FirstEnergy

2003 ANNUAL REPORT

H. PETER BURG
1946 - 2004

We were deeply saddened by the untimely loss of FirstEnergy Chairman and Chief Executive Officer H. Peter Burg, who passed away on January 13, 2004. Mr. Burg had been undergoing treatment for leukemia.

Mr. Burg had an unwavering commitment to enhancing the value of your investment in FirstEnergy, and played a key role in helping your Company become the nation's fifth largest electric system. Under his leadership, our market value increased by $4 billion, and our customer base and assets doubled.

His contributions to customers and our communities were also significant, with his tireless support of many civic and business organizations that provided substantial benefits to the people we serve.

Mr. Burg was a man of the highest integrity who dedicated his life to his family, your Company, and our communities. His legacy includes the dedication and hard work of employees, who continue to be inspired by his vision, leadership and humanity.

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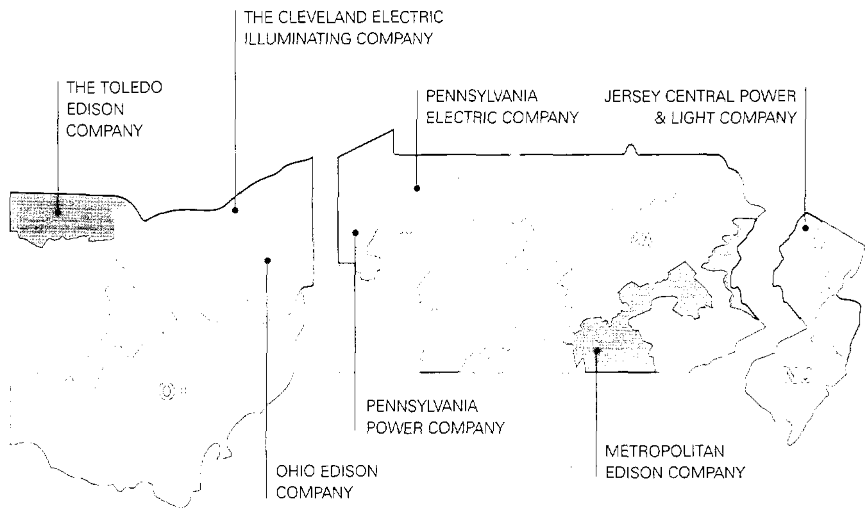
Electric Utility Operating Companies



CORPORATE PROFILE

FirstEnergy Corp. (NYSE: FE) is a registered public utility holding company headquartered in Akron, Ohio. FirstEnergy subsidiaries and affiliates are involved in the generation, transmission and distribution of electricity; exploration and production of oil and natural gas; transmission and marketing of natural gas; and energy management and other energy-related services.

FirstEnergy's electric utility operating companies comprise the nation's fifth largest investor-owned electric system, based on 4.4 million customers served.

FINANCIAL HIGHLIGHTS

(Dollars in thousands, except per share amounts)

	2003	2002
Total revenues	**$12,307,047**	$12,047,348
Income before discontinued operations and cumulative effect of accounting change*	**$421,996**	$632,667
Net income	**$422,764**	$552,804
Basic earnings per common share:		
Before discontinued operations and cumulative effect of accounting change	**$1.39**	$2.16
After discontinued operations and cumulative effect of accounting change	**$1.39**	$1.89
Diluted earnings per common share:		
Before discontinued operations and cumulative effect of accounting change	**$1.39**	$2.15
After discontinued operations and cumulative effect of accounting change	**$1.39**	$1.88
Dividends per common share	**$1.50**	$1.50
Book value per common share	**$25.35**	$24.01
Net cash from operations	**$1,952,462**	$1,915,287

** The 2003 and 2002 discontinued operations are described in Note 2(I) to the Consolidated Financial Statements. The 2003 accounting change is described in Note 2(J) to the Consolidated Financial Statements.*

The following analysis reconciles basic earnings per share of common stock in 2003 and 2002 computed under generally accepted accounting principles (GAAP) to adjusted basic earnings per share excluding unusual items in both years (non-GAAP)*.

	2003	2002
Adjusted basic earnings per share:		
Basic earnings per share (GAAP)	**$1.39**	$1.89
Claim settlement	**(0.33)**	—
Davis-Besse extended outage impacts	**0.56**	0.47
Rate case disallowance	**0.36**	—
Asset impairments	**0.41**	0.21
Retaining generating units planned for sale	—	0.06
Discontinued operations	**0.33**	0.27
Cumulative effect of accounting change	**(0.33)**	—
Other unusual items (see Management's Discussion)	**0.03**	0.13
Adjusted basic earnings per share (non-GAAP)	**$2.42**	$3.03

** Generally, a non-GAAP financial measure is a numerical measure of a company's historical or future financial performance, financial position, or cash flows that either excludes or includes amounts that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with GAAP.*

This report contains forward-looking statements within the meaning of Safe Harbor provisions of the United States Private Securities Litigation Reform Act of 1995. Investors are cautioned that such statements with respect to revenues, earnings, performance, strategies, prospects and other aspects of FirstEnergy's operations are based on current expectations that are subject to risks and uncertainties. For more information, please refer to FirstEnergy's Safe Harbor statement contained in this report and the Company's reports filed periodically with the Securities and Exchange Commission, or to the Company's Web site, *www.firstenergycorp.com.*

MESSAGE TO SHAREHOLDERS

The year 2003 was difficult for your Company. We faced a number of challenges, including restart efforts at Davis-Besse, the August 14 power outage and others detailed in this report. And, clearly, earnings of $1.39 per share of common stock were disappointing.

My top priority as your new chief executive officer is to increase the value of your investment by enhancing our operational performance and financial strength. With several key challenges behind us, including approval to restart Davis-Besse, we're on track to deliver strong performance in 2004 and in the years ahead.

Providing High-Quality Customer Service

With our electric business at the core, our road map to success continues to be our retail business strategy, which is disciplined, integrated and regional in scope. Our seven electric operating companies generate strong and stable cash flow and remain our platform for growth.

While three-quarters of customers surveyed continue to give us high marks in key areas – such as service reliability and restoration, and employee performance – we recognize we must continually work to ensure our service areas remain the preferred location for our customers to live and do business.

Among the steps we've taken are reorganizing and strengthening our Energy Delivery management team, providing an even greater focus on reliability, standardizing practices across our service areas, and enhancing our responsiveness and accountability to customers.

We're also making prudent and targeted system improvements to help ensure that all of our companies match the strong performance we've historically achieved. For example, to enhance service in New Jersey, we accelerated the investment of $60 million in system improvements. In addition, we've implemented an enhanced vegetation management program systemwide to further support our efforts to provide reliable customer service.

We completed the conversion of our computer system to an SAP-based platform. This new system provides significant benefits, including more comprehensive information for customer service and outage management programs.

We're also installing a state-of-the-art computer control system for our transmission operations that offers redundant capabilities for our control centers in Ohio and Pennsylvania. This process started prior to the August 14 outage.

As became clear after the outage, the transmission grid is being used in ways for which it wasn't designed, including large-scale, long-distance transfers of power by others across our part of the system.

The U.S.-Canada Power System Outage Task Force's interim report pointed to events on our system – including several transmission line trips and problems with our computer monitoring system – as some of the contributing factors. We have fully cooperated with the Task Force and various other reviews. However, we remain convinced, as do other experts, that the August 14 outage cannot be explained by the events on our system alone or on any other single utility system.

Enhancing the Performance of Our Generating Fleet

Our generating fleet delivered another year of strong performance in 2003, driven mainly by our baseload coal-fired plants. Capacity factors of these units reached a record 82 percent, and are on track to exceed that level in 2004.

We are optimizing our baseload units by operating them at more consistent output factors, instead of cycling them to follow customer load. This approach reduces wear and tear, lowers operating and maintenance costs, and improves our cost competitiveness.

Strong performance by our coal-fired plants helped offset last year's decline in nuclear power production resulting from the extended outage at Davis-Besse, and scheduled refueling outages at our Beaver Valley and Perry plants. However, with Davis-Besse's return to service and two fewer refueling outages scheduled in 2004, we expect to increase nuclear production by more

> "With our electric business at the core, our road map to success continues to be our retail business strategy, which is disciplined, integrated and regional in scope."

> "The hard work and dedication of employees pulled us through a very difficult period in our history...."

than one-third, which should help our generating fleet achieve record output this year.

During the extended outage at Davis-Besse, we replaced the damaged reactor vessel head; strengthened the management teams at the plant and within our FirstEnergy Nuclear Operating Company (FENOC) subsidiary; made numerous improvements to plant systems and equipment; and, most important, greatly enhanced the focus on safe operations by plant management and employees.

We invested a great deal of time and money to bring the 883-megawatt plant back on line because we believe that operating a baseload generating unit of this size will remain a competitive advantage. We're confident our nuclear fleet will achieve solid performance under FENOC's new business plan, which is designed to help our nuclear plants become top-quartile performers in the industry.

While strong performance by our generating fleet lowers our reliance on the wholesale market, we still are focused on ensuring sound risk management. In 2003, we enhanced our hedging strategy by implementing further protections against price volatility in the market that our Company and industry have faced in recent years.

Protecting the Environment

We're continuing to fulfill our commitment to protecting the environment, while meeting customer needs for reliable and affordable electricity.

Through the installation of selective catalytic reduction and other environmental control systems, as well as other measures, we've made steady progress, reducing emissions of nitrogen oxides by 60 percent and sulfur dioxide by 52 percent since 1990. Despite these results, the U.S. Environmental Protection Agency continues to pursue legal action against our W. H. Sammis Plant and dozens of other plants in the U.S.

We strongly disagree with an August 2003 federal district court decision related to that action. It adopted the EPA's claim that routine maintenance, repairs and replacements at our plant – like those performed for decades at coal-fired power plants across the country – triggered New Source Review provisions of the Clean Air Act, even though capacity and hourly emission rates did not increase. The remedy trial of the Sammis case is scheduled to begin in July. We continue to evaluate our legal options, which may include a resolution by the appellate courts because of conflicting judicial decisions in other cases.

Increasing Our Financial Strength and Flexibility

Increasing our financial strength remains a key element of our business strategy. We're focusing on specific initiatives, which include continuing to generate strong and stable cash flow and reducing costs.

We're also taking aggressive actions to improve our credit quality. Our common equity offering completed during the third quarter was an important step. We issued 32 million common shares, generating net proceeds of $935 million, which helped reduce net debt and preferred stock by $1.9 billion last year. These actions, along with refinancings and other activities to reduce interest costs during the year, are expected to produce approximately $155 million in annualized pre-tax savings.

