

Report of Previous Independent Public Accountants

To the Stockholders and Board of Directors of FirstEnergy Corp.

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of FirstEnergy Corp. (an Ohio corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, common stockholders' equity, preferred stock, cash flows and taxes for each of the three years in the period ended December 31, 2001. 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 in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of FirstEnergy Corp. and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Note 1 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for derivative instruments and hedging activities by adopting Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities", as amended.

Arthur Andersen LLP

Arthur Andersen LLP Cleveland, Ohio, March 18, 2002

SELECTED FINANCIAL DATA

(In thousands, except per share amounts)

For the Years Ended December 31,	2002	2001	2000	1999	1998
Revenues	**$12,151,997**	$ 7,999,362	$ 7,028,961	$ 6,319,647	$ 5,874,906
Income Before Extraordinary Item and Cumulative Effect of Accounting Changes	**$ 686,401**	$ 654,946	$ 598,970	$ 568,299	$ 441,396
Net Income	**$ 629,280**	$ 646,447	$ 598,970	$ 568,299	$ 410,874
Basic Earnings per Share of Common Stock:					
Before Extraordinary Item and Cumulative Effect of Accounting Changes	**$2.34**	$2.85	$2.69	$2.50	$1.95
After Extraordinary Item and Cumulative Effect of Accounting Changes	**$2.15**	$2.82	$2.69	$2.50	$1.82
Diluted Earnings per Share of Common Stock:					
Before Extraordinary Item and Cumulative Effect of Accounting Changes	**$2.33**	$2.84	$2.69	$2.50	$1.95
After Extraordinary Item and Cumulative Effect of Accounting Changes	**$2.14**	$2.81	$2.69	$2.50	$1.82
Dividends Declared per Share of Common Stock	**$1.50**	$1.50	$1.50	$1.50	$1.50
Total Assets	**$33,580,773**	$37,351,513	$17,941,294	$18,224,047	$18,192,177
Capitalization at December 31:					
Common Stockholders' Equity	**$ 7,120,049**	$ 7,398,599	$ 4,653,126	$ 4,563,890	$ 4,449,158
Preferred Stock:					
Not Subject to Mandatory Redemption	**335,123**	480,194	648,395	648,395	660,195
Subject to Mandatory Redemption	**428,388**	594,856	161,105	256,246	294,710
Long-Term Debt*	**10,872,216**	12,865,352	5,742,048	6,001,264	6,352,359
Total Capitalization*	**$18,755,776**	$21,339,001	$11,204,674	$11,469,795	$11,756,422

**2001 includes approximately $1.4 billion of long-term debt (excluding long-term debt due to be repaid within one year) included in "Liabilities Related to Assets Pending Sale" on the Consolidated Balance Sheet as of December 31, 2001.*

PRICE RANGE OF COMMON STOCK

The Common Stock of FirstEnergy Corp. is listed on the New York Stock Exchange under the symbol "FE" and is traded on other registered exchanges.

	2002		2001	
First Quarter High-Low	**$39.12**	**$30.30**	$31.75	$25.10
Second Quarter High-Low	**35.12**	**31.61**	32.20	26.80
Third Quarter High-Low	**34.78**	**24.85**	36.28	29.60
Fourth Quarter High-Low	**33.85**	**25.60**	36.98	32.85
Yearly High-Low	**39.12**	**24.85**	36.98	25.10

Prices are based on reports published in The Wall Street Journal for New York Stock Exchange Composite Transactions.

HOLDERS OF COMMON STOCK

There were 163,423 and 162,762 holders of 297,636,276 shares of FirstEnergy's Common Stock as of December 31, 2002 and January 31, 2003, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 5A.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

This discussion includes forward-looking statements based on information currently available to management that is subject to certain risks and uncertainties Such statements typically contain, but are not limited to, the terms anticipate, potential, expect, believe, estimate and similar words. Actual results may differ materially due to the speed and nature of increased competition and deregulation in the electric utility industry, economic or weather conditions affecting future sales and margins, changes in markets for energy services, changing energy and commodity market prices, legislative and regulatory changes (including revised environmental requirements), the availability and cost of capital, our ability to accomplish or realize anticipated benefits from strategic initiatives and other similar factors.

FirstEnergy Corp. is a registered public utility holding company that provides regulated and competitive energy services (see Results of Operations - Business Segments) domestically and internationally. The international operations were acquired as part of FirstEnergy's acquisition of GPU, Inc. in November 2001. GPU Capital, Inc and its subsidiaries provide electric distribution services in foreign countries. GPU Power, Inc and its subsidiaries develop, own and operate generation facilities in foreign countries Sales are planned but not pending for all of the international operations (see Capital Resources and Liquidity) Prior to the GPU merger, regulated electric distribution services were provided to portions of Ohio and Pennsylvania by our wholly owned subsidiaries - Ohio Edison Company (OE), The Cleveland Electric Illuminating Company (CEI), Pennsylvania Power Company (Penn) and The Toledo Edison Company (TE) with American Transmission Systems, Inc. (ATSI) providing transmission services. Following the GPU merger, regulated services are also provided through wholly owned subsidiaries - Jersey Central Power & Light Company (JCP&L), Metropolitan Edison Company (Met-Ed) and Pennsylvania Electric Company (Penelec) - providing electric distribution and transmission services to portions of Pennsylvania and New Jersey. The coordinated delivery of energy and energy-related products, including electricity, natural gas and energy management services, to customers in competitive markets is provided through a number of subsidiaries, often under master contracts providing for the delivery of multiple energy and energy-related services Prior to the GPU merger, competitive services were principally provided by FirstEnergy Solutions Corp. (FES), FirstEnergy Facilities Services Group, LLC (FSG) and MARBEL Energy Corporation Following the GPU merger, competitive services are also provided through MYR Group, Inc.

GPU Merger

On November 7, 2001, the merger of FirstEnergy and GPU became effective with FirstEnergy being the surviving company. The merger was accounted for using purchase accounting under the guidelines of Statement of Financial Accounting Standards No. (SFAS) 141, "Business Combinations." Under purchase accounting, the results of operations for the combined entity are reported from the point of consummation forward. As a result, our financial statements for 2001 reflect twelve months of operations for our pre-merger organization and seven weeks of operations (November 7, 2001 to December 31, 2001) for the former GPU companies. In 2002, our financial statements include twelve months of operations for both our pre-merger organization and the former GPU companies. Additional goodwill resulting from the merger ($2.3 billion) plus goodwill existing at GPU ($1.9 billion) at the time of the merger is not being amortized, reflecting the application of SFAS 142, "Goodwill and Other Intangible Assets " Goodwill continues to be subject to review for potential impairment (see Significant Accounting Policies - Goodwill). As a result of the merger, we issued nearly 73.7 million shares of our common stock, which are reflected in the calculation of earnings per share of common stock in 2002 and for the seven-week period outstanding in 2001.

Results of Operations

Net income decreased to $629.3 million in 2002, compared to $646 4 million in 2001 and $599 0 million in 2000 Net income in 2002 included the net after-tax charge of $57.1 million resulting from the cumulative effect of changes in accounting resulting from divestiture activities discussed below Net income in 2001 included the cumulative effect of an accounting change resulting in a net after-tax charge of $8 5 million (see Cumulative Effect of Accounting Changes) Excluding the former GPU companies' results (and related interest expense on acquisition debt), net income decreased to $469 4 million in 2002 from $615.5 million in 2001 due in large part to the incremental costs related to the extended Davis-Besse outage and a number of one-time charges summarized in the table on the following page. In addition, SFAS 142, implemented January 1, 2002, resulted in the cessation of goodwill amortization. In 2001, amortization of goodwill reduced net income by approximately $57 million ($0.25 per share of common stock). Excluding the former GPU companies' results (and related interest expense on acquisition debt), net income increased in 2001 due to reduced depreciation and amortization, general taxes and net interest charges The benefits of these reductions were offset in part by lower retail electric sales, increased other operating expenses and higher gas costs.

Incremental costs related to the extended outage at the Davis-Besse nuclear plant (see Davis-Besse Restoration) reduced basic and diluted earnings per share of common stock by $0 47 in 2002 In addition, the table on the following page displays one-time charges that resulted in a comparative net reduction to basic and diluted earnings of $0 46 per share of common stock in 2002, compared to 2001.

The impact of domestic and world economic conditions on the electric power industry limited our divestiture program during 2002. By the end of 2001, we had successfully completed the sale of our Australian gas transmission companies, had reached agreement with Aquila, Inc. for the sale of our holdings of electric distribution facilities in the United Kingdom (UK) and executed an agreement with NRG Energy Inc. (NRG) for the sale of four coal-fired power plants. However, the UK transaction with Aquila closed on May 8, 2002 and reflected the March 2002 modification of Aquila's initial offer such that Aquila acquired a 79.9 percent equity interest in Avon Energy

Partners Holdings (Avon) for approximately $1.9 billion (including the assumption of $1.7 billion of debt). In the fourth quarter of 2002, we recognized a $50 million impairment of our Avon investment. On August 8, 2002, we notified NRG that we were canceling our agreement with them for their purchase of the four fossil plants because NRG had stated that it could not complete the transaction under the original terms of the agreement. We were also actively pursuing the sale of an electric distribution company in Argentina - GPU Empressa Distribuidora Electrica Regional S.A. and its affiliates (Emdersa). With the deteriorating economic conditions in Argentina, no sale could be completed by December 31, 2002. Further information on the impact of the changes in accounting related to our divestiture activities is available in the "Cumulative Effect of Accounting Changes" section and in the discussion of depreciation charges in the "Expenses" section below.

One-time pre-tax charges to earnings before the cumulative effect of accounting changes are summarized in the following table:

One-time Charges	2002	2001	Change
		(In millions)	
Investment impairments	**$100.7**	—	$100.7
Pennsylvania deferred energy costs	**55.8**	—	55.8
Lake Plants – depreciation and sale costs	**29.2**	—	29.2
Long-term derivative contract adjustment	**18.1**	—	18.1
Generation project cancellation	**17.1**	—	17.1
Severance costs – 2002	**11.3**	—	11.3
Uncollectible reserve and contract losses	—	9.2	(9.2)
Early retirement costs – 2001	—	8.8	(8.8)
Estimated claim settlement	**16.8**	—	16.8
	$249.0	$18.0	$231.0
Reduction to earnings per share of common stock			
Basic	**$0.51**	$0.05	$0.46
Diluted	**$0.51**	$0.05	$0.46

Previously reported variances of revenues, expenses, income taxes and net income between 2001 as compared to 2000 included in Results of Operations – Business Segments have been reclassified as a result of segment information reclassifications (see Note 8 for additional discussion). In addition, previously reported comparisons of sales of electricity between 2001 as compared to 2000 have also been reclassified as a result of adoption of Emerging Issues Task Force (EITF) Issue No. 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (see Implementation of Recent Accounting Standard for additional disclosure).

Revenues

Total revenues increased $4.2 billion in 2002, which included more than $4.5 billion incremental revenues for the former GPU companies in 2002 (twelve months), compared to 2001 (seven weeks). Excluding results from the former GPU companies, total revenues increased $24.7 million following a $336.7 million increase in 2001. The additional sales in both years resulted from an expansion of our unregulated businesses, which more than offset lower sales from our electric utility operating companies (EUOC). Sources of changes in pre-merger and post-merger companies' revenues during 2002 and 2001, compared to the prior year, are summarized in the following table:

Sources of Revenue Changes	2002	2001
Increase (Decrease)	*(In millions)*	
Pre-Merger Companies:		
Electric Utilities (Regulated Services):		
Retail electric sales	**$ (328.5)**	$ (240.5)
Other revenues	**18.4**	(22.6)
Total Electric Utilities	**(310.1)**	(263.1)
Unregulated Businesses (Competitive Services):		
Retail electric sales	**136.4**	(19.9)
Wholesale electric sales:		
Nonaffiliated	**140.0**	254.4
Affiliated	**345.3**	32.7
Gas sales	**(171.7)**	226.1
Other revenues	**(115.2)**	106.5
Total Unregulated Businesses	**334.8**	599.8
Total Pre-Merger Companies	**24.7**	336.7
Former GPU Companies:		
Electric utilities	**3,782.4**	570.4
Unregulated businesses	**687.4**	101.9
Total Former GPU Companies	**4,469.8**	672.3
Intercompany Revenues	**(341.9)**	(38.6)
Net Revenue Increase	**$4,152.6**	$ 970.4

Electric Sales

Shopping by Ohio customers for alternative energy suppliers combined with the effect of a sluggish national economy on regional business reduced retail electric sales revenues of our pre-merger EUOCs by $328.5 million (or 7.1%) in 2002 compared to 2001. Since Ohio opened its retail electric market to competing generation suppliers in 2001, sales of electric generation by alternative suppliers in our franchise areas have risen steadily, providing 23.6% of total energy delivered to retail customers in 2002, compared to 11.3% in 2001. As a result, generation kilowatt-hour sales to retail customers by the EUOC were 14.2% lower in 2002 than the prior year, which reduced regulated retail electric sales revenues by $230.6 million.

Revenue from distribution deliveries decreased by $11.7 million in 2002 compared to 2001. Kilowatt-hour deliveries to franchise customers were 0.5% lower in 2002 compared to the prior year. The decrease resulted from the net effect of a 6.3% increase in kilowatt-hour deliveries to residential customers (due in large part to warmer summer weather in 2002) offset by a 3.2% decline in kilowatt-hour deliveries to commercial and industrial customers as a result of sluggish economic conditions.

The remaining decrease in regulated retail electric sales revenues resulted from additional transition plan incentives provided to customers to promote customer shopping for alternative suppliers - $86.0 million of additional credits in 2002 compared to 2001. These reductions to revenue are deferred for future recovery under our Ohio transition plan and do not materially affect current period earnings.

Despite the decrease in kilowatt-hour sales by our pre-merger EUOC, total electric generation sales increased by 22.0% in 2002 compared to the prior year as a result of higher kilowatt-hour sales by our competitive services segment. Revenues from the wholesale market increased $501.4 million in 2002 from 2001 and kilowatt-hour sales more than doubled. More than half of the increase resulted from additional affiliated company sales by FES to Met-Ed and Penelec. FES assumed the supply obligation in the third quarter of 2002 for a portion of Met-Ed's and Penelec's provider of last resort (PLR) supply requirements (see State Regulatory Matters - Pennsylvania). The increase also included sales into the New Jersey market as an alternative supplier for a portion of New Jersey's basic generation service (BGS). Retail sales by our competitive services segment increased by $136.4 million as a result of a 59 0% increase in kilowatt-hour sales in 2002 from 2001. That increase resulted from retail customers switching to FES, our unregulated subsidiary, under Ohio's electricity choice program The higher kilowatt-hour sales in Ohio were partially offset by lower retail sales in markets outside of Ohio

In 2001, our pre-merger EUOC retail revenues decreased by $240.5 million compared to 2000, principally due to lower generation sales volume resulting from the first year of customer choice in Ohio. Sales by alternative suppliers increased to 11 3% of total energy delivered compared to 0 8% in 2000 Implementation of a 5% reduction in generation charges for residential customers as part of Ohio's electric utility restructuring in 2001 also contributed $51.2 million to the reduced electric sales revenues Kilowatt-hour deliveries to franchise customers were down a more moderate 1 7% due in part to the decline in economic conditions, which was a major factor resulting in a 3.1% decrease in kilowatt-hour deliveries to commercial and industrial customers Other regulated electric revenues decreased by $22 6 million in 2001, compared to the prior year, due in part to reduced customer reservation of transmission capacity

Total electric generation sales increased by 2 7% in 2001 compared to the prior year with sales to the wholesale market being the largest single factor contributing to this increase Kilowatt-hour sales to wholesale customers more than doubled from 2000 and revenues increased $287 1 million in 2001 from the prior year The higher kilowatt-hour sales benefited from increased availability of power to sell into the wholesale market, due to additional internal generation and increased shopping by retail customers from alternative suppliers, which allowed us to take advantage of wholesale market opportunities Retail kilowatt-hour sales by our competitive services segment increased by 3 6% in 2001, compared to 2000, primarily due to expanding sales within Ohio as a result of retail customers switching to FES under Ohio's electricity choice program. The higher kilowatt-hour sales in Ohio were partially offset by lower sales in markets outside of Ohio as some customers returned to their local distribution companies Despite an increase in kilowatt-hour sales in Ohio's competitive market, declining sales to higher-priced eastern markets contributed to an overall decline in retail competitive sales revenue in 2001 from the prior year.

Changes in electric generation sales and distribution deliveries in 2002 and 2001 for our pre-merger companies are summarized in the following table

Changes in kilowatt-hour Sales	2002	2001
Increase (Decrease)		
Electric Generation Sales		
Retail –		
Regulated services	(14 2)%	(12 2)%
Competitive services	59 0%	3 6%
Wholesale	122 6%	117 2%
Total Electric Generation Sales	22 0%	2 7%
EUOC Distribution Deliveries		
Residential	6.3%	1 7%
Commercial and industrial	(3.2)%	(3 1)%
Total Distribution Deliveries	(0.5)%	(1 7)%

Our regulated and unregulated subsidiaries record purchase and sales transactions with PJM Interconnection ISO, an independent system operator, on a gross basis in accordance with Emerging Issues Task Force (EITF) Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent " This gross basis classification of revenues and costs may not be comparable to other energy companies that operate in regions that have not established ISOs and do not meet EITF 99-19 criteria.

The aggregate purchase and sales transactions for the three years ended December 31, 2002, are summarized as follows·

	2002	2001	2000
		(In millions)	
Sales	$453	$142	$315
Purchases	687	204	271

FirstEnergy's revenues on the Consolidated Statements of Income include wholesale electricity sales revenues from the PJM ISO from power sales (as reflected in the table above) during periods when we had additional available power capacity. Revenues also include sales by FirstEnergy of power sourced from the PJM ISO (reflected as purchases in the table above) during periods when we required additional power to meet our retail load requirements and, secondarily, to sell in the wholesale market

Nonelectric Sales

Nonelectric sales revenues declined by $284.6 million in 2002 from 2001 The elimination of coal trading activities in the second half of 2001 and reduced natural gas sales were the primary factors contributing to the lower revenues. Reduced gas revenues resulted principally from lower prices compared to 2001. Despite a slight reduction in sales volume and lower prices in 2002, margins from gas sales improved (see Expenses below). Reduced revenues from the facilities services group also contributed to the decrease in other sales revenue in 2002, compared to 2001 In 2001, nonelectric revenues increased $332.6 million, with natural gas revenues providing the largest source of increase. Beginning November 1, 2000, residential and small business customers in the service area of a nonaffiliated gas utility began shopping among alternative gas suppliers as part of a customer choice program FES's ability to take advantage of this opportunity to expand its customer base contributed to the increase in natural gas revenues.

Expenses

Total expenses increased nearly $3.7 billion in 2002, which included more than $3.7 billion of incremental expenses for the former GPU companies in 2002 (twelve months), compared to 2001 (seven weeks) For our pre-merger companies, total expenses increased $295.7 million in 2002 and $280.4 million in 2001, compared to the respective prior years Sources of changes in pre-merger and post-merger companies' expenses in 2002 and 2001, compared to the prior year, are summarized in the following table:

Sources of Expense Changes	2002	2001
Increase (Decrease)	*(In millions)*	
Pre-Merger Companies:		
Fuel and purchased power	**$ 441.7**	$ 48.7
Purchased gas	**(227.9)**	266.5
Other operating expenses	**178.5**	178.2
Depreciation and amortization	**(125.1)**	(99.0)
General taxes	**28.5**	(114.0)
Total Pre-Merger Companies	**295.7**	280.4
Former GPU Companies	**3,713.8**	542.4
Intercompany Expenses	**(353.9)**	(32.6)
Net Expense Increase	**$3,655.6**	$ 790.2

The following comparisons reflect variances for the pre-merger companies only, excluding the incremental expenses for the former GPU companies in 2002 and 2001.

Higher fuel and purchased power costs in 2002 compared to 2001 primarily reflect additional purchased power costs of $342.2 million. The increase resulted from additional volumes to cover supply obligations assumed by FES. These included a portion of Met-Ed's and Penelec's PLR supply requirements (which started in the third quarter of 2002), contract sales including sales to the New Jersey market to provide BGS, and additional supplies required to replace Davis-Besse power during its extended outage (see Davis-Besse Restoration). Fuel expense increased $99.5 million in 2002 from the prior year principally due to additional internal generation (5.4% higher) and an increased mix of coal and natural gas generation in 2002. The extended outage at the Davis-Besse nuclear plant produced a decline in nuclear generation of 14.6% in 2002, compared to 2001. Purchased gas costs decreased by $227.9 million primarily due to lower unit costs of natural gas purchased in 2002 compared to the prior year resulting in a $48.4 million improvement in gas margins.

In 2001, the increase in fuel expense compared to 2000 ($24.3 million) resulted from the substitution of coal and natural gas fired generation for nuclear generation during a period of reduced nuclear availability resulting from both planned and unplanned outages. Higher unit costs for coal consumed also contributed to the increase during that period. Purchased power costs increased early in 2001, compared to 2000, due to higher winter prices and additional purchased power requirements during that period, with the balance of the year offsetting all but $24.4 million of that increase as a result of generally lower prices and reduced external power needs compared to 2000. Purchased gas costs increased 48% in 2001 compared to 2000, principally due to the expansion of FES's retail gas business.

Other operating expenses increased $178.5 million in 2002 from the previous year. The increase principally resulted from several large offsetting factors. Nuclear costs increased $125.3 million primarily due to $115.0 million of incremental Davis-Besse costs related to its extended outage (see Davis-Besse Restoration). One-time charges, discussed above, added $98.3 million and an aggregate increase in administrative and general expenses and non-operating costs of $127.4 million resulted in large part from higher employee benefit expenses. Partially offsetting these higher costs were the elimination in the second half of 2001 of coal trading activities ($95.4 million) and reduced facilities service business ($58.9 million).

In 2001, other operating expenses increased by $178.2 million compared to the prior year. The significant reduction in 2001 of gains from the sale of emission allowances, higher fossil operating costs and additional employee benefit costs accounted for $144.5 million of the increase in 2001. Additionally, higher operating costs from the competitive services business segment due to expanded operations contributed $56.9 million to the increase. Partially offsetting these higher other operating expenses was a reduction in low-income payment plan customer costs and a $30.2 million decrease in nuclear operating costs in 2001, compared to 2000, resulting from one less refueling outage.

Fossil operating costs increased $44.3 million in 2001 from 2000 due principally to planned maintenance work at the Bruce Mansfield generating plant. Pension costs increased by $32.6 million in 2001 from 2000 primarily due to lower returns on pension plan assets (due to significant market-related reductions in the value of pension plan assets), the completion of the 15-year amortization of OE's pension transition asset and changes to plan benefits. Health care benefit costs also increased by $21.4 million in 2001, compared to 2000, principally due to an increase in the health care cost trend rate assumption for computing post-retirement health care benefit liabilities.

Charges for depreciation and amortization decreased $125.1 million in 2002 from the preceding year. This decrease resulted from two factors: shopping incentive deferrals and tax-deferrals under the Ohio transition plan ($108.5 million) and the cessation of goodwill amortization ($56.4 million) beginning January 1, 2002. However, several items offset a portion of the above reduction. The start up of a new fluidized bed boiler in January 2002, owned by Bayshore Power Company, a wholly owned subsidiary, resulted in higher depreciation expense in 2002. Also, new combustion turbine capacity added in late 2001 and two months of 2001 depreciation recorded in 2002 (for the four fossil plants we chose not to sell) increased depreciation expense in 2002.

In 2001, charges for depreciation and amortization decreased by $99.0 million from the prior year. Approximately $64.6 million of the decrease resulted from lower incremental transition cost amortization under our Ohio transition plan compared to accelerated cost recovery in connection with OE's prior rate plan. The reduction in depreciation and amortization also reflected additional cost deferrals of $51.2 million for recoverable shopping incentives under the Ohio transition plan, partially offset by increases associated with depreciation on completed combustion turbines in the fourth quarter of 2001.

General taxes increased $28.5 million in 2002 from 2001 principally due to additional property taxes and the absence in 2002 of a one-time benefit of $15 million resulting from the successful resolution of certain property tax issues in the prior year. In 2001, general taxes declined $114.0 million from 2000 primarily due to reduced property taxes and other state tax changes in connection with the Ohio electric industry restructuring. The reduction in general taxes was partially offset by $66.6 million of new Ohio franchise taxes, which are classified as state income taxes on the Consolidated Statements of Income.

Net Interest Charges

Net interest charges increased $390 6 million in 2002, compared to 2001. These increases included interest on $4 billion of long-term debt issued by FirstEnergy in connection with the merger Excluding the results associated with the former GPU companies and merger-related financing, net interest charges decreased $57 0 million in 2002, compared to a $39.8 million decrease in 2001 from 2000 Our continued redemption and refinancing of our outstanding debt and preferred stock during 2002, maintained our downward trend in financing costs before the effects of the GPU merger. Excluding activities related to the former GPU companies, redemption and refinancing activities for 2002 totaled $1 1 billion and $143 4 million, respectively, and are expected to result in annualized savings of $86 0 million We also exchanged existing fixed-rate payments on outstanding debt (principal amount of $593.5 million at year end 2002) for short-term variable rate payments through interest rate swap transactions (see Market Risk Information – Interest Rate Swap Agreements below) Net interest charges were reduced by $17 4 million in 2002 as a result of these swaps

Cumulative Effect of Accounting Changes

Earnings for 2002 were affected by two accounting changes. As of the merger date, certain former GPU international operations were identified as "assets pending sale " Avon and Emdersa were the two remaining operations identified for sale following the completed sale of Australian operations in December 2001 Subsequent to the merger date, results of operations and incremental interest costs related to these international subsidiaries were not included in our Consolidated Statement of Income On February 6, 2002, discussions began with Aquila, Inc. on modifying its initial offer for the acquisition of Avon, which resulted in a change in accounting for this investment, and a $31.7 million after-tax increase to earnings. Also, as of December 31, 2002, we had not reached a definitive agreement to sell Emdersa As a result, Emdersa could no longer be considered as "assets pending sale," which resulted in a change in accounting for this investment and an after-tax reduction to earnings of $88 8 million. The amount of this one-time, after-tax charge was comprised of $104.1 million in currency transaction losses arising principally from U S dollar denominated debt offset by $15 3 million of operating income In 2001, we adopted SFAS 133, "Accounting for Derivative Instruments and Hedging Activities" resulting in an $8.5 million after-tax charge.

Postretirement Plans

Sharp declines in equity markets since the second quarter of 2000 and a reduction in our assumed discount rate in 2001 have combined to produce a negative trend in pension expenses – moving from a net increase to earnings in 2000 and 2001 to a reduction of earnings in 2002. Also, increases in health care payments and a related increase in projected trend rates have led to higher health care costs The following table presents the pre-tax pension and other post-employment benefits (OPEB) expenses for our pre-merger companies (excluding amounts capitalized)

Postretirement Expenses (Income)	2002	2001	2000
	(In millions)		
Pension	$ 16 4	$(11 1)	$(40 6)
OPEB	99 1	86 6	65 5
Total	$115 5	$ 75 5	$ 24 9

The pension and OPEB expense increases are included in various cost categories and have contributed to other cost increases discussed above See "Significant Accounting Policies – Pension and Other Postretirement Benefits Accounting" for a discussion of the impact of underlying assumptions on postretirement expenses and anticipated pension and OPEB expense increases in 2003.

Results of Operations – Business Segments

We manage our business as two separate major business segments – regulated services and competitive services The regulated services segment designs, constructs, operates and maintains our regulated domestic transmission and distribution systems. It also provides generation services to franchise customers who have not chosen an alternative generation supplier OE, CEI and TE (Ohio Companies) and Penn obtain generation through a power supply agreement with the competitive services segment (see Outlook – Business Organization). The competitive services segment includes all competitive energy and energy-related services including commodity sales (both electricity and natural gas) in the retail and wholesale markets, marketing, generation, trading and sourcing of commodity requirements, as well as other competitive energy application services. Competitive products are increasingly marketed to customers as bundled services, often under master contracts. Financial results discussed below include intersegment revenue. A reconciliation of segment financial results to consolidated financial results is provided in Note 8 to the consolidated financial statements Financial data for 2002 and 2001 for the major business segments include reclassifications to conform with the current business segment organizations and operations, which affect 2002 and 2001 results discussed below

Regulated Services

Net income increased to $997 1 million in 2002, compared to $729.1 million in 2001 and $562 5 million in 2000. Excluding additional net income of $312 7 million associated with the former GPU companies, net income decreased by $44.7 million in 2002. The changes in pre-merger net income are summarized in the following table:

Regulated Services	2002	2001
Increase (Decrease)	*(In millions)*	
Revenues	$(529 5)	$(116 4)
Expenses	(346 6)	(344.1)
Income Before Interest and Income Taxes	(182 9)	227 7
Net interest charges	(128 0)	(16 8)
Income taxes	(10 2)	132 7
Net Income Change	$ (44.7)	$ 111 8

Lower generation sales, additional transition plan incentives and a slight decline in revenue from distribution deliveries combined for a $312 5 million reduction in external revenues in 2002 from the prior year Shopping by Ohio customers from alternative energy suppliers combined with the effect of a sluggish national economy on our regional business reduced retail electric sales revenues. In addition, a $188 0 million decline in revenues resulted from reduced sales to FES, due to the extended outage of the Davis-Besse nuclear plant, which reduced generation available for sale. The $346 6 million decrease in expenses resulted from three major factors a $179 8 million decrease in purchased power, a $35 6 million reduction in other operating expenses and a $141 8 million decrease in depreciation expense. Lower generation sales reduced the need for purchased power and other operating expenses reflected reduced costs in jobbing and contracting work and decreased uncollectible accounts expense.

Reduced depreciation and amortization resulted from $108.5 million of new deferred regulatory assets under the Ohio transition plan and the cessation of goodwill amortization beginning January 1, 2002.

In 2001, distribution throughput was 1.7% lower, compared to 2000, reducing external revenues by $245.7 million. Partially offsetting the decrease in external revenues were revenues from FES for the rental of fossil generating facilities and the sale of generation from nuclear plants, resulting in a net $116.4 million reduction to total revenues. Expenses were $344.1 million lower in 2001 than 2000 due to lower purchased power, depreciation and amortization and general taxes, offset in part by higher other operating expenses. Lower generation sales reduced the need to purchase power from FES, with a resulting $267.8 million decline in those costs in 2001 from the prior year. Other operating expenses increased by $178.5 million in 2001 from the previous year reflecting a significant reduction in 2001 of gains from the sale of emission allowances, higher fossil operating costs and additional employee benefit costs. Lower incremental transition cost amortization and the new shopping incentive deferrals under our Ohio transition plan as compared with the accelerated cost recovery in connection with OE's prior rate plan in 2000 resulted in a $131.0 million reduction in depreciation and amortization in 2001. A $123.6 million decrease in general taxes in 2001 from the prior year primarily resulted from reduced property taxes and other state tax changes in connection with the Ohio electric industry restructuring.

Competitive Services

Net losses increased to $119.0 million in 2002, compared to $31.8 million in 2001 and net income of $39.1 million in 2000. Excluding additional net income of $2.6 million associated with the former GPU companies, net losses increased by $89.8 million in 2002. The changes to pre-merger earnings are summarized in the following table:

Competitive Services	2002	2001
Increase (Decrease)	*(In millions)*	
Revenues	**$211.5**	$289.3
Expenses	**351.1**	392.5
Income Before Interest and Income Taxes	**(139.6)**	(103.2)
Net interest charges	**21.9**	13.5
Income taxes	**(63.2)**	(51.3)
Cumulative effect of a change in accounting	**8.5**	(8.5)
Net Loss Increase	**$ 89.8**	$ 73.9

The $211.5 million increase in revenues in 2002, compared to 2001, represents the net effect of several factors. Revenues from the wholesale electricity market increased $485.3 million in 2002 from the prior year and kilowatt-hour sales more than doubled. More than half of the increase resulted from additional sales to Met-Ed and Penelec to supply a portion of their PLR supply requirements in Pennsylvania, as well as BGS sales in New Jersey and sales under several other contracts. Retail kilowatt-hour sales revenues increased $136.4 million as a result of expanding kilowatt-hour sales within Ohio under Ohio's electricity choice program. Total electric sales revenue increased $621.7 million in 2002 from 2001, accounting for almost all of the net increase in revenues. Offsetting the higher electric sales revenue were reduced natural gas revenues ($171.7 million) primarily due to lower prices and less revenue from FSG ($65.5 million) reflecting the sluggish economy. Internal sales to the regulated services segment decreased $179.8 million in large part due to the impact of customer shopping reducing requirements by the regulated services segment. Expenses increased $351.1 million in 2002 from the prior year, due to additional purchased power ($342.2 million) to supply the incremental kilowatt-hour sales to wholesale and retail customers. Other operating expenses increased $207.2 million from the prior year as a result of higher nuclear costs due to incremental Davis-Besse costs from its extended outage. One-time charges discussed above increased costs by $75.6 million. Offsetting these increases were reduced purchased gas costs ($227.9 million) primarily resulting from lower prices and reduced costs from FSG reflecting reduced business activity.

In 2001, sales to nonaffiliates increased $523.2 million, compared to the prior year, with electric revenues contributing $299.8 million, natural gas revenues adding $226.1 million and the balance of the change from energy-related services. Reduced power requirements by the regulated services segment reduced internal revenues by $267.8 million. Expenses increased $392.5 million in 2002 from 2001 primarily due to a $266.5 million increase in purchased gas costs and increases resulting from additional fuel and purchased power costs (see Results of Operations above) as well as higher expenses for energy-related services. Reduced margins for both major competitive product areas - electricity and natural gas - contributed to the reduction in net income, along with higher interest charges and the cumulative effect of the SFAS 133 accounting change. Margins for electricity and gas sales were both adversely affected by higher fuel costs.

Capital Resources and Liquidity

Changes in Cash Position

The primary source of ongoing cash for FirstEnergy, as a holding company, is cash dividends from its subsidiaries. The holding company also has access to $1.5 billion of revolving credit facilities, which it can draw upon. In 2002, FirstEnergy received $447 million of cash dividends on common stock from its subsidiaries and paid $440 million in cash dividends on common stock to its shareholders. There are no material restrictions on the issuance of cash dividends by FirstEnergy's subsidiaries.

As of December 31, 2002, we had $196.3 million of cash and cash equivalents (including $50 million that redeemed long-term debt in January 2003) on our Consolidated Balance Sheet. This compares to $220.2 million as of December 31, 2001. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Our consolidated net cash from operating activities is provided by our regulated and competitive energy services businesses (see Results of Operations - Business Segments above). Net cash flows from operating activities in 2002 reflect twelve months of cash flows for the former GPU companies while 2001 includes only seven weeks of those companies' operations (November 7, 2001 to December 31, 2001). Both periods include a full twelve months for the pre-merger companies. Net cash provided from operating activities was $1.915 billion in 2002 and $1.282 billion in 2001. The modest contribution to operating cash flows in 2002 by the former GPU companies reflects in part the deferrals of purchased power costs related to their PLR obligations (see State Regulatory Matters - New Jersey and - Pennsylvania below). Cash flows provided from 2002 operating activities of our pre-merger companies and former GPU companies are as follows:

Operating Cash Flows	2002	2001
	(In millions)	
Pre-merger companies		
Cash earnings [1]	$1,149	$1,551
Working capital and other	315	21
Total pre-merger companies	1,464	1,572
Former GPU companies	563	166
Eliminations	(112)	(456)
Total	$1,915	$1,282

[1] *Includes net income, depreciation and amortization, deferred costs recoverable as regulatory assets, deferred income taxes, investment tax credits and major noncash charges.*

Excluding the former GPU companies, cash flows from operating activities totaled $1 464 billion in 2002 primarily due to cash earnings and to a lesser extent working capital and other changes In 2001, cash flows from operating activities totaled $1 572 billion principally due to cash earnings.

Cash Flows From Financing Activities

In 2002, the net cash used for financing activities of $1 123 billion primarily reflects the redemptions of debt and preferred stock shown below In 2001, net cash provided from financing activities totaled $1 964 billion, primarily due to $4 billion of long-term debt issued in connection with the GPU acquisition, which was partially offset by $2.1 billion of redemptions and refinancings The following table provides details regarding new issues and redemptions during 2002.

Securities Issued or Redeemed	2002
	(In millions)
New Issues	
Pollution Control Notes	$ 143
Transition Bonds (See Note 5H)	320
Unsecured Notes	210
Other, principally debt discounts	(4)
	$ 669
Redemptions	
First Mortgage Bonds	$ 728
Pollution Control Notes	93
Secured Notes	278
Unsecured Notes	189
Preferred Stock	522
Other, principally redemption premiums	21
	$1,831
Short-term Borrowings, Net	$ 479

We had approximately $1.093 billion of short-term indebtedness at the end of 2002 compared to $614.3 million at the end of 2001 Available borrowing capability included $177 million under the $1.5 billion revolving lines of credit and $64 million under bilateral bank facilities. At the end of 2002, OE, CEI, TE and Penn had the aggregate capability to issue $2 1 billion of additional first mortgage bonds (FMB) on the basis of property additions and retired bonds JCP&L, Met-Ed and Penelec no longer issue FMB other than as collateral for senior notes, since their senior note indentures prohibit them (subject to certain exceptions) from issuing any debt which is senior to the senior notes As of December 31, 2002, JCP&L, Met-Ed and Penelec had the aggregate capability to issue $474 million of additional senior notes based upon FMB collateral Based upon applicable earnings coverage tests and their respective charters, OE, Penn, TE and JCP&L could issue a total of $4 3 billion of preferred stock (assuming no additional debt was issued) as of the end of 2002. CEI, Met-Ed and Penelec have no restrictions on the issuance of preferred stock (see Note 5G – Long-Term Debt for discussion of debt covenants)

At the end of 2002, our common equity as a percentage of capitalization stood at 38% compared to 35% and 42% at the end of 2001 and 2000, respectively The lower common equity percentage in 2002 compared to 2000 resulted from the effect of the GPU acquisition. The increase in the 2002 equity percentage from 2001 primarily reflects net redemptions of preferred stock and long-term debt, financed in part by short-term borrowings, and the increase in retained earnings.

Cash Flows From Investing Activities

Net cash flows used in investing activities totaled $816 million in 2002. The net cash used for investing principally resulted from property additions Regulated services expenditures for property additions primarily include expenditures supporting the distribution of electricity Expenditures for property additions by the competitive services segment are principally generation-related including capital additions at the Davis-Besse nuclear plant during its extended outage. The following table summarizes 2002 investments by our regulated services and competitive services segments

Summary of 2002 Cash Flows Used for Investing Activities

	Property Additions	Investments	Other	Total
		(In millions)		
Regulated Services	$(490)	$ 87	$ (21)	$(424)
Competitive Services	(403)	—	10	(393)
Other	(105)	149*	(54)	(10)
Eliminations	—	—	11	11
Total	$(998)	$236	$ (54)	$(816)

** Includes $155 million of cash proceeds from the sale of Avon (see Note 3)*

In 2001, cash flows used in investing activities totaled $3 075 billion, principally due to the GPU acquisition ($2 013 billion) and property additions ($852 million).

Our cash requirements in 2003 for operating expenses, construction expenditures, scheduled debt maturities and preferred stock redemptions are expected to be met without increasing our net debt and preferred stock outstanding Available borrowing capacity under short-term credit facilities will be used to manage working capital requirements Over the next three years, we expect to meet our contractual obligations with cash from operations Thereafter, we expect to use a combination of cash from operations and funds from the capital markets

Contractual Obligations

	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
			(In millions)		
Long-term debt	$12,465	$1,073	$2,210	$1,654	$ 7,528
Short-term borrowings	1,093	1,093	—	—	—
Preferred stock[1]	445	2	4	14	425
Capital leases[2]	31	5	11	7	8
Operating leases[2]	2,697	153	365	349	1,830
Purchases[3]	13,156	2,149	2,902	2,634	5,471
Total	$29,887	$4,475	$5,492	$4,658	$15,262

[1] *Subject to mandatory redemption*
[2] *See Note 4*
[3] *Fuel and power purchases under contracts with fixed or minimum quantities and approximate timing*

Our capital spending for the period 2003-2007 is expected to be about $3.1 billion (excluding nuclear fuel), of which approximately $727 million applies to 2003. Investments for additional nuclear fuel during the 2003-2007 period are estimated to be approximately $485 million, of which about $69 million applies to 2003. During the same period, our nuclear fuel investments are expected to be reduced by approximately $483 million and $88 million, respectively, as the nuclear fuel is consumed.

In May 2002, we sold a 79.9 percent equity interest in Avon, our former wholly owned holding company of Midlands Electricity plc, to Aquila, Inc. (formerly UtiliCorp United) for approximately $1.9 billion (including assumption of $1.7 billion of debt). We received approximately $155 million in cash proceeds and approximately $87 million of long-term notes (representing the present value of $19 million per year to be received over six years beginning in 2003). In the fourth quarter of 2002, we recorded a $50 million charge to reduce the carrying value of our remaining Avon 20.1 percent equity investment.

On August 8, 2002, we notified NRG that we were canceling a November 2001 agreement to sell four fossil plants for approximately $1.5 billion ($1.355 billion in cash and $145 million in debt assumption) to NRG because NRG had stated it could not complete the transaction under the original terms of the agreement. In December 2002, we announced that we would retain ownership of the plants after reviewing subsequent bids from other potential buyers. As a result of this decision, we recorded an aggregate charge of $74 million ($43 million, net of tax) in the fourth quarter of 2002, consisting of $57 million ($33 million, net of tax) in non-cash depreciation charges that were not recorded while the plants were pending sale and $17 million ($10 million, net of tax) of transaction-related fees (see Note 3).

We did not reach a definitive agreement to sell Emdersa, our Argentina operations, as of December 31, 2002. Therefore, we no longer classified its assets as "Assets Pending Sale" on our Consolidated Balance Sheet and recorded its cumulative results of operations from November 7, 2001 through October 31, 2002 as a one-time, after-tax charge of $88.8 million in our 2002 Consolidated Statement of Income (see Cumulative Effect of Accounting Changes above). In addition, we began recognizing Emdersa's results of operations beginning November 1, 2002 in our consolidated financial statements. We continue to seek opportunities to sell our foreign operations acquired in the 2001 merger with GPU.

On February 22, 2002, Moody's Investors Service changed its credit rating outlook for FirstEnergy, Met-Ed and Penelec from stable to negative. The change was based upon a decision by the Commonwealth Court of Pennsylvania to remand to the Pennsylvania Public Utility Commission (PPUC) for reconsideration its decision on the mechanism for sharing merger savings and reversed the PPUC decisions regarding rate relief and accounting deferrals rendered in connection with its approval of the GPU merger (see Note 2). On March 20, 2002, Moody's changed its outlook for CEI and TE from stable to negative and retained a negative outlook for FirstEnergy based on the uncertain outcome of the Davis-Besse extended outage. On April 4, 2002, Standard & Poor's (S&P) changed its outlook for our credit ratings from stable to negative citing recent developments including: damage to the Davis-Besse reactor vessel head, the Pennsylvania Commonwealth Court decision, and deteriorating market conditions for some sales of our remaining non-core assets. On July 31, 2002, Fitch revised its rating outlook for FirstEnergy, CEI and TE securities to negative from stable. The revised outlook reflected the adverse impact of the unplanned Davis-Besse outage, Fitch's judgment about NRG's financial ability to consummate the purchase of four power plants from FirstEnergy and Fitch's expectation of subsequent delays in debt reduction. On August 1, 2002, S&P concluded that while NRG's liquidity position added uncertainty to our sale of power plants to NRG, our ratings would not be affected. S&P found our cash flows sufficiently stable to support a continued (although delayed) program of debt and preferred stock redemption. S&P noted that it would continue to closely monitor our progress on various initiatives. On January 21, 2003, S&P indicated its concern about our disclosure of non-cash charges related to deferred costs in Pennsylvania, pension and other post-retirement benefits, and Emdersa, which were higher than anticipated in the third quarter of 2002. S&P identified the restart of the Davis-Besse nuclear plant "...without significant delay beyond April 2003..." as key to maintaining our current debt ratings. S&P also identified other issues it would continue to monitor including: our deleveraging efforts, free cash generated during 2003, the JCP&L rate case, successful hedging of our short power position, and continued capture of projected merger savings. While we anticipate being prepared to restart the Davis-Besse plant in the spring of 2003 (see Davis-Besse Restoration below), the Nuclear Regulatory Commission (NRC) must authorize the unit's restart following a formal inspection process prior to our returning the unit to service. Significant delays in the planned date of Davis-Besse's return to service or other factors (identified above) affecting the speed with which we reduce debt could put additional pressure on our credit ratings.

Other Obligations

Obligations not included on our Consolidated Balance Sheet primarily consist of sale and leaseback arrangements involving Perry Unit 1, Beaver Valley Unit 2 and the Bruce Mansfield Plant, which are reflected in the operating lease payments disclosed above (see Note 4). The present value as of December 31, 2002, of these sale and leaseback operating lease commitments, net of trust investments, total $1.5 billion. CEI and TE sell substantially all of their retail customer receivables, which provided $170 million of off-balance sheet financing as of December 31, 2002 (see Note 2C – Revenues).

Guarantees and Other Assurances

As part of normal business activities, we enter into various agreements on behalf of our subsidiaries to provide financial or performance assurances to third parties. Such agreements include contract guarantees, surety bonds, and rating-contingent collateralization provisions.

As of December 31, 2002, the maximum potential future payments under outstanding guarantees and other assurances totaled $913 million, as summarized below:

Guarantees and Other Assurances	Maximum Exposure
	(In millions)
FirstEnergy Guarantees of Subsidiaries:	
Energy and Energy-Related Contracts[1]	$ 670
Financings[2][3]	186
	856
Surety Bonds	26
Rating-Contingent Collateralization[4]	31
Total Guarantees and Other Assurances	$ 913

[1] *Issued for a one-year term, with a 10-day termination right by FirstEnergy.*

[2] *Includes parental guarantees of subsidiary debt and lease financing including our letters of credit supporting subsidiary debt.*

[3] *Issued for various terms.*

[4] *Estimated net liability under contracts subject to rating-contingent collateralization provisions.*

We guarantee energy and energy-related payments of our subsidiaries involved in energy marketing activities - principally to facilitate normal physical transactions involving electricity, gas, emission allowances and coal We also provide guarantees to various providers of subsidiary financings principally for the acquisition of property, plant and equipment These agreements legally obligate us and our subsidiaries to fulfill the obligations of our subsidiaries directly involved in these energy and energy-related transactions or financings where the law might otherwise limit the counterparties' claims If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, our guarantee enables the counterparty's legal claim to be satisfied by our other assets. The likelihood is remote that such parental guarantees will increase amounts otherwise paid by us to meet our obligations incurred in connection with financings and ongoing energy and energy-related contracts.

Most of our surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction contracts, environmental commitments and various retail transactions.

Various contracts include credit enhancements in the form of cash collateral, letters of credit or other security in the event of a reduction in credit rating These provisions vary and typically require more than one rating reduction to below investment grade by S&P or Moody's to trigger additional collateralization

Market Risk Information

We use various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price and interest rate fluctuations Our Risk Policy Committee, comprised of executive officers, exercises an independent risk oversight function to ensure compliance with corporate risk management policies and prudent risk management practices

Commodity Price Risk

We are exposed to market risk primarily due to fluctuations in electricity, natural gas and coal prices To manage the volatility relating to these exposures, we use a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps The derivatives are used principally for hedging purposes and, to a much lesser extent, for trading purposes Most of our non-hedge derivative contracts represent non-trading positions that do not qualify for hedge treatment under SFAS 133. The change in the fair value of commodity derivative contracts related to energy production during 2002 is summarized in the following table:

Increase (Decrease) in the Fair Value of Commodity Derivative Contracts

	Non-Hedge	Hedge	Total
		(In millions)	
Outstanding net asset (liability) as of January 1, 2002	$ 9 9	$(76 3)	$(66 4)
New contract value when entered	—	2 2	2 2
Additions/Increase in value of existing contracts	55 5	73 9	129 4
Change in techniques/assumptions	(20 1)	—	(20 1)
Settled contracts	8 5	24 3	32 8
Outstanding net asset as of December 31, 2002[1]	**53 8**	**24.1**	**77.9**
Non-commodity net assets as of December 31, 2002 Interest Rate Swaps[2]	—	20 5	20 5
Net Assets - Derivatives Contracts as of December 31, 2002[3]	**$ 53 8**	**$ 44 6**	**$ 98.4**
Impact of Changes in Commodity Derivative Contracts[4]			
Income Statement Effects (Pre-Tax)	$ 13 9	$ —	$ 13 9
Balance Sheet Effects			
Other Comprehensive Income (OCI) (Pre-Tax)	$ —	$ 98 2	$ 98 2
Regulatory Liability	$ 30 0	$ —	$ 30 0

[1] Includes $34 2 million in non-hedge commodity derivative contracts which are offset by a regulatory liability
[2] Interest rate swaps are primarily treated as fair value hedges. Changes in derivative values of the fair value hedges are offset by changes in the hedged debts' premium or discount (see Interest Rate Swap Agreements below)
[3] Excludes $9 3 million of derivative contract fair value decrease, as of December 31, 2002, representing our 50% share of Great Lakes Energy Partners, LLC
[4] Represents the increase in value of existing contracts, settled contracts and changes in techniques/assumptions

Derivatives Included on the Consolidated Balance Sheet as of December 31, 2002:

	Non-Hedge	Hedge	Total
		(In millions)	
Current-			
Other Assets	$ 31 2	$ 14 9	$ 46 1
Other Liabilities	(16 2)	(8 8)	(25 0)
Non-Current-			
Other Deferred Charges	39 6	39 4	79 0
Other Deferred Credits	(0 8)	(0 9)	(1 7)
Net assets	**$ 53.8**	**$ 44 6**	**$ 98 4**

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, we rely on model-based information The model provides estimates of future regional prices for electricity and an estimate of related price volatility We use these results to develop estimates of fair value for financial reporting purposes and for internal management decision making Sources of information for the valuation of derivative contracts by year are summarized in the following table.

Source of Information – Fair Value by Contract Year

	2003	2004	2005	2006	Thereafter	Total
			(In millions)			
Prices actively quoted[1]	$16 0	$1 5	$ —	$—	$ —	$17 5
Other external sources[2]	22 2	2 1	(0 9)	—	—	23 4
Prices based on models	—	—	—	5 5	31 5	37 0
Total[3]	**$38.2**	**$3 6**	**$(0.9)**	**$5 5**	**$31 5**	**$77.9**

[1] Exchange traded
[2] Broker quote sheets
[3] Includes $34 2 million from an embedded option that is offset by a regulatory liability and does not affect earnings

We perform sensitivity analyses to estimate our exposure to the market risk of our commodity positions. A hypothetical 10% adverse shift in quoted market prices in the near term on both our trading and nontrading derivative instruments would not have had a material effect on our consolidated financial position or cash flows as of December 31, 2002. We estimate that if energy commodity prices experienced an adverse 10% change, net income for the next twelve months would decrease by approximately $3.7 million.

Interest Rate Risk

Our exposure to fluctuations in market interest rates is reduced since a significant portion of our debt has fixed interest rates, as noted in the table below.

We are subject to the inherent interest rate risks related to refinancing maturing debt by issuing new debt securities. As discussed in Note 4 to the consolidated financial statements, our investments in capital trusts effectively reduce future lease obligations, also reducing interest rate risk. Changes in the market value of our nuclear decommissioning trust funds had been recognized by making corresponding changes to the decommissioning liability, as described in Note 2 to the consolidated financial statements. In conjunction with the adoption of SFAS 143 "Accounting for Asset Retirement Obligations," on January 1, 2003, we reclassified unrealized gains or losses to OCI in accordance with SFAS 115, "Accounting for Certain Investments in Debt and Equity." While fluctuations in the fair value of our Ohio EUOC's trust balances will eventually affect earnings (affecting OCI initially) based on the guidance provided by SFAS 115, our non-Ohio EUOC have the opportunity to recover from customers the difference between the investments held in trust and their decommissioning obligations. Thus, in absence of disallowed costs, there should be no earnings effect from fluctuations in their decommissioning trust balances. As of December 31, 2002, decommissioning trust balances totaled $1.050 billion, with $698 million held by our Ohio EUOC and the balance held by our non-Ohio EUOC. As of year end 2002, trust balances included 51% of equity and 49% of debt instruments.

Interest Rate Swap Agreements

During 2002, FirstEnergy entered into fixed-to-floating interest rate swap agreements, to increase the variable-rate component of its debt portfolio from 16% to approximately 20% at year end. These derivatives are treated as fair value hedges of fixed-rate, long-term debt issues – protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. Swap maturities, call options and interest payment dates match those of the underlying obligations. During the fourth quarter of 2002, in a period of steadily declining market interest rates, we unwound swaps with a total notional amount of $400 million that we had entered into during the second and third quarters of 2002. Under fair-value accounting, the swaps' fair value ($19.9 million asset) was added to the carrying value of the hedged debt and will be amortized to maturity. Offsets to interest expense recorded in 2002 due to the difference between fixed and variable debt rates totaled $17.4 million. As of December 31, 2002, the debt underlying FirstEnergy's outstanding interest rate swaps had a weighted average fixed interest rate of 7.76%, which the swaps have effectively converted to a current weighted average variable interest rate of 3.04%. GPU Power (through a subsidiary) used dollar-denominated interest rate swap agreements in 2002. In 2001, Penelec, GPU Power (through a subsidiary) and GPU Electric, Inc. (through GPU Power UK) used interest rate swaps denominated in dollars and sterling. All of the agreements of the former GPU companies convert variable-rate debt to fixed-rate debt to manage the risk of increases in variable interest rates. GPU Power's swaps had a weighted average fixed interest rate of 6.68% in 2002 and 6.99% in 2001. The following summarizes the principal characteristics of the swap agreements:

Interest Rate Swaps

	December 31, 2002			December 31, 2001		
Denomination	Notional Amount	Maturity Date	Fair Value	Notional Amount	Maturity Date	Fair Value
	(dollars/sterling in millions)					
Fixed to Floating Rate						
Dollar	444	2023	15.5			
	150	2025	5.9			
Floating to Fixed Rate						
Dollar	16	2005	(0.9)	50	2002	(1.8)
				26	2005	(1.1)
Sterling				125	2003	(2.3)

Comparison of Carrying Value to Fair Value

Year of Maturity	2003	2004	2005	2006	2007	Thereafter	Total	Fair Value
				(Dollars in millions)				
Assets								
Investments other than Cash and Cash Equivalents-Fixed Income	$ 115	$327	$ 72	$ 90	$ 85	$1,843	**$ 2,532**	**$ 2,638**
Average interest rate	7.5%	7.8%	8.1%	8.1%	8.2%	6.3%	6.8%	
Liabilities								
Long-term Debt:								
Fixed rate	$ 964	$939	$867	$1,401	$252	$6,386	**$10,809**	**$11,119**
Average interest rate	7.7%	7.2%	8.1%	5.7%	6.7%	7.0%	7.0%	
Variable rate	$ 109	$399	$ 5	$ 1		$1,142	**$ 1,656**	**$ 1,642**
Average interest rate	5.4%	2.6%	6.7%	6.1%		2.7%	2.9%	
Short-term Borrowings	$1,093						**$ 1,093**	**$ 1,093**
Average interest rate	2.4%						2.4%	
Preferred Stock	$ 2	$ 2	$ 2	$ 2	$ 12	$ 425	**$ 445**	**$ 454**
Average dividend rate	7.5%	7.5%	7.5%	7.5%	7.6%	8.1%	8.1%	

Equity Price Risk

Included in nuclear decommissioning trusts are marketable equity securities carried at their market value of approximately $532 million and $568 million as of December 31, 2002 and 2001, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges, would result in a $53 million reduction in fair value as of December 31, 2002 (see Note 2J – Supplemental Cash Flows Information)

Foreign Currency Risk

We are exposed to foreign currency risk from investments in international business operations acquired through the merger with GPU While such risks are likely to diminish over time as we sell our international operations, we expect such risks to continue in the near term. In 2002, we experienced net foreign currency translation losses in connection with our Argentina operations (see Note 3 – Divestitures) A hypothetical 20% adverse change in our foreign currency positions in the near term would not have had a material effect on our consolidated financial position, cash flows or earnings as of December 31, 2002

Outlook

We continue to pursue our goal of being the leading regional supplier of energy and related services in the northeastern quadrant of the United States, where we see the best opportunities for growth We believe that our strategy has received some measure of validation by the major industry events of 2002 and we continue to build toward a strong regional presence. We intend to provide competitively priced, high-quality products and value-added services – energy sales and services, energy delivery, power supply and supplemental services related to our core business As our industry changes to a more competitive environment, we have taken and expect to take actions designed to create a larger, stronger regional enterprise that will be positioned to compete in the changing energy marketplace

Business Organization

Beginning in 2001, Ohio utilities that offered both competitive and regulated retail electric services were required to implement a corporate separation plan approved by the Public Utilities Commission of Ohio (PUCO) – one which provided a clear separation between regulated and competitive operations Our business is separated into three distinct units – a competitive services segment, a regulated services segment and a corporate support segment FES provides competitive retail energy services while the EUOC continue to provide regulated transmission and distribution services FirstEnergy Generation Corp (FGCO), a wholly owned subsidiary of FES, leases fossil and hydroelectric plants from the EUOC and operates those plants We expect the transfer of ownership of EUOC non-nuclear generating assets to FGCO will be substantially completed by the end of the market development period in 2005 All of the EUOC power supply requirements for the Ohio Companies and Penn are provided by FES to satisfy their PLR obligations, as well as grandfathered wholesale contracts.

Optimizing the Use of Assets

A significant step toward being the leading regional supplier in our target market was achieved when we merged with GPU in November 2001, making us the fourth largest investor-owned electric system in the nation based on the number of customers served Through the merger we are creating a stronger enterprise with greater resources and more opportunities to provide value to our customers, shareholders and employees. However, additional steps must be taken in order to deliver the full value of the merger While GPU's former domestic electric utility companies fit well with our regional market focus, GPU's former international companies do not. In December 2001, we divested GasNet, an Australian natural gas transmission company. In May 2002, we sold a 79.9 percent interest in Avon's UK operations to Aquila for approximately $1.9 billion We and Aquila together own all of the outstanding shares of Avon through a jointly owned subsidiary, with each company having a 50-percent voting interest.