At year-end, our adjusted debt ratio was 59 percent, and our goal is to lower that to about 50 percent by the end of 2005. We'll achieve that by continuing to dedicate our free cash flow – cash flow after the payment of common stock dividends and capital expenditures – to debt reduction.

We further strengthened our financial position by achieving savings of $120 million in 2003 related to our 2001 merger with the former GPU, Inc. We are on track to reach $150 million at the end of this year. We expect to save another $135 million by the end of 2004 through other cost-reduction initiatives.

And, we divested our remaining international holdings acquired through the GPU merger, as well as other non-core assets, consistent with our commitment to focus on our core electric business.

In addition, approval of our Ohio rate stabilization plan would provide a longer period of revenue and cash flow predictability for our Ohio operating companies and rate stability for customers.

While 2003 was a challenging year, our four-year annualized total shareholder return at year-end of 17.2 percent still ranked us 20th among the 64 U.S. investor-owned electric utilities that comprise the Edison Electric Institute Index. This key measure represents the market appreciation of common stock, including the reinvestment of dividends.

Delivering Stronger Performance

Our foundation for growth remains sound, and our commitment to delivering stronger performance is unwavering. The hard work and dedication of employees pulled us through a very difficult period in our history, which was compounded by the loss of our Chairman and CEO H. Peter Burg.

With their drive and resolve, and your support, we intend to enhance the value of your investment in FirstEnergy this year, and achieve continued success in the years ahead.

Sincerely,

Anthony J. Alexander

Anthony J. Alexander
President and Chief Executive Officer

March 19, 2004

FIRSTENERGY BOARD OF DIRECTORS

Dear Shareholders:

It is my honor to serve as chairman of FirstEnergy's Board of Directors. I want to assure you that your Board is continually reviewing its corporate governance policies and procedures in light of the challenges facing public companies today. Part of that effort has been to further enhance the already strong, independent oversight of the Board with my role as your Company's first non-executive chairman.

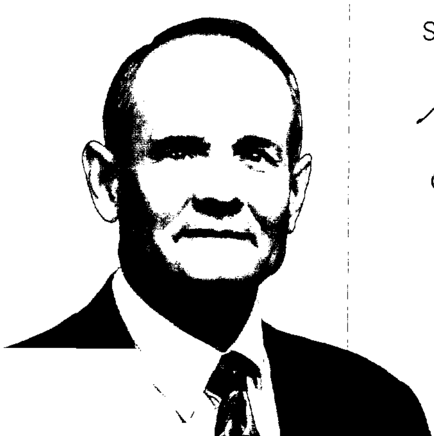
Your Board has taken additional actions related to corporate governance, including our recent decision on early termination of our Shareholder Rights Plan. We have implemented other policies, including holding executive sessions of independent directors following each regularly scheduled meeting of the Board, consistent with New York Stock Exchange guidelines.

We also have submitted for your vote at the 2004 Annual Meeting of Shareholders two other governance changes. The first would phase out the classified structure of the Board, meaning directors would be elected annually as opposed to serving three-year terms. The other would reduce the percentage of affirmative votes from 80 percent to two-thirds of shares outstanding needed for making certain amendments to the Company's governing documents.

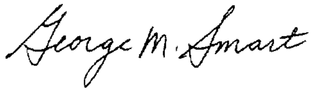
Your Board has been and remains fully committed to ensuring that appropriate and effective governance policies are in place to help your Company achieve continued success.

We all were saddened by the tragic loss of Chairman and CEO H. Peter Burg, who passed away in January. Pete's sound leadership helped guide the growth of FirstEnergy into one of the nation's largest investor-owned electric utility systems.

I also would like to extend the Board's sincere appreciation to directors Robert L. Loughhead and Robert B. Heisler, Jr., who are not standing for reelection, for their many contributions to your Company's growth and success.



Sincerely,



George M. Smart
Chairman of the Board

Paul T. Addison

Anthony J. Alexander

Robert N. Pokelwaldt

Paul J. Powers

Paul T. Addison, 57
Retired, formerly Managing Director of Salomon Smith Barney (Citigroup). Member, Audit and Finance Committees. Director of FirstEnergy Corp. since 2003.

Anthony J. Alexander, 52
President and Chief Executive Officer of FirstEnergy Corp. Director of FirstEnergy Corp. since 2002.

Dr. Carol A. Cartwright, 62
President, Kent State University. Chair, Corporate Governance Committee; Member, Compensation Committee. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1992-1997.

William T. Cottle, 58
Retired, formerly Chairman, President and Chief Executive Officer of STP Nuclear Operating Company. Chair, Nuclear Committee; Member, Corporate Governance Committee. Director of FirstEnergy Corp. since 2003.

Robert B. Heisler, Jr., 55
Chairman of the Board and Chief Executive Officer of KeyBank. Member, Compensation and Corporate Governance Committees. Director of FirstEnergy Corp. since 1998.

Dr. Carol A. Cartwright


William T. Cottle


Robert B. Heisler, Jr.


Robert L. Loughhead


Russell W. Maier


John M. Pietruski



Catherine A. Rein


Robert C. Savage


George M. Smart


Jesse T. Williams, Sr.


Dr. Patricia K. Woolf

Robert L. Loughhead, 74
Retired, formerly Chairman of the Board, President and Chief Executive Officer of Weirton Steel Corporation. Member, Audit and Finance Committees. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1980-1997.

Russell W. Maier, 67
President and Chief Executive Officer of Michigan Seamless Tube. Member, Audit and Nuclear Committees. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1995-1997.

John M. Pietruski, 71
Chairman of the Board of Encysive Pharmaceuticals, Inc. Chair, Compensation Committee; Member, Finance Committee. Director of FirstEnergy Corp. since 2001 and of the former GPU from 1989-2001.

Robert N. Pokelwaldt, 67
Retired, formerly Chairman of the Board and Chief Executive Officer of YORK International Corporation. Member, Audit and Finance Committees. Director of FirstEnergy Corp. since 2001 and of the former GPU from 2000-2001.

Paul J. Powers, 69
Retired, formerly Chairman of the Board and Chief Executive Officer of Commercial Intertech Corp. Chair, Finance Committee; Member, Compensation Committee. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1992-1997.

Catherine A. Rein, 61
President and Chief Executive Officer of Metropolitan Property and Casualty Insurance Company. Member, Audit and Compensation Committees. Director of FirstEnergy Corp. since 2001 and of the former GPU from 1989-2001.

Robert C. Savage, 66
Chairman of the Board of Savage & Associates, Inc. Member, Finance and Nuclear Committees. Director of FirstEnergy Corp. since 1997 and of the former Centerior Energy Corporation from 1990-1997.

George M. Smart, 58
Chairman of the FirstEnergy Board of Directors. Retired, formerly President of Sonoco-Phoenix, Inc. Chair, Audit Committee. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1988-1997.

Jesse T. Williams, Sr., 64
Retired, formerly Vice President of Human Resources Policy, Employment Practices and Systems of The Goodyear Tire & Rubber Company. Member, Corporate Governance and Nuclear Committees. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1992-1997.

Dr. Patricia K. Woolf, 69
Consultant, Author, and Lecturer, Department of Molecular Biology at Princeton University. Member, Corporate Governance and Nuclear Committees. Director of FirstEnergy Corp. since 2001 and of the former GPU from 1983-2001.

FirstEnergy Officers

FirstEnergy Corp.

Anthony J. Alexander
President and Chief Executive 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, FirstEnergy Solutions Corp. and FirstEnergy Nuclear Operating Company.

FirstEnergy Service Company

Anthony J. Alexander
President and Chief Executive Officer

Mark T. Clark
Senior Vice President

Charles E. Jones
Senior Vice President

Kevin J. Keough
Senior Vice President

Guy L. Pipitone
Senior Vice President

Carole B. Snyder
Senior Vice President

Thomas M. Welsh
Senior Vice President

Mary Beth Carroll
Vice President

Lynn M. Cavalier
Vice President

Kathryn W. Dindo
Vice President and Chief Risk Officer

Ralph J. DiNicola
Vice President

Michael J. Dowling
Vice President

Bradley S. Ewing
Vice President

Terrance G. Howson
Vice President

Ali Jamshidi
Vice President and Chief Information Officer

Mark A. Julian
Vice President

David C. Luff
Vice President

Stanley F. Szwed
Vice President

Bradford F. Tobin
Vice President and Chief Procurement Officer

Harvey L. Wagner
Vice President and Controller

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

FirstEnergy Solutions Corp.

Mark T. Clark
President

Douglas S. Elliott
Senior 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

Anthony J. Alexander
Chief Executive Officer

Gary R. Leidich
President and Chief Nuclear Officer

Joseph J. Hagan
Senior Vice President

Lew W. Myers
Chief Operating Officer

Mark B. Bezilla
Vice President, Davis-Besse

William R. Kanda
Vice President, Perry

L. William Pearce
Vice President, Beaver Valley

Frederick G. von Ahn
Vice President

Harvey L. Wagner
Vice President and Controller

David W. Whitehead
Corporate Secretary

FirstEnergy Regional Operations Management

Dennis M. Chack
Regional President
The Cleveland Electric Illuminating Company

Paul W. Allison
Regional Vice President
The Cleveland Electric Illuminating Company

Thomas A. Clark
Regional President
Ohio Edison Company

Jeffrey A. Elser
Regional Vice President
Ohio Edison Company

James M. Murray
Regional President
The Toledo Edison Company

Charles H. Krueger
Regional Vice President
The Toledo Edison Company

Stephen E. Morgan
President
Jersey Central Power & Light Company

Donald M. Lynch
Regional President
Jersey Central Power & Light Company

Steven E. Strah
Regional President
Jersey Central Power & Light Company

Stephen L. Feld
Regional Vice President
Jersey Central Power & Light Company

Ronald P. Lantzy
Regional President
Metropolitan Edison Company

Steven A. Schumacher
Regional Vice President
Metropolitan Edison Company

John E. Paganie
Regional President
Pennsylvania Electric Company

Jacqueline L. Roth
Regional Vice President
Pennsylvania Electric Company

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 auditors, have expressed an unqualified opinion on the Company's 2003 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 independent 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 auditors and the internal auditors; 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 is directly responsible for appointing the Company's independent auditors (subject to shareholder approval) and is charged with reviewing and approving all services performed for the Company by the independent auditors and for reviewing and approving the related fees. The Committee reviews the independent auditors' internal quality control procedures and reviews all relationships between the independent auditors 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 Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held ten meetings in 2003.

R.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 AUDITORS

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

In our opinion, the accompanying consolidated balance sheets and consolidated statements 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, 2003 and 2002 and the results of their operations and their cash flows for the years 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 audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion. The consolidated financial statements of FirstEnergy Corp. and subsidiaries for the year ended December 31, 2001, prior to the revisions described in Notes 2(F), 2(L) and 8, were audited by other independent auditors who have ceased operations. Those independent auditors expressed an unqualified opinion on those financial statements in their report dated March 18, 2002.