On August 8, 2002, we notified NRG that we were canceling our agreement with it for its purchase of four fossil plants because NRG had stated that it could not complete the sale transaction under the original terms of the agreement Based on subsequent bids received, we concluded that retaining the plants to serve our customers was in the best interest of our customers and our shareholders Following our decision to retain the four plants, we performed a comprehensive fossil operations review and subsequently decided to close the Ashtabula C-Plant (three 44 megawatt (MW), coal-fired boilers) This action is part of our strategy to provide competitively priced energy – replacing less-efficient peaking generation in our portfolio of generation resources, with the development of new, higher-efficiency peaking plants. While deteriorating economic conditions in Argentina delayed our sale of Emdersa, we continue to pursue the sale of assets that do not support our strategy in order to increase our financial flexibility by reducing debt and preferred stock

State Regulatory Matters

In Ohio, New Jersey and Pennsylvania, laws applicable to electric industry deregulation included similar provisions which are reflected in our EUOC's respective state regulatory plans. However, despite these similarities, the specific approach taken by each state and for each of our EUOCs varies Those provisions include

- allowing the EUOC's electric customers to select their generation suppliers,
- establishing PLR obligations to non-shopping customers in the EUOC's service areas,
- allowing recovery of potentially stranded investment (or transition costs) not otherwise recoverable in a competitive generation market,
- itemizing (unbundling) the price of electricity into its component elements - including generation, transmission, distribution and stranded costs recovery charges;
- deregulating the EUOC's electric generation businesses, and
- continuing regulation of the EUOC's transmission and distribution systems

Regulatory assets are costs which the respective regulatory agencies have authorized for recovery from customers in future periods and, without such authorization, would have been charged to income when incurred All of the regulatory assets are expected to continue to be recovered under the provisions of the respective transition and regulatory plans as discussed below. The regulatory assets of the individual companies are as follows:

Regulatory Assets as of December 31,

Company	2002	2001
	(In millions)	
OE	**$1,855.9**	$2,025.4
CEI	**939.8**	874.5
TE	**392.6**	388.8
Penn	**156.9**	208.8
JCP&L	**3,199.0**	3,324.8
Met-Ed	**1,179.1**	1,320.5
Penelec	**599.7**	769.8
Total	**$8,323.0**	$8,912.6

Ohio

FirstEnergy's transition plan (which we filed on behalf of the Ohio Companies) included approval for recovery of transition costs, including regulatory assets, as filed in the transition plan through no later than 2006 for OE, mid-2007 for TE and 2008 for CEI, except where a longer period of recovery is provided for in the settlement agreement. The approved plan also granted preferred access over our subsidiaries to nonaffiliated marketers, brokers and aggregators to 1,120 MW of generation capacity through 2005 at established prices for sales to the Ohio Companies' retail customers. Customer prices are frozen through a five-year market development period (2001-2005), except for certain limited statutory exceptions including a 5% reduction in the price of generation for residential customers. In February 2003, the Ohio Companies were authorized increases in revenues aggregating approximately $50 million (OE - $41 million, CEI - $4 million and TE - $5 million) to recover their higher tax costs resulting from the Ohio deregulation legislation.

Our Ohio customers choosing alternative suppliers receive an additional incentive applied to the shopping credit (generation component) of 45% for residential customers, 30% for commercial customers and 15% for industrial customers. The amount of the incentive is deferred for future recovery from customers - recovery will be accomplished by extending the respective transition cost recovery period. If the customer shopping goals established in the agreement had not been achieved by the end of 2005, the transition cost recovery periods could have been shortened for OE, CEI and TE to reduce recovery by as much as $500 million (OE-$250 million, CEI-$170 million and TE-$80 million). That goal was achieved in 2002. Accordingly, FirstEnergy does not believe that there will be any regulatory action reducing the recoverable transition costs.

New Jersey

Under New Jersey transition legislation, all electric distribution companies were required to file rate cases to determine the level of unbundled rate components to become effective August 1, 2003. On August 1, 2002, JCP&L submitted two rate filings with the New Jersey Board of Public Utilities (NJBPU). The first filing requested increases in base electric rates of approximately $98 million annually. The second filing was a request to recover deferred costs that exceeded amounts being recovered under the current market transition charge (MTC) and societal benefits charge (SBC) rates; one proposed method of recovery of these costs is the securitization of the deferred balance. This securitization methodology is similar to the Oyster Creek securitization discussed below. Hearings began in February 2003. The Administrative Law Judge's recommended decision is due in June 2003 and the NJBPU's subsequent decision is due in July 2003.

JCP&L's regulatory plan provided for the ability to securitize stranded costs associated with the divested Oyster Creek Nuclear Generating Station. A February 2002 NJBPU order authorized JCP&L to issue $320 million of transition bonds to securitize the recovery of these costs and provided for a usage-based non-bypassable transition bond charge and for the transfer of the bondable transition property to another entity. JCP&L sold $320 million of transition bonds through a wholly owned subsidiary, JCP&L Transition Funding LLC, in June 2002 — that debt is recognized on the Consolidated Balance Sheet (see Note 5). JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers and costs incurred under nonutility generation (NUG) agreements exceed amounts collected through BGS and MTC rates. As of December 31, 2002, the accumulated deferred cost balance totaled approximately $549 million. The NJBPU also allowed securitization of JCP&L's deferred balance to the extent permitted by law upon application by JCP&L and a determination by the NJBPU that the conditions of the New Jersey restructuring legislation are met.

In December 2001, the NJBPU authorized the auctioning of BGS for the period from August 1, 2002 through July 31, 2003 to meet the electricity demands of all customers who have not selected an alternative supplier. The results of the February 2002 auction, with the NJBPU's approval, removed JCP&L's BGS obligation of 5,100 MW for the period August 1, 2002 through July 31, 2003. In February 2003, the auctioning of BGS for the period beginning August 1, 2003 took place. The auction covered a fixed price bid (applicable to all residential and smaller commercial and industrial customers) and an hourly price bid (applicable to all large industrial customers) process. JCP&L will sell all self-supplied energy (NUGs and owned generation) to the wholesale market with offsets to its deferred energy cost balances.

Pennsylvania

Effective September 1, 2002, Met-Ed and Penelec assigned their PLR responsibility to FES through a wholesale power sale which expires in December 2003 and may be extended for each successive calendar year. Under the terms of the wholesale agreement, FES assumed the supply obligation and the energy supply profit and loss risk, for the portion of power supply requirements not self-supplied by Met-Ed and Penelec under their NUG contracts and other existing power contracts with nonaffiliated third party suppliers. This arrangement reduces Met-Ed's and Penelec's exposure to high wholesale power prices by providing power at or below the shopping credit for their uncommitted PLR energy costs during the term of the agreement with FES. FES has hedged most of Met-Ed's and Penelec's unfilled PLR obligation through 2005. Met-Ed and Penelec will continue to defer those cost differences between NUG contract rates and the rates reflected in their capped generation rates.

In its February 21, 2002 decision on Petitions for Review regarding the June 2001 PPUC orders which approved the FirstEnergy/GPU merger and provided Met-Ed and Penelec deferral accounting treatment for energy costs, the Commonwealth Court of Pennsylvania affirmed the PPUC merger decision, remanding the decision to the PPUC only with respect to the issue of merger savings. The Court reversed the PPUC's decision regarding the PLR obligations of Met-Ed and Penelec, and denied the companies authority to defer for future recovery the difference between their wholesale power costs and the amount that they collect from retail customers. FirstEnergy and the PPUC each filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court in March 2002, asking it to review the Commonwealth Court decision. In September 2002, FirstEnergy established reserves against Met-Ed's and Penelec's PLR deferred energy costs which aggregated $287.1 million. The reserves reflected the potential adverse impact of a pending Pennsylvania Supreme Court decision whether to review the Commonwealth Court ruling. FirstEnergy recorded an aggregate non-cash charge to income of $55.8 million ($32.6 million net of tax) for the deferred costs incurred subsequent to the merger. The reserve for the remaining $231.3 million of pre-merger deferred costs increased goodwill by an aggregate net of tax amount of $135.3 million. On January 17, 2003, the Pennsylvania Supreme Court denied further appeals of the Commonwealth Court's decision which effectively affirmed the PPUC's order approving the merger between FirstEnergy and GPU, let stand the Commonwealth Court's denial of PLR rate relief for Met-Ed and Penelec and remanded the merger savings issue back to the

PPUC. Because FirstEnergy had already reserved for the deferred energy costs and FES has largely hedged the anticipated PLR energy supply requirements for Met-Ed and Penelec through 2005, FirstEnergy, Met-Ed and Penelec believe that the disallowance of competitive transition charge recovery of PLR costs above Met-Ed's and Penelec's capped generation rates will not have a future adverse financial impact

FERC Regulatory Matters

On December 19, 2002, the Federal Energy Regulatory Commission (FERC) granted unconditional Regional Transmission Organization status to PJM Interconnection, LLC which includes JCP&L, Met-Ed and Penelec as transmission owners Also, on December 19, 2002, the FERC conditionally accepted GridAmerica's filing to become an independent transmission company within Midwest Independent System Operator, Inc (MISO). GridAmerica will operate ATSI's transmission facilities GridAmercia expects to begin operations in the second quarter of 2003 subject to approval of certain compliance filings with the FERC Compliance filings were made by the GridAmerica companies (including ATSI) on January 31 and February 19, 2003.

Supply Plan

We are obligated to provide generation service for an estimated 2003 peak demand of 18,450 MW. These obligations arise from customers who have elected to continue to receive generation service from the EUOCs under regulated retail rate tariffs and from customers who have selected FES as their alternate generation provider Geographically, approximately 11,000 MW of the obligations are in the East Central Area Reliability Agreement market and 7,450 MW are in the PJM ISO market area. These obligations include approximately 1,700 MW of load that FES obtained in New Jersey's BGS auction Additionally, if alternative suppliers fail to deliver power to their customers located in the EUOCs' service areas, we could be required to serve an additional 1,400 MW as PLR. In the event we must procure replacement power for an alternative supplier, the cost of that power would be recovered under the applicable state regulatory rules

To meet their obligations, our subsidiaries have 13,101 MW of installed generating capacity, 1,540 MW of long-term power purchase contracts (exceeding one year), 2,800 MW under short-term purchase contracts and approximately 800 MW of interruptible and controllable load contracts. Any additional power requirements will be satisfied through spot market purchases

All utilities in New Jersey are required to participate in an annual auction through which the entire obligation for all of their BGS requirements are auctioned to alternate suppliers Through this auction process, the 286 MW of JCP&L's installed capacity and approximately 800 MW of long-term purchases from NUGs are made available to the winning bidders. FES participates in this annual auction as an alternate supplier and currently has an obligation to provide 1,700 MW of power for summer peak demand through July 31, 2003

Davis-Besse Restoration

On April 30, 2002, the NRC initiated a formal inspection process at the Davis-Besse nuclear plant This action was taken in response to corrosion found by FENOC in the reactor vessel head near the nozzle penetration hole during a refueling outage in the first quarter of 2002 The purpose of the formal inspection process is to establish criteria for NRC oversight of the licensee's performance and to provide a record of the major regulatory and licensee actions taken, and technical issues resolved, leading to the NRC's approval of restart of the plant

Restart activities include both hardware and management issues In addition to refurbishment and installation work at the plant, we have made significant management and human performance changes with the intent of establishing the proper safety culture throughout the workforce Work was completed on the reactor head during 2002 and is continuing on efforts designed to enhance the unit's reliability and performance. We are also accelerating maintenance work that had been planned for future refueling and maintenance outages. At a meeting with the NRC in November 2002, we discussed plans to test the bottom of the reactor for leaks and to install a state-of-the-art leak-detection system around the reactor The additional maintenance work being performed has expanded the previous estimates of restoration work We anticipate that the unit will be ready for restart in the spring of 2003 after completion of the additional maintenance work and regulatory reviews The NRC must authorize restart of the plant following its formal inspection process before the unit can be returned to service. While the additional maintenance work has delayed our plans to reduce post-merger debt levels we believe such investments in the unit's future safety, reliability and performance to be essential Significant delays in Davis-Besse's return to service, which depends on the successful resolution of the management and technical issues as well as NRC approval, could trigger an evaluation for impairment of the nuclear plant (see Significant Accounting Policies below)

The actual costs (capital and expense) associated with the extended Davis-Besse outage in 2002 and estimated costs in 2003 are

Costs of Davis-Besse Extended Outage

	(In millions)
2002 - Actual	
Capital Expenditures:	
Reactor head and restart	$ 63 3
Incremental Expenses (pre-tax)	
Maintenance	$115 0
Fuel and purchased power	119 5
Total	$234 5
2003 - Estimated	
Primarily operating expenses (pre-tax)	
Maintenance (including acceleration of programs)	$50
Replacement power per month	$12-18

We have fully hedged the on-peak replacement energy supply for Davis-Besse through the spring of 2003 and have completed some hedging for the balance of 2003 as well

Environmental Matters

We believe we are in compliance with the current sulfur dioxide (SO2) and nitrogen oxide (NOx) reduction requirements under the Clean Air Act Amendments of 1990. In 1998, the Environmental Protection Agency (EPA) finalized regulations requiring additional NOx reductions in the future from our Ohio and Pennsylvania facilities. Various regulatory and judicial actions have since sought to further define NOx reduction requirements (see Note 7D – Environmental Matters). We continue to evaluate our compliance plans and other compliance options.

Violations of federally approved SO2 regulations can result in shutdown of the generating unit involved and/or civil or criminal penalties of up to $31,500 for each day a unit is in violation. The EPA has an interim enforcement policy for SO2 regulations in Ohio that allows for compliance based on a 30-day averaging period. We cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

In 1999 and 2000, the EPA issued Notices of Violation (NOV) or a Compliance Order to nine utilities covering 44 power plants, including the W.H. Sammis Plant. In addition, the U.S. Department of Justice filed eight civil complaints against various investor-owned utilities, which included a complaint against OE and Penn in the U.S. District Court for the Southern District of Ohio, for which hearings began on February 3, 2003. The NOV and complaint allege violations of the Clean Air Act (CAA). The civil complaint against OE and Penn requests installation of "best available control technology" as well as civil penalties of up to $27,500 per day. Although unable to predict the outcome of these proceedings, we believe the Sammis Plant is in full compliance with the CAA and that the NOV and complaint are without merit. Penalties could be imposed if the Sammis Plant continues to operate without correcting the alleged violations and a court determines that the allegations are valid. The Sammis Plant continues to operate while these proceedings are pending.

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants. The EPA identified mercury as the hazardous air pollutant of greatest concern. The EPA established a schedule to propose regulations by December 2003 and issue final regulations by December 2004. The future cost of compliance with these regulations may be substantial.

As a result of the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act of 1976, federal and state hazardous waste regulations have been promulgated. Certain fossil-fuel combustion waste products, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation. The EPA has issued its final regulatory determination that regulation of coal ash as a hazardous waste is unnecessary. In April 2000, the EPA announced that it will develop national standards regulating disposal of coal ash under its authority to regulate nonhazardous waste.

The Companies have been named as "potentially responsible parties" (PRPs) at waste disposal sites which may require cleanup under the Comprehensive Environmental Response, Compensation and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site be held liable on a joint and several basis. Therefore, potential environmental liabilities have been recognized on the Consolidated Balance Sheet as of December 31, 2002, based on estimates of the total costs of cleanup, the Companies' proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay. In addition, JCP&L has accrued liabilities for environmental remediation of former manufactured gas plants in New Jersey; those costs are being recovered by JCP&L through the SBC. The Companies have accrued liabilities aggregating approximately $54.3 million as of December 31, 2002.

The effects of compliance on the Companies with regard to environmental matters could have a material adverse effect on our earnings and competitive position. These environmental regulations affect our earnings and competitive position to the extent we compete with companies that are not subject to such regulations and therefore do not bear the risk of costs associated with compliance, or failure to comply, with such regulations. We believe we are in material compliance with existing regulations, but are unable to predict how and when applicable environmental regulations may change and what, if any, the effects of any such change would be.

Legal Matters

Various lawsuits, claims and proceedings related to our normal business operations are pending against FirstEnergy and its subsidiaries. The most significant are described below.

Due to our merger with GPU, we own Unit 2 of the Three Mile Island Nuclear Plant (TMI-2). As a result of the 1979 TMI-2 accident, claims for alleged personal injury against JCP&L, Met-Ed, Penelec and GPU had been filed in the U.S. District Court for the Middle District of Pennsylvania. In 1996, the District Court granted a motion for summary judgment filed by the GPU companies and dismissed the ten initial "test cases" which had been selected for a test case trial. On January 15, 2002, the District Court granted our motion for summary judgment on the remaining 2,100 pending claims. On February 14, 2002, the plaintiffs filed a notice of appeal of this decision (see Note 7E – Other Legal Proceedings). In December 2002, the Court of Appeals for the Third Circuit refused to hear the appeal which effectively ended further legal action for those claims.

In July 1999, the Mid-Atlantic states experienced a severe heat storm which resulted in power outages throughout the service areas of many electric utilities, including JCP&L. In an investigation into the causes of the outages and the reliability of the transmission and distribution systems of all four New Jersey electric utilities, the NJBPU concluded that there was not a prima facie case demonstrating that, overall, JCP&L provided unsafe, inadequate or improper service to its customers. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against JCP&L, GPU and other GPU companies seeking compensatory and punitive damages arising from the service interruptions of July 1999 in the JCP&L territory. In May 2001, the court denied without prejudice the defendant's motion seeking decertification of the class. Discovery continues in the class action, but no trial date has been set. In October 2001, the court held argument on the plaintiffs' motion for partial summary judgment, which contends that JCP&L is bound to several findings of the NJBPU investigation. The plaintiffs' motion was denied by the Court in November 2001 and the plaintiffs' motion seeking permission to file an appeal on this denial of their motion was rejected by the New Jersey Appellate Division. We have also filed a motion for partial summary judgment that is currently pending before the Superior Court. We are unable to predict the outcome of these matters.

Implementation of Recent Accounting Standard

In June 2002, the Emerging Issues Task Force (EITF) reached a partial consensus on Issue No 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." Based on the EITF's partial consensus position, for periods after July 15, 2002, mark-to-market revenues and expenses and their related kilowatt-hour (KWH) sales and purchases on energy trading contracts must be shown on a net basis in the Consolidated Statements of Income We previously reported such contracts as gross revenues and purchased power costs Comparative quarterly disclosures and the Consolidated Statements of Income for revenues and expenses have been reclassified for 2002 only to conform with the revised presentation (see Note 11 - Summary of Quarterly Financial Data) In addition, the related KWH sales and purchases statistics described above under Results of Operations were reclassified (7.2 billion KWH in 2002 and 3 7 billion KWH in 2001). The following table displays the impact of changing to a net presentation for our energy trading operations

2002 Impact of Recording Energy Trading Net

	Revenues	Expenses
	(In millions)	
Total before adjustment	$12,420	$10,238
Adjustment	(268)	(268)
Total as reported	$12,152	$ 9,970

Significant Accounting Policies

We prepare our consolidated financial statements in accordance with accounting principles that are generally accepted in the United States. Application of these principles often requires a high degree of judgment, estimates and assumptions that affect financial results All of our assets are subject to their own specific risks and uncertainties and are regularly reviewed for impairment. Assets related to the application of the policies discussed below are similarly reviewed with their risks and uncertainties reflecting these specific factors Our more significant accounting policies are described below

Purchase Accounting - Acquisition of GPU

Purchase accounting requires judgment regarding the allocation of the purchase price based on the fair values of the assets acquired (including intangible assets) and the liabilities assumed The fair values of the acquired assets and assumed liabilities for GPU were based primarily on estimates The more significant of these included the estimation of the fair value of the international operations, certain domestic operations and the fair value of the pension and other post-retirement benefit assets and liabilities The purchase price allocations for the GPU acquisition were finalized in the fourth quarter of 2002 (see Note 12)

Regulatory Accounting

Our regulated services segment is subject to regulation that sets the prices (rates) it is permitted to charge its customers based on costs that the regulatory agencies determine we are permitted to recover At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by an unregulated company This rate-making process results in the recording of regulatory assets based on anticipated future cash inflows As a result of the changing regulatory framework in each state in which we operate, a significant amount of regulatory assets have been recorded - $8 3 billion as of December 31, 2002 We regularly review these assets to assess their ultimate recoverability within the approved regulatory guidelines Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future

Derivative Accounting

Determination of appropriate accounting for derivative transactions requires the involvement of management representing operations, finance and risk assessment. In order to determine the appropriate accounting for derivative transactions, the provisions of the contract need to be carefully assessed in accordance with the authoritative accounting literature and management's intended use of the derivative New authoritative guidance continues to shape the application of derivative accounting Management's expectations and intentions are key factors in determining the appropriate accounting for a derivative transaction and, as a result, such expectations and intentions are documented. Derivative contracts that are determined to fall within the scope of SFAS 133, as amended, must be recorded at their fair value Active market prices are not always available to determine the fair value of the later years of a contract, requiring that various assumptions and estimates be used in their valuation We continually monitor our derivative contracts to determine if our activities, expectations, intentions, assumptions and estimates remain valid. As part of our normal operations, we enter into significant commodity contracts, as well as interest rate and currency swaps, which increase the impact of derivative accounting judgments

Revenue Recognition

We follow the accrual method of accounting for revenues, recognizing revenue for KWH that have been delivered but not yet billed through the end of the accounting period The determination of unbilled revenues requires management to make various estimates including

- Net energy generated or purchased for retail load
- Losses of energy over transmission and distribution lines
- Mix of KWH usage by residential, commercial and industrial customers
- KWH of customers receiving electricity from alternative suppliers

Pension and Other Postretirement Benefits Accounting

Our reported costs of providing non-contributory defined pension benefits and postemployment benefits other than pensions (OPEB) are dependent upon numerous factors resulting from actual plan experience and certain assumptions.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions we make to the plans, and earnings on plan assets Such factors may be further affected by business combinations (such as our merger with GPU, Inc in November 2001), which impacts employee demographics, plan experience and other factors. Pension and OPEB costs may also be affected by changes to key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations and pension and OPEB costs.

In accordance with SFAS 87, "Employers' Accounting for Pensions" and SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," changes in pension and OPEB obligations associated with these factors may not be immediately recognized as costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. SFAS 87 and SFAS 106 delay recognition of changes due to the long-term nature of pension and OPEB obligations and the varying market conditions likely to occur over long periods of time. As such, significant portions of pension and OPEB costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants and are significantly influenced by assumptions about future market conditions and plan participants' experience.

In selecting an assumed discount rate, we consider currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. Due to the significant decline in corporate bond yields and interest rates in general during 2002, we reduced the assumed discount rate as of December 31, 2002 to 6.75% from 7.25% used in 2001 and 7.75% used in 2000.

Our assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by our pension trusts. The market values of our pension assets have been affected by sharp declines in the equity markets since mid-2000. In 2002, 2001 and 2000, plan assets have earned (11.3)%, (5.5)% and (0.3)%, respectively. Our pension costs in 2002 were computed assuming a 10.25% rate of return on plan assets. As of December 31, 2002 the assumed return on plan assets was reduced to 9.00% based upon our projection of future returns and pension trust investment allocation of approximately 60% large cap equities, 10% small cap equities and 30% bonds.

Based on pension assumptions and pension plan assets as of December 31, 2002, we will not be required to fund our pension plans in 2003. While OPEB plan assets have also been affected by sharp declines in the equity market, the impact is not as significant due to the relative size of the plan assets. However, health care cost trends have significantly increased and will affect future OPEB costs. The 2003 composite health care trend rate assumption is approximately 10%-12% gradually decreasing to 5% in later years, compared to our 2002 assumption of approximately 10% in 2002, gradually decreasing to 4%-6% in later years. In determining our trend rate assumptions, we included the specific provisions of our health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in our health care plans, and projections of future medical trend rates. The effect on our SFAS 87 and 106 costs and liabilities from changes in key assumptions are as follows:

Increase in Costs from Adverse Changes in Key Assumptions

Assumption	Adverse Change	Pension	OPEB	Total
			(In millions)	
Discount rate	Decrease by 0.25%	$10.3	$ 7.4	$17.7
Long-term return on assets	Decrease by 0.25%	$ 6.9	$ 1.2	$ 8.1
Health care trend rate	Increase by 1%	na	$20.7	$20.7

Increase in Minimum Liability

Discount rate	Decrease by 0.25%	$99.4	na	$99.4

As a result of the reduced market value of our pension plan assets, we were required to recognize an additional minimum liability as prescribed by SFAS 87 and SFAS 132, "Employers' Disclosures about Pension and Postretirement Benefits," as of December 31, 2002. We eliminated our prepaid pension asset of $286.9 million and established a minimum liability of $548.6 million, recording an intangible asset of $78.5 million and reducing OCI by $444.2 million (recording a related deferred tax benefit of $312.8 million). The charge to OCI will reverse in future periods to the extent the fair value of trust assets exceed the accumulated benefit obligation. The amount of pension liability recorded as of December 31, 2002 increased due to the lower discount rate assumed and reduced market value of plan assets as of December 31, 2002. Our non-cash, pre-tax pension and OPEB expense under SFAS 87 and SFAS 106 is expected to increase by $125 million and $45 million, respectively – a total of $170 million in 2003 as compared to 2002.

Long-Lived Assets

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," we periodically evaluate our long-lived assets to determine whether conditions exist that would indicate that the carrying value of an asset may not be fully recoverable. The accounting standard requires that if the sum of future cash flows (undiscounted) expected to result from an asset, is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. If impairment, other than of a temporary nature, has occurred, we recognize a loss - calculated as the difference between the carrying value and the estimated fair value of the asset (discounted future net cash flows).

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by SFAS 142, we evaluate our goodwill for impairment at least annually and would make such an evaluation more frequently if indicators of impairment should arise. In accordance with the accounting standard, if the fair value of a reporting unit is less than its carrying value including goodwill, an impairment for goodwill must be recognized in the financial statements. If impairment were to occur we would recognize a loss - calculated as the difference between the implied fair value of a reporting unit's goodwill and the carrying value of the goodwill. Our annual review was completed in the third quarter of 2002. The results of that review indicated no impairment of goodwill — fair value was higher than carrying value for each of our reporting units. The forecasts used in our evaluations of goodwill reflect operations consistent with our general business assumptions. Unanticipated changes in those assumptions could have a significant effect on our future evaluations of goodwill. As of December 31, 2002, we had $5.9 billion of goodwill that primarily relates to our regulated services segment.

Recently Issued Accounting Standards Not Yet Implemented

SFAS 143, "Accounting for Asset Retirement Obligations"

In June 2001, the FASB issued SFAS 143. The new statement provides accounting standards for retirement obligations associated with tangible long-lived assets, with adoption required by January 1, 2003. SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recorded in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Over time the capitalized costs are depreciated and the present value of the asset retirement liability increases, resulting in a period expense. However, rate-regulated entities may recognize regulatory assets or liabilities if the criteria for such treatment are met. Upon retirement, a gain or loss would be recorded if the cost to settle the retirement obligation differs from the carrying amount.

We have identified applicable legal obligations as defined under the new standard, principally for nuclear power plant decommissioning. Upon adoption of SFAS 143, in January 2003, asset retirement costs of $807 million were recorded as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $437 million Due to the increased carrying amount, the related long-lived assets were tested for impairment in accordance with SFAS 144. No impairment was indicated The asset retirement liability at the date of adoption was $1 109 billion. As of December 31, 2002, FirstEnergy had recorded decommissioning liabilities of $1 232 billion, including unrealized gains on decommissioning trust funds of $12 million The change in the estimated liabilities resulted from changes in methodology and various assumptions, including changes in the projected dates for decommissioning.

Management expects that substantially all nuclear decommissioning costs for Met-Ed, Penelec, JCP&L and Penn will be recoverable through their regulated rates Therefore, we recognized a regulatory liability of $185 million upon adoption of SFAS 143 for the transition amounts related to establishing the asset retirement obligations for nuclear decommissioning The remaining cumulative effect adjustment to recognize the undepreciated asset retirement cost and the asset retirement liability offset by the reversal of the previously recorded decommissioning liabilities was a $298 million increase to income ($174 million net of tax) The $12 million of unrealized gains ($7 million net of tax) included in the decommissioning liability balances as of December 31, 2002, were offset against OCI upon adoption of SFAS 143

SFAS 146, "Accounting for Costs Associated with Exit or Disposal Activities"

This statement, which was issued by the FASB in July 2002, requires the recognition of costs associated with exit or disposal activities at the time they are incurred rather than when management commits to a plan of exit or disposal. It also requires the use of fair value for the measurement of such liabilities The new standard supersedes guidance provided by EITF Issue No 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (Including Certain Costs Incurred in a Restructuring) " This new standard was effective for exit and disposal activities initiated after December 31, 2002 Since it is applied prospectively, there will be no impact upon adoption However, SFAS 146 could change the timing and amount of costs recognized in connection with future exit or disposal activities

SFAS 148, "Accounting for Stock-Based Compensation – Transition and Disclosure"

SFAS 148 provides alternative approaches for voluntarily transitioning to the fair value method of accounting for stock-based compensation as described by SFAS 123 "Accounting for Stock-Based Compensation." Under current GAAP, we do not intend to adopt fair value accounting It also amends SFAS 123 disclosure requirements for those companies applying APB 25, "Accounting for Stock Issued to Employees" and FASB Interpretation 44, "Accounting for Transactions involving Stock Compensation – an interpretation of APB Opinion No. 44 " The amendment requires prominent display of differences between the SFAS 123 fair-value approach and the intrinsic-value approach described by APB 25 in a prescribed format SFAS 148 also amends APB 28, "Interim Financial Reporting," to require that these disclosures be made on an interim basis The new disclosure requirements are effective for 2002 year-end reporting (see Note 2B – Earnings Per Share) and for quarterly reporting beginning in 2003 Application of the alternative transition approaches is effective in 2003.