As discussed in Note 2(L) to the consolidated financial statements, the Company changed its method of accounting for goodwill as of January 1, 2002. As discussed in Note 2(F) to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations as of January 1, 2003. As discussed in Note 9 to the consolidated financial statements, the Company changed its method of accounting for the consolidation of variable interest entities as of December 31, 2003.

As discussed above, the consolidated financial statements of FirstEnergy Corp. and subsidiaries for the year ended December 31, 2001 were audited by other independent auditors who have ceased operations. As described in Note 2(L) to the consolidated financial statements, the financial statements have been revised 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. As described in Note 2(F) to the consolidated financial statements, the financial statements have been revised to include the transitional disclosures required by Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, which was adopted by the Company as of January 1, 2003. As described in Note 8 to the consolidated financial statements, the Company changed the composition of its reportable segments in 2002. We audited the transitional disclosures described in Notes 2(F) and 2(L) and the adjustments that were applied to restate the 2001 reportable segments disclosures discussed in Note 8. In our opinion, such adjustments to the reportable segments disclosures are appropriate and have been properly applied and the transitional disclosures for 2001 are appropriate. However, we were not engaged to audit, review, or apply any procedures to the 2001 consolidated financial statements of the Company other than with respect to such transitional disclosures and adjustments to the reportable segments disclosures and, accordingly, we do not express an opinion or any other form of assurance on the 2001 consolidated financial statements taken as a whole.

PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Cleveland, Ohio
February 25, 2004

The following report is a copy of a report previously issued by Arthur Andersen LLP (Andersen). This report has not been reissued by Andersen and Andersen did not consent to the incorporation by reference of this report into any of the Company's registration statements.
As discussed in Note 2(L) to the consolidated financial statements, the Company has revised its consolidated financial statements for the year ended December 31, 2001 to include the transitional disclosures required by Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets." As discussed in Note 2(F) to the consolidated financial statements, the Company has revised its consolidated financial statements for the year ended December 31, 2001 to include the transitional disclosures required by Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations." Additionally, as discussed in Note 8 to the consolidated financial statements, the Company has revised its consolidated financial statements for the year ended December 31, 2001 to reflect changes in the composition of its reportable segments adopted in 2002. The Andersen report does not extend to these changes. The revisions to the 2001 financial statements related to these transitional disclosures and the revisions that were applied to restate the 2001 reportable segments disclosures were reported on by PricewaterhouseCoopers LLP, as stated in their report appearing herein.

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,	2003	2002*	2001	2000	1999
Revenues	**$12,307,407**	$12,047,348	$ 7,999,362	$ 7,028,961	$ 6,319,647
Income Before Discontinued Operations and Cumulative Effect of Accounting Changes	**$ 421,996**	$ 632,667	$ 654,946	$ 598,970	$ 568,299
Net Income	**$ 422,764**	$ 552,804	$ 646,447	$ 598,970	$ 568,299
Basic Earnings per Share of Common Stock:					
Before Discontinued Operations and Cumulative Effect of Accounting Changes	**$ 1.39**	$ 2.16	$ 2.85	$ 2.69	$ 2.50
After Discontinued Operations and Cumulative Effect of Accounting Changes	**$ 1.39**	$ 1.89	$ 2.82	$ 2.69	$ 2.50
Diluted Earnings per Share of Common Stock:					
Before Discontinued Operations and Cumulative Effect of Accounting Changes	**$ 1.39**	$ 2.15	$ 2.84	$ 2.69	$ 2.50
After Discontinued Operations and Cumulative Effect of Accounting Changes	**$ 1.39**	$ 1.88	$ 2.81	$ 2.69	$ 2.50
Dividends Declared per Share of Common Stock	**$ 1.50**	$ 1.50	$ 1.50	$ 1.50	$ 1.50
Total Assets	**$32,909,948**	$34,386,353	$37,351,513	$17,941,294	$18,224,047
Capitalization as of December 31:					
Common Stockholders' Equity	**$ 8,289,341**	$ 7,050,661	$ 7,398,599	$ 4,653,126	$ 4,563,890
Preferred Stock:					
Not Subject to Mandatory Redemption	**335,123**	335,123	480,194	648,395	648,395
Subject to Mandatory Redemption	**–**	428,388	594,856	161,105	256,246
Long-Term Debt	**9,789,066**	10,872,216	12,865,352	5,742,048	6,001,264
Total Capitalization	**$18,413,530**	$18,686,388	$21,339,001	$11,204,674	$11,469,795

**See Note 2(I) regarding reclassification of discontinued operations.*

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.

	2003		2002	
First Quarter High-Low	**$35.19**	**$27.04**	$39.12	$30.30
Second Quarter High-Low	**38.90**	**30.57**	35.12	31.61
Third Quarter High-Low	**38.75**	**25.82**	34.78	24.85
Fourth Quarter High-Low	**35.95**	**31.66**	33.85	25.60
Yearly High-Low	**38.90**	**25.82**	39.12	24.85

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

HOLDERS OF COMMON STOCK

There were 153,020 and 152,288 holders of 329,836,276 shares of FirstEnergy's Common Stock as of December 31, 2003 and January 31, 2004, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 5(A).

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. Such statements are subject to certain risks and uncertainties. These 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, replacement power costs being higher than anticipated or inadequately hedged, maintenance costs being higher than anticipated, legislative and regulatory changes (including revised environmental requirements), adverse regulatory or legal decisions and the outcome of governmental investigations, availability and cost of capital, the continuing availability and operation of generating units, inability of the Davis-Besse Nuclear Power Station to restart (including because of an inability to obtain a favorable final determination from the Nuclear Regulatory Commission) in early 2004, the inability to accomplish or realize anticipated benefits from strategic goals, the ability to improve electric commodity margins and to experience growth in the distribution business, the ability to access the public securities market, further investigation into the causes of the August 14, 2003 regional power outage and the outcome, cost and other effects of present and potential legal and administrative proceedings and claims related to the outage, a denial of or material change to the Company's Application related to its Rate Stabilization Plan, and other similar factors.

FirstEnergy's Business

FirstEnergy Corp. is a registered public utility holding company headquartered in Akron, Ohio that provides regulated and competitive energy services (see Results of Operations – Business Segments). Our vision is to become the leading retail energy and related services provider in the northeast and mid-Atlantic region of the United States. Our eight electric utility operating companies (EUOC) comprise the nation's fifth largest investor-owned electric system, serving 4.4 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey.

Transmission and Distribution Services	Area Served	Customers Served
Ohio Edison Company (OE)	Central and northeastern Ohio	1,019,280
Pennsylvania Power Company (Penn)	Western Pennsylvania	155,929
The Cleveland Electric Illuminating Company (CEI)	Northeastern Ohio	752,537
The Toledo Edison Company (TE)	Northwestern Ohio	307,893
Jersey Central Power & Light Company (JCP&L)	Northern, western and east central New Jersey	1,049,547
Metropolitan Edison Company (Met-Ed)	Eastern Pennsylvania	516,536
Pennsylvania Electric Company (Penelec)	Western Pennsylvania	585,089
American Transmission Systems, Incorporated (ATSI)	Service areas of OE, Penn, CEI and TE	

Competitive services are principally provided by FirstEnergy Solutions Corp. (FES), FirstEnergy Facilities Services Group, LLC (FSG), MARBEL Energy Corporation, MYR Group, Inc., and our majority owned First Communications, LLC. Through its 50% interest in Great Lakes Energy Partners, LLC, MARBEL is involved in the exploration and production of oil and natural gas, and transmission and marketing of natural gas. Other subsidiaries provide a wide range of services, including heating, ventilating, air-conditioning, refrigeration, process piping, plumbing, electrical and facility control systems and high-efficiency electrotechnologies. Telecommunication services are also provided – local and long-distance phone service is provided to more than 65,000 customers. While competitive revenues have increased since 2001, regulated energy services continue to provide, in aggregate, the majority of FirstEnergy's revenues and earnings.

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. FES provides competitive retail energy services while the EUOC 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. Under the terms of the current corporate separation plan, the transfer of ownership of EUOC non-nuclear generating assets to FGCO would be substantially completed by the end of the Ohio market development period. All of the EUOC power supply requirements for the Ohio Companies (OE, CEI, and TE) and Penn are provided by FES to satisfy their provider of last resort (PLR) obligations, as well as their grandfathered wholesale contracts.

FirstEnergy acquired international assets in the merger with GPU, Inc. in November 2001. GPU Capital, Inc. and its subsidiaries had provided electric distribution services in foreign countries (see Results of Operations – Discontinued Operations). GPU Power, Inc. and its subsidiaries owned and operated generation facilities in foreign countries. As of January 30, 2004, all of the international operations had been divested (see Note 3) because those assets were not consistent with the role we envision for FirstEnergy in the energy industry.

Orderly Transition of Leadership

On January 13, 2004, FirstEnergy Chairman and Chief Executive Officer H. Peter Burg, passed away. Mr. Burg had taken a leave of absence beginning December 22, 2003, to undergo treatment for leukemia. At that time, the Board of Directors of FirstEnergy named President and Chief Operating Officer Anthony J. Alexander acting Chief Executive Officer. On January 20, 2004, the Board of Directors elected Mr. Alexander President and Chief Executive Officer, and also elected George M. Smart as Chairman. Mr. Smart was elected to Ohio Edison Company's Board of Directors in 1988 and to FirstEnergy's Board of Directors in 1997. Mr. Smart will not hold an executive position with FirstEnergy.

Strategy and Risks

We continue to pursue our goal of being the leading regional supplier of energy and related services in the northeast and mid-Atlantic region, where we see the best opportunities for growth. Our fundamental business strategy remains stable and unchanged. While we continue to build toward a strong regional presence, key elements for our strategy are in place and management's focus continues to be on execution. We intend to continue providing 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.

Our current focus includes: (1) minimizing unplanned extended generation outages; (2) improving our system reliability; (3) optimizing our generation portfolio; (4) effectively managing commodity supplies and risks; (5) reducing our cost structure; (6) enhancing our credit profile and financial flexibility; (7) managing the skills and diversity of our workforce; and (8) satisfactory resolution of the pending Ohio rate plan.

Risks

We face a number of industry and enterprise risks and challenges, among which include:

- Weather and other weather-related phenomena (short-term and long-term)
- General economic conditions and the resulting impact on our service-area economies
- Conditions in capital markets affecting availability of funds and interest rates
- Environmental laws and regulations
- Fluctuations in commodity prices
- Actions taken by regulatory agencies
- Changing competitive landscape
- Potential acts of terrorism

Supply Plan

Our affiliates are obligated to provide generation service with an estimated power supply of 100,000 gigawatt-hours for 2004. These obligations arise from customers who have elected to continue to receive generation service from our EUOCs under regulated retail rate tariffs and from customers who have selected FES as their alternate generation provider. Geographically, approximately 64% of the total generation service obligation is for customers located in the Midwest Independent System Operator (ISO) market area and 36% for customers located in the PJM Interconnection, LLC ISO market area. Included in the PJM ISO market area are obligations of FES to provide power to electric distribution companies in the state of New Jersey, including JCP&L. FES incurred this obligation as a successful bidder in the State of New Jersey's auction of basic generation service (BGS).

Within the franchise territories of the EUOC, alternative energy suppliers currently provide generation service for approximately 1,400 megawatts (MW) (summer peak) of load with an estimated energy requirement of 6,700 gigawatt-hours. If these alternate suppliers fail to deliver power to their customers located in the EUOC's service areas, the EUOC must procure replacement power in the role of PLR (See Note 2(D) for discussion of the auction of JCP&L's PLR obligation). The EUOC costs for any replacement power would be recovered under the applicable state regulatory rules.

To meet these generation service obligations, our affiliates own and operate 13,387 MW of installed generating capacity which for 2004 is expected to provide approximately 75% of the power supply required. The balance of the power supply expected to be required in 2004 has been secured through a mix of long-term purchases (term of contract greater than one year) and short-term purchases (term of contract less than one year). Changes in power supply requirements will be met through spot market transactions.

Davis-Besse Restoration

On April 30, 2002, the Nuclear Regulatory Commission (NRC) initiated a formal inspection process at the Davis-Besse nuclear plant. This action was taken in response to corrosion found by FirstEnergy Nuclear Operating Company (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 made significant management and human performance changes with the intent of re-establishing the proper safety culture throughout the workforce. Work was completed on the reactor head during 2002 and efforts continued in 2003 to focus on design enhancements to the unit's reliability and performance. We also accelerated maintenance work that had been planned for future refueling and maintenance outages. We installed a state-of-the-art leak-detection system around the reactor, as well as modified high-pressure injection pumps. Testing of the bottom of the reactor for leaks was completed in October 2003 and no indication of leakage was discovered. The focus of activities now involves management and human performance issues. As a result, incremental maintenance and capital expenditures declined in 2003 as emphasis shifted to performance issues; replacement power costs were higher in 2003. We anticipate that Davis-Besse will be ready for restart in the first quarter of 2004. The NRC must authorize restart of the plant following its formal inspection process before the unit can be returned to service. Delays in Davis-Besse's return to service contributed to Standard & Poor's (S&P's) reduction in our credit rating in the fourth quarter of 2003 (see Cash Flows from Financing Activities below).

Incremental costs associated with the extended

Davis-Besse outage for 2003 and 2002 were as follows:

Costs of Davis-Besse Extended Outage	2003	2002	Increase (Decrease)
		(In millions)	
Incremental Expense			
Replacement power	$196	$120	$ 76
Maintenance	93	115	(22)
Total	$289	$235	$ 54
Incremental Net of Tax Expense	$170	$138	$ 32
Capital Expenditures	$ 21	$ 63	$(42)

We anticipate spending $10 million in 2004 for remaining non-capital restart activities, expected NRC inspection activities after Davis-Besse's return to service and other related activities. No additional capital expenditures related to the restoration are expected. Replacement power costs are expected to be approximately $15–20 million per month during the remaining period of the outage. We have hedged the on-peak replacement energy supply for Davis-Besse for the expected length of the outage. If there are significant delays in the NRC approval process, replacement power costs will continue to be incurred, adversely affecting FirstEnergy's cash flows and results of operations.

Power Outage

On August 14, 2003, various states in the northeast United States and southern Canada experienced a widespread power outage. That outage affected approximately 1.4 million customers in FirstEnergy's service area. FirstEnergy continues to accumulate data and evaluate the status of its electrical system prior to and during the outage event, and continues to cooperate with the U.S.–Canada Power System Outage Task Force (Task Force) investigating the August 14th outage. The interim report issued by the Task Force on November 18, 2003 concluded that the problems leading up to the outage began in FirstEnergy's service area. Specifically, the interim report concludes, among other things, that the initiation of the August 14th outage resulted from the coincidence on that afternoon of the following events: (1) inadequate situational awareness at FirstEnergy; (2) FirstEnergy's failure to adequately manage tree growth in its transmission rights of way; and (3) failure of the interconnected grid's reliability organizations (Midwest ISO and PJM Interconnection) to provide effective diagnostic support. We believe that the interim report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14th outage and that it does not adequately address the underlying causes of the outage. We remain convinced that the outage cannot be explained by events on any one utility's system. On November 25, 2003, the PUCO ordered FirstEnergy to file a plan with the PUCO no later than March 1, 2004, illustrating how FirstEnergy will correct problems identified by the Task Force as events contributing to the August 14th outage and addressing how FirstEnergy proposes to upgrade its control room computer hardware and software and improve the training of control room operators to ensure that similar problems do not occur in the future. The PUCO, in consultation with the North American Electric Reliability Council, will review the plan before determining the next steps in the proceeding. On December 24, 2003, the Federal Energy Regulatory Commission (FERC) ordered FirstEnergy to pay for an independent study of part of Ohio's power grid. The study has commenced and will examine the stability of the grid in critical points in the Cleveland and Akron areas; the status of projected power reserves during summer 2004 through 2008; and the need for new transmission lines or other grid projects. The FERC ordered the study to be completed within 120 days. At this time, we do not know how the results of the study will impact FirstEnergy.

Restatements and Reclassifications

We filed an amended Form 10-K during 2003 to restate our consolidated financial statements for the year ended December 31, 2002 to reflect a change in the method of amortizing costs being recovered under the Ohio transition plan and to recognize above-market liabilities of certain leased generation facilities. In addition, the restated Consolidated Statement of Income for the year ended December 31, 2002 reflects reclassifying the results of divested businesses as discontinued operations (see Note 2(I)). Financial comparisons described below reflect the effect of these restatements and reclassifications of 2002 financial results. The 2001 results of the divested entities were not significant and the 2001 Consolidated Statement of Income was not reclassified to separately report discontinued operations.

Merger With GPU

On November 7, 2001, the merger of FirstEnergy and GPU became effective with FirstEnergy as 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 2003 and 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 ($3.8 billion) as of December 31, 2003, is not being amortized, reflecting the application of SFAS 142, "Goodwill and Other Intangible Assets." Goodwill is subject to review, at least annually, for potential impairment (see Critical 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 2003 and 2002 and for the seven-week period outstanding in 2001.

Results of Operations

Net Income and Earnings Per Share

Net income decreased to $423 million in 2003, compared to $553 million in 2002 and $646 million in 2001. Net income in 2003 and 2002 included after-tax charges for discontinued operations of $101 million and $80 million, respectively, or $0.33 and $0.27 per share (basic and diluted), primarily reflecting losses on the sale or abandonment of remaining international operations acquired through the merger with GPU (see Discontinued Operations below). Results for 2003 also include an after-tax credit of $102 million from the cumulative effect of an accounting change (basic and diluted earnings per share of $0.33). The 2003 credit resulted from the January 2003 adoption of SFAS 143, "Accounting for Asset Retirement Obligations." Net income in 2001 also included the cumulative effect of an accounting change resulting in a net after-tax charge of $9 million (see Cumulative Effect of Accounting Change below).

Major factors reducing net income in 2003, compared to 2002, included the adverse impact from the JCP&L rate case decision to disallow costs of $109 million ($0.36 per share of common stock), a non-cash goodwill impairment charge of $81 million ($0.27 per share of common stock), asset impairments of $47 million ($0.15 per share of common stock) and increased costs associated with the Davis-Besse extended outage of $32 million ($0.09 per share of common stock). Of the $81 million goodwill impairment charge, $3 million is included in the net of tax loss from discontinued operations. Partially offsetting these charges was a gain of $99 million or $0.33 per share of common stock representing net proceeds from the settlement of our claim against NRG Energy, Inc. relating to the terminated sale of four fossil power plants.

On September 17, 2003, we completed the issuance and sale of 32.2 million shares of common stock (see Cash Flows from Financing Activities below) which were included in the calculation of earnings per share on a weighted average basis in 2003. The additional shares reduced earnings per share of common stock by $0.04 (basic and diluted). If the shares had been outstanding for the entire year, basic and diluted earnings would have been reduced by $0.13 per share of common stock.

FirstEnergy	2003	2002	2001
		(In millions)	
Total revenues	$12,307	$12,047	$7,999
Income before interest and income taxes	1,640	2,115	1,685
Income before discontinued operations and cumulative effect of accounting changes	422	633	655
Discontinued operations	(101)	(80)	–
Cumulative effect of accounting changes	102	–	(9)
Net Income	$ 423	$ 553	$ 646
Basic Earnings Per Share:			
Income before discontinued operations and cumulative effect of accounting changes	$ 1.39	$ 2.16	$ 2.85
Discontinued operations	(0.33)	(0.27)	–
Cumulative effect of accounting changes	0.33	–	(.03)
Net Income	$ 1.39	$ 1.89	$ 2.82
Diluted Earnings Per Share:			
Income before discontinued operations and cumulative effect of accounting changes	$ 1.39	$ 2.15	$ 2.84
Discontinued operations	(0.33)	(0.27)	–
Cumulative effect of accounting changes	0.33	–	(0.03)
Net Income	$ 1.39	$ 1.88	$ 2.81

Unusual Items

Unusual charges (credits) included in income before discontinued operations and the cumulative effect of accounting changes are summarized in the following table:

Unusual Items (pre-tax)	2003	2002	2001
		(In millions)	
Investment impairments	$56	$101	$ –
Regulatory assets disallowance - JCP&L	185	–	–
Lake plants transaction			
– net settlement proceeds	(168)	–	–
– depreciation & sales costs	–	29	–
Goodwill impairment	117	–	–
Environmental liability	15	–	–
Long-term derivative contract adjustment	–	18	–
Generation project cancellation	–	17	–
Severance costs	–	11	–
Uncollectible reserve and contract losses	–	–	9
Early retirement costs	–	–	9
Estimated claim settlement	–	17	–
Decrease in Pre-tax Earnings	$205	$193	$18
Reduction to earnings per share of common stock:			
Basic	$0.47	$0.40	$0.05
Diluted	$0.47	$0.40	$0.05

Results of Operations - 2003 Compared With 2002

Sources of changes in total revenues are summarized in the following table:

Sources of Revenue Changes	2003	2002	Increase (Decrease)
		(In millions)	
Retail Electric Sales:			
Regulated services	$7,926	$8,229	$(303)
Competitive services	566	348	218
Wholesale Electric Sales:			
Regulated services	593	550	43
Competitive services	1,182	570	612
Electric Sales	10,267	9,697	570
Gas Sales	624	613	11
Other Revenues:			
Regulated – principally transmission services	459	386	73
Competitive products and services	886	964	(78)
International	25	294	(269)
Other	46	93	(47)
Total Revenues	$12,307	$12,047	$260

Changes in electric generation sales and distribution deliveries in 2003 are summarized in the following table:

Changes in KWH Sales	Increase (Decrease)
Electric Generation Sales:	
Retail -	
Regulated services	(7.2)%
Competitive services	53.0%
Wholesale	40.2%
Total Electric Generation Sales	8.3%
EUOC Distribution Deliveries:	
Residential	(0.7)%
Commercial and industrial	0.3%
Total Distribution Deliveries	– %

Retail electric sales from our regulated services segment declined principally due to increased sales by alternative suppliers in our franchise areas. Alternative suppliers provided 21.8% of the total energy delivered to retail customers in 2003, compared to 15.7% in 2002. As a result, generation kilowatt-hour sales to retail customers of our regulated services were 7.2% lower, which reduced retail electric sales revenues by $250 million. Additional credits provided to customers under the Ohio transition plan to promote customer shopping for alternative suppliers further reduced regulated retail electric sales revenues by

$45 million. The latter decreases in revenues, are deferred for future recovery under our Ohio transition plan and do not materially affect current period earnings.