FASB Interpretation (FIN) No. 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"

The FASB issued FIN 45 in January 2003. This interpretation identifies minimum guarantee disclosures required for annual periods ending after December 15, 2002 (see Guarantees and Other Assurances) It also clarifies that providers of guarantees must record the fair value of those guarantees at their inception This accounting guidance is applicable on a prospective basis to guarantees issued or modified after December 31, 2002 We do not believe that implementation of FIN 45 will be material but we will continue to evaluate anticipated guarantees.

FIN 46, "Consolidation of Variable Interest Entities – an interpretation of ARB 51"

In January 2003, the FASB issued this interpretation of ARB No 51, "Consolidated Financial Statements" The new interpretation provides guidance on consolidation of variable interest entities (VIEs), generally defined as certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties This interpretation requires an enterprise to disclose the nature of its involvement with a VIE if the enterprise has a significant variable interest in the VIE and to consolidate a VIE if the enterprise is the primary beneficiary VIEs created after January 31, 2003 are immediately subject to the provisions of FIN 46 VIEs created before February 1, 2003 are subject to this interpretation's provisions in the first interim or annual reporting period beginning after June 15, 2003 (our third quarter of 2003) The FASB also identified transitional disclosure provisions for all financial statements issued after January 31, 2003

FirstEnergy currently has transactions with entities in connection with sale and leaseback arrangements, the sale of preferred securities and debt secured by bondable property, which may fall within the scope of this interpretation, and which are reasonably possible of meeting the definition of a VIE in accordance with FIN 46

We currently consolidate the majority of these entities and believe we will continue to consolidate following the adoption of FIN 46 In addition to the entities we are currently consolidating we believe that the PNBV Capital Trust, which reacquired a portion of the off-balance sheet debt issued in connection with the sale and leaseback of OE's interest in the Perry Nuclear Plant and Beaver Valley Unit 2, would require consolidation Ownership of the trust includes a three-percent equity interest by a nonaffiliated party and a three-percent equity interest by OES Ventures, a wholly owned subsidiary of OE. Full consolidation of the trust under FIN 46 would change the characterization of the PNBV trust investment to a lease obligation bond investment. Also, consolidation of the outside minority interest would be required, which would increase assets and liabilities by $12 0 million

CONSOLIDATED STATEMENTS OF INCOME

(In thousands, except per share amounts)

For the Years Ended December 31,	2002	2001	2000
REVENUES:			
Electric utilities	**$ 9,165,805**	$ 5,729,036	$ 5,421,668
Unregulated businesses	**2,986,192**	2,270,326	1,607,293
Total revenues	**12,151,997**	7,999,362	7,028,961
EXPENSES:			
Fuel and purchased power	**3,673,610**	1,421,525	1,110,845
Purchased gas	**592,116**	820,031	553,548
Other operating expenses	**3,947,855**	2,727,794	2,378,296
Provision for depreciation and amortization	**1,105,904**	889,550	933,684
General taxes	**650,329**	455,340	547,681
Total expenses	**9,969,814**	6,314,240	5,524,054
INCOME BEFORE INTEREST AND INCOME TAXES	**2,182,183**	1,685,122	1,504,907
NET INTEREST CHARGES:			
Interest expense	**891,833**	519,131	493,473
Capitalized interest	**(24,474)**	(35,473)	(27,059)
Subsidiaries' preferred stock dividends	**78,947**	72,061	62,721
Net interest charges	**946,306**	555,719	529,135
INCOME TAXES	**549,476**	474,457	376,802
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGES	**686,401**	654,946	598,970
CUMULATIVE EFFECT OF ACCOUNTING CHANGES (NET OF INCOME TAXES (BENEFIT) OF $13,600,000 AND ($5,839,000), RESPECTIVELY) (Notes 2J and 3)	**(57,121)**	(8,499)	—
NET INCOME	**$ 629,280**	$ 646,447	$ 598,970
BASIC EARNINGS PER SHARE OF COMMON STOCK (Note 2J):			
Income before cumulative effect of accounting changes	**$2.34**	$2.85	$2.69
Cumulative effect of accounting changes (Notes 2J and 3)	**(.19)**	(.03)	—
Net income	**$2.15**	$2.82	$2.69
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	**293,194**	229,512	222,444
DILUTED EARNINGS PER SHARE OF COMMON STOCK (Note 2J):			
Income before cumulative effect of accounting changes	**$2.33**	$2.84	$2.69
Cumulative effect of accounting changes (Notes 2J and 3)	**(.19)**	(.03)	—
Net income	**$2.14**	$2.81	$2.69
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	**294,421**	230,430	222,726
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	**$1.50**	$1.50	$1.50

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

CONSOLIDATED BALANCE SHEETS

(In thousands)

As of December 31,	2002	2001
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 196,301	$ 220,178
Receivables-		
Customers (less accumulated provisions of $52,514,000 and $65,358,000, respectively, for uncollectible accounts)	1,153,486	1,074,664
Other (less accumulated provisions of $12,851,000 and $7,947,000, respectively, for uncollectible accounts)	473,106	473,550
Materials and supplies, at average cost-		
Owned	253,047	256,516
Under consignment	174,028	141,002
Prepayments and other	203,630	336,610
	2,453,598	2,502,520
ASSETS PENDING SALE (Note 3)	—	3,418,225
PROPERTY, PLANT AND EQUIPMENT		
In service	20,372,224	19,981,749
Less—Accumulated provision for depreciation	8,551,427	8,161,022
	11,820,797	11,820,727
Construction work in progress	859,016	607,702
	12,679,813	12,428,429
INVESTMENTS		
Capital trust investments (Note 4)	1,079,435	1,166,714
Nuclear plant decommissioning trusts	1,049,560	1,014,234
Letter of credit collateralization (Note 4)	277,763	277,763
Pension investments (Note 2I)	—	273,542
Other	918,874	898,311
	3,325,632	3,630,564
DEFERRED CHARGES		
Regulatory assets	8,323,001	8,912,584
Goodwill	5,896,292	5,600,918
Other	902,437	858,273
	15,121,730	15,371,775
	$33,580,773	$37,351,513
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Currently payable long-term debt and preferred stock	$ 1,702,822	$ 1,867,657
Short-term borrowings (Note 6)	1,092,817	614,298
Accounts payable	918,268	704,184
Accrued taxes	456,178	418,555
Other	1,000,415	1,064,763
	5,170,500	4,669,457
LIABILITIES RELATED TO ASSETS PENDING SALE (Note 3)	—	2,954,753
CAPITALIZATION (See Consolidated Statements of Capitalization)		
Common stockholders' equity	7,120,049	7,398,599
Preferred stock of consolidated subsidiaries-		
Not subject to mandatory redemption	335,123	480,194
Subject to mandatory redemption	18,521	65,406
Subsidiary-obligated mandatorily redeemable preferred securities (Note 5F)	409,867	529,450
Long-term debt	10,872,216	11,433,313
	18,755,776	19,906,962
DEFERRED CREDITS		
Accumulated deferred income taxes	2,367,997	2,684,219
Accumulated deferred investment tax credits	235,758	260,532
Nuclear plant decommissioning costs	1,254,344	1,201,599
Power purchase contract loss liability	3,136,538	3,566,531
Retirement benefits	1,564,930	838,943
Other	1,094,930	1,268,517
	9,654,497	9,820,341
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Notes 4 and 7)		
	$33,580,773	$37,351,513

The accompanying Notes to Consolidated Financial Statements are an integral part of these balance sheets

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Dollars in thousands, except per share amounts)

As of December 31,					2002	2001
COMMON STOCKHOLDERS' EQUITY:						
Common stock, $0.10 par value - authorized 375,000,000 shares – 297,636,276 shares outstanding					**$ 29,764**	$ 29,764
Other paid-in capital					**6,120,341**	6,113,260
Accumulated other comprehensive loss (Note 5I)					**(663,236)**	(169,003)
Retained earnings (Note 5A)					**1,711,457**	1,521,805
Unallocated employee stock ownership plan common stock-3,966,269 and 5,117,375 shares, respectively (Note 5B)					**(78,277)**	(97,227)
Total common stockholders' equity					**7,120,049**	7,398,599
	Number of Shares Outstanding		Optional Redemption Price			
	2002	2001	Per Share	Aggregate		
PREFERRED STOCK OF CONSOLIDATED SUBSIDIARIES (Note 5D):						
Ohio Edison Company						
Cumulative, $100 par value-Authorized 6,000,000 shares						
Not Subject to Mandatory Redemption:						
3.90%	152,510	152,510	$103.63	$ 15,804	**15,251**	15,251
4.40%	176,280	176,280	108.00	19,038	**17,628**	17,628
4.44%	136,560	136,560	103.50	14,134	**13,656**	13,656
4.56%	144,300	144,300	103.38	14,917	**14,430**	14,430
	609,650	609,650		63,893	**60,965**	60,965
Cumulative, $25 par value- Authorized 8,000,000 shares						
Not Subject to Mandatory Redemption:						
7.75%	—	4,000,000	—	—	**—**	100,000
Total Not Subject to Mandatory Redemption	609,650	4,609,650		$ 63,893	**60,965**	160,965
Pennsylvania Power Company						
Cumulative, $100 par value- Authorized 1,200,000 shares						
Not Subject to Mandatory Redemption:						
4.24%	40,000	40,000	103.13	$ 4,125	**4,000**	4,000
4.25%	41,049	41,049	105.00	4,310	**4,105**	4,105
4.64%	60,000	60,000	102.98	6,179	**6,000**	6,000
7.75%	250,000	250,000	—	—	**25,000**	25,000
Total Not Subject to Mandatory Redemption	391,049	391,049		$ 14,614	**39,105**	39,105
Subject to Mandatory Redemption (Note 5E):						
7.625%	142,500	150,000	103.81	$ 14,793	**14,250**	15,000
Redemption Within One Year					**(750)**	(750)
Total Subject to Mandatory Redemption	142,500	150,000		$ 14,793	**13,500**	14,250
Cleveland Electric Illuminating Company						
Cumulative, without par value- Authorized 4,000,000 shares						
Not Subject to Mandatory Redemption:						
$ 7.40 Series A	500,000	500,000	101.00	$ 50,500	**50,000**	50,000
$ 7.56 Series B	—	450,000	—	—	**—**	45,071
Adjustable Series L	474,000	474,000	100.00	47,400	**46,404**	46,404
$42.40 Series T	—	200,000	—	—	**—**	96,850
	974,000	1,624,000		97,900	**96,404**	238,325
Redemption Within One Year					**—**	(96,850)
Total Not Subject to Mandatory Redemption	974,000	1,624,000		$ 97,900	**96,404**	141,475
Subject to Mandatory Redemption (Note 5E):						
$ 7.35 Series C	60,000	70,000	101.00	$ 6,060	**6,021**	7,030
$90.00 Series S	—	17,750	—	—	**—**	17,268
	60,000	87,750		6,060	**6,021**	24,298
Redemption Within One Year					**(1,000)**	(18,010)
Total Subject to Mandatory Redemption	60,000	87,750		$ 6,060	**5,021**	6,288

CONSOLIDATED STATEMENTS OF CAPITALIZATION *(Cont'd)*

(Dollars in thousands, except per share amounts)

As of December 31,	Number of Shares Outstanding		Optional Redemption Price		2002	2001
	2002	2001	Per Share	Aggregate		
PREFERRED STOCK OF CONSOLIDATED SUBSIDIARIES (Cont'd)						
Toledo Edison Company						
Cumulative, $100 par value- Authorized 3,000,000 shares						
Not Subject to Mandatory Redemption						
$ 4 25	160,000	160,000	$104 63	$ 16,740	**$ 16,000**	$ 16,000
$ 4 56	50,000	50,000	101 00	5,050	**5,000**	5,000
$ 4 25	100,000	100,000	102 00	10,200	**10,000**	10,000
$ 8 32	—	100,000	—	—	**—**	10,000
$ 7 76	—	150,000	—	—	**—**	15,000
$ 7 80	—	150,000	—	—	**—**	15,000
$10 00	—	190,000	—	—	**—**	19,000
	310,000	900,000		31,990	**31,000**	90,000
Redemption Within One Year					**—**	(59,000)
	310,000	900,000		31,990	**31,000**	31,000
Cumulative, $25 par value- Authorized 12,000,000 shares						
Not Subject to Mandatory Redemption						
$2 21	—	1,000,000	—	—	**—**	25,000
$2 365	1,400,000	1,400,000	27 75	38,850	**35,000**	35,000
Adjustable Series A	1,200,000	1,200,000	25 00	30,000	**30,000**	30,000
Adjustable Series B	1,200,000	1,200,000	25 00	30,000	**30,000**	30,000
	3,800,000	4,800,000		98,850	**95,000**	120,000
Redemption Within One Year					**—**	(25,000)
	3,800,000	4,800,000		98,850	**95,000**	95,000
Total Not Subject to Mandatory Redemption	4,110,000	5,700,000		$ 130,840	**126,000**	126,000
Jersey Central Power & Light Company						
Cumulative, $100 stated value- Authorized 15,600,000 shares						
Not Subject to Mandatory Redemption						
4 00% Series	125,000	125,000	106 50	$ 13,313	**12,649**	12,649
Subject to Mandatory Redemption						
8 65% Series J	—	250,001	—	$ —	**—**	26,750
7 52% Series K	—	265,000	—	—	**—**	28,951
	—	515,001		—	**—**	55,701
Redemption Within One Year					**—**	(10,833)
Total Subject to Mandatory Redemption	—	515,001		$ —	**—**	44,868
SUBSIDIARY-OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUST OR LIMITED PARTNERSHIP HOLDING SOLELY SUBORDINATED DEBENTURES OF SUBSIDIARIES (NOTE 5F)						
Ohio Edison Co						
Cumulative, $25 stated value- Authorized 4,800,000 shares						
9 00%	—	4,800,000	—	$ —	**—**	120,000
Cleveland Electric Illuminating Co						
Cumulative, $25 stated value- Authorized 4,000,000 shares						
9 00%	4,000,000	4,000,000	—	$ —	**100,000**	100,000
Jersey Central Power & Light Co						
Cumulative, $25 stated value- Authorized 5,000,000 shares						
8 56%	5,000,000	5,000,000	25 00	$ 125,000	**125,244**	125,250
Metropolitan Edison Co						
Cumulative, $25 stated value- Authorized 4,000,000 shares						
7 35%	4,000,000	4,000,000	—	$ —	**92,409**	92,200
Pennsylvania Electric Co						
Cumulative, $25 stated value- Authorized 4,000,000 shares						
7 34%	4,000,000	4,000,000	—	$ —	**92,214**	92,000

CONSOLIDATED STATEMENTS OF CAPITALIZATION *(Cont'd)*

LONG-TERM DEBT (Note 5G) (Interest rates reflect weighted average rates) *(In thousands)*

	First Mortgage Bonds			Secured Notes			Unsecured Notes			Total	
As of December 31,		**2002**	**2001**		**2002**	**2001**		**2002**	**2001**	**2002**	**2001**
Ohio Edison Co. -											
Due 2002-2007	8.02%	$ 230,000	$ 509,265	7.66%	$ 186,549	$ 231,907	4.17%	$441,725	$441,725		
Due 2008-2012	—	—	—	7.00%	5,468	5,468	—	—	—		
Due 2013-2017	—	—	—	5.09%	59,000	59,000	—	—	—		
Due 2018-2022	8.75%	50,960	50,960	7.01%	60,443	60,443	—	—	—		
Due 2023-2027	7.76%	168,500	168,500	—	—	—	—	—	—		
Due 2028-2032	—	—	—	3.60%	249,634	249,634	—	—	—		
Due 2033-2037	—	—	—	2.43%	71,900	71,900	—	—	—		
Total-Ohio Edison		449,460	728,725		632,994	678,352		441,725	441,725	**$ 1,524,179**	$ 1,848,802
Cleveland Electric Illuminating Co. -											
Due 2002-2007	8.97%	400,000	595,000	5.74%	680,175	713,205	5.58%	27,700	27,700		
Due 2008-2012	6.86%	125,000	125,000	7.43%	151,610	151,610	—	—	—		
Due 2013-2017	—	—	—	7.88%	300,000	378,700	6.00%	78,700	—		
Due 2018-2022	—	—	—	6.24%	140,560	140,560	—	—	—		
Due 2023-2027	9.00%	150,000	150,000	7.64%	218,950	218,950	—	—	—		
Due 2028-2032	—	—	—	5.38%	5,993	5,993	—	—	—		
Due 2033-2037	—	—	—	1.60%	30,000	—	—	—	—		
Total-Cleveland Electric		675,000	870,000		1,527,288	1,609,018		106,400	27,700	**2,308,688**	2,506,718
Toledo Edison Co. -											
Due 2002-2007	7.90%	178,725	179,125	6.19%	229,700	258,700	4.83%	91,100	226,130		
Due 2008-2012	—	—	—	—	—	—	10.00%	760	760		
Due 2013-2017	—	—	—	—	—	—	—	—	—		
Due 2018-2022	—	—	—	7.89%	114,000	129,000	—	—	—		
Due 2023-2027	—	—	—	7.31%	60,800	60,800	—	—	—		
Due 2028-2032	—	—	—	5.38%	3,751	3,751	—	—	—		
Due 2033-2037	—	—	—	1.68%	51,100	30,900	—	—	—		
Total-Toledo Edison		178,725	179,125		459,351	483,151		91,860	226,890	**729,936**	889,166
Pennsylvania Power Co. -											
Due 2002-2007	7.19%	79,370	80,344	2.99%	10,300	10,300	4.39%	19,700	5,200		
Due 2008-2012	9.74%	4,870	4,870	—	—	—	—	—	—		
Due 2013-2017	9.74%	4,870	4,870	3.12%	29,525	29,525	—	—	—		
Due 2018-2022	8.58%	29,231	29,231	3.94%	31,282	31,282	—	—	—		
Due 2023-2027	7.63%	6,500	6,500	6.15%	12,700	27,200	—	—	—		
Due 2028-2032	—	—	—	5.79%	23,172	23,172	—	—	—		
Total-Penn Power		124,841	125,815		106,979	121,479		19,700	5,200	**251,520**	252,494
Jersey Central Power & Light Co. -											
Due 2002-2007	6.90%	442,674	541,260	5.60%	241,135	150,000	7.69%	93	107		
Due 2008-2012	7.13%	5,040	5,040	5.39%	52,273	—	7.69%	134	134		
Due 2013-2017	7.10%	12,200	12,200	6.01%	176,592	—	7.69%	193	193		
Due 2018-2022	8.62%	76,586	170,000	—	—	—	7.69%	280	280		
Due 2023-2027	7.37%	365,000	365,000	—	—	—	7.69%	406	406		
Due 2028-2032	—	—	—	—	—	—	7.69%	588	588		
Due 2033-2037	—	—	—	—	—	—	7.69%	851	851		
Due 2038-2042	—	—	—	—	—	—	7.69%	439	439		
Total-Jersey Central		901,500	1,093,500		470,000	150,000		2,984	2,998	**1,374,484**	1,246,498
Metropolitan Edison Co. -											
Due 2002-2007	6.71%	202,175	262,175	5.79%	150,000	100,000	7.69%	185	214		
Due 2008-2012	6.00%	6,525	6,525	—	—	—	7.69%	267	267		
Due 2013-2017	—	—	—	—	—	—	7.69%	387	387		
Due 2018-2022	7.86%	88,500	88,500	—	—	—	7.69%	560	560		
Due 2023-2027	7.55%	133,690	133,690	—	—	—	7.69%	812	812		
Due 2028-2032	—	—	—	—	—	—	7.69%	1,176	1,176		
Due 2033-2037	—	—	—	—	—	—	7.69%	1,703	1,703		
Due 2038-2042	—	—	—	—	—	—	7.69%	878	878		
Total-Metropolitan Edison		430,890	490,890		150,000	100,000		5,968	5,997	**586,858**	596,887

CONSOLIDATED STATEMENTS OF CAPITALIZATION *(Cont'd)*

LONG-TERM DEBT (Interest rates reflect weighted average rates) (Cont'd) *(In thousands)*

As of December 31,	First Mortgage Bonds			Secured Notes			Unsecured Notes			Total	
		2002	2001		2002	2001		2002	2001	2002	2001
Pennsylvania Electric Co -											
Due 2002-2007	6 13%	$ 3,905	$ 4,110	—	$ —	$ —	5 86%	$ 133,093	$ 183,107		
Due 2008-2012	5 35%	24,310	24,310	—	—	—	6 55%	135,134	135,134		
Due 2013-2017	—	—	—	—	—	—	7 69%	193	193		
Due 2018-2022	5 80%	20,000	20,000	—	—	—	6 63%	125,280	125,280		
Due 2023-2027	6 05%	25,000	25,000	—	—	—	7 69%	406	406		
Due 2028-2032	—	—	—	—	—	—	7 69%	588	588		
Due 2033-2037	—	—	—	—	—	—	7 69%	851	851		
Due 2038-2042	—	—	—	—	—	—	7 69%	439	439		
Total-Pennsylvania Electric		73,215	73,420		—	—		395,984	445,998	**$ 469,199**	$ 519,418
FirstEnergy Corp -											
Due 2002-2007	—	—	—	—	—	—	5 28%	1,695,000	1,550,000		
Due 2008-2012	—	—	—	—	—	—	6 45%	1,500,000	1,500,000		
Due 2013-2017	—	—	—	—	—	—	—	—	—		
Due 2018-2022	—	—	—	—	—	—	—	—	—		
Due 2023-2027	—	—	—	—	—	—	—	—	—		
Due 2028-2032	—	—	—	—	—	—	7 38%	1,500,000	1,500,000		
Total-FirstEnergy		—	—		—	—		4,695,000	4,550,000	**4,695,000**	4,550,000
OES Fuel	—	—	—	—	—	81,515	—	—	—	—	81,515
AFN Finance Co No 1	—	—	—	—	—	15,000	—	—	—	—	15,000
AFN Finance Co No 3	—	—	—	—	—	4,000	—	—	—	—	4,000
Bay Shore Power	—	—	—	6 24%	143,200	145,400	—	—	—	**143,200**	145,400
MARBEL Energy Corp	—	—	—	—	—	—	—	—	569	—	569
Facilities Services Group	—	—	—	4 86%	13,205	15,735	—	—	—	**13,205**	15,735
FirstEnergy Generation	—	—	—	—	—	—	5 00%	15,000	—	**15,000**	—
FirstEnergy Properties	—	—	—	7 89%	9,679	9,902	—	—	—	**9,679**	9,902
Warrenton River Terminal	—	—	—	5 25%	634	776	—	—	—	**634**	776
GPU Capital*	—	—	—	—	—	—	5 78%	101,467	1,629,582	**101,467**	1,629,582
GPU Power	—	—	—	7 14%	174,760	239,373	11 87%	67,372	56,048	**242,132**	295,421
Total		$2,833,631	$3,561,475		$3,688,090	$3,653,701		$5,943,460	$7,392,707	**12,465,181**	14,607,883
Capital lease obligations										**15,761**	19,390
Net unamortized premium on debt*										**92,346**	213,834
Long-term debt due within one year*										**(1,701,072)**	(1,975,755)
Total long-term debt*										**10,872,216**	12,865,352
TOTAL CAPITALIZATION*										**$18,755,776**	$21,339,001

** 2001 includes amounts in "Liabilities Related to Assets Pending Sale" on the Consolidated Balance Sheet as of December 31, 2001*

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

(Dollars in thousands)

	Comprehensive Income	Number of Shares	Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Unallocated ESOP Common Stock
Balance, January 1, 2000		232,454,287	$23,245	$3,722,375	$ (195)	$ 945,241	$(126,776)
Net income	$598,970					598,970	
Minimum liability for unfunded retirement benefits, net of $85,000 of income taxes	(134)				(134)		
Unrealized gain on investment in securities available for sale	922				922		
Comprehensive income	$599,758						
Reacquired common stock		(7,922,707)	(792)	(194,210)			
Allocation of ESOP shares				3,656			15,044
Cash dividends on common stock						(334,220)	
Balance, December 31, 2000		224,531,580	22,453	3,531,821	593	1,209,991	(111,732)
GPU acquisition		73,654,696	7,366	2,586,097			
Net income	$646,447					646,447	
Minimum liability for unfunded retirement benefits, net of $(182,000) of income taxes	(268)				(268)		
Unrealized loss on derivative hedges, net of $(116,521,000) of income taxes	(169,408)				(169,408)		
Unrealized gain on investments, net of $56,000 of income taxes	81				81		
Unrealized currency translation adjustments, net of $(1,000) of income taxes	(1)				(1)		
Comprehensive income	$476,851						
Reacquired common stock		(550,000)	(55)	(15,253)			
Allocation of ESOP shares				10,595			14,505
Cash dividends on common stock						(334,633)	
Balance, December 31, 2001		297,636,276	29,764	6,113,260	(169,003)	1,521,805	(97,227)
Net income	$629,280					629,280	
Minimum liability for unfunded retirement benefits, net of $(316,681,000) of income taxes	(449,615)				(449,615)		
Unrealized gain on derivative hedges, net of $37,458,000 of income taxes	59,187				59,187		
Unrealized loss on investments, net of $(8,721,000) of income taxes	(12,357)				(12,357)		
Unrealized currency translation adjustments	(91,448)				(91,448)		
Comprehensive income	$135,047						
Stock options exercised				(8,169)			
Allocation of ESOP shares				15,250			18,950
Cash dividends on common stock						(439,628)	
Balance, December 31, 2002		297,636,276	$29,764	$6,120,341	$(663,236)	$1,711,457	$ (78,277)

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

CONSOLIDATED STATEMENTS OF PREFERRED STOCK

(Dollars in thousands)

	Not Subject to Mandatory Redemption		Subject to Mandatory Redemption	
	Number of Shares	Par or Stated Value	Number of Shares	Par or Stated Value
Balance, January 1, 2000	12,324,699	$648,395	5,269,680	$294,710
Redemptions-				
8 45% Series			(50,000)	(5,000)
$7 35 Series C			(10,000)	(1,000)
$88 00 Series E			(3,000)	(3,000)
$91 50 Series Q			(10,714)	(10,714)
$90 00 Series S			(18,750)	(18,750)
Amortization of fair market value adjustments-				
$7 35 Series C				(69)
$88 00 Series R				(3,872)
$90 00 Series S				(5,734)
Balance, December 31, 2000	12,324,699	648,395	5,177,216	246,571
GPU acquisition	125,000	12,649	13,515,001	365,151
Issues-				
9 00% Series			4,000,000	100,000
Redemptions-				
8 45% Series			(50,000)	(5,000)
$7 35 Series C			(10,000)	(1,000)
$88 00 Series R			(50,000)	(50,000)
$91 50 Series Q			(10,716)	(10,716)
$90 00 Series S			(18,750)	(18,750)
Amortization of fair market value adjustments-				
$7 35 Series C				(11)
$88 00 Series R				(1,128)
$90 00 Series S				(668)
Balance, December 31, 2001	12,449,699	661,044	22,552,751	624,449
Redemptions-				
7 75% Series	(4,000,000)	(100,000)		
$7 56 Series B	(450,000)	(45,071)		
$42 40 Series T	(200,000)	(96,850)		
$8 32 Series	(100,000)	(10,000)		
$7 76 Series	(150,000)	(15,000)		
$7 80 Series	(150,000)	(15,000)		
$10 00 Series	(190,000)	(19,000)		
$2 21 Series	(1,000,000)	(25,000)		
7 625% Series			(7,500)	(750)
$7 35 Series C			(10,000)	(1,000)
$90 00 Series S			(17,750)	(17,010)
8 65% Series J			(250,001)	(26,750)
7 52% Series K			(265,000)	(28,951)
9 00% Series			(4,800,000)	(120,000)
Amortization of fair market value adjustments-				
$7 35 Series C				(9)
$90 00 Series S				(258)
8 56% Series				(6)
7 35% Series				209
7 34% Series				214
Balance, December 31, 2002	6,209,699	$335,123	17,202,500	$430,138