Revenues from distribution deliveries decreased $8 million with kilowatt-hour deliveries to franchise customers unchanged in 2003. The slight decrease in revenues resulted from additional distribution deliveries to the commercial sector due to the strengthening in the service area economy toward the end of 2003 which nearly offset a slight decline in distribution deliveries to residential and industrial customers. Regulated retail revenues were reduced by the New Jersey Board of Public Utilities (NJBPU) decision in July 2003 (see State Regulatory Matters – New Jersey) that lowered JCP&L's base electric rates effective August 1, 2003, on an annualized basis, by approximately $62 million.

Retail sales by our competitive services segment increased by $218 million as a result of a 53% increase in kilowatt-hour sales. That increase primarily resulted from retail customers within our Ohio franchise areas switching to FES under Ohio's electricity choice program and from growth in competitive retail sales outside our franchise areas.

Revenues from the wholesale market increased significantly by $655 million and kilowatt-hour sales rose by 40%. A majority of the increase was due to sales by our competitive services segment for a portion of New Jersey's BGS requirements and sales in the spot market.

Higher electric sales revenues were more than offset by increased fuel and purchased power costs. Purchased power costs increased by $889 million due to higher unit costs and additional quantities purchased. Increased volumes were required to supply obligations assumed by FES for BGS sales in New Jersey, as well as other wholesale commitments, and additional supplies were required to replace reduced nuclear generation (down 14%). Reduced nuclear generation output resulted from additional refueling outage work performed at the Perry and Beaver Valley plants in 2003. Reported purchased power costs in 2003 also included $153 million of power costs that were disallowed in the JCP&L rate case decision (see State Regulatory Matters – New Jersey). Electric sales revenues net of fuel and purchased power reduced income before interest and taxes by $328 million.

Other factors contributing to reduced income before interest and taxes in 2003 include:

- Asset impairment charges of $56 million incurred in 2003 including a $26 million non-cash charge related to the divestiture of our interest in Termobarranquilla S.A., Empresa de Servicios Publicos (TEBSA), a Colombian electric generation operation; a $13 million impairment on the monetization of the note received from the sale of our 79.9% interest in Avon Energy Partners Holding's (see Note 3); an additional $5 million impairment upon the divestiture of our remaining interest in Avon; and $12 million related to the disposition of Northeast Ohio Natural Gas (see Note 2(I)) and the write down of our investment in Pantellos, an internet business-to-business marketplace serving the utility sector.
- A non-cash goodwill impairment charge of $117 million recorded in the third quarter of 2003 reducing the carrying value of FSG. This charge reflects the continued slow down in the development of competitive retail markets and depressed economic conditions that affect the value of FSG.
- Increased energy delivery costs of $86 million principally due to storm restoration expenses and an accelerated reliability program within JCP&L's service territory.
- Higher nuclear production costs of $54 million as a result of an additional nuclear refueling outage in 2003 and unplanned work performed during the refueling outages at the Perry Plant and Beaver Valley Unit 1. The higher production costs were partially offset by lower maintenance costs at the Davis-Besse Plant.
- Planned maintenance outages at three of our fossil generating plants during the fourth quarter of 2003 increased non-nuclear operating expenses by approximately $25 million.
- Increased postretirement plan expenses (see Postretirement Plans below) offset in part by lower incentive compensation costs contributed to a net cost increase of $94 million.
- Revenues less operating expenses for energy-related services declined $17 million due to general declines associated with economic conditions.
- An estimated environmental liability of $15 million was recognized in the fourth quarter of 2003.

Partially offsetting these higher costs were three factors:

- A settlement of our claim against NRG for the terminated sale of four fossil plants resulted in a $168 million gain.
- Charges for depreciation and amortization decreased by $17 million due to: higher shopping incentive deferrals under the Ohio transition plan ($45 million); lower charges resulting from the implementation of SFAS 143 ($61 million); revised service life assumptions for nuclear generating plants ($28 million) and reduced depreciation rates resulting from the JCP&L rate case ($18 million). Partially offsetting these decreases were higher charges resulting from increased amortization of the Ohio transition regulatory assets ($70 million), termination of tax related deferrals in 2003 ($36 million), and costs disallowed in the JCP&L rate case decision ($33 million).
- The absence of unusual charges recognized in 2002 resulted in a further net reduction of other operating expenses ($181 million) in 2003.

Income before discontinued operations and the cumulative effect of accounting changes decreased $211 million from the prior period. The change also reflects reduced net interest charges ($146 million) and income taxes ($118 million), in addition to the changes discussed above. The decrease in interest expenses reflects debt and preferred stock redemptions and financing activities and the sale of our 79.9% interest in Avon in 2002. Redemption and refinancing activities for debt and preferred stock aggregated approximately $2.582 billion during 2003. Proceeds from the issuance of 32.2 million shares of common stock in September 2003 accelerated the repayment of debt. The redemption and refinancing activities and pollution control note repricings are expected to result in annualized savings of $125 million. We also exchanged existing fixed-rate payments on outstanding debt (notional amount of $1.15 billion at year end 2003) 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 $27 million in 2003 as a result of these swaps. Counter parties called $594 million of our swaps during 2003 yielding total payments to FirstEnergy of $20 million. Interest expense in 2003 was reduced $4 million due to cancellation of the swaps related primarily to our unregulated generation capacity.

Discontinued Operations

In 2003 and 2002, discontinued operations were reflected for GPU Empresa Distribuidora Electrica Regional S.A. and affiliates (Emdersa) and Empresa Guaracachi S.A. (EGSA), as we substantially completed our exit from foreign operations acquired through the merger with GPU in 2001. In addition, the results for the FSG subsidiaries, Colonial Mechanical, Webb Technologies and Ancoma, Inc. and the MARBEL subsidiary, Northeast Ohio Natural Gas Corp., which were divested in 2003, have been reported as discontinued operations for the years 2003 and 2002. The following table summarizes the sources of losses from discontinued operations:

Discontinued Operations (Net of Tax)	2003	2002
	(In millions)	
Emdersa – Abandonment	$ (67)	$ –
EGSA – Loss on sale	(33)	–
Ancoma – Loss on sale	(3)	–
Total losses	(103)	–
Reclassification of operating income (loss) to discontinued operations	2	(80)
Total	$(101)	$(80)

Cumulative Effect of Accounting Change

Results in 2003 include an after-tax credit to net income of $102 million recorded upon the adoption of SFAS 143 in January 2003 (see discussion below). FirstEnergy identified applicable legal obligations as defined under the new standard for nuclear power plant decommissioning, reclamation of a sludge disposal pond at the Bruce Mansfield Plant and two coal ash disposal sites. As a result of adopting SFAS 143 in January 2003, asset retirement costs of $602 million were recorded as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $415 million. The asset retirement obligation (ARO) liability at the date of adoption was $1.107 billion, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. As of December 31, 2002, FirstEnergy had recorded decommissioning liabilities of $1.244 billion. FirstEnergy expects substantially all of its nuclear decommissioning costs for Met-Ed, Penelec, JCP&L and Penn to be recoverable in rates over time. Therefore, FirstEnergy recognized a regulatory liability of $185 million upon adoption of SFAS 143 for the transition amounts related to establishing the ARO for nuclear decommissioning for those companies. The remaining cumulative effect adjustment for unrecognized depreciation and accretion offset by the reduction in the existing decommissioning liabilities and the reversal of accumulated estimated removal costs for non-regulated generation assets, was a $175 million increase to income, or $102 million net of income taxes.

Earnings Effect of SFAS 143

The application of SFAS 143 (excluding the cumulative adjustment described above) resulted in the following changes to expense categories and net income in 2003:

Effect of SFAS 143	Increase (Decrease)
	(In millions)
Other operating expense:	
Cost of removal expenditures (previously included in depreciation)	$10
Depreciation:	
Elimination of decommissioning expense	(89)
Depreciation of asset retirement cost	2
Accretion of asset retirement liability	42
Elimination of removal cost component	(16)
Net decrease to depreciation	(61)
Income taxes	21
Net income effect	$30

Results of Operations - 2002 Compared With 2001

Net income in 2002 included an after-tax loss of $80 million for discontinued operations. The loss primarily resulted from our divesting ownership of Emdersa through the abandonment of our shares in the parent company of the Argentina operation. We reclassified the results of Emdersa for the year ended December 31, 2002, recording its after-tax loss as discontinued operations. In the fourth quarter of 2002 we recognized a $50 million impairment charge on our remaining 20.1% interest in Avon. Originally acquired as part of the merger with GPU, we previously sold a 79.9% equity interest in Avon to Aquila in May 2002.

As a result of our merger with GPU, results for 2002 include twelve months of operations for the former GPU companies compared to only seven weeks in 2001. The following table and related discussion excludes results for the former GPU companies in the 2002 and 2001 periods in order to provide a meaningful comparison.

FirstEnergy (Pre-Merger)	2002	2001	Increase (Decrease)
		(In millions)	
Total revenues	$7,235	$7,366	$(131)
Income before interest and income taxes	1,171	1,561	(390)
Income before discontinued operations and cumulative effect of accounting change	391	624	(233)
Discontinued operations	2	–	2
Cumulative effect of accounting change	–	(9)	9
Net Income	$ 393	$ 615	$(222)

Sources of changes in pre-merger revenues are summarized in the following table:

Sources of Revenue Changes	2002	2001	Increase (Decrease)
	(In millions)		
Retail Electric Sales:			
Regulated services	$4,282	$4,610	$(328)
Competitive services	348	212	136
Wholesale Electric Sales:			
Regulated services	319	303	16
Competitive services:			
Nonaffiliated	570	430	140
Affiliated (former GPU companies)	378	33	345
Electric Sales	5,897	5,588	309
Gas Sales	613	792	(179)
Other Revenues:			
Regulated – principally transmission services	248	246	2
Competitive products and services	477	740	(263)
Total Revenues	$7,235	$7,366	$(131)

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

Changes in KWH Sales	Increase (Decrease)
Electric Generation Sales:	
Retail –	
Regulated services	(14.2)%
Competitive services	59.0%
Wholesale	122.6%
Total Electric Generation Sales	22.0%
EUOC Distribution Deliveries:	
Residential	6.3%
Commercial and industrial	(3.2)%
Total Distribution Deliveries	(0.5)%

Retail electric sales from our regulated services segment declined due in large part to increased sales by alternative suppliers in our franchise areas (23.6% of total energy delivered in 2002 versus 11.3% in 2001). Generation kilowatt-hour sales to retail customers were 14.2% lower in 2002 than the prior year, which reduced retail electric sales revenues by $230 million.

Revenue from distribution deliveries decreased by $12 million or 0.4% in 2002 compared to 2001. Kilowatt-hour deliveries to franchise customers were lower due to a decline in kilowatt-hour deliveries to commercial and industrial customers as a result of sluggish economic conditions, offset in part by higher kilowatt-hour deliveries to residential customers primarily due to warmer summer weather in 2002.

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 million of additional credits. These reductions to revenues are deferred for future recovery under our Ohio transition plan and do not materially affect current period earnings.

Retail sales by our competitive services segment increased by $136 million as a result of a 59% increase in kilowatt-hour sales. 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.

Revenues from the wholesale market increased $501 million in 2002 from 2001 as 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 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 BGS.

Reduced gas revenues resulted principally from lower prices combined with a slight decline in sales volume. The elimination of coal trading activities in the second half of 2001 also contributed to the reduction in other competitive revenues along with reduced revenues from FSG primarily reflecting the divestiture of Colonial Mechanical and Webb Technologies in early 2003.

Higher electric revenues were more than offset by increased fuel and purchased power costs. Purchased power costs increased by $332 million due to additional volumes to cover supply obligations assumed by FES. Fuel expense increased $100 million principally due to additional internal generation (5.4% higher) and an increased mix of higher cost coal and natural gas generation in 2002. The extended outage at the Davis-Besse nuclear plant produced a 15% decline in nuclear generation. An increase in natural gas margins resulted from purchased gas costs (i.e. lower unit costs) declining more than our gas sales prices.

Higher other operating expenses also reduced income before interest and income taxes. Nuclear operating costs increased $125 million primarily due to $115 million of incremental Davis-Besse costs related to its extended outage (see Davis-Besse Restoration). An aggregate increase in administrative and general expenses and non-operating costs of $127 million resulted in large part from higher employee benefit expenses.

FSG revenues, net of related expenses, reduced income before interest and taxes by $13 million. A number of unusual charges further contributed to the decrease as follows:

Unusual Charges — Pre-Merger Companies (pre-tax)	2002	2001	Increase (Decrease)
	(In millions)		
Investment impairments	$48	$ –	$48
Lake Plants – sales costs	17	–	17
Long-term derivative contract adjustment	18	–	18
Generation project cancellation	17	–	17
Severance costs – 2002	11	–	11
Uncollectible reserve and contract losses	–	9	(9)
Early retirement costs – 2001	–	9	(9)
Estimated claim settlement	5	–	5
	$116	$18	$98

Charges for depreciation and amortization increased $74 million. This increase resulted from several factors: (1) higher amortization costs under the Ohio transition plan; (2) higher depreciation from the start-up of a new fluidized bed boiler in January 2002, owned by Bayshore Power Company, a wholly owned subsidiary; (3) new combustion turbine capacity added in late 2001; and (4) two months of 2001 depreciation ($12 million) recorded in 2002 (for the four fossil plants we chose not to sell) increased depreciation expense in 2002. However, two factors offset a portion of the above increase: shopping incentive deferrals and tax deferrals under the Ohio transition plan ($109 million) and the cessation of goodwill amortization ($56 million) beginning January 1, 2002.

General taxes increased $28 million principally due to additional property taxes and the absence in 2002 of a benefit of $15 million resulting from the successful resolution of certain property tax issues in the prior year.

Partially offsetting these higher costs were the elimination in the second half of 2001 of coal trading activities ($95 million) and the reversal of lease obligations related to the Bruce Mansfield fossil facility and Beaver Valley nuclear facility which reduced other operating expenses by $85 million.

Income before discontinued operations and cumulative effect of accounting changes decreased $233 million. The change reflects reduced net interest charges ($62 million) and income taxes ($95 million) in addition to the changes discussed above. 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 merger with GPU. Excluding activities related to the former GPU companies, redemption and refinancing activities for debt and preferred stock aggregated approximately $1.2 billion during 2002 and is expected to result in annualized savings of $86 million. We also exchanged existing fixed-rate payments on outstanding debt (principal amount of $594 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 for both pre-merger and post-merger companies were reduced by $17 million in 2002 as a result of these swaps. The related cash premiums will be recognized as a component of interest expense over the remaining maturity of each respective hedged security. The effective tax rate was 45.2% for 2002 compared to 42.0% in 2001. The increase in the effective tax rate was primarily attributable to new Ohio Franchise and Municipal income taxes implemented in 2002 as a result of Ohio Electric Restructuring.

Discontinued Operations

The divestiture of Colonial, Webb, Ancoma and Northeast Ohio Natural Gas resulted in their revenues and expenses, with net after-tax earnings of $2 million, being reported as discontinued operations in 2002.

Cumulative Effect of Accounting Change

In 2001, we adopted SFAS 133 (as amended), "Accounting for Derivative Instruments and Hedging Activities" resulting in a $9 million after-tax charge.

Postretirement Plans

Declines in equity markets in 2001 and 2002 and a reduction in our assumed discount rate in 2002 have combined to produce a negative trend in pension expenses. Also, increases in health care payments and a related increase in projected trend rates have led to higher other post-employment benefits (OPEB). The following table includes the portion of postretirement costs that were expensed in 2003 and 2002:

Postretirement Expenses (Income)	2003	2002	Increase
		(In millions)	
Pension	$123	$(14)	$137
OPEB	156	102	54
Total	$279	$88	$191

The following table presents the pre-tax pension and OPEB expenses for 2002 and 2001 excluding the former GPU companies.

Postretirement Expenses (Income)	2002	2001	Increase
		(In millions)	
Pension	$ 16	$(11)	$27
OPEB	99	87	12
Total	$115	$ 76	$39

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

PJM Interconnection Transactions

Our 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, 2003, are summarized as follows:

	2003	2002	2001
		(In millions)	
Sales	$990	$453	$142
Purchases	1,019	687	204

Our revenues on the Consolidated Statements of Income include wholesale electricity sales revenues from the PJM ISO for power sales (as reflected in the table above) during periods when we had additional available power for sale. Revenues also include our sales 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.

Results of Operations – Business Segments

We manage our business as two separate major business segments – regulated services and competitive services. The regulated services segment operates and maintains our regulated domestic transmission and distribution systems and also provides generation services to franchise customers who have not chosen an alternative generation supplier. The Ohio Companies (OE, CEI and TE) and Penn obtain generation through a power supply agreement with the competitive services segment. The competitive services segment also supplies a substantial portion of the PLR requirements for Met-Ed and Penelec through a wholesale contract. 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 such as heating, ventilation and air-conditioning. International operations, corporate support costs and interest costs on holding company debt are included in the aggregate "other" segment (see Note 8 for further discussion). Our two major business segments include all or a portion of the following business entities:

- Regulated operations include the regulated sale of electricity and distribution and transmission services by OE, CEI, TE, Penn, JCP&L, Met-Ed, Penelec and ATSI.
- Competitive operations include the operation of generation facilities owned by OE, CEI, TE and Penn, and all operations of FES, FSG, MYR, MARBEL and First Communications.

Financial results discussed below include revenues and expenses from transactions among our business segments. A reconciliation of segment financial results to consolidated financial results is provided in Note 8 to the consolidated financial statements. Net income (loss) by business segment was as follows:

Net Income (Loss) By Business Segment	2003	2002	2001
		(In millions)	
Regulated services	$986	$928	$729
Competitive services	(210)	(109)	(32)
Other	(353)	(266)	(51)
Total	$423	$553	$646

Excluding the results associated with the former GPU companies, comparable results for 2002 and 2001 are as follows:

Net Income (Loss) By Business Segment	2002	2001
	(In millions)	
Regulated services	$560	$674
Competitive services	(114)	(35)
Other	(53)	(24)
Total	$393	$615

Regulated Services

2003 versus 2002:
Financial results for 2003 and 2002 include an entire year of operations for the former GPU companies.

Regulated Services	2003	2002	Increase (Decrease)
		(In millions)	
Total revenues	$10,070	$10,218	$(148)
Income before interest and income taxes	2,034	2,214	(180)
Income before cumulative effect of accounting changes	885	928	(43)
Net Income	986	928	58

The change in operating revenues resulted from the following sources:

Sources of Revenue Changes	2003	2002	Increase (Decrease)
		(In millions)	
Electric:			
External sales	$ 8,519	$ 8,779	$(260)
Internal sales	777	741	36
	9,296	9,520	(224)
Other			
External sales	459	387	72
Internal sales	315	311	4
	774	698	76
Total Revenues	$10,070	$10,218	$(148)

External electric sales revenues declined $260 million, reflecting a $303 million decrease in retail revenues partially offset by a $43 million increase in sales to wholesale customers. The net decline in retail revenues resulted from the following factors:

- Reduced generation sales revenue of $250 million on a 7.2% reduction in kilowatt-hour sales (6.1 percentage point increase in generation provided to customers by alternative suppliers);
- Additional reductions to revenues from increased credits of $45 million provided to customers to promote shopping for alternative suppliers; and
- Lower revenues from distribution deliveries of $8 million.

The additional internal sales resulted from sales by the EUOC to FES.