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

For the Years Ended December 31,	2002	2001	2000
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	**$ 629,280**	$ 646,447	$ 598,970
Adjustments to reconcile net income to net cash from operating activities:			
Provision for depreciation and amortization	**1,105,904**	889,550	933,684
Nuclear fuel and lease amortization	**80,507**	98,178	113,330
Other amortization, net (Note 2)	**(16,593)**	(11,927)	(11,635)
Deferred costs recoverable as regulatory assets	**(362,956)**	(31,893)	—
Avon investment impairment (Note 3)	**50,000**	—	—
Deferred income taxes, net	**91,032**	31,625	(79,429)
Investment tax credits, net	**(27,071)**	(22,545)	(30,732)
Cumulative effect of accounting change	**43,521**	14,338	—
Receivables	**(78,378)**	53,099	(150,520)
Materials and supplies	**(29,557)**	(50,052)	(29,653)
Accounts payable	**214,084**	(84,572)	118,282
Other (Note 9)	**215,514**	(250,564)	45,529
Net cash provided from operating activities	**1,915,287**	1,281,684	1,507,826
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Preferred stock	—	96,739	—
Long-term debt	**668,676**	4,338,080	307,512
Short-term borrowings, net	**478,520**	—	281,946
Redemptions and Repayments-			
Common stock	—	(15,308)	(195,002)
Preferred stock	**(522,223)**	(85,466)	(38,464)
Long-term debt	**(1,308,814)**	(394,017)	(901,764)
Short-term borrowings, net	—	(1,641,484)	—
Common Stock Dividend Payments	**(439,628)**	(334,633)	(334,220)
Net cash provided from (used for) financing activities	**(1,123,469)**	1,963,911	(879,992)
CASH FLOWS FROM INVESTING ACTIVITIES:			
GPU acquisition, net of cash	—	(2,013,218)	—
Property additions	**(997,723)**	(852,449)	(587,618)
Proceeds from sale of Midlands	**155,034**	—	—
Avon cash and cash equivalents (Note 3)	**31,326**	—	—
Net assets held for sale	**(31,326)**	—	—
Cash investments (Note 2)	**81,349**	24,518	17,449
Other (Note 9)	**(54,355)**	(233,526)	(120,195)
Net cash provided from (used for) investing activities	**(815,695)**	(3,074,675)	(690,364)
Net increase (decrease) in cash and cash equivalents	**(23,877)**	170,920	(62,530)
Cash and cash equivalents at beginning of year	**220,178**	49,258	111,788
Cash and cash equivalents at end of year*	**$ 196,301**	$ 220,178	$ 49,258
SUPPLEMENTAL CASH FLOWS INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	**$ 881,515**	$ 425,737	$ 485,374
Income taxes	**$ 389,180**	$ 433,640	$ 512,182

** 2001 excludes amounts in "Assets Pending Sale" on the Consolidated Balance Sheet as of December 31, 2001.*

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

CONSOLIDATED STATEMENTS OF TAXES

(In thousands)

For the Years Ended December 31,	2002	2001	2000
GENERAL TAXES			
Real and personal property	**$ 218,683**	$ 176,916	$ 281,374
State gross receipts*	**132,622**	102,335	221,385
Kilowatt-hour excise*	**219,970**	117,979	—
Social security and unemployment	**46,345**	44,480	39,134
Other	**32,709**	13,630	5,788
Total general taxes	**$ 650,329**	$ 455,340	$ 547,681
PROVISION FOR INCOME TAXES			
Currently payable-			
Federal	**$ 332,253**	$ 375,108	$ 467,045
State	**103,886**	84,322	19,918
Foreign	**20,624**	108	—
	456,763	459,538	486,963
Deferred, net-			
Federal	**99,297**	37,888	(60,831)
State	**20,487**	(6,177)	(18,598)
Foreign	**13,600**	(86)	—
	133,384	31,625	(79,429)
Investment tax credit amortization	**(27,071)**	(22,545)	(30,732)
Total provision for income taxes	**$ 563,076**	$ 468,618	$ 376,802
RECONCILIATION OF FEDERAL INCOME TAX EXPENSE AT STATUTORY RATE TO TOTAL PROVISION FOR INCOME TAXES			
Book income before provision for income taxes	**$1,192,356**	$1,115,065	$ 975,772
Federal income tax expense at statutory rate	**$ 417,325**	$ 390,273	$ 341,520
Increases (reductions) in taxes resulting from-			
Amortization of investment tax credits	**(27,071)**	(22,545)	(30,732)
State income taxes, net of federal income tax benefit	**80,842**	50,794	1,133
Amortization of tax regulatory assets	**27,455**	30,419	38,702
Amortization of goodwill	**—**	18,416	18,420
Preferred stock dividends	**13,634**	19,733	18,172
Valuation reserve for foreign tax benefits	**31,087**	—	—
Other, net	**19,804**	(18,472)	(10,413)
Total provision for income taxes	**$ 563,076**	$ 468,618	$ 376,802
ACCUMULATED DEFERRED INCOME TAXES AT DECEMBER 31			
Property basis differences	**$2,052,594**	$1,996,937	$1,245,297
Customer receivables for future income taxes	**144,073**	178,683	62,527
Competitive transition charge	**1,234,491**	1,289,438	1,070,161
Deferred sale and leaseback costs	**(99,647)**	(77,099)	(128,298)
Nonutility generation costs	**(228,476)**	(178,393)	—
Unamortized investment tax credits	**(78,227)**	(86,256)	(85,641)
Unused alternative minimum tax credits	**—**	—	(32,215)
Other comprehensive income	**(240,663)**	(115,395)	—
Other (Notes 2 and 9)	**(416,148)**	(323,696)	(37,724)
Net deferred income tax liability**	**$2,367,997**	$2,684,219	$2,094,107

*Collected from customers through regulated rates and included in revenue on the Consolidated Statements of Income

**2001 excludes amounts in "Liabilities Related to Assets Pending Sale" on the Consolidated Balance Sheet as of December 31, 2001

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. General:

The consolidated financial statements include FirstEnergy Corp., a public utility holding company, and its principal electric utility operating subsidiaries, Ohio Edison Company (OE), The Cleveland Electric Illuminating Company (CEI), Pennsylvania Power Company (Penn), The Toledo Edison Company (TE), American Transmission Systems, Inc. (ATSI), Jersey Central Power & Light Company (JCP&L), Metropolitan Edison Company (Met-Ed) and Pennsylvania Electric Company (Penelec). ATSI owns and operates FirstEnergy's transmission facilities within the service areas of OE, CEI and TE (Ohio Companies) and Penn. The utility subsidiaries are referred to throughout as "Companies." FirstEnergy's 2001 results include the results of JCP&L, Met-Ed and Penelec from the period they were acquired on November 7, 2001 through December 31, 2001. The consolidated financial statements also include FirstEnergy's other principal subsidiaries: FirstEnergy Solutions Corp. (FES); FirstEnergy Facilities Services Group, LLC (FSG); MYR Group, Inc.; MARBEL Energy Corporation; FirstEnergy Nuclear Operating Company (FENOC); GPU Capital, Inc.; GPU Power, Inc.; FirstEnergy Service Company (FECO); and GPU Service, Inc. (GPUS). FES provides energy-related products and services and, through its FirstEnergy Generation Corp. (FGCO) subsidiary, operates FirstEnergy's nonnuclear generation business. FENOC operates the Companies' nuclear generating facilities. FSG is the parent company of several heating, ventilating, air conditioning and energy management companies, and MYR is a utility infrastructure construction service company. MARBEL is a fully integrated natural gas company. GPU Capital owns and operates electric distribution systems in foreign countries and GPU Power owns and operates generation facilities in foreign countries. FECO and GPUS provide legal, financial and other corporate support services to affiliated FirstEnergy companies. Significant intercompany transactions have been eliminated in consolidation.

The Companies follow the accounting policies and practices prescribed by the Securities and Exchange Commission (SEC), the Public Utilities Commission of Ohio (PUCO), the Pennsylvania Public Utility Commission (PPUC), the New Jersey Board of Public Utilities (NJBPU) and the Federal Energy Regulatory Commission (FERC). The preparation of financial statements in conformity with accounting principles generally accepted in the United States (GAAP) requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates. Certain prior year amounts have been reclassified to conform with the current year presentation, as described further in Notes 8 and 9.

2. Summary of Significant Accounting Policies:

(A) Consolidation-

FirstEnergy consolidates all majority-owned subsidiaries, after eliminating the effects of intercompany transactions. Non-majority owned investments, including investments in limited liability companies, partnerships and joint ventures, are accounted for under the equity method when FirstEnergy is able to influence their financial or operating policies. Investments in corporations resulting in voting control of 20% or more are presumed to be equity method investments. Limited partnerships are evaluated in accordance with SEC Staff Guidance D-46, "Accounting for Limited Partnership Investments" and American Institute of Certified Public Accountants (AICPA) Statement of Position (SOP) 78-9, "Accounting for Investments in Real Estate Ventures," which specify a 3 to 5 percent threshold for the presumption of influence. For all remaining investments (excluding those within the scope of Statement of Financial Accounting Standards (SFAS) 115, FirstEnergy applies the cost method.

(B) Earnings Per Share-

Basic earnings per share are computed using the weighted average of actual common shares outstanding as the denominator. Diluted earnings per share reflect the weighted average of actual common shares outstanding plus the potential additional common shares that could result if dilutive securities and agreements were exercised in the denominator. In 2002, 2001 and 2000, stock based awards to purchase shares of common stock totaling 3.4 million, 0.1 million and 1.8 million, respectively, were excluded from the calculation of diluted earnings per share of common stock because their exercise prices were greater than the average market price of common shares during the period. The numerators for the calculations of basic and diluted earnings per share are Income Before Cumulative Effect of Changes in Accounting and Net Income. The following table reconciles the denominators for basic and diluted earnings per share:

Denominator for Earnings per Share Calculations

	Years Ended December 31,		
	2002	2001	2000
	(In thousands)		
Denominator for basic earnings per share (weighted average shares actually outstanding)	293,194	229,512	222,444
Assumed exercise of dilutive securities or agreements to issue common stock	1,227	918	282
Denominator for diluted earnings per share	294,421	230,430	222,726

(C) Revenues-

The Companies' principal business is providing electric service to customers in Ohio, Pennsylvania and New Jersey. The Companies' retail customers are metered on a cycle basis. Revenue is recognized for unbilled electric service provided through the end of the year. See Note 9 – Other Information for discussion of reporting of Independent System Operator (ISO) transactions.

Receivables from customers include sales to residential, commercial and industrial customers and sales to wholesale customers. There was no material concentration of receivables as of December 31, 2002 or 2001, with respect to any particular segment of FirstEnergy's customers.

CEI and TE sell substantially all of their retail customers' receivables to Centerior Funding Corporation (CFC), a wholly owned subsidiary of CEI. CFC subsequently transfers the receivables to a trust (an SFAS 140 "qualified special purpose entity") under an asset-backed securitization agreement. Transfers are made in return for an interest in the trust (41% as of December 31, 2002), which is stated at fair value, reflecting adjustments for anticipated credit losses. The average collection period for billed receivables is 28 days. Given the short collection period after billing, the fair value of CFC's interest in the trust approximates the stated value of its retained interest in underlying receivables after adjusting for anticipated credit losses. Accordingly, subsequent measurements of the retained interest under SFAS 115 (as an available-for-sale financial instrument) result in no material change in value. Sensitivity analyses reflecting 10% and 20% increases in the rate of anticipated credit losses would not have significantly affected FirstEnergy's retained interest in the pool of receivables through the trust. Of the $272 million sold to the trust and outstanding as of December 31, 2002, FirstEnergy's retained interests in $111 million of the receivables are included as other receivables on the Consolidated Balance Sheets Accordingly, receivables recorded on the Consolidated Balance Sheets were reduced by approximately $161 million due to these sales Collections of receivables previously transferred to the trust and used for the purchase of new receivables from CFC during 2002 totaled approximately $2 2 billion CEI and TE processed receivables for the trust and received servicing fees of approximately $3 8 million in 2002. Expenses associated with the factoring discount related to the sale of receivables were $4.7 million in 2002.

In June 2002, the Emerging Issues Task Force (EITF) reached a partial consensus on Issue No. 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities " Based on the EITF's partial consensus position, for periods after July 15, 2002, mark-to-market revenues and expenses and their related kilowatt-hour (KWH) sales and purchases on energy trading contracts must be shown on a net basis in the Consolidated Statements of Income FirstEnergy has previously reported such contracts as gross revenues and purchased power costs. Comparative quarterly disclosures and the Consolidated Statements of Income for revenues and expenses have been reclassified for 2002 only to conform with the revised presentation (see Note 11 – Summary of Quarterly Financial Data). In addition, the related KWH sales and purchases statistics described under Management's Discussion and Analysis – Results of Operations were reclassified (7.2 billion KWH in 2002 and 3 7 billion KWH in 2001). The following table displays the impact of changing to a net presentation of FirstEnergy's energy trading operations

2002 Impact of Recording Energy Trading Net

	Revenues	Expenses
	(In millions)	
Total before adjustments	$12,420	$10,238
Adjustments	(268)	(268)
Total as reported	$12,152	$ 9,970

(D) Regulatory Matters-

In Ohio, New Jersey and Pennsylvania, laws applicable to electric industry deregulation included similar provisions which are reflected in the Companies' respective state regulatory plans

- allowing the Companies' electric customers to select their generation suppliers;
- establishing provider of last resort (PLR) obligations to customers in the Companies' service areas,
- allowing recovery of potentially stranded investment (or transition costs),
- itemizing (unbundling) the price of electricity into its component elements - including generation, transmission, distribution and stranded costs recovery charges;
- deregulating the Companies' electric generation businesses, and
- continuing regulation of the Companies' transmission and distribution systems.

Ohio

In July 1999, Ohio's electric utility restructuring legislation, which allowed Ohio electric customers to select their generation suppliers beginning January 1, 2001, was signed into law Among other things, the legislation provided for a 5% reduction on the generation portion of residential customers' bills and the opportunity to recover transition costs, including regulatory assets, from January 1, 2001 through December 31, 2005 (market development period). The period for the recovery of regulatory assets only can be extended up to December 31, 2010 The PUCO was authorized to determine the level of transition cost recovery, as well as the recovery period for the regulatory assets portion of those costs, in considering each Ohio electric utility's transition plan application.

In July 2000, the PUCO approved FirstEnergy's transition plan for the Ohio Companies as modified by a settlement agreement with major parties to the transition plan The application of SFAS 71, "Accounting for the Effects of Certain Types of Regulation" to OE's generation business and the nonnuclear generation businesses of CEI and TE was discontinued with the issuance of the PUCO transition plan order, as described further below. Major provisions of the settlement agreement consisted of approval of recovery of generation-related transition costs as filed of $4 0 billion net of deferred income taxes (OE -$1 6 billion, CEI- $1 6 billion and TE-$0 8 billion) and transition costs related to regulatory assets as filed of $2 9 billion net of deferred income taxes (OE-$1 0 billion, CEI-$1.4 billion and TE-$0 5 billion), with recovery through no later than 2006 for OE, mid-2007 for TE and 2008 for CEI, except where a longer period of recovery is provided for in the settlement agreement. The generation-related transition costs include $1 4 billion, net of deferred income taxes, (OE-$1.0 billion, CEI-$0 2 billion and TE-$0 2 billion) of impaired generating assets recognized as regulatory assets as described further below, $2 4 billion, net of deferred income taxes, (OE-$1 2 billion, CEI-$0 4 billion and TE-$0 8 billion) of above market operating lease costs and $0 8 billion (CEI-$0.5 billion and TE-$0 3 billion) of additional plant costs that were reflected on CEI's and TE's regulatory financial statements

Also as part of the settlement agreement, FirstEnergy is giving preferred access over its subsidiaries to nonaffiliated marketers, brokers and aggregators to 1,120 megawatts (MW) of generation capacity through 2005 at established prices for sales to the Ohio Companies' retail customers Customer prices are frozen through the five-year market development period except for certain limited statutory exceptions, including the 5% reduction referred to above In February 2003, the Ohio Companies were authorized increases in annual revenues aggregating approximately $50 million (OE-$41 million, CEI-$4 million and TE-$5 million) to recover their higher tax costs resulting from the Ohio deregulation legislation

FirstEnergy's Ohio customers choosing alternative suppliers receive an additional incentive applied to the shopping credit (generation component) of 45% for residential customers, 30% for commercial customers and 15% for industrial customers The amount of the incentive is deferred for future recovery from customers - recovery will be accomplished by extending the respective transition cost recovery period If the customer shopping goals established in the agreement had not been achieved by the end of 2005, the transition cost recovery periods could have been shortened for OE, CEI and TE to reduce recovery by as much as $500 million (OE - $250 million, CEI - $170 million and TE - $80 million). The Ohio Companies achieved all of their required 20% customer shopping goals in 2002. Accordingly, FirstEnergy believes that there will be no regulatory action reducing the recoverable transition costs

New Jersey

JCP&L's 2001 Final Decision and Order (Final Order) with respect to its rate unbundling, stranded cost and restructuring filings confirmed rate reductions set forth in its 1999 Summary Order, which remain in effect at increasing levels through July 2003. The Final Order also confirmed the establishment of a non-bypassable societal benefits charge (SBC) to recover costs which include nuclear plant decommissioning and manufactured gas plant remediation, as well as a non-bypassable market transition charge (MTC) primarily to recover stranded costs. The NJBPU has deferred making a final determination of the net proceeds and stranded costs related to prior generating asset divestitures until JCP&L's request for an Internal Revenue Service (IRS) ruling regarding the treatment of associated federal income tax benefits is acted upon. Should the IRS ruling support the return of the tax benefits to customers, there would be no effect to FirstEnergy's or JCP&L's net income since the contingency existed prior to the merger.

In addition, the Final Order provided for the ability to securitize stranded costs associated with the divested Oyster Creek Nuclear Generating Station. In February 2002, JCP&L received NJBPU authorization to issue $320 million of transition bonds to securitize the recovery of these costs. The NJBPU order also provided for a usage-based non-bypassable transition bond charge and for the transfer of the bondable transition property to another entity. JCP&L sold $320 million of transition bonds through its wholly owned subsidiary, JCP&L Transition Funding LLC, in June 2002 – those bonds are recognized on the Consolidated Balance Sheet (see Note 5H).

JCP&L's PLR obligation to provide basic generation service (BGS) to non-shopping customers is supplied almost entirely from contracted and open market purchases. JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers and costs incurred under nonutility generation (NUG) agreements exceed amounts collected through BGS and MTC rates. As of December 31, 2002, the accumulated deferred cost balance totaled approximately $549 million. The NJBPU also allowed securitization of JCP&L's deferred balance to the extent permitted by law upon application by JCP&L and a determination by the NJBPU that the conditions of the New Jersey restructuring legislation are met. There can be no assurance as to the extent, if any, that the NJBPU will permit such securitization.

Under New Jersey transition legislation, all electric distribution companies were required to file rate cases to determine the level of unbundled rate components to become effective August 1, 2003. On August 1, 2002, JCP&L submitted two rate filings with the NJBPU. The first filing requested increases in base electric rates of approximately $98 million annually. The second filing was a request to recover deferred costs that exceeded amounts being recovered under the current MTC and SBC rates; one proposed method of recovery of these costs is the securitization of the deferred balance. This securitization methodology is similar to the Oyster Creek securitization discussed above. Hearings began in February 2003. The Administrative Law Judge's recommended decision is due in June 2003 and the NJBPU's subsequent decision is due in July 2003.

In December 2001, the NJBPU authorized the auctioning of BGS for the period from August 1, 2002 through July 31, 2003 to meet the electricity demands of all customers who have not selected an alternative supplier. The auction results were approved by the NJBPU in February 2002, removing JCP&L's BGS obligation of 5,100 MW for the period August 1, 2002 through July 31, 2003. In February 2003, NJBPU approved the BGS auction results for the period beginning August 1, 2003. The auction covered a fixed price bid (applicable to all residential and smaller commercial and industrial customers) and an hourly price bid (applicable to all large industrial customers) process. JCP&L will sell all self-supplied energy (NUGs and owned generation) to the wholesale market with offsets to its deferred energy cost balances.

Pennsylvania

The PPUC authorized 1998 rate restructuring plans for Penn, Met-Ed and Penelec. In 2000, the PPUC disallowed a portion of the requested additional stranded costs above those amounts granted in Met-Ed's and Penelec's 1998 rate restructuring plan orders. The PPUC required Met-Ed and Penelec to seek an IRS ruling regarding the return of certain unamortized investment tax credits and excess deferred income tax benefits to customers. Similar to JCP&L's situation, if the IRS ruling ultimately supports returning these tax benefits to customers, there would be no effect to FirstEnergy's, Met-Ed's or Penelec's net income since the contingency existed prior to the merger.

As a result of their generating asset divestitures, Met-Ed and Penelec obtained their supply of electricity to meet their PLR obligations almost entirely from contracted and open market purchases. In 2000, Met-Ed and Penelec filed a petition with the PPUC seeking permission to defer, for future recovery, energy costs in excess of amounts reflected in their capped generation rates; the PPUC subsequently consolidated this petition in January 2001 with the FirstEnergy/GPU merger proceeding.

In June 2001, the PPUC entered orders approving the Settlement Stipulation with all of the major parties in the combined merger and rate relief proceedings which approved the merger and provided Met-Ed and Penelec PLR deferred accounting treatment for energy costs. The PPUC permitted Met-Ed and Penelec to defer for future recovery the difference between their actual energy costs and those reflected in their capped generation rates, retroactive to January 1, 2001. Correspondingly, in the event that energy costs incurred by Met-Ed and Penelec would be below their respective capped generation rates, that difference would have reduced costs that had been deferred for recovery in future periods. This PLR deferral accounting procedure was denied in a court decision discussed below. Met-Ed's and Penelec's PLR obligations extend through December 31, 2010; during that period competitive transition charge (CTC) revenues would have been applied to their stranded costs. Met-Ed and Penelec would have been permitted to recover any remaining stranded costs through a continuation of the CTC after December 31, 2010 through no later than December 31, 2015. Any amounts not expected to be recovered by December 31, 2015 would have been written off at the time such nonrecovery became probable.

Several parties had filed Petitions for Review in June and July 2001 with the Commonwealth Court of Pennsylvania regarding the June 2001 PPUC orders. On February 21, 2002, the Court affirmed the PPUC decision regarding the FirstEnergy/ GPU merger, remanding the decision to the PPUC only with respect to the issue of merger savings. The Court reversed the PPUC's decision regarding the PLR obligations of Met-Ed and Penelec, and rejected those parts of the settlement that permitted the companies to defer for accounting purposes the difference between their wholesale power costs and the amount that they collect from retail customers. FirstEnergy and the PPUC each filed a Petition for Allowance of Appeal with the Pennsylvania Supreme Court on March 25, 2002, asking it to review the Commonwealth Court decision. Also on March 25, 2002, Citizens Power filed a motion seeking an appeal of the Commonwealth Court's decision to affirm the FirstEnergy and GPU merger with the Pennsylvania Supreme Court. In September

2002, FirstEnergy established reserves for Met-Ed's and Penelec's PLR deferred energy costs which aggregated $287 1 million The reserves reflected the potential adverse impact of a pending Pennsylvania Supreme Court decision whether to review the Commonwealth Court ruling FirstEnergy recorded an aggregate non-cash charge of $55.8 million ($32 6 million net of tax) to income for the deferred costs incurred subsequent to the merger The reserve for the remaining $231.3 million of deferred costs increased goodwill by an aggregate net of tax amount of $135 3 million.

On January 17, 2003, the Pennsylvania Supreme Court denied further appeals of the February 21, 2002 Pennsylvania Commonwealth Court decision, which effectively affirmed the PPUC's order approving the merger between FirstEnergy and GPU, let stand the Commonwealth Court's denial of PLR rate relief for Met-Ed and Penelec and remanded the merger savings issue back to the PPUC Because FirstEnergy had already reserved for the deferred energy costs and FES has largely hedged the anticipated PLR energy supply requirements for Met-Ed and Penelec through 2005 as discussed further below, FirstEnergy, Met-Ed and Penelec believe that the disallowance of CTC recovery of PLR costs above Met-Ed's and Penelec's capped generation rates will not have a future adverse financial impact

Effective September 1, 2002, Met-Ed and Penelec assigned their PLR responsibility to their FES affiliate through a wholesale power sale agreement The PLR sale, which initially ran through the end of 2002, was extended through December 2003 and will be automatically extended for each successive calendar year unless any party elects to cancel the agreement by November 1 of the preceding year Under the terms of the wholesale agreement, FES assumes the supply obligation and the energy supply profit and loss risk, for the portion of power supply requirements not self-supplied by Met-Ed and Penelec under their NUG contracts and other existing power contracts with nonaffiliated third party suppliers This arrangement reduces Met-Ed's and Penelec's exposure to high wholesale power prices by providing power at or below the shopping credit for their uncommitted PLR energy costs during the term of the agreement with FES FES has hedged most of Met-Ed's and Penelec's unfilled PLR obligation through 2005, the period during which deferred accounting was previously allowed under the PPUC's order Met-Ed and Penelec are authorized to continue deferring differences between NUG contract costs and amounts recovered through their capped generation rates

The application of SFAS 71 has been discontinued with respect to the Companies' generation operations The SEC issued interpretive guidance regarding asset impairment measurement, concluding that any supplemental regulated cash flows such as a CTC should be excluded from the cash flows of assets in a portion of the business not subject to regulatory accounting practices If those assets are impaired, a regulatory asset should be established if the costs are recoverable through regulatory cash flows Consistent with the SEC guidance, $1 8 billion of impaired plant investments ($1 2 billion, $227 million, $304 million and $53 million for OE, Penn, CEI and TE, respectively) were recognized as regulatory assets recoverable as transition costs through future regulatory cash flows The following summarizes net assets included in property, plant and equipment relating to operations for which the application of SFAS 71 was discontinued, compared with the respective company's total assets as of December 31, 2002.

	SFAS 71 Discontinued Net Assets	Total Assets
	(In millions)	
OE	$ 947	$7,160
CEI	1,406	5,935
TE	559	2,617
Penn	82	908
JCP&L	44	8,053
Met-Ed	17	3,565
Penelec	—	3,163

(E) Property, Plant and Equipment

Property, plant and equipment reflects original cost (except for nuclear generating units and the international properties which were adjusted to fair value), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs JCP&L holds a 50% ownership interest in Yards Creek Pumped Storage Facility – its net book value was approximately $21.3 million as of December 31, 2002 FirstEnergy also shares ownership interests in various foreign properties with an aggregate net book value of $154 million, representing the fair value of FirstEnergy's interest FirstEnergy's accounting policy for planned major maintenance projects is to recognize liabilities as they are incurred

The Companies provide for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service The respective annual composite rates for the Companies' electric plant in 2002, 2001 and 2000 (post merger periods only for JCP&L, Met-Ed and Penelec) are shown in the following table:

Annual Composite Depreciation Rate	2002	2001	2000
OE	2.7%	2 7%	2 8%
CEI	3 4	3 2	3 4
TE	3 9	3 5	3 4
Penn	2.9	2 9	2 6
JCP&L	3 5	3 4	
Met-Ed	3 0	3 0	
Penelec	3.0	2 9	

Annual depreciation expense in 2002 included approximately $125 million for future decommissioning costs applicable to the Companies' ownership and leasehold interests in five nuclear generating units (Davis-Besse Unit 1, Beaver Valley Units 1 and 2, Perry Unit 1 and Three Mile Island Unit 2 (TMI-2)), a demonstration nuclear reactor (Saxton Nuclear Experimental Facility) owned by a wholly-owned subsidiary of JCP&L, Met-Ed and Penelec, and decommissioning liabilities for previously divested GPU nuclear generating units The Companies' share of the future obligation to decommission these units is approximately $2 6 billion in current dollars and (using a 4 0% escalation rate) approximately $5.3 billion in future dollars The estimated obligation and the escalation rate were developed based on site specific studies Decommissioning of the demonstration nuclear reactor is expected to be completed in 2003, payments for decommissioning of the nuclear generating units are expected to begin in 2014, when actual decommissioning work is expected to begin The Companies have recovered approximately $671 million for decommissioning through their electric rates from customers through December 31, 2002 The Companies have also recognized an estimated liability of approximately $37 million related to decontamination and decommissioning of nuclear enrichment facilities operated by the United States Department of Energy, as required by the Energy Policy Act of 1992

In June 2001, the FASB issued SFAS 143, "Accounting for Asset Retirement Obligations". The new statement provides accounting standards for retirement obligations associated with tangible long-lived assets, with adoption required by January 1, 2003. SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recorded in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Over time the capitalized costs are depreciated and the present value of the asset retirement liability increases, resulting in a period expense. However, rate-regulated entities may recognize a regulatory asset or liability if the criteria for such treatment are met. Upon retirement, a gain or loss would be recorded if the cost to settle the retirement obligation differs from the carrying amount.

FirstEnergy has identified applicable legal obligations as defined under the new standard, principally for nuclear power plant decommissioning. Upon adoption of SFAS 143, asset retirement costs of $807 million were recorded as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $437 million. Due to the increased carrying amount, the related long-lived assets were tested for impairment in accordance with SFAS 144, "Accounting for Impairment or Disposal of Long-Lived Assets". No impairment was indicated.

The asset retirement liability at the date of adoption will be $1.109 billion. As of December 31, 2002, FirstEnergy had recorded decommissioning liabilities of $1.232 billion, including unrealized gains on decommissioning trust funds of $12 million. The change in the estimated liabilities resulted from changes in methodology and various assumptions, including changes in the projected dates for decommissioning.

Management expects that the ultimate nuclear decommissioning costs for Met-Ed, Penelec, JCP&L and Penn will be tracked and recovered through their regulated rates. Therefore, FirstEnergy recognized a regulatory liability of $185 million upon adoption of SFAS 143 for the transition amounts related to establishing the asset retirement obligations for nuclear decommissioning for those companies. The remaining cumulative effect adjustment to recognize the undepreciated asset retirement cost and the asset retirement liability offset by the reversal of the previously recorded decommissioning liabilities was a $298 million increase to income, or $174 million net of tax. The $12 million of unrealized gains, $7 million net of tax, included in the decommissioning liability balances as of December 31, 2002, was offset against other comprehensive income (OCI) upon adoption of SFAS 143.

The FASB approved SFAS 141, "Business Combinations" and SFAS 142, "Goodwill and Other Intangible Assets," on June 29, 2001. SFAS 141 requires all business combinations initiated after June 30, 2001, to be accounted for using purchase accounting. The provisions of the new standard relating to the determination of goodwill and other intangible assets have been applied to the GPU merger, which was accounted for as a purchase transaction, and have not materially affected the accounting for this transaction. Under SFAS 142, amortization of existing goodwill ceased January 1, 2002. Instead, goodwill is tested for impairment at least on an annual basis - based on the results of the transition analysis and the 2002 annual analysis, no impairment of FirstEnergy's goodwill is required. The impairment analysis includes a significant source of cash representing EUOC recovery of transition costs as described above under "Regulatory Matters." FirstEnergy does not believe that completion of transition cost recovery will result in an impairment of goodwill relating to its regulated business segment. Prior to the adoption of SFAS 142, FirstEnergy amortized about $57 million ($.23 per share of common stock) of goodwill annually. There was no goodwill amortization in 2001 associated with the GPU merger under the provisions of the new standard.

The following table displays what net income and earnings per share would have been if goodwill amortization had been excluded in 2001 and 2000:

	2002	2001	2000
	(In thousands, except per share amounts)		
Reported net income	$629,280	$646,447	$598,970
Goodwill amortization (net of tax)	—	54,584	54,138
Adjusted net income	$629,280	$701,031	$653,108
Basic earnings per common share:			
Reported earnings per share	$2.15	$2.82	$2.69
Goodwill amortization	—	0.23	0.25
Adjusted earnings per share	$2.15	$3.05	$2.94
Diluted earnings per common share:			
Reported earnings per share	$2.14	$2.81	$2.69
Goodwill amortization	—	0.23	0.24
Adjusted earnings per share	$2.14	$3.04	$2.93

The net change of $295 million in the goodwill balance as of December 31, 2002 compared to the December 31, 2001 balance primarily reflects the $135.3 million after-tax effect of the Pennsylvania PLR reserve discussed in Note 2D - Regulatory Matters - Pennsylvania and finalization of the initial purchase price allocation for the GPU acquisition (see Note 12).

(F) Nuclear Fuel-

Nuclear fuel is recorded at original cost, which includes material, enrichment, fabrication and interest costs incurred prior to reactor load. The Companies amortize the cost of nuclear fuel based on the rate of consumption.

(G) Stock-Based Compensation-

FirstEnergy applies the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25 (APB 25), "Accounting for Stock Issued to Employees" and related Interpretations in accounting for its stock-based compensation plans (see Note 5C). No material stock-based employee compensation expense is reflected in net income as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the grant date, resulting in substantially no intrinsic value.

If FirstEnergy had accounted for employee stock options under the fair value method, a higher value would have been assigned to the options granted. The weighted average assumptions used in valuing the options and their resulting estimated fair values would be as follows:

	2002	2001	2000
Valuation assumptions:			
Expected option term (years)	8.1	8.3	7.6
Expected volatility	23.31%	23.45%	21.77%
Expected dividend yield	4.36%	5.00%	6.68%
Risk-free interest rate	4.60%	4.67%	5.28%
Fair value per option	$6.45	$4.97	$2.86

The effects of applying fair value accounting to FirstEnergy's stock options would be to reduce net income and earnings per share The following table summarizes this effect

	2002	2001	2000
	(In thousands)		
Net Income, as reported	$629,280	$646,447	$598,970
Add back compensation expense reported in net income, net of tax (based on APB 25)	166	25	144
Deduct compensation expense based upon fair value, net of tax	(8,825)	(3,748)	(1,736)
Adjusted net income	$620,621	$642,724	$597,378
Earnings Per Share of Common Stock – Basic			
As Reported	$2 15	$2 82	$2 69
Adjusted	$2 11	$2 80	$2 69
Diluted			
As Reported	$2 14	$2 81	$2 69
Adjusted	$2 11	$2 79	$2 69

(H) Income Taxes-

Details of the total provision for income taxes are shown on the Consolidated Statements of Taxes Deferred income taxes result from timing differences in the recognition of revenues and expenses for tax and accounting purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property The liability method is used to account for deferred income taxes Deferred income tax liabilities related to tax and accounting basis differences are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Valuation allowances of $465 million were established and included in the Consolidated Balance Sheet as of December 31, 2002, primarily associated with certain fair value adjustments (see Note 12) and capital losses related to the divestitures of international assets owned by the former GPU, Inc. prior to its acquisition by FirstEnergy. Of the total valuation allowance, $325 million relates to capital loss carryforwards that expire at the end of 2007 Management is unable to predict whether sufficient capital gains will be generated to utilize all of these capital loss carryforwards. Any ultimate utilization of these capital loss carryforwards for which valuation allowances have been established would reduce goodwill

(I) Retirement Benefits-

FirstEnergy's trusteed, noncontributory defined benefit pension plan covers almost all full-time employees Upon retirement, employees receive a monthly pension based on length of service and compensation On December 31, 2001, the GPU pension plans were merged with the FirstEnergy plan FirstEnergy uses the projected unit credit method for funding purposes and was not required to make pension contributions during the three years ended December 31, 2002 The assets of the pension plan consist primarily of common stocks, United States government bonds and corporate bonds Costs for the year 2001 include the former GPU companies' pension and other postretirement benefit costs for the period November 7, 2001 through December 31, 2001.

FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and copayments, are also available to retired employees, their dependents and, under certain circumstances, their survivors FirstEnergy pays insurance premiums to cover a portion of these benefits in excess of set limits, all amounts up to the limits are paid by FirstEnergy. FirstEnergy recognizes the expected cost of providing other postretirement benefits to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits

As a result of the reduced market value of FirstEnergy's pension plan assets, it was required to recognize an additional minimum liability as prescribed by SFAS 87 and SFAS 132, "Employees' Disclosures about Pension and Postretirement Benefits," as of December 31, 2002. FirstEnergy's accumulated benefit obligation of $3 438 billion exceeded the fair value of plan assets ($2 889 billion) resulting in a minimum pension liability of $548 6 million FirstEnergy eliminated its prepaid pension asset of $286.9 million and established a minimum liability of $548 6 million, recording an intangible asset of $78 5 million and reducing OCI by $444 2 million (recording a related deferred tax asset of $312.8 million) The charge to OCI will reverse in future periods to the extent the fair value of trust assets exceed the accumulated benefit obligation The amount of pension liability recorded as of December 31, 2002, increased due to the lower discount rate and asset returns assumed as of December 31, 2002

The following sets forth the funded status of the plans and amounts recognized on the Consolidated Balance Sheets as of December 31.

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
	(In millions)			
Change in benefit obligation				
Benefit obligation as of January 1	$3,547 9	$1,506 1	$1,581 6	$ 752 0
Service cost	58 8	34 9	28 5	18 3
Interest cost	249 3	133 3	113 6	64 4
Plan amendments	—	3 6	(121 1)	—
Actuarial loss	268 0	123 1	440 4	73 3
Voluntary early retirement program	—	—	—	2 3
GPU acquisition (Note 12)	(11 8)	1,878 3	110 0	716 9
Benefits paid	(245 8)	(131 4)	(83 0)	(45 6)
Benefit obligation as of December 31	3,866 4	3,547 9	2,070 0	1,581 6
Change in fair value of plan assets				
Fair value of plan assets as of January 1	3,483 7	1,706 0	535 0	23 0
Actual return on plan assets	(348 9)	8 1	(57 1)	12 7
Company contribution	—	—	37 9	43 3
GPU acquisition	—	1,901 0	—	462 0
Benefits paid	(245 8)	(131 4)	(42 5)	(6 0)
Fair value of plan assets as of December 31	2,889 0	3,483 7	473 3	535 0
Funded status of plan	(977 4)	(64 2)	(1,596 7)	(1,046 6)
Unrecognized actuarial loss	1,185 8	222 8	751 6	212 8
Unrecognized prior service cost	78 5	87 9	(106 8)	17 7
Unrecognized net transition obligation	—	—	92 4	101 6
Net amount recognized	$ 286 9	$ 246 5	$ (859 5)	$ (714 5)
Consolidated Balance Sheets classification				
Prepaid (accrued) benefit cost	$ (548 6)	$ 246 5	$ (859 5)	$ (714 5)
Intangible asset	78 5	—	—	—
Accumulated other comprehensive loss	757 0	—	—	—
Net amount recognized	$ 286 9	$ 246 5	$ (859 5)	$ (714 5)
Assumptions as of December 31				
Discount rate	6 75%	7 25%	6 75%	7 25%
Expected long-term return on plan assets	9 00%	10 25%	9 00%	10 25%
Rate of compensation increase	3 50%	4 00%	3 50%	4 00%

Net pension and other postretirement benefit costs for the three years ended December 31, 2002 were computed as follows:

	Pension Benefits			Other Postretirement Benefits		
	2002	2001	2000	2002	2001	2000
	(In millions)					
Service cost	$ 58.8	$ 34.9	$ 27.4	$ 28.5	$18.3	$11.3
Interest cost	249.3	133.3	104.8	113.6	64.4	45.7
Expected return on plan assets	(346.1)	(204.8)	(181.0)	(51.7)	(9.9)	(0.5)
Amortization of transition obligation (asset)	—	(2.1)	(7.9)	9.2	9.2	9.2
Amortization of prior service cost	9.3	8.8	5.7	3.2	3.2	3.2
Recognized net actuarial loss (gain)	—	—	(9.1)	11.2	4.9	—
Voluntary early retirement program	—	6.1	17.2	—	2.3	—
Net periodic benefit cost (income)	$ (28.7)	$ (23.8)	$ (42.9)	$114.0	$92.4	$68.9

The composite health care cost trend rate assumption is approximately 10%-12% in 2003, 9% in 2004 and 8% in 2005, decreasing to 5% in later years. Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plan. An increase in the health care cost trend rate assumption by one percentage point would increase the total service and interest cost components by $20.7 million and the postretirement benefit obligation by $232.2 million. A decrease in the same assumption by one percentage point would decrease the total service and interest cost components by $16.7 million and the postretirement benefit obligation by $204.3 million.

(J) Supplemental Cash Flows Information-

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. As of December 31, 2002, cash and cash equivalents included $50 million used for the redemption of long-term debt in January 2003. Noncash financing and investing activities included the 2001 FirstEnergy common stock issuance of $2.6 billion for the GPU acquisition and capital lease transactions amounting to $3.1 million and $89.3 million for the years 2001 and 2000, respectively. There were no capital lease transactions in 2002. Commercial paper transactions of OES Fuel, Incorporated (a wholly owned subsidiary of OE) that had initial maturity periods of three months or less were reported net within financing activities under long-term debt, prior to the expiration of the related long-term financing agreement in March 2002, and were reflected as currently payable long-term debt on the Consolidated Balance Sheet as of December 31, 2001. Net losses on foreign currency exchange transactions reflected in FirstEnergy's 2002 Consolidated Statement of Income consisted of approximately $104.1 million from FirstEnergy's Argentina operations (see Note 3 – Divestitures).

In the Consolidated Statements of Cash Flows, the amounts included in "Cash investments" under Net cash used for Investing Activities primarily consist of changes in capital trust investments of $(87) million (see Note 4 – Leases) and other cash investments of $6 million. The amounts included in "Other amortization, net" under Net cash provided from Operating Activities primarily consist of amounts from the reduction of an electric service obligation under a CEI electric service prepayment program.

All borrowings with initial maturities of less than one year are defined as financial instruments under GAAP and are reported on the Consolidated Balance Sheets at cost, which approximates their fair market value. The following sets forth the approximate fair value and related carrying amounts of all other long-term debt, preferred stock subject to mandatory redemption and investments other than cash and cash equivalents as of December 31:

	2002		2001	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Long-term debt*	$12,465	$12,761	$12,897	$13,097
Preferred stock	$ 445	$ 454	$ 636	$ 626
Investments other than cash and cash equivalents:				
Debt securities:				
-Maturity (5-10 years)	$ 502	$ 471	$ 439	$ 402
-Maturity (more than 10 years)	927	1,030	990	1,009
Equity securities	15	15	15	15
All other	1,668	1,669	1,730	1,734
	$ 3,112	$ 3,185	$ 3,174	$ 3,160

**Excluding approximately $1.75 billion of long-term debt in 2001 related to pending divestitures.*

The fair values of long-term debt and preferred stock reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective year. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to the Companies' ratings.

The fair value of investments other than cash and cash equivalents represent cost (which approximates fair value) or the present value of the cash inflows based on the yield to maturity. The yields assumed were based on financial instruments with similar characteristics and terms. Investments other than cash and cash equivalents include decommissioning trust investments. The Companies have no securities held for trading purposes. See Note 9 – Other Information for discussion of SFAS 115 activity related to equity investments.

The investment policy for the nuclear decommissioning trust funds restricts or limits the ability to hold certain types of assets including private or direct placements, warrants, securities of FirstEnergy, investments in companies owning nuclear power plants, financial derivatives, preferred stocks, securities convertible into common stock and securities of the trust fund's custodian or managers and their parents or subsidiaries. The investments that are held in the decommissioning trusts (included as "All other" in the table above) consist of equity securities, government bonds and corporate bonds. Unrealized gains and losses applicable to the decommissioning trusts have been recognized in the trust investment with a corresponding change to the decommissioning liability. In conjunction with the adoption of SFAS 143 on January 1, 2003, unrealized gains or losses were reclassified to OCI in accordance with SFAS 115. Realized gains (losses) are recognized as additions (reductions) to trust asset balances. For the year 2002, net realized gains (losses) were approximately $(15 6) million and interest and dividend income totaled approximately $33.2 million

On January 1, 2001, FirstEnergy adopted SFAS 133, "Accounting for Derivative Instruments and Hedging Activities", as amended by SFAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities — an amendment of FASB Statement No 133." The cumulative effect to January 1, 2001 was a charge of $8 5 million (net of $5 8 million of income taxes) or $ 03 per share of common stock The reported results of operations for the year ended December 31, 2000 would not have been materially different if this accounting had been in effect during that year

FirstEnergy is exposed to financial risks resulting from the fluctuation of interest rates and commodity prices, including electricity, natural gas and coal To manage the volatility relating to these exposures, FirstEnergy uses a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps The derivatives are used principally for hedging purposes, and to a lesser extent, for trading purposes FirstEnergy's Risk Policy Committee, comprised of executive officers, exercises an independent risk oversight function to ensure compliance with corporate risk management policies and prudent risk management practices

FirstEnergy uses derivatives to hedge the risk of price and interest rate fluctuations FirstEnergy's primary ongoing hedging activity involves cash flow hedges of electricity and natural gas purchases The maximum periods over which the variability of electricity and natural gas cash flows are hedged are two and three years, respectively Gains and losses from hedges of commodity price risks are included in net income when the underlying hedged commodities are delivered Also, gains and losses are included in net income when ineffectiveness occurs on certain natural gas hedges The impact of ineffectiveness on earnings during 2002 was not material FirstEnergy entered into interest rate derivative transactions during 2001 to hedge a portion of the anticipated interest payments on debt related to the GPU acquisition Gains and losses from hedges of anticipated interest payments on acquisition debt will be included in net income over the periods that hedged interest payments are made – 5, 10 and 30 years. Gains and losses from derivative contracts are included in other operating expenses The current net deferred loss of $110 2 million included in Accumulated Other Comprehensive Loss (AOCL) as of December 31, 2002, for derivative hedging activity, as compared to the December 31, 2001 balance of $169 4 million in net deferred losses, resulted from the reversal of $6 0 million of derivative losses related to the sale of Avon, a $33 0 million reduction related to current hedging activity and a $20 2 million reduction due to net hedge gains included in earnings during the year. Approximately $19 0 million (after tax) of the current net deferred loss on derivative instruments in AOCL is expected to be reclassified to earnings during the next twelve months as hedged transactions occur However, the fair value of these derivative instruments will fluctuate from period to period based on various market factors and will generally be more than offset by the margin on related sales and revenues FirstEnergy also entered into fixed-to-floating interest rate swap agreements during 2002 to increase the variable-rate component of its debt portfolio from 16% to approximately 20% at year end These derivatives are treated as fair value hedges of fixed-rate, long-term debt issues-protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates Swap maturities, call options and interest payment dates match those of the underlying obligations resulting in no ineffectiveness in these hedge positions After reaching a maximum notional position of $993 5 million in the third quarter of 2002, FirstEnergy unwound $400 million of these swaps in the fourth quarter of 2002 during a period of steadily declining market interest rates Gains recognized from unwinding these swaps were added to the carrying value of the hedged debt and will be recognized over the remaining life of the underlying debt (through November 2006)

FirstEnergy engages in the trading of commodity derivatives and periodically experiences net open positions. FirstEnergy's risk management policies limit the exposure to market risk from open positions and require daily reporting to management of potential financial exposures

(K) Regulatory Assets-

The Companies recognize, as regulatory assets, costs which the FERC, PUCO, PPUC and NJBPU have authorized for recovery from customers in future periods Without such authorization, the costs would have been charged to income as incurred. All regulatory assets are expected to continue to be recovered from customers under the Companies' respective transition and regulatory plans Based on those plans, the Companies continue to bill and collect cost-based rates for their transmission and distribution services, which remain regulated, accordingly, it is appropriate that the Companies continue the application of SFAS 71 to those operations OE and Penn recognized additional cost recovery of $270 million in 2000 as additional regulatory asset amortization in accordance with their prior Ohio and current Pennsylvania regulatory plans. The Ohio Companies and Penn recognized incremental transition cost recovery aggregating $323 million in 2002 and $309 million in 2001, in accordance with the current Ohio transition plan and Pennsylvania regulatory plan Regulatory assets which do not earn a current return totaled approximately $475.2 million as of December 31, 2002.

Net regulatory assets on the Consolidated Balance Sheets are comprised of the following

	2002	2001
	(In millions)	
Regulatory transition charge	$7,365 3	$7,751 5
Customer receivables for future income taxes	394 0	433 0
Societal benefits charge	143 8	166 6
Loss on reacquired debt	73 7	80 0
Employee postretirement benefit costs	87 7	98 6
Nuclear decommissioning, decontamination and spent fuel disposal costs	98 8	80 2
Provider of last resort costs	—	116 2
Property losses and unrecovered plant costs	87 8	104 1
Other	71 9	82.4
Total	$8,323 0	$8,912 6

3. DIVESTITURES:

International Operations-

FirstEnergy identified certain former GPU international operations for divestiture within one year of the merger. These operations constitute individual "lines of business" as defined in APB 30, "Reporting the Results of Operations - Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions," with physically and operationally separable activities Application of EITF Issue No 87-11, "Allocation of Purchase Price to Assets to Be Sold," required that expected, pre-sale cash flows, including incremental interest costs on related acquisition debt, of these operations be considered part of the purchase price allocation Accordingly, subsequent to the merger date, results of operations and incremental interest costs related to these international subsidiaries were not included in

FirstEnergy's 2001 Consolidated Statements of Income. Additionally, assets and liabilities of these international operations were segregated under separate captions on the Consolidated Balance Sheet as of December 31, 2001 as "Assets Pending Sale" and "Liabilities Related to Assets Pending Sale."

Upon completion of its merger with GPU, FirstEnergy accepted an October 2001 offer from Aquila, Inc. (formerly UtiliCorp United) to purchase Avon Energy Partners Holdings (Avon), FirstEnergy's wholly owned holding company for Midlands Electricity plc, for $2.1 billion (including the assumption of $1.7 billion of debt). The transaction closed on May 8, 2002 and reflected the March 2002 modification of Aquila's initial offer such that Aquila acquired a 79.9 percent equity interest in Avon for approximately $1.9 billion (including the assumption of $1.7 billion of debt). Proceeds to FirstEnergy included $155 million in cash and a note receivable for approximately $87 million (representing the present value of $19 million per year to be received over six years beginning in 2003) from Aquila for its 79.9 percent interest. FirstEnergy and Aquila together own all of the outstanding shares of Avon through a jointly owned subsidiary, with each company having a 50 percent voting interest. Originally, in accordance with applicable accounting guidance, the earnings of those foreign operations were not recognized in current earnings from the date of the GPU acquisition until February 6, 2002, the date when Aquila began discussions to revise its initial offer to purchase Avon. However, the revision to the initial offer by Aquila caused a reversal of this accounting in the first quarter of 2002, resulting in the recognition of a cumulative effect of a change in accounting which increased net income by $31.7 million. This resulted from the application of guidance provided by EITF Issue No. 90-6, "Accounting for Certain Events Not Addressed in Issue No. 87-11 relating to an Acquired Operating Unit to Be Sold," and accounting under EITF Issue No. 87-11, recognizing the net income of Avon from November 7, 2001 to February 6, 2002 that previously was not recognized by FirstEnergy in its consolidated earnings as discussed above. In the fourth quarter of 2002, FirstEnergy recorded a $50 million charge ($32.5 million net of tax) to reduce the carrying value of its remaining 20.1 percent interest.

GPU's former Argentina operations were also identified by FirstEnergy for divestiture within one year of the merger. FirstEnergy determined the fair value of its Argentina operations, GPU Empresa Distribuidora Electrica Regional S.A. and affiliates (Emdersa), based on the best available information as of the date of the merger. Subsequent to that date, a number of economic events have occurred in Argentina which may have an impact on FirstEnergy's ability to realize Emdersa's estimated fair value. These events include currency devaluation, restrictions on repatriation of cash, and the anticipation of future asset sales in that region by competitors. FirstEnergy did not reach a definitive agreement to sell Emdersa as of December 31, 2002. Therefore, these assets were no longer classified as "Assets Pending Sale" on the Consolidated Balance Sheet as of December 31, 2002 and Emdersa's results of operations were included in FirstEnergy's 2002 Consolidated Statement of Income. As a result, under EITF Issue No. 90-6, FirstEnergy recorded in the fourth quarter a one-time, non-cash "Cumulative Effect of Accounting Change" on its 2002 Consolidated Statement of Income related to Emdersa's cumulative results of operations from November 7, 2001 through October 31, 2002. The amount of this one-time, after-tax charge was $88.8 million, or $0.30 per share of common stock (comprised of $104.1 million in currency transaction losses arising principally from U.S. dollar denominated debt, offset by $15.3 million of operating income).

On November 1, 2002, FirstEnergy began consolidating the results of Emdersa's operations in its financial statements. In addition to the currency transaction losses of $104.1 million, FirstEnergy recognized a currency translation adjustment in other comprehensive income of $91.5 million as of December 31, 2002, which reduced FirstEnergy's common stockholders' equity. This adjustment represents the impact of translating Emdersa's financial statements from its functional currency to the U.S. dollar for GAAP financial reporting.

Sale of Generating Assets-

In November 2001, FirstEnergy reached an agreement to sell four coal-fired power plants totaling 2,535 MW to NRG Energy Inc. On August 8, 2002, FirstEnergy notified NRG that it was canceling the agreement because NRG stated that it could not complete the transaction under the original terms of the agreement. FirstEnergy also notified NRG that FirstEnergy reserves the right to pursue legal action against NRG, its affiliate and its parent, Xcel Energy, for damages, based on the anticipatory breach of the agreement. On February 25, 2003, the U.S. Bankruptcy Court in Minnesota approved FirstEnergy's request for arbitration against NRG.

In December 2002, FirstEnergy decided to retain ownership of these plants after reviewing other bids it subsequently received from other parties who had expressed interest in purchasing the plants. Since FirstEnergy did not execute a sales agreement by year-end, it reflected approximately $74 million ($43 million net of tax) of previously unrecognized depreciation and other transaction costs in the fourth quarter of 2002 related to these plants from November 2001 through December 2002 on its Consolidated Statement of Income.

4. LEASES:

The Companies lease certain generating facilities, office space and other property and equipment under cancelable and noncancelable leases.

OE sold portions of its ownership interests in Perry Unit 1 and Beaver Valley Unit 2 and entered into operating leases on the portions sold for basic lease terms of approximately 29 years. CEI and TE also sold portions of their ownership interests in Beaver Valley Unit 2 and Bruce Mansfield Units 1, 2 and 3 and entered into similar operating leases for lease terms of approximately 30 years. During the terms of their respective leases, OE, CEI and TE continue to be responsible, to the extent of their individual combined ownership and leasehold interests, for costs associated with the units including construction expenditures, operation and maintenance expenses, insurance, nuclear fuel, property taxes and decommissioning. They have the right, at the expiration of the respective basic lease terms, to renew their respective leases. They also have the right to purchase the facilities at the expiration of the basic lease term or any renewal term at a price equal to the fair market value of the facilities. The basic rental payments are adjusted when applicable federal tax law changes.

OES Finance, Incorporated, a wholly owned subsidiary of OE, maintains deposits pledged as collateral to secure reimbursement obligations relating to certain letters of credit supporting OE's obligations to lessors under the Beaver Valley Unit 2 sale and leaseback arrangements. The deposits of approximately $278 million pledged to the financial institution providing those letters of credit are the sole property of OES Finance and are investments which are classified as "Held to Maturity". In the event of liquidation, OES Finance, as a separate corporate entity, would have to satisfy its obligations to creditors before any of its assets could be made available to OE as sole owner of OES Finance common stock.

Consistent with the regulatory treatment, the rentals for capital and operating leases are charged to operating expenses on the Consolidated Statements of Income. Such costs for the three years ended December 31, 2002, are summarized as follows:

	2002	2001	2000
		(In millions)	
Operating leases			
Interest element	$188.4	$194.1	$202.4
Other	135.9	120.5	111.1
Capital leases			
Interest element	2.4	8.0	12.3
Other	2.5	35.5	64.2
Total rentals	$329.2	$358.1	$390.0

The future minimum lease payments as of December 31, 2002, are:

	Capital Leases	Operating Leases: Lease Payments	Operating Leases: Capital Trusts	Operating Leases: Net
			(In millions)	
2003	$ 4.6	$ 331.9	$ 178.8	$ 153.1
2004	6.0	293.8	111.8	182.0
2005	5.4	313.4	130.3	183.1
2006	5.4	322.0	141.8	180.2
2007	1.8	299.5	130.7	168.8
Years thereafter	8.0	2,807.9	977.7	1,830.2
Total minimum lease payments	31.2	$4,368.5	$1,671.1	$2,697.4
Executory costs	7.1			
Net minimum lease payments	24.1			
Interest portion	8.3			
Present value of net minimum lease payments	15.8			
Less current portion	1.8			
Noncurrent portion	$14.0			

OE invested in the PNBV Capital Trust, which was established to purchase a portion of the lease obligation bonds issued on behalf of lessors in OE's Perry Unit 1 and Beaver Valley Unit 2 sale and leaseback transactions. CEI and TE established the Shippingport Capital Trust to purchase the lease obligation bonds issued on behalf of lessors in their Bruce Mansfield Units 1, 2 and 3 sale and leaseback transactions. The PNBV and Shippingport capital trust arrangements effectively reduce lease costs related to those transactions.

5. CAPITALIZATION:

(A) Retained Earnings-

There are no restrictions on retained earnings for payment of cash dividends on FirstEnergy's common stock.

(B) Employee Stock Ownership Plan-

An ESOP Trust funds most of the matching contribution for FirstEnergy's 401(k) savings plan. All full-time employees eligible for participation in the 401(k) savings plan are covered by the ESOP. The ESOP borrowed $200 million from OE and acquired 10,654,114 shares of OE's common stock (subsequently converted to FirstEnergy common stock) through market purchases. Dividends on ESOP shares are used to service the debt. Shares are released from the ESOP on a pro rata basis as debt service payments are made. In 2002, 2001 and 2000, 1,151,106 shares, 834,657 shares and 826,873 shares, respectively, were allocated to employees with the corresponding expense recognized based on the shares allocated method. The fair value of 3,966,269 shares unallocated as of December 31, 2002, was approximately $130.8 million. Total ESOP-related compensation expense was calculated as follows:

	2002	2001	2000
		(In millions)	
Base compensation	$34.2	$25.1	$18.7
Dividends on common stock held by the ESOP and used to service debt	(7.8)	(6.1)	(6.4)
Net expense	$26.4	$19.0	$12.3

(C) Stock Compensation Plans-

In 2001, FirstEnergy assumed responsibility for two new stock-based plans as a result of its acquisition of GPU. No further stock-based compensation can be awarded under the GPU, Inc. Stock Option and Restricted Stock Plan for MYR Group Inc. Employees (MYR Plan) or the 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries (GPU Plan). All options and restricted stock under both Plans have been converted into FirstEnergy options and restricted stock. Options under the GPU Plan became fully vested on November 7, 2001, and will expire on or before June 1, 2010. Under the MYR Plan, all options and restricted stock maintained their original vesting periods, which range from one to four years, and will expire on or before December 17, 2006.

Additional stock-based plans administered by FirstEnergy include the Centerior Equity Plan (CE Plan) and the FirstEnergy Executive and Director Incentive Compensation Plan (FE Plan). All options are fully vested under the CE Plan, and no further awards are permitted. Outstanding options will expire on or before February 25, 2007. Under the FE Plan, total awards cannot exceed 22.5 million shares of common stock or their equivalent. Only stock options and restricted stock have been granted, with vesting periods ranging from six months to seven years.