Lower electric sales revenue due to reduced kilowatt-hour sales, an increase in purchased power costs and higher energy delivery and other costs, particularly employee benefit costs, combined to reduce income before interest and taxes by $391 million. The increase of $86 million in energy delivery costs was principally due to storm restoration expenses and an accelerated reliability plan within JCP&L's service territory. Partially offsetting these factors were:

- Settlement of our claim against NRG for the terminated sale of four fossil plants resulted in our recording a $168 million pre-tax credit to earnings.
- Charges for depreciation and amortization decreased $25 million. This decrease resulted from several factors: higher shopping incentive deferrals under the Ohio transition plan, lower charges resulting from the implementation of SFAS 143, revised service life assumptions for nuclear generating plants and reduced depreciation rates resulting from the JCP&L rate case. Partially offsetting these decreases were increased charges resulting from increased amortization of the Ohio transition regulatory assets, termination of tax related deferrals in 2003, and costs disallowed in the JCP&L rate case decision.
- The absence of unusual charges recognized in 2002 resulted in a further net reduction of other operating expenses ($35 million) from last year.

2002 versus 2001:
Excluding the results associated with the former GPU companies, comparable results for 2002 and 2001 are as follows:

Regulated Services (Pre-Merger)	2002	2001	(Decrease)
		(In millions)	
Total revenues	$5,870	$6,400	$(530)
Income before interest and income taxes	1,407	1,713	(306)
Net Income	560	674	(114)

Lower generation sales, additional transition plan incentives and a slight decline in revenue from distribution deliveries combined for a $312 million reduction in external revenues in 2002 from the prior year. Shopping by Ohio customers for alternative energy suppliers together with the effect of a sluggish national economy on our regional business reduced retail electric sales revenues. In addition, a $188 million decline in revenues resulted from lower sales to FES, due to the extended outage of the Davis-Besse nuclear plant, which reduced generation available for sale.

A reduction in purchased power costs of $180 million reflects the impact of the lower generation kilowatt-hour sales discussed above. Excluding the net effect of lower electric revenues and purchased power, income before interest and taxes increased $44 million. The increase was caused by reduced operating costs ($114 million) offset in part by higher depreciation ($59 million) and general taxes ($11 million). The increase in depreciation resulted from higher incremental transition costs partially offset by new deferred regulatory assets under the Ohio transition plan and the cessation of goodwill amortization beginning January 1, 2002.

Net income decreased $114 million. The change reflects decreased net interest charges ($132 million) and reduced income taxes ($60 million) in addition to the changes discussed above.

Competitive Services

2003 versus 2002:
Financial results for 2003 and 2002 include a full twelve months of operations for the former GPU companies.

Competitive Services	2003	2002	Increase (Decrease)
		(In millions)	
Total revenues	$5,402	$4,526	$876
Loss before interest and income tax benefit	(287)	(154)	(133)
Loss before discontinued operations and cumulative effect of accounting changes	(205)	(111)	(94)
Net loss	(210)	(109)	(101)

The change in total revenues resulted from the following sources:

Sources of Revenue Changes	2003	2002	Increase (Decrease)
		(In millions)	
Electric:			
External sales	$1,748	$918	$830
Internal sales	2,168	2,044	124
	3,916	2,962	954
Other External			
Natural Gas sales	624	613	11
Energy-related sales	766	904	(138)
Other	96	47	49
	1,486	1,564	(78)
Total Revenues	$5,402	$4,526	$876

The increase in external electric revenues resulted from:

- Retail sales increased by $218 million as a result of a 53% increase in kilowatt-hour sales. The increase primarily resulted from retail customers within our Ohio franchise areas switching to FES under Ohio's electricity choice program and from growth in competitive retail sales outside our franchise areas.
- Revenues from the wholesale market increased $612 million and kilowatt-hour sales rose by 75%. The increase reflects sales as an alternative supplier for a portion of New Jersey's BGS requirements.

Internal electric revenues increased from sales by FES to the EUOC to meet their energy requirements. Revenues from energy-related services declined 15% due to declines associated with weak economic conditions.

Electric revenue, net of purchased power costs and the absence of $69 million of unusual charges (representing the net of unusual changes in 2003 and 2002), contributed $185 million to income before interest and taxes. Offsetting these increases were:

- Recognition of a non-cash goodwill impairment charge of $117 million (excluding amount in discontinued operations) in the third quarter of 2003 reducing the carrying value of FSG. This charge reflects the continued slow down in the development of competitive retail markets and depressed economic conditions that affect the value of FSG.
- Nuclear production costs increased $54 million as a result of an additional nuclear refueling outage in 2003 and longer outages involving additional maintenance work, offset in part by reduced maintenance work at Davis-Besse.
- Planned maintenance outages at three of our fossil generating plants during the fourth quarter of 2003 increased non-nuclear operating expenses by approximately $25 million.
- Revenues less expenses for energy-related services declined $17 million due to declines associated with economic conditions.
- General taxes increased $15 million in 2003 compared to last year. Higher payroll and kilowatt-hour taxes in 2003 were the principal factors contributing to the increase.
- Higher depreciation and employee benefits costs also contributed to the decrease in income before interest and taxes.

2002 versus 2001:
Excluding the results associated with the former GPU companies, comparable results for 2002 and 2001 are as follows:

Competitive Services (Pre-Merger)	2002	2001	Increase (Decrease)
		(In millions)	
Total revenues	$4,005	$3,948	$57
Loss before interest and income tax benefit	(162)	(27)	(135)
Loss before discontinued operations and cumulative effect of accounting changes	(116)	(26)	(90)
Net loss	(114)	(35)	(79)

The $57 million increase in revenues in 2002, compared to 2001, is the net effect of several factors. Kilowatt-hour sales in the wholesale market more than doubled in 2002, increasing revenues by $485 million. More than half of the increase resulted from additional kilowatt-hour sales to Met-Ed and Penelec to supply a portion of their PLR requirements in Pennsylvania, as well as BGS sales in New Jersey and sales under several other contracts. Retail revenues increased by $137 million as a result of additional kilowatt-hour sales within Ohio under Ohio's electricity choice program. Total electric sales revenue increased $622 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 ($179 million) primarily due to lower prices, and less revenue from FSG ($213 million) reflecting its reclassification to discontinued operations and the sluggish economy. Internal sales to the regulated services segment decreased $180 million in large part due to the impact of customer shopping reducing requirements by the regulated services segment.

Higher electric revenues were nearly offset by increased fuel and purchased power costs. Higher purchased power costs resulted from additional volumes to cover supply obligations assumed by FES. Fuel costs increased in part due to an increased mix of higher cost fossil generation in 2002. The extended outage at the Davis-Besse nuclear plant produced a 15% decline in nuclear generation. Lower purchased gas costs due to lower unit costs more than offset reduced gas revenues resulting in an improvement in gas margins.

Nuclear operating costs increased $125 million primarily due to $115 million of incremental Davis-Besse costs related to its extended outage (see Davis-Besse Restoration). A number of unusual charges discussed above increased other expenses by $76 million in 2002.

Loss before discontinued operations and cumulative effect of accounting changes increased $90 million. The change reflects increased net interest charges ($20 million) and increased income tax benefit ($66 million), as well as the changes discussed above.

The divestiture of Colonial, Webb, Ancoma and Northeast Ohio Natural Gas resulted in their revenues and expenses, with net after-tax earnings of $2 million, being reported as discontinued operations in 2002.

Net income in 2001 also includes the cumulative effect of an accounting change from the adoption of SFAS 133, "Accounting for Derivative Instruments and Hedging Activities" which resulted in an after-tax charge of $9 million.

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 $1.25 billion through revolving credit facilities. In 2003, FirstEnergy received $864 million of cash dividends on common stock from its subsidiaries and paid $453 million in cash dividends on common stock to its shareholders. There are no material restrictions on the payments of cash dividends by FirstEnergy's subsidiaries.

As of December 31, 2003, we had $114 million of cash and cash equivalents, compared with $196 million as of December 31, 2002. Cash and cash equivalents as of December 31, 2003 included $32 million received in December 2003 which was included in the NRG settlement claim sold in January 2004 (see Note 3). Cash and cash equivalents as of December 31, 2002 included $50 million used for the redemption of long-term debt in January 2003. 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 provided from operating activities was $1.952 billion in 2003, $1.915 billion in 2002 and $1.282 billion in 2001, summarized as follows:

Operating Cash Flows	2003	2002	2001
		(In millions)	
Cash earnings [1]	$1,829	$1,655	$1,294
Working capital and other	123	260	(12)
Total	$1,952	$1,915	$1,282

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

Net cash provided from operating activities increased $37 million in 2003 compared to 2002 due to a $174 million increase in cash earnings and a $137 million decrease from changes in working capital. Net cash from operating activities in 2001 included seven weeks of results of the former GPU companies. Excluding the former GPU companies, 2002 and 2001 cash flows from operating activities totaled $1.464 billion and $1.572 billion, respectively, with the decrease principally reflecting reduced cash earnings.

Cash Flows From Financing Activities

In 2003 and 2002, the net cash used for financing activities of $1.323 billion and $1.123 billion, respectively, primarily reflects the redemptions of debt and preferred stock shown below. The following table provides details regarding new issues and redemptions during 2003 and 2002:

Securities Issued or Redeemed	2003	2002
	(In millions)	
New Issues		
Pollution Control Notes	$ –	$ 143
Transition Bonds (See Note 5(H))	–	320
Secured Notes	400	–
Unsecured Notes	627	210
Other, principally debt discounts	–	(4)
	$1,027	$ 669
Redemptions		
First Mortgage Bonds	$1,483	$ 728
Pollution Control Notes	238	93
Secured Notes	323	278
Unsecured Notes	85	189
Preferred Stock	127	522
Other, principally redemption premiums	–	21
	$2,256	$1,831
Short-term Borrowings, Net	$ (575)	$ 479

Net cash used for financing activities increased by $199 million in 2003 as compared to 2002. The increase in funds used for financing activities resulted from an increase in net redemptions of debt and preferred securities of $1.1 billion partially offset by $934 million of common equity financing in 2003.

We had approximately $522 million of short-term indebtedness at the end of 2003 compared to approximately $1.1 billion at the end of 2002. Available borrowing capability as of December 31, 2003 included the following:

Borrowing Capability	FirstEnergy Holding Company	OE	TE	Total
		(In millions)		
Long-Term Revolver	$875	$375	$ –	$1,250
Utilized	(270)	(40)	–	(310)
Letters of Credit	(184)	-	–	(184)
Net	421	335	–	756
Short-Term Facilities:				
Revolver	375	125	–	500
Bank	–	34	70	104
	375	159	70	604
Utilized:				
Revolver	(280)	–	–	(280)
Bank	–	(17)	(70)	(87)
Net	95	142	–	237
Amount Available	$516	$477	$ –	$993

At the end of 2003, the Ohio Companies and Penn had the aggregate capability to issue approximately $3.1 billion of additional first mortgage bonds (FMB) on the basis of property additions and retired bonds, although unsecured senior note indentures entered into by OE and CEI in 2003 limit each company's ability to issue secured debt, including FMBs, subject to certain exceptions. 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, 2003, JCP&L, Met-Ed and Penelec had the aggregate capability to issue $339 million of additional senior notes using FMB collateral. Based upon applicable earnings coverage tests in their respective charters, OE, Penn, TE and JCP&L could issue a total of $2.8 billion of preferred stock (assuming no additional debt was issued) as of the end of 2003. CEI, Met-Ed and Penelec have no restrictions on the issuance of preferred stock (see Note 5(E) – Long-Term Debt for discussion of debt covenants).