Collectively, the above plans are referred to as the FE Programs. Restricted common stock grants under the FE Programs were as follows:

	2002	2001	2000
Restricted common shares granted	36,922	133,162	208,400
Weighted average market price	$36.04	$35.68	$26.63
Weighted average vesting period (years)	3.2	3.7	3.8
Dividends restricted	Yes	*	Yes

** FE Plan dividends are paid as restricted stock on 4,500 shares, MYR Plan dividends are paid as unrestricted cash on 128,662 shares.*

Under the Executive Deferred Compensation Plan (EDCP), covered employees can direct a portion of their Annual Incentive Award and/or Long-Term Incentive Award into an unfunded FirstEnergy Stock Account to receive vested stock units. An additional 20% premium is received in the form of stock units based on the amount allocated to the FirstEnergy Stock Account. Dividends are calculated quarterly on stock units outstanding and are paid in the form of additional stock units. Upon withdrawal, stock units are converted to FirstEnergy shares. Payout typically occurs three years from the date of deferral, however, an election can be made in the year prior to payout to further defer shares into a retirement stock account that will pay out in cash upon retirement. As of December 31, 2002, there were 296,008 stock units outstanding.

See Note 9 - Other Information for discussion of stock-based employee compensation expense recognized for restricted stock and EDCP stock units.

Stock option activities under the FE Programs for the past three years were as follows:

Stock Option Activities	Number of Options	Weighted Average Exercise Price
Balance, January 1, 2000	2,153,369	$25.32
(159,755 options exercisable)		24.87
Options granted	3,011,584	23.24
Options exercised	90,491	26.00
Options forfeited	52,600	22.20
Balance, December 31, 2000	5,021,862	24.09
(473,314 options exercisable)		24.11
Options granted	4,240,273	28.11
Options exercised	694,403	24.24
Options forfeited	120,044	28.07
Balance, December 31, 2001	8,447,688	26.04
(1,828,341 options exercisable)		24.83
Options granted	3,399,579	34.48
Options exercised	1,018,852	23.56
Options forfeited	392,929	28.19
Balance, December 31, 2002	10,435,486	28.95
(1,400,206 options exercisable)		26.07

As of December 31, 2002, the weighted average remaining contractual life of outstanding stock options was 7.6 years.

No material stock-based employee compensation expense is reflected in net income for stock options granted under the above plans since the exercise price was equal to the market value of the underlying common stock on the grant date. The effect of applying fair value accounting to FirstEnergy's stock options is summarized in Note 2G – Stock-Based Compensation.

(D) Preferred and Preference Stock-

Penn's 7.75% series has a restriction which prevents early redemption prior to July 2003. All other preferred stock may be redeemed by the Companies in whole, or in part, with 30-90 days' notice.

Met-Ed's and Penelec's preferred stock authorization consists of 10 million and 11.435 million shares, respectively, without par value. No preferred shares are currently outstanding for the two companies.

The Companies' preference stock authorization consists of 8 million shares without par value for OE; 3 million shares without par value for CEI; and 5 million shares, $25 par value for TE. No preference shares are currently outstanding.

(E) Preferred Stock Subject to Mandatory Redemption-

Annual sinking fund provisions for the Companies' preferred stock are as follows:

	Series	Shares	Redemption Price Per Share
CEI	$ 7.35 C	10,000	$ 100
Penn	7.625%	7,500	100

Annual sinking fund requirements for the next five years are $1.8 million in each year 2003 through 2006 and $12.3 million in 2007.

(F) Subsidiary-Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trust or Limited Partnership Holding Solely Subordinated Debentures of Subsidiaries-

CEI formed a statutory business trust as a wholly owned financing subsidiary. The trust sold preferred securities and invested the gross proceeds in the 9.00% subordinated debentures of CEI and the sole assets of the trust are the applicable subordinated debentures. Interest payment provisions of the subordinated debentures match the distribution payment provisions of the trust's preferred securities. In addition, upon redemption or payment at maturity of subordinated debentures, the trust's preferred securities will be redeemed on a pro rata basis at their liquidation value. Under certain circumstances, the applicable subordinated debentures could be distributed to the holders of the outstanding preferred securities of the trust in the event that the trust is liquidated. CEI has effectively provided a full and unconditional guarantee of payments due on its trust's preferred securities. Its trust preferred securities are redeemable at 100% of their principal amount at CEI's option, beginning in December 2006.

Met-Ed and Penelec each formed statutory business trusts for substantially similar transactions as CEI. However, ownership of the respective Met-Ed and Penelec trusts is through separate wholly-owned limited partnerships, of which a wholly-owned subsidiary of each company is the sole general partner. In these transactions, each trust invested the gross proceeds from the sale of its trust preferred securities in the preferred securities of the applicable limited partnership, which in turn invested those proceeds in the 7.35% and 7.34% subordinated debentures of Met-Ed and Penelec, respectively. In each case, the applicable parent company has effectively provided a full and unconditional guarantee of its obligations under its trust's preferred securities. The Met-Ed and Penelec trust preferred securities are redeemable at the option of Met-Ed and Penelec beginning in May 2004 and September 2004, respectively, at 100% of their principal amount.

JCP&L formed a limited partnership for a substantially similar transaction; however, no statutory trust is involved. That limited partnership, of which JCP&L is the sole general partner, invested the gross proceeds from the sale of its monthly income preferred securities (MIPS) in JCP&L's 8.56% subordinated debentures. JCP&L has effectively provided a full and unconditional guarantee of its obligations under the limited partnership's MIPS. The limited partnership's MIPS are redeemable at JCP&L's option at 100% of their principal amount.

In each of these transactions, interest on the subordinated debentures (and therefore the distributions on trust preferred securities or MIPS) may be deferred for up to 60 months, but the parent company may not pay dividends on, or redeem or acquire, any of its cumulative preferred or common stock until deferred payments on its subordinated debentures are paid in full.

The following table lists the subsidiary trusts and limited partnership and information regarding their preferred securities outstanding as of December 31, 2002

	Maturity	Rate	Stated Value (a)	Subordinated Debentures
			(In millions)	
Cleveland Electric Financing Trust (b)	2031	9 00%	$100 0	$103 1
Met-Ed Capital Trust (c)	2039	7 35%	$100 0	$103 1
Penelec Capital Trust (c)	2039	7 34%	$100 0	$103 1
JCP&L, Capital L P (b)	2044	8 56%	$125 0	$128 9

(a) The liquidation value is $25 per security

(b) The sole assets of the trust or limited partnership are the parent company's subordinated debentures with the same rate and maturity date as the preferred securities

(c) The sole assets of the trust are the preferred securities of Met-Ed Capital II, L P and Penelec Capital II, L P, respectively, whose sole assets are the parent company's subordinated debentures with the same rate and maturity date as the preferred securities

(G) Long-Term Debt-

Each of the Companies has a first mortgage indenture under which it issues from time to time first mortgage bonds secured by a direct first mortgage lien on substantially all of its property and franchises, other than specifically excepted property FirstEnergy and its subsidiaries have various debt covenants under their respective financing arrangements The most restrictive of the debt covenants relate to the nonpayment of interest and/or principal on debt and the maintenance of certain financial ratios The nonpayments debt covenant which could trigger a default is applicable to financing arrangements of FirstEnergy and all of the Companies. The maintenance of minimum fixed charge ratios and debt to capitalization ratios covenants is applicable to financing arrangements of FirstEnergy, the Ohio Companies and Penn. There also exists cross-default provisions among financing arrangements of FirstEnergy and the Companies

Based on the amount of bonds authenticated by the respective mortgage bond trustees through December 31, 2002, the Companies' annual improvement fund requirements for all bonds issued under the mortgages amounts to $61 5 million OE and Penn expect to deposit funds with their respective mortgage bond trustees in 2003 that will then be withdrawn upon the surrender for cancellation of a like principal amount of bonds, specifically authenticated for such purposes against unfunded property additions or against previously retired bonds This method can result in minor increases in the amount of the annual sinking fund requirement JCP&L, Met-Ed and Penelec expect to fulfill their sinking and improvement fund obligation by providing bondable property additions and/or retired bonds to the respective mortgage bond trustees

Sinking fund requirements for first mortgage bonds and maturing long-term debt (excluding capital leases) for the next five years are:

	(In millions)
2003	$1,698 8
2004	1,603 8
2005	918 5
2006	1,402 2
2007	251 9

Included in the table above are amounts for various variable interest rate long-term debt which have provisions by which individual debt holders have the option to "put back" or require the respective debt issuer to redeem their debt at those times when the interest rate may change prior to its maturity date These amounts are $626 million, $266 million and $47 million in 2003, 2004 and 2005, respectively, which represents the next date at which the debt holders may exercise this provision.

The Companies' obligations to repay certain pollution control revenue bonds are secured by several series of first mortgage bonds Certain pollution control revenue bonds are entitled to the benefit of irrevocable bank letters of credit of $287 6 million and noncancelable municipal bond insurance policies of $544 1 million to pay principal of, or interest on, the pollution control revenue bonds To the extent that drawings are made under the letters of credit or policies, the Companies are entitled to a credit against their obligation to repay those bonds. The Companies pay annual fees of 1 00% to 1 375% of the amounts of the letters of credit to the issuing banks and are obligated to reimburse the banks for any drawings thereunder.

FirstEnergy had unsecured borrowings of $395 million as of December 31, 2002, under its $500 million long-term revolving credit facility agreement which expires November 29, 2004. FirstEnergy currently pays an annual facility fee of 0 25% on the total credit facility amount The fee is subject to change based on changes to FirstEnergy's credit ratings.

CEI and TE have unsecured letters of credit of approximately $215 9 million in connection with the sale and leaseback of Beaver Valley Unit 2 that expire in April 2005 CEI and TE are jointly and severally liable for the letters of credit. In connection with its Beaver Valley Unit 2 sale and leaseback arrangements, OE has similar letters of credit secured by deposits held by its subsidiary, OES Finance (see Note 4)

(H) Securitized Transition Bonds-

On June 11, 2002, JCP&L Transition Funding LLC (Issuer), a wholly owned limited liability company of JCP&L, sold $320 million of transition bonds to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station

JCP&L does not own nor did it purchase any of the transition bonds, which are included in long-term debt on FirstEnergy's and JCP&L's Consolidated Balance Sheets The transition bonds represent obligations only of the Issuer and are collateralized solely by the equity and assets of the Issuer, which consist primarily of bondable transition property The bondable transition property is solely the property of the Issuer

Bondable transition property represents the irrevocable right of a utility company to charge, collect and receive from its customers, through a non-bypassable transition bond charge, the principal amount and interest on the transition bonds and other fees and expenses associated with their issuance. JCP&L, as servicer, manages and administers the bondable transition property, including the billing, collection and remittance of the transition bond charge, pursuant to a servicing agreement with the Issuer. JCP&L is entitled to a quarterly servicing fee of $100,000 that is payable from transition bond charge collections

(I) Comprehensive Income-

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholders' equity except those resulting from transactions with common stockholders. As of December 31, 2002, accumulated other comprehensive income (loss) consisted of a minimum liability for unfunded retirement benefits of $450.2 million, unrealized losses on investments in securities available for sale of $11.4 million, unrealized losses on derivative instrument hedges of $110.2 million and unrealized currency translation adjustments of $91.4 million. See Note 9 – Other Information for discussion of derivative instruments reclassifications to net income.

(J) Stock Repurchase Program-

The Board of Directors authorized the repurchase of up to 15 million shares of FirstEnergy's common stock over a three-year period beginning in 1999. Repurchases were made on the open market, at prevailing prices, and were funded primarily through the use of operating cash flows. During 2001 and 2000, FirstEnergy repurchased and retired 550,000 shares (average price of $27.82 per share), and 7.9 million shares (average price of $24.51 per share), respectively.

6. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT:

Short-term borrowings outstanding as of December 31, 2002, consisted of $933.1 million of bank borrowings and $159.7 million of OES Capital, Incorporated commercial paper. OES Capital is a wholly owned subsidiary of OE whose borrowings are secured by customer accounts receivable. OES Capital can borrow up to $170 million under a receivables financing agreement at rates based on certain bank commercial paper and is required to pay an annual fee of 0.20% on the amount of the entire finance limit. The receivables financing agreement expires in August 2003.

FirstEnergy and its subsidiaries have various credit facilities (including a FirstEnergy $1 billion short-term revolving credit facility) with domestic and foreign banks that provide for borrowings of up to $1.084 billion under various interest rate options. To assure the availability of these lines, FirstEnergy and its subsidiaries are required to pay annual commitment fees that vary from 0.125% to 0.20%. These lines expire at various times during 2003. The weighted average interest rates on short-term borrowings outstanding as of December 31, 2002 and 2001, were 2.41% and 3.80%, respectively.

7. COMMITMENTS, GUARANTEES AND CONTINGENCIES:

(A) Capital Expenditures-

FirstEnergy's current forecast reflects expenditures of approximately $3.1 billion for property additions and improvements from 2003-2007, of which approximately $727 million is applicable to 2003. Investments for additional nuclear fuel during the 2003-2007 period are estimated to be approximately $485 million, of which approximately $69 million applies to 2003. During the same periods, the Companies' nuclear fuel investments are expected to be reduced by approximately $483 million and $88 million, respectively, as the nuclear fuel is consumed.

(B) Nuclear Insurance-

The Price-Anderson Act limits the public liability relative to a single incident at a nuclear power plant to $9.5 billion. The amount is covered by a combination of private insurance and an industry retrospective rating plan. The Companies' maximum potential assessment under the industry retrospective rating plan would be $352.4 million per incident but not more than $40 million in any one year for each incident.

The Companies are also insured under policies for each nuclear plant. Under these policies, up to $2.75 billion is provided for property damage and decontamination costs. The Companies have also obtained approximately $1.2 billion of insurance coverage for replacement power costs. Under these policies, the Companies can be assessed a maximum of approximately $68.4 million for incidents at any covered nuclear facility occurring during a policy year which are in excess of accumulated funds available to the insurer for paying losses.

The Companies intend to maintain insurance against nuclear risks as described above as long as it is available. To the extent that replacement power, property damage, decontamination, repair and replacement costs and other such costs arising from a nuclear incident at any of the Companies' plants exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by the Companies' insurance policies, or to the extent such insurance becomes unavailable in the future, the Companies would remain at risk for such costs.

(C) Guarantees and Other Assurances-

As part of normal business activities, FirstEnergy enters into various agreements on behalf of its subsidiaries to provide financial or performance assurances to third parties. Such agreements include contract guarantees, surety bonds and rating-contingent collateralization provisions. As of December 31, 2002, outstanding guarantees and other assurances aggregated $913 million.

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy marketing activities - principally to facilitate normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of subsidiary financing principally for the acquisition of property, plant and equipment. These agreements legally obligate FirstEnergy and its subsidiaries to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financing where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, FirstEnergy's guarantee enables the counterparty's legal claim to be satisfied by other FirstEnergy assets. The likelihood that such parental guarantees of $856 million as of December 31, 2002 will increase amounts otherwise to be paid by FirstEnergy to meet its obligations incurred in connection with financings and ongoing energy and energy-related contracts is remote.

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related FirstEnergy guarantees of $26 million provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction jobs, environmental commitments and various retail transactions.

Various energy supply contracts contain credit enhancement provisions in the form of cash collateral or letters of credit in the event of a reduction in credit rating below investment grade. These provisions vary and typically require more than one rating reduction to fall below investment grade by Standard & Poor's or Moody's Investors Service to trigger additional collateralization by FirstEnergy. As of December 31, 2002, rating-contingent collateralization totaled $31 million.

(D) Environmental Matters-

Various federal, state and local authorities regulate the Companies with regard to air and water quality and other environmental matters FirstEnergy estimates additional capital expenditures for environmental compliance of approximately \$159 million, which is included in the construction forecast provided under "Capital Expenditures" for 2003 through 2007

The Companies are required to meet federally approved sulfur dioxide (SO2) regulations. Violations of such regulations can result in shutdown of the generating unit involved and/or civil or criminal penalties of up to \$31,500 for each day the unit is in violation The Environmental Protection Agency (EPA) has an interim enforcement policy for SO2 regulations in Ohio that allows for compliance based on a 30-day averaging period. The Companies cannot predict what action the EPA may take in the future with respect to the interim enforcement policy

The Companies believe they are in compliance with the current SO2 and nitrogen oxide (NOx) reduction requirements under the Clean Air Act Amendments of 1990 SO2 reductions are being achieved by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances NOx reductions are being achieved through combustion controls and the generation of more electricity at lower-emitting plants In September 1998, the EPA finalized regulations requiring additional NOx reductions from the Companies' Ohio and Pennsylvania facilities The EPA's NOx Transport Rule imposes uniform reductions of NOx emissions (an approximate 85% reduction in utility plant NOx emissions from projected 2007 emissions) across a region of nineteen states and the District of Columbia, including New Jersey, Ohio and Pennsylvania, based on a conclusion that such NOx emissions are contributing significantly to ozone pollution in the eastern United States State Implementation Plans (SIP) must comply by May 31, 2004 with individual state NOx budgets established by the EPA. Pennsylvania submitted a SIP that requires compliance with the NOx budgets at the Companies' Pennsylvania facilities by May 1, 2003 and Ohio submitted a SIP that requires compliance with the NOx budgets at the Companies' Ohio facilities by May 31, 2004

In July 1997, the EPA promulgated changes in the National Ambient Air Quality Standard (NAAQS) for ozone emissions and proposed a new NAAQS for previously unregulated ultra-fine particulate matter In May 1999, the U S Court of Appeals for the D C Circuit found constitutional and other defects in the new NAAQS rules In February 2001, the U S Supreme Court upheld the new NAAQS rules regulating ultra-fine particulates but found defects in the new NAAQS rules for ozone and decided that the EPA must revise those rules The future cost of compliance with these regulations may be substantial and will depend if and how they are ultimately implemented by the states in which the Companies operate affected facilities

In 1999 and 2000, the EPA issued Notices of Violation (NOV) or a Compliance Order to nine utilities covering 44 power plants, including the W H Sammis Plant In addition, the U S Department of Justice filed eight civil complaints against various investor-owned utilities, which included a complaint against OE and Penn in the U S District Court for the Southern District of Ohio, for which hearings began on February 3, 2003 The NOV and complaint allege violations of the Clean Air Act based on operation and maintenance of the Sammis Plant dating back to 1984 The complaint requests permanent injunctive relief to require the installation of "best available control technology" and civil penalties of up to \$27,500 per day of violation Although unable to predict the outcome of these proceedings, FirstEnergy believes the Sammis Plant is in full compliance with the Clean Air Act and the NOV and complaint are without merit Penalties could be imposed if the Sammis Plant continues to operate without correcting the alleged violations and a court determines that the allegations are valid The Sammis Plant continues to operate while these proceedings are pending

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants The EPA identified mercury as the hazardous air pollutant of greatest concern The EPA established a schedule to propose regulations by December 2003 and issue final regulations by December 2004 The future cost of compliance with these regulations may be substantial

As a result of the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act of 1976, federal and state hazardous waste regulations have been promulgated Certain fossil-fuel combustion waste products, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation The EPA has issued its final regulatory determination that regulation of coal ash as a hazardous waste is unnecessary In April 2000, the EPA announced that it will develop national standards regulating disposal of coal ash under its authority to regulate nonhazardous waste.

The Companies have been named as "potentially responsible parties" (PRPs) at waste disposal sites which may require cleanup under the Comprehensive Environmental Response, Compensation and Liability Act of 1980 Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute, however, federal law provides that all PRPs for a particular site be held liable on a joint and several basis Therefore, potential environmental liabilities have been recognized on the Consolidated Balance Sheet as of December 31, 2002, based on estimates of the total costs of cleanup, the Companies' proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay In addition, JCP&L has accrued liabilities for environmental remediation of former manufactured gas plants in New Jersey, those costs are being recovered by JCP&L through its SBC The Companies have total accrued liabilities aggregating approximately \$54 3 million as of December 31, 2002.

The effects of compliance on the Companies with regard to environmental matters could have a material adverse effect on FirstEnergy's earnings and competitive position. These environmental regulations affect FirstEnergy's earnings and competitive position to the extent it competes with companies that are not subject to such regulations and therefore do not bear the risk of costs associated with compliance, or failure to comply, with such regulations FirstEnergy believes it is in material compliance with existing regulations but is unable to predict whether environmental regulations will change and what, if any, the effects of such change would be.

(E) Other Legal Proceedings-

Various lawsuits, claims for personal injury, asbestos and property damage and proceedings related to FirstEnergy's normal business operations are pending against FirstEnergy and its subsidiaries. The most significant are described below.

TMI-2 was acquired by FirstEnergy in 2001 as part of the merger with GPU As a result of the 1979 TMI-2 accident, claims for alleged personal injury against JCP&L, Met-Ed, Penelec and GPU had been filed in the U S District Court for the Middle

District of Pennsylvania. In 1996, the District Court granted a motion for summary judgment filed by GPU and dismissed the ten initial "test cases" which had been selected for a test case trial. On January 15, 2002, the District Court granted GPU's July 2001 motion for summary judgment on the remaining 2,100 pending claims. On February 14, 2002, plaintiffs filed a notice of appeal to the United States Court of Appeals for the Third Circuit. In December 2002, the Court of Appeals refused to hear the appeal which effectively ended further legal action for those claims.

In July 1999, the Mid-Atlantic states experienced a severe heat storm which resulted in power outages throughout the service territories of many electric utilities, including JCP&L's territory. In an investigation into the causes of the outages and the reliability of the transmission and distribution systems of all four New Jersey electric utilities, the NJBPU concluded that there was not a prima facie case demonstrating that, overall, JCP&L provided unsafe, inadequate or improper service to its customers. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against JCP&L, GPU and other GPU companies seeking compensatory and punitive damages arising from the July 1999 service interruptions in the JCP&L territory. In May 2001, the court denied without prejudice the defendants' motion seeking decertification of the class. Discovery continues in the class action, but no trial date has been set. In October 2001, the court held argument on the plaintiffs' motion for partial summary judgment, which contends that JCP&L is bound to several findings of the NJBPU investigation. The plaintiffs' motion was denied by the Court in November 2001 and the plaintiffs' motion to file an appeal of this decision was denied by the New Jersey Appellate Division. JCP&L has also filed a motion for partial summary judgment that is currently pending before the Superior Court. FirstEnergy is unable to predict the outcome of these matters.

(F) Other Commitments and Contingencies-

GPU made significant investments in foreign businesses and facilities through its GPU Capital and GPU Power subsidiaries. Although FirstEnergy will attempt to mitigate its risks related to foreign investments, it faces additional risks inherent in operating in such locations, including foreign currency fluctuations.

EI Barranquilla, a wholly owned subsidiary of GPU Power, is a 28.67% equity investor in Termobarranquilla S.A., Empresa de Servicios Publicos (TEBSA), which owns a Colombian independent power generation project. GPU Power is committed, under certain circumstances, to make additional standby equity contributions of $21.3 million, which FirstEnergy has guaranteed. The total outstanding senior debt of the TEBSA project is $254 million as of December 31, 2002. The lenders include the Overseas Private Investment Corporation, US Export Import Bank and a commercial bank syndicate. FirstEnergy has guaranteed the obligations of the operators of the TEBSA project, up to a maximum of $5.9 million (subject to escalation) under the project's operations and maintenance agreement.

8. SEGMENT INFORMATION:

FirstEnergy operates under two reportable segments: regulated services and competitive services. The aggregate "Other" segments do not individually meet the criteria to be considered a reportable segment. "Other" consists of interest expense related to the 2001 merger acquisition debt; the corporate support services operating segment and the international businesses acquired in the 2001 merger. The international business assets reflected in the 2001 "Other" assets amount included assets in the United Kingdom identified for divestiture (see Note 3 - Divestitures) which were sold in 2002. As those assets were in the process of being sold, their performance was not being reviewed by a chief operating decision maker and in accordance with SFAS 131, "Disclosures about Segments of an Enterprise and Related Information," did not qualify as an operating segment. The remaining assets and revenues for the corporate support services and the remaining international businesses were below the quantifiable threshold for operating segments for separate disclosure as "reportable segments." FirstEnergy's primary segment is its regulated services segment, which includes eight electric utility operating companies in Ohio, Pennsylvania and New Jersey that provide electric transmission and distribution services. Its other material business segment consists of the subsidiaries that operate unregulated energy and energy-related businesses.

The regulated services segment designs, constructs, operates and maintains FirstEnergy's regulated transmission and distribution systems. It also provides generation services to regulated franchise customers who have not chosen a competing generation supplier. The regulated services segment obtains a portion of its required generation through power supply agreements with the competitive services segment.

The competitive services segment includes all domestic unregulated energy and energy-related services including commodity sales (both electricity and natural gas) in the retail and wholesale markets, marketing, generation and sourcing of commodity requirements, as well as other competitive energy-application services. Competitive products are increasingly marketed to customers as bundled services.

Segment financial data in 2001 and 2000 have been reclassified to conform with the current year business segment organizations and operations. Changes in the current year methodology for computing revenues and expenses used in management reporting for the Competitive Services segment have been reflected in reclassified 2001 and 2000 financial results. Methodology changes included using a fixed rate revenues calculation for the Competitive Services segment's power sales agreement with the Regulated Services segment. This change, when applied to previously reported results, caused lower revenues, income taxes and net income as compared to prior calculated amounts and, correspondingly, reduced purchased power expenses and increased income taxes and net income for the Regulated Services segment. Financial data for these business segments are as follows:

SEGMENT FINANCIAL INFORMATION

	Regulated Services	Competitive Services	Other	Reconciling Adjustments		Consolidated
			(In millions)			
2002						
External revenues	$ 8,794	$3,015	$ 330	$ 13	(a)	$ 12,152
Internal revenues	1,052	1,666	478	(3,196)	(b)	—
Total revenues	9,846	4,681	808	(3,183)		12,152
Depreciation and amortization	1,034	30	42	—		1,106
Net interest charges	591	46	367	(58)	(b)	946
Income taxes	748	(85)	(114)	—		549
Income before cumulative effect of a change in accounting	997	(119)	(192)	—		686
Net income	997	(119)	(249)	—		629
Total assets	29,689	2,281	1,611	—		33,581
Total goodwill	5,611	285	—	—		5,896
Property additions	490	403	105	—		998
2001						
External revenues	$ 5,729	$2,165	$ 11	$ 94	(a)	$ 7,999
Internal revenues	1,645	1,846	350	(3,841)	(b)	—
Total revenues	7,374	4,011	361	(3,747)		7,999
Depreciation and amortization	841	21	28	—		890
Net interest charges	571	25	74	(114)	(b)	556
Income taxes	537	(23)	(40)	—		474
Income before cumulative effect of a change in accounting	729	(23)	(51)	—		655
Net income	729	(32)	(51)	—		646
Total assets	28,054	2,981	6,317	—		37,352
Total goodwill	5,325	276	—	—		5,601
Property additions	447	375	30	—		852
2000						
External revenues	$ 5,415	$1,545	$ 1	$ 68	(a)	$ 7,029
Internal revenues	1,222	2,114	306	(3,642)	(b)	—
Total revenues	6,637	3,659	307	(3,574)		7,029
Depreciation and amortization	919	13	2	—		934
Net interest charges	558	10	19	(58)	(b)	529
Income taxes	365	27	(15)	—		377
Net income	563	39	(3)	—		599
Total assets	14,682	2,685	574	—		17,941
Total goodwill	1,867	222	—	—		2,089
Property additions	422	126	40	—		588

Reconciling adjustments to segment operating results from internal management reporting to consolidated external financial reporting
(a) Principally fuel marketing revenues which are reflected as reductions to expenses for internal management reporting purposes
(b) Elimination of intersegment transactions

PRODUCTS AND SERVICES

Year	Electricity Sales	Oil & Gas Sales	Energy Related Sales and Services
		(In millions)	
2002	$9,697	$620	$1,052
2001	6,078	792	693
2000	5,537	582	563

GEOGRAPHIC INFORMATION

	2002		2001	
	Revenues	Assets	Revenues	Assets
		(In millions)		
United States	$11,908	$32,823	$7,991	$32,187
Foreign countries*	244	758	8	5,165
Total	$12,152	$33,581	$7,999	$37,352

**See Note 3 for discussion of future divestitures of international operations*

9. OTHER INFORMATION:

The following financial data provides supplemental information to the consolidated financial statements and notes previously reported in 2001 and 2000:

(A) Consolidated Statements of Cash Flows

	2002	2001	2000
		(In thousands)	
Other Cash Flows from Operating Activities:			
Accrued taxes	$ 37,623	$ 8,915	$ (84)
Accrued interest	(25,444)	117,520	(8,853)
Retail rate refund obligation payments	(43,016)	—	—
Interest rate hedge	—	(132,376)	—
Prepayments and other	132,980	(146,741)	(21,975)
All other	113,371	(97,882)	76,441
Total-Other	$ 215,514	$(250,564)	$ 45,529
Other Cash Flows From Investing Activities:			
Retirements and transfers	$ 29,619	$ 40,106	$ (11,721)
Nonutility generation trusts investments	49,044	—	—
Nuclear decommissioning trust investments	(86,221)	(73,381)	(30,704)
Aquila notes receivable	(91,335)	—	—
Other comprehensive income	8,745	(49,653)	—
Other investments	(16,689)	(116,285)	(25,481)
All other	52,482	(34,313)	(52,289)
Total-Other	$ (54,355)	$(233,526)	$(120,195)

(B) Consolidated Statements of Taxes

	2002	2001	2000
		(In thousands)	
Accumulated Deferred Income Taxes at December 31:			
Other consists of the following:			
Retirement Benefits	$ (381,285)	$ (133,282)	$(60,491)
Oyster Creek securitization (Note 5H)	202,447	—	—
Purchase accounting basis differences	(2,657)	(147,450)	—
Sale of generation assets	(11,786)	207,787	—
Provision for rate refund	(29,370)	(46,942)	—
All other	(193,497)	(203,809)	22,767
Total-Other	$ (416,148)	$ (323,696)	$(37,724)

(C) Revenues - Independent System Operator (ISO) Transactions

FirstEnergy's regulated and competitive subsidiaries record purchase and sales transactions with PJM Interconnection ISO, an independent system operator, on a gross basis in accordance with EITF Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent." The aggregate purchase and sales transactions for the three years ended December 31, 2002, are summarized as follows:

	2002	2001	2000
		(In millions)	
Sales	$453	$142	$315
Purchases	687	204	271

FirstEnergy's revenues on the Consolidated Statements of Income include wholesale electricity sales revenues from the PJM ISO from power sales (as reflected in the table above) during periods when FirstEnergy had additional available power capacity. Revenues also include sales by FirstEnergy of power sourced from the PJM ISO (reflected as purchases in the table above) during periods when FirstEnergy required additional power to meet its retail load requirements and, secondarily, to make sales to the wholesale market.

(D) Stock Based Compensation

Stock-based employee compensation expense recognized for the FE Programs' restricted stock during 2002, 2001 and 2000 totaled $2,259,000, $1,342,000 and $1,104,000, respectively. In addition, stock-based employee compensation expense of $206,000, $1,637,000 and $1,646,000 during 2002, 2001 and 2000, respectively, was recognized for EDCP stock units (see Note 5C - Stock Compensation Plans for further disclosure).

(E) SFAS 115 Activity

All other investments included under Investments other than cash and cash equivalents in the table in Note 2J - Supplemental Cash Flows Information include available-for-sale securities, at fair value, with the following results:

	2002	2001	2000
		(In thousands)	
Unrealized holding gains	$ 202	$2,236	$992
Unrealized holding losses	4,991	432	70
Proceeds from sales	7,875	25	66
Gross realized gains	31	—	46
Gross realized losses	—	3	—

(F) Derivative Instruments Reclassifications to Net Income

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholders' equity except those resulting from transactions with common stockholders (see Note 5I - Comprehensive Income for further disclosure). Other comprehensive income (loss) reclassified to net income in 2002 and 2001 totaled $(9.9) million and $30.7 million, respectively. These amounts were net of income taxes in 2002 and 2001 of $(6.8) million and $21.7 million, respectively. There were no reclassifications to net income in 2000.

10. OTHER RECENTLY ISSUED ACCOUNTING STANDARDS

FASB Interpretation (FIN) No. 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"

The FASB issued FIN 45 in January 2003. This interpretation identifies minimum guarantee disclosures required for annual periods ending after December 15, 2002 It also clarifies that providers of guarantees must record the fair value of those guarantees at their inception. This accounting guidance is applicable on a prospective basis to guarantees issued or modified after December 31, 2002 FirstEnergy does not believe that implementation of FIN 45 will be material but it will continue to evaluate anticipated guarantees

FIN 46, "Consolidation of Variable Interest Entities – an interpretation of ARB 51"

In January 2003, the FASB issued this interpretation of ARB No 51, "Consolidated Financial Statements". The new interpretation provides guidance on consolidation of variable interest entities (VIEs), generally defined as certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties This interpretation requires an enterprise to disclose the nature of its involvement with a VIE if the enterprise has a significant variable interest in the VIE and to consolidate a VIE if the enterprise is the primary beneficiary VIEs created after January 31, 2003 are immediately subject to the provisions of FIN 46 VIEs created before February 1, 2003 are subject to this interpretation's provisions in the first interim or annual reporting period beginning after June 15, 2003 (our third quarter of 2003) The FASB also identified transitional disclosure provisions for all financial statements issued after January 31, 2003

FirstEnergy currently has transactions with entities in connection with sale and leaseback transactions, the sale of preferred securities and debt secured by bondable property, which may fall within the scope of this interpretation, and which are reasonably possible of meeting the definition of a VIE in accordance with FIN 46

FirstEnergy currently consolidates the majority of these entities and believes it will continue to consolidate following the adoption of FIN 46 In addition to the entities FirstEnergy is currently consolidating it believes that the PNBV Capital Trust, reacquired a portion of the off-balance sheet debt issued in connection with the sale and leaseback of OE's interest in the Perry Nuclear Plant and Beaver Valley Unit 2, would require consolidation. Ownership of the trust includes a three-percent equity interest by a nonaffiliated party and a three-percent equity interest by OES Ventures, a wholly owned subsidiary of OE Full consolidation of the trust under FIN 46 would change the characterization of the PNBV trust investment to a lease obligation bond investment Also, consolidation of the outside minority interest would be required, which would increase assets and liabilities by $12 0 million

11. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED):

The following summarizes certain consolidated operating results by quarter for 2002 and 2001.

Three Months Ended	March 31, 2002	June 30, 2002	September 30, 2002	December 31, 2002
	(In millions, except per share amounts)			
Revenues (a)	$2,762 0	$2,898 5	$3,451 2	$3,040 3
Expenses (a)	2,336 5	2,230 4	2,681 7	2,721 2
Income Before Interest and Income Taxes	425 5	668 1	769 5	319 1
Net Interest Charges	259 8	250 3	220 4	215 8
Income Taxes	80 9	184 5	238 8	45 3
Income Before Cumulative Effect of Accounting Change	84 8	233 3	310 3	58 0
Cumulative Effect of Accounting Change (Net of Income Taxes) (Note 3)	31 7	—	—	(88 8)
Net Income (Loss)	$ 116 5	$ 233 3	$ 310 3	$ (30 8)
Basic Earnings (Loss) Per Share of Common Stock Before Cumulative Effect of Accounting Change	$ 29	$ 80	$ 1 06	$ 20
Cumulative Effect of Accounting Change (Net of Income Taxes) (Note 3)	11	—	—	(30)
Basic Earnings (Loss) Per Share of Common Stock	$ 40	$ 80	$ 1 06	$ (10)
Diluted Earnings (Loss) Per Share of Common Stock Before Cumulative Effect of Accounting Change	$ 29	$ 79	$ 1 05	$ 20
Cumulative Effect of Accounting Change (Net of Income Taxes) (Note 3)	11	—	—	(30)
Diluted Earnings (Loss) Per Share of Common Stock	$ 40	$ 79	$ 1 05	$ (10)

Three Months Ended	March 31, 2001	June 30, 2001	September 30, 2001	December 31, 2001(b)
	(In millions, except per share amounts)			
Revenues	$1,985 7	$1,804 1	$1,951 6	$2,257 9
Expenses	1,669 4	1,416 7	1,412 1	1,816 0
Income Before Interest and Income Taxes	316 3	387 4	539 5	441 9
Net Interest Charges	126 3	121 0	124 1	184 3
Income Taxes	83 8	120 4	181 3	89 0
Income Before Cumulative Effect of Accounting Change	106 2	146 0	234 1	168 6
Cumulative Effect of Accounting Change (Net of Income Taxes) (Note 2J)	(8 5)	—	—	—
Net Income	$ 97 7	$ 146 0	$ 234 1	$ 168 6
Basic Earnings Per Share of Common Stock Before Cumulative Effect of Accounting Change	$ 49	$ 67	$ 1 07	$ 64
Cumulative Effect of Accounting Change (Net of Income Taxes) (Note 2J)	(04)	—	—	—
Basic Earnings Per Share of Common Stock	$ 45	$ 67	$ 1 07	$ 64
Diluted Earnings Per Share of Common Stock: Before Cumulative Effect of Accounting Change	$ 49	$ 67	$ 1 06	$ 64
Cumulative Effect of Accounting Change (Net of Income Taxes) (Note 2J)	(04)	—	—	—
Diluted Earnings Per Share of Common Stock	$ 45	$ 67	$ 1 06	$ 64

(a) 2002 revenues and expenses related to trading activities reflect reclassifications as a result of implementing EITF Issue No 02-03 (see Note 2C – Revenues)

(b) Results for the former GPU companies are included from the November 7, 2001 acquisition date through December 31, 2001

12. PRO FORMA COMBINED CONDENSED FIRSTENERGY STATEMENTS OF INCOME (UNAUDITED):

On November 7, 2001, the merger of FirstEnergy and GPU became effective pursuant to the Agreement and Plan of Merger, dated August 8, 2000 (Merger Agreement). As a result of the merger, GPU's former wholly owned subsidiaries, including JCP&L, Met-Ed and Penelec, (collectively, the Former GPU Companies), became wholly owned subsidiaries of FirstEnergy. Under the terms of the Merger Agreement, GPU shareholders received the equivalent of $36.50 for each share of GPU common stock they owned, payable in cash and/or FirstEnergy common stock. GPU shareholders receiving FirstEnergy shares received 1.2318 shares of FirstEnergy common stock for each share of GPU common stock they exchanged. The cash portion of the merger consideration was approximately $2.2 billion and nearly 73.7 million shares of FirstEnergy common stock were issued to GPU shareholders for the share portion of the transaction consideration.

The merger was accounted for by the purchase method of accounting and, accordingly, the Consolidated Statements of Income include the results of the Former GPU Companies beginning November 7, 2001. The assets acquired and liabilities assumed were recorded at estimated fair values as determined by FirstEnergy's management based on information currently available and on current assumptions as to future operations. The merger purchase accounting adjustments, which were recorded in the records of GPU's direct subsidiaries, primarily consist of: (1) revaluation of GPU's international operations to fair value; (2) revaluation of property, plant and equipment; (3) adjusting preferred stock subject to mandatory redemption and long-term debt to estimated fair value; (4) recognizing additional obligations related to retirement benefits; and (5) recognizing estimated severance and other compensation liabilities. Other assets and liabilities were not adjusted since they remain subject to rate regulation on a historical cost basis. The severance and compensation liabilities are based on anticipated workforce reductions reflecting duplicate positions primarily related to corporate support groups including finance, legal, communications, human resources and information technology. The workforce reductions represent the expected reduction of approximately 700 employees at a cost of approximately $140 million. Merger related staffing reductions began in late 2001 and the remaining reductions are anticipated to occur through 2003 as merger-related transition assignments are completed.

The merger greatly expanded the size and scope of our electric business and the goodwill recognized primarily relates to the regulated services segment. The combination of FirstEnergy and GPU was a key strategic step in FirstEnergy achieving its vision of being the leading energy and related services provider in the region. The merger combined companies with the management, employee experience and technical expertise, retail customer base, energy and related services platform and financial resources to grow and succeed in a rapidly changing energy marketplace. The merger also allowed for a natural alliance of companies with adjoining service areas and interconnected transmission systems to eliminate duplicative costs, maximize efficiencies and increase management and operational flexibility in order to enhance operations and become a more effective competitor.

Under the purchase method of accounting, tangible and identifiable intangible assets acquired and liabilities assumed are recorded at their estimated fair values. The excess of the purchase price, including estimated fees and expenses related to the merger, over the net assets acquired (which included existing goodwill of $1.9 billion), is classified as goodwill and amounts to an additional $2.3 billion. The following table summarizes the estimated fair values of the assets acquired and liabilities assumed on the date of acquisition.

	(In millions)
Current assets	$ 1,027
Goodwill	3,698
Regulatory assets	4,352
Other	5,595
Total assets acquired	14,672
Current liabilities	(2,615)
Long-term debt	(2,992)
Other	(4,785)
Total liabilities assumed	$(10,392)
Net assets acquired pending sale	566
Net assets acquired	$ 4,846

During 2002, certain pre-acquisition contingencies and other final adjustments to the fair values of the assets acquired and liabilities assumed were reflected in the final allocation of the purchase price. These adjustments primarily related to: (1) final actuarial calculations related to pension and postretirement benefit obligations; (2) updated valuations of GPU's international operations as of the date of the merger; (3) establishment of a reserve for deferred energy costs recognized prior to the merger; and (4) return to accrual adjustments for income taxes. As a result of these adjustments, goodwill increased by approximately $290 million, which is attributable to the regulated services segment.

The following pro forma combined condensed statements of income of FirstEnergy give effect to the FirstEnergy/GPU merger as if it had been consummated on January 1, 2000, with the purchase accounting adjustments actually recognized in the business combination. The pro forma combined condensed financial statements have been prepared to reflect the merger under the purchase method of accounting with FirstEnergy acquiring GPU. In addition, the pro forma adjustments reflect a reduction in debt from application of the proceeds from certain pending divestitures as well as the related reduction in interest costs.

	Year Ended December 31,	
	2001	**2000**
	(In millions, except per share amounts)	
Revenues	$12,108	$11,703
Expenses	9,768	9,377
Income Before Interest and Income Taxes	2,340	2,326
Net Interest Charges	941	977
Income Taxes	561	527
Net Income	$ 838	$ 822
Earnings per Share of Common Stock	$ 2.87	$ 2.77

CONSOLIDATED FINANCIAL AND PRO FORMA COMBINED OPERATING STATISTICS *(Unaudited)*

	2002	2001	2000	1999	1998	1997	1992
GENERAL FINANCIAL INFORMATION							
(Dollars in thousands)							
Revenues	**$12,151,997**	$ 7,999,362	$ 7,028,961	$ 6,319,647	$ 5,874,906	$ 2,961,125	$2,332,378
Net Income	**$ 629,280**	$ 646,447	$ 598,970	$ 568,299	$ 410,874	$ 305,774	$ 253,060
SEC Ratio of Earnings to							
Fixed Charges	**1 93**	2 21	2 10	2 01	1 77	2 18	2 01
Net Property, Plant and Equipment	**$12,679,813**	$12,428,429	$ 7,575,076	$ 9,093,341	$ 9,242,574	$ 9,635,992	$5,979,538
Capital Expenditures	**$ 903,606**	$ 887,929	$ 568,711	$ 474,118	$ 305,577	$ 188,145	$ 252,592
Total Capitalization(a)	**$18,755,776**	$21,339,001	$11,204,674	$11,469,795	$11,756,422	$12,124,492	$5,943,913
Capitalization Ratios (a)							
Common Stockholders' Equity	**37 9%**	34 7%	41 5%	39 8%	37 9%	34 3%	40 5%
Preferred and Preference Stock							
Not Subject to Mandatory Redemption	**1.8**	2 2	5 8	5 7	5 6	5 5	6 0
Subject to Mandatory Redemption	**2 3**	2 8	1 4	2 2	2 5	2 7	1 0
Long-Term Debt	**58 0**	60 3	51 3	52 3	54 0	57 5	52 5
Total Capitalization	**100 0%**	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%
Average Capital Costs							
Preferred and Preference Stock	**7.50%**	7 90%	7 92%	7 99%	8 01%	8 02%	7 32%
Long-Term Debt	**6 56%**	6 98%	7 84%	7 65%	7 83%	8 02%	8 53%
COMMON STOCK DATA							
Earnings per Share (b)							
Basic	**$2 34**	$2 85	$2 69	$2 50	$1 95	$1 94	$1 70
Diluted	**$2 33**	$2 84	$2 69	$2 50	$1 95	$1 94	$1 70
Return on Average Common Equity (b)	**9.1%**	12 9%	13 0%	12 7%	10 3%	11 0%	10 8%
Dividends Paid per Share	**$1 50**	$1 50	$1 50	$1 50	$1 50	$1 50	$1 50
Dividend Payout Ratio (b)	**64%**	53%	56%	60%	77%	77%	88%
Dividend Yield	**4 5%**	4 3%	4 8%	6 6%	4 6%	5 2%	6 5%
Price/Earnings Ratio (b)	**14.1**	12 3	11 7	9 1	16 7	14 9	13 6
Book Value per Share	**$24 25**	$25 29	$21 29	$20 22	$19 37	$18 71	$15 78
Market Price per Share	**$32.97**	$34 98	$31 56	$22 69	$32 56	$29 00	$23 13
Ratio of Market Price to Book Value	**136%**	138%	148%	112%	168%	155%	147%
OPERATING STATISTICS (c)							
Generation Kilowatt-Hour Sales (Millions)							
Residential	**31,937**	32,708	32,519	32,616	31,220	30,653	28,076
Commercial	**32,892**	32,170	33,139	30,311	31,033	30,149	25,898
Industrial	**32,726**	33,024	31,140	30,422	36,683	36,531	33,202
Other	**531**	536	522	566	611	612	1,416
Total Retail	**98,086**	98,438	97,320	93,915	99,547	97,945	88,592
Total Wholesale	**30,007**	20,240	13,761	14,631	9,910	11,657	15,383
Total Sales	**128,093**	118,678	111,081	108,546	109,457	109,602	103,975
Customers Served							
Residential	**3,868,499**	3,833,013	3,798,716	3,767,534	3,735,308	3,708,760	3,550,043
Commercial	**471,440**	464,053	472,410	455,919	447,087	444,582	410,866
Industrial	**18,416**	18,652	18,996	19,549	19,902	21,028	22,033
Other	**5,716**	5,762	6,001	5,992	5,876	5,835	7,719
Total	**4,364,071**	4,321,480	4,296,123	4,248,994	4,208,173	4,180,205	3,990,661
Number of Employees	**17,560**	18,700	18,912	19,470	20,392	18,867	26,608

(a) 2001 capitalization includes approximately $1 4 billion of long-term debt (excluding long-term debt due to be repaid within one year) included in "Liabilities Related to Assets Pending Sale" on the Consolidated Balance Sheet as of December 31, 2001

(b) Before an accounting change in 2002 and 2001 and an extraordinary charge in 1998

(c) Reflects pro forma combined FirstEnergy and GPU statistics in the years 1998 to 2001 and pro forma combined Ohio Edison, Centerior and GPU statistics in years prior to 1998

SHAREHOLDER INFORMATION

Investor Services, Transfer Agent and Registrar

We act as our own transfer agent and registrar for all stock issues of FirstEnergy and its subsidiaries. Shareholders wanting to transfer stock, or who need assistance or information, can send their stock or write to Investor Services, FirstEnergy Corp., 76 South Main Street, Akron, Ohio 44308-1890. Shareholders also can call the following toll-free telephone number, which is valid in the United States, Canada, Puerto Rico and the Virgin Islands, weekdays between 8 a.m. and 4:30 p.m., Eastern time: 1-800-736-3402. For Internet access to general shareholder information and useful forms, visit our Web site at *http://www.firstenergycorp.com/ir.* Former GPU registered common shareholders should call Mellon Investor Services at 1-800-279-1228 for historical information on their account prior to November 7, 2001.

Stock Listings and Trading

Newspapers generally report FirstEnergy common stock under the abbreviation FSTENGY, but this can vary depending upon the newspaper. The common stock of FirstEnergy and preferred stock of its electric utility subsidiaries are listed on the following stock exchanges:

Company	Stock Exchange	Symbol
FirstEnergy	New York	FE
The Illuminating Company	New York, OTC	CVE
Jersey Central	New York	JYP
Ohio Edison	New York	OEC
Pennsylvania Power	Philadelphia	PPC
Toledo Edison	New York, OTC American	TED

Dividends

Proposed dates for the payment of FirstEnergy common stock dividends in 2003, which are subject to declaration by the Board of Directors, are:

Ex-Dividend Date	Record Date	Payment Date
February 5	February 7	March 1
May 5	May 7	June 1
August 5	August 7	September 1
November 5	November 7	December 1

Direct Dividend Deposit

Shareholders can have their dividend payments automatically deposited to checking and savings accounts at any financial institution that accepts electronic direct deposits. Use of this free service ensures that payments will be available to you on the payment date, eliminating the possibility of mail delay or lost checks. To receive an authorization form, contact Investor Services.

Stock Investment Plan

Shareholders and others can purchase or sell shares of FirstEnergy common stock through the Company's Stock Investment Plan. Investors who are not registered shareholders can enroll with an initial $250 cash investment. Participants may invest all or some of their dividends or make optional cash payments at any time of at least $25 per payment up to $100,000 annually. To receive an enrollment form, contact Investor Services.

Safekeeping of Shares

Shareholders can request that the Company hold their shares of FirstEnergy common stock in safekeeping. To take advantage of this service, shareholders should forward their stock certificate(s) to the Company along with a signed letter requesting that the Company hold the shares. They should also state whether future dividends for the held shares are to be reinvested or paid in cash. The certificate(s) should not be endorsed, and registered mail is suggested. The shares will be held in uncertificated form and we will make certificate(s) available to shareholders upon request at no cost. Shares held in safekeeping will be reported on dividend checks or Stock Investment Plan statements.

Combining Stock Accounts

If you have more than one stock account and want to combine them, please write or call Investor Services and specify the account that you want to retain as well as the registration of each of your accounts.

Form 10-K Annual Report

Form 10-K, the Annual Report to the Securities and Exchange Commission, will be sent without charge by writing to David W. Whitehead, Corporate Secretary, FirstEnergy Corp., 76 South Main Street, Akron, Ohio 44308-1890.

Institutional Investor and Security Analyst Inquiries

Institutional investors and security analysts should direct inquiries to: Kurt E. Turosky, Director, Investor Relations, 330-384-5500.

Annual Meeting of Shareholders

Shareholders are invited to attend the 2003 Annual Meeting of Shareholders on Tuesday, May 20, at 10 a.m., at the John S. Knight Center in Akron, Ohio. Registered holders of common stock not attending the meeting can appoint a proxy and vote on the items of business by telephone, Internet or by completing and returning the proxy card that is sent to them. Shareholders whose shares are held in the name of a broker can attend the meeting if they present a letter from their broker indicating ownership of FirstEnergy common stock on the record date of March 25, 2003.

FirstEnergy Officers

FirstEnergy Corp.

H. Peter Burg
Chairman and
Chief Executive Officer

Anthony J. Alexander
President and Chief
Operating Officer

Richard H. Marsh*
Senior Vice President
and Chief Financial
Officer

Leila L. Vespoli*
Senior Vice President
and General Counsel

Harvey L. Wagner
Vice President,
Controller and
Chief Accounting Officer

David W. Whitehead
Corporate Secretary

Thomas C. Navin*
Treasurer

Paulette R. Chatman*
Assistant Controller

Jeffrey R. Kalata*
Assistant Controller

Randy Scilla*
Assistant Treasurer

Edward J. Udovich*
Assistant Corporate
Secretary

**Also holds the same title with FirstEnergy Service Company and FirstEnergy Solutions Corp*

FirstEnergy Service Company

H. Peter Burg
Chief Executive Officer

Anthony J. Alexander
President and
Chief Operating Officer

Earl T. Carey
Senior Vice President

Kevin J. Keough
Senior Vice President
and Regional President –
Central Ohio

Carole B. Snyder
Senior Vice President

Mary Beth Carroll
Vice President

Lynn M. Cavalier
Vice President

Mark T. Clark
Vice President

Kathryn W. Dindo
Vice President and
Chief Risk Officer

Michael J. Dowling
Vice President

Terrance G. Howson
Vice President

Ali Jamshidi
Vice President and
Chief Information Officer

Charles E. Jones
Regional Vice President
- Operations

David C. Luff
Vice President

Stephen E. Morgan
Vice President

Stanley F. Szwed
Vice President

Bradford F. Tobin
Vice President and
Chief Procurement
Officer

Harvey L. Wagner
Vice President and
Controller

Thomas M. Welsh
Vice President

David W. Whitehead
Vice President,
Corporate Secretary and
Chief Ethics Officer

FirstEnergy Solutions Corp.

Arthur R. Garfield
President

Douglas S. Elliott
Senior Vice President

Guy L. Pipitone
Senior Vice President

R. Joseph Hrach
Vice President

Alfred G. Roth
Vice President

Donald R. Schneider
Vice President

Trent A. Smith
Vice President

Harvey L. Wagner
Vice President and
Controller

David W. Whitehead
Corporate Secretary

FirstEnergy Nuclear Operating Company

H. Peter Burg
Chairman and
Chief Executive Officer

Robert F. Saunders
President and
Chief Nuclear Officer

Gary R. Leidich
Executive Vice President

Lew W. Myers
Vice President,
Davis-Besse, and
Chief Operating Officer

Mark B. Bezilla
Vice President, Beaver
Valley

William R. Kanda
Vice President, Perry

L. William Pearce
Vice President

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Northern Region
Dennis M. Chack
President

Paul W. Allison
Vice President

Eastern Region
Thomas A. Clark
President

Jeffrey A. Elser
Vice President

Southern Region
Ronald P. Lantzy
President

Central Region
Kevin J. Keough
President

Western Region
James M. Murray
President

Pennsylvania

Eastern Region
Jack A. Kline
President

Steven A. Schumacher
Vice President

Western Region
John E. Paganie
President

Jacqueline L. Roth
Vice President

New Jersey

Central Region
Donald M. Lynch
President

Northern Region
Steven E. Strah
President

Stephen L. Feld
Vice President

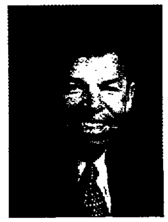
FirstEnergy Board of Directors

H. Peter Burg

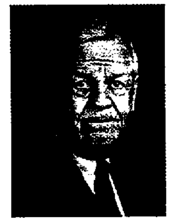
Anthony J. Alexander

Dr. Carol A. Cartwright

William F. Conway



Robert B. Heisler, Jr.



Robert L. Loughhead

Russell W. Maier

John M. Pietruski

Robert N. Pokelwaldt

Paul J. Powers

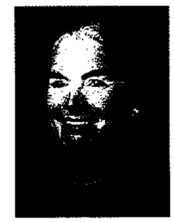
Catherine A. Rein

Robert C. Savage

George M. Smart

Carlisle A.H. Trost

Jesse T. Williams, Sr.



Dr. Patricia K. Woolf

H. Peter Burg, 56
Chairman of the Board and Chief Executive Officer of FirstEnergy Corp. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1989-1997.

Anthony J. Alexander, 51
President and Chief Operating Officer of FirstEnergy Corp. Director of FirstEnergy Corp. since 2002.

Dr. Carol A. Cartwright, 61
President, Kent State University, Kent, Ohio. Chair, Corporate Governance Committee; Member, Compensation Committee. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1992-1997.

William F. Conway, 72
President of William F. Conway & Associates, Inc., Scottsdale, Arizona. Chair, Nuclear Committee; Member, Audit Committee. Director of FirstEnergy Corp. since 1997 and of the former Centerior Energy from 1994-1997.

Robert B. Heisler, Jr., 54
Chairman of the Board and Chief Executive Officer of KeyBank, Cleveland, Ohio. Member, Compensation and Corporate Governance Committees. Director of FirstEnergy Corp. since 1998.

Robert L. Loughhead, 73
Retired, formerly Chairman of the Board, President and Chief Executive Officer of Weirton Steel Corporation, Weirton, West Virginia. Member, Audit and Finance Committees. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1980-1997.

Russell W. Maier, 66
President and Chief Executive Officer of Michigan Seamless Tube, South Lyon, Michigan. Member, Audit and Nuclear Committees. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1995-1997.

John M. Pietruski, 70
Chairman of the Board of Texas Biotechnology Corporation, Houston, Texas. Chair, Compensation Committee; Member, Finance Committee. Director of FirstEnergy Corp. since 2001 and of the former GPU from 1989-2001.

Robert N. Pokelwaldt, 66
Retired, formerly Chairman of the Board and Chief Executive Officer of YORK International Corporation, York, Pennsylvania. Member, Audit and Finance Committees. Director of FirstEnergy Corp. since 2001 and of the former GPU from 2000-2001.

Paul J. Powers, 68
Retired, formerly Chairman of the Board and Chief Executive Officer of Commercial Intertech Corp., Youngstown, Ohio. Chair, Finance Committee; Member, Compensation Committee. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1992-1997.

Catherine A. Rein, 60
President and Chief Executive Officer of Metropolitan Property and Casualty Insurance Company, Warwick, Rhode Island. Member, Audit and Compensation Committees. Director of FirstEnergy Corp. since 2001 and of the former GPU from 1989-2001.

Robert C. Savage, 65
President and Chief Executive Officer of Savage & Associates, Inc., Toledo, Ohio. Member, Finance and Nuclear Committees. Director of FirstEnergy Corp. since 1997 and of the former Centerior Energy from 1990-1997.

George M. Smart, 57
President of Sonoco-Phoenix, Inc., North Canton, Ohio. Chair, Audit Committee; Member, Compensation Committee. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1988-1997.

Carlisle A. H. Trost, 72
Admiral, United States Navy (Retired), former Chief of Naval Operations, Annapolis, Maryland. Member, Corporate Governance and Nuclear Committees. Director of FirstEnergy Corp. since 2001 and of the former GPU from 1990-2001.

Jesse T. Williams, Sr., 63
Retired, formerly Vice President of Human Resources Policy, Employment Practices and Systems of The Goodyear Tire & Rubber Company, Akron, Ohio. Member, Corporate Governance and Nuclear Committees. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1992-1997.

Dr. Patricia K. Woolf, 68
Consultant, Author, and Lecturer, in the Department of Molecular Biology at Princeton University, Princeton, New Jersey. Member, Corporate Governance and Nuclear Committees. Director of FirstEnergy Corp. since 2001 and of the former GPU from 1983-2001.

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