In March 2003, we filed a registration statement with the U.S. Securities and Exchange Commission covering securities in the aggregate of up to $2 billion. The shelf registration provides the flexibility to issue and sell various types of securities, including common stock, debt securities, and share purchase contracts and related share purchase units. In September 2003, we used approximately one-half of the amount available with a common stock issuance of 32.2 million shares at $30 per share for net proceeds of approximately $935 million.

At the end of 2003, our common equity as a percentage of capitalization stood at 45% compared to 38% and 35% at the end of 2002 and 2001, respectively. The higher common equity percentage in 2003 compared to 2001 reflects net redemptions of preferred stock and long-term debt, the issuance of equity discussed above, and the increase in retained earnings.

In October 2003, FirstEnergy restructured its $1 billion 364-day revolving credit facility through a syndicated bank offering that was completed on October 23, 2003. The new syndicated FirstEnergy facilities consist of a $375 million 364-day revolving credit facility and a $375 million three-year revolving credit facility. Also on October 23, 2003, OE entered into a syndicated $125 million 364-day revolving credit facility and a syndicated $125 million three-year revolving credit facility. Combined with an existing syndicated $500 million three-year facility for FirstEnergy, maturing in November 2004, and an existing syndicated $250 million two-year facility for OE, maturing in May 2005, FirstEnergy's primary syndicated credit facilities total $1.75 billion. These facilities are intended to provide liquidity to meet the short-term working capital requirements of FE and its subsidiaries. Available borrowing capacity under existing facilities totaled $993 million as of December 31, 2003.

Borrowings under these facilities are conditioned on FirstEnergy and/or OE maintaining compliance with certain financial covenants in the agreements. FirstEnergy, under its $375 million 364-day and $375 million three-year facilities, and OE, under its $125 million 364-day and $250 million two-year facilities, are each required to maintain a debt to total capitalization ratio of no more than 0.65 to 1 and a contractually-defined fixed charge coverage ratio of no less than 2 to 1. Under its $500 million three-year facility, FirstEnergy is required to maintain a debt to total capitalization ratio of no more than 0.69 to 1 and a contractually-defined fixed charge coverage ratio for the most recent fiscal quarter of no less than 1.5 to 1. FirstEnergy and OE are in compliance with all of these financial covenants. The ability to draw on each of these facilities is also conditioned upon FirstEnergy or OE making certain representations and warranties to the lending banks prior to drawing on their respective facilities, including a representation that there has been no material adverse change in its business, its condition (financial or otherwise), its results of operations, or its prospects.

None of FirstEnergy's or OE's primary credit facilities contain provisions, whereby their ability to borrow would be restricted or denied, or repayment of outstanding loans under the facilities accelerated, as a result of any change in the credit ratings of FirstEnergy or OE by any of the nationally-recognized rating agencies. Borrowings under each of the primary facilities do contain "pricing grids", whereby the cost of funds borrowed under the facilities is related to the credit ratings of the company borrowing the funds.

Our regulated companies have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among our competitive companies. FirstEnergy Service Company administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and competitive subsidiaries, as well as proceeds available from bank borrowings. For the regulated companies, available bank borrowings include $1.75 billion from FirstEnergy's and OE's revolving credit facilities. For the competitive companies, available bank borrowings include only the $1.25 billion of FirstEnergy's revolving credit facility. Companies receiving a loan under the money pool agreements must repay the principal amount of such a loan, together with accrued interest, within 364 days of borrowing the funds. For the regulated and competitive money pools, the rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in 2003 was 1.47% for the regulated companies' pool and 1.90% for the competitive companies' pool.

Our access to capital markets and costs of financing are dependent on the ratings of our securities. The following table shows our securities' ratings following the downgrade by Moody's Investors Service in February 2004. The ratings outlook on all securities is stable.

Ratings of Securities	Securities	S&P	Moody's	Fitch
FirstEnergy	Senior unsecured	BB+	Baa3	BBB-
OE	Senior secured	BBB	Baa1	BBB+
	Senior unsecured	BB+	Baa2	BBB
	Preferred stock	BB	Ba1	BBB-
CEI	Senior secured	BBB-	Baa2	BBB-
	Senior unsecured	BB+	Baa3	BB
	Preferred stock	BB	Ba2	BB-
TE	Senior secured	BBB-	Baa2	BBB-
	Senior unsecured	BB+	Baa3	BB
	Preferred stock	BB	Ba2	BB-
Penn	Senior secured	BBB-	Baa1	BBB+
	Senior unsecured [1]	BB+	Baa2	BBB
	Preferred stock	BB	Ba1	BBB-
JCP&L	Senior secured	BBB	Baa1	BBB+
	Preferred stock	BB	Ba1	BBB
Met-Ed	Senior secured	BBB	Baa1	BBB+
Penelec	Senior secured	BBB	Baa1	BBB+
	Senior unsecured	BBB-	Baa2	BBB

[1] Penn's only senior unsecured debt obligations are pollution control revenue refunding bonds issued in the name of the Ohio Air Quality Development Authority to which this rating applies.

On September 30, 2003, Fitch Ratings lowered the senior unsecured ratings of FirstEnergy to "BBB-" from "BBB." Fitch also lowered the senior secured, senior unsecured, and preferred stock ratings of Met-Ed, Penelec, CEI, and TE. In addition, Fitch affirmed the ratings of OE, Penn and JCP&L. Fitch announced that the Rating Outlook is Stable for the securities of FirstEnergy, and all of the securities of its electric utility operating companies. Fitch stated that the changes to the long-term ratings were "driven by the high debt leverage of the parent, FirstEnergy. Despite management's commitment to reduce debt related to the GPU merger, subsequent cash flows have been vulnerable to unfavorable events, slowing the pace of FirstEnergy's debt reduction efforts. The Stable Outlook reflects the success of FirstEnergy's recent common equity offering and management's focus on a relatively conservative integrated utility strategy."

On December 23, 2003, S&P lowered its corporate credit ratings on FirstEnergy and its regulated utility subsidiaries to "BBB-" from "BBB" and lowered FirstEnergy's senior unsecured debt rating to "BB+" from "BBB-". Except for OE's senior secured issue rating, which was left unchanged, all other subsidiary ratings were lowered one notch as well (see table above). The ratings were removed from CreditWatch with negative implications, where they had been placed by S&P on August 18, 2003, and the Ratings Outlook returned to Stable. The rating action followed a revision in S&P's assessment of our consolidated business risk profile to '6' from '5' ('1' equals low risk, '10' equals high risk), with S&P citing operational and management challenges as well as heightened regulatory uncertainty for its revision of our business risk assessment score. S&P's rationale for its revisions in our ratings included uncertainty regarding the timing of the Ohio Rate Plan filing (see State Regulatory Matters), the pending final report on the August 14th power outage (see Power Outage), the outcome of the remedial phase of litigation relating to the Sammis plant (see Environmental Matters), and the extended Davis-Besse outage and the related pending subpoena (see Davis-Besse Restoration). S&P further stated that the restart of Davis-Besse and a supportive Ohio Rate Plan extension will be vital positive developments that would aid an upgrade of FirstEnergy's ratings. S&P's reduction of our credit ratings in December 2003 triggered cash and letter-of-credit collateral calls (see Guarantees and Other Assurances below) in addition to higher interest rates for some outstanding borrowings.

On February 6, 2004, Moody's downgraded FirstEnergy senior unsecured debt to Baa3 from Baa2 and downgraded the senior secured debt of JCP&L, Met-Ed and Penelec to Baa1 from A2. Moody's also downgraded the preferred stock rating of JCP&L to Ba1 from Baa2 and the senior unsecured rating of Penelec to Baa2 from A2. The ratings of OE, CEI, TE and Penn were confirmed. Moody's said that the lower ratings were prompted by: "1) high consolidated leverage with significant holding company debt, 2) a degree of regulatory uncertainty in the service territories in which the company operates, 3) risks associated with investigations of the causes of the August 2003 blackout, and related securities litigation, and 4) a narrowing of the ratings range for the FirstEnergy operating utilities, given the degree to which FirstEnergy increasingly manages the utilities as a single system and the significant financial interrelationship among the subsidiaries."

Cash Flows From Investing Activities

Net cash flows used in investing activities totaled $712 million in 2003. The net cash used for investing was principally for 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 $21 million for capital additions at the Davis-Besse nuclear plant during its extended outage. The following table summarizes 2003 investments by our regulated services and competitive services segments:

Summary of 2003 Cash Flows Used for Investing Activities	Property Additions	Investments	Other	Total
Sources (Uses)		*(In millions)*		
Regulated Services	$(434)[1]	$(38)[3]	$16	$(456)
Competitive Services	(345)[2]	2[4]	(13)	(356)
Other	(77)	101[5]	76	100
Total	$(856)	$ 65	$79	$(712)

[1] Property additions primarily for transmission and distribution facilities.

[2] Property additions to generation facilities.

[3] Net of several items from cash and other investments and Penelec's nonutility generation (NUG) trust offset in part by investments in nuclear decommissioning trusts.

[4] Net proceeds from sale of assets.

[5] Proceeds from Aquile Note.

In 2002, net cash flows used in investing activities totaled $816 million, principally due to property additions ($998 million) which were partially offset by proceeds from the sale of Midlands ($155 million).

Net cash used for investing activities decreased by $104 million in 2003 compared to 2002 primarily due to decreased capital expenditures partially offset by net changes in nuclear decommissioning and NUG trust investments and decreased proceeds from sale of assets.

Our cash requirements in 2004 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. In addition, a refunding payment of $50 million was made to the NUG trust fund (see State Regulatory Matters – Pennsylvania) in January 2004. Available borrowing capacity under existing credit facilities will be used to manage working capital requirements. Over the next three years, we expect our cash requirements will be met with cash from operations and funds from the capital markets, if needed.

Our capital spending for the period 2004-2006 is expected to be about $2.3 billion (excluding nuclear fuel), of which approximately $713 million applies to 2004. Investments for additional nuclear fuel during the 2004-2006 period are estimated to be approximately $323 million, of which about $90 million applies to 2004. During the same period, our nuclear fuel investments are expected to be reduced by approximately $285 million and $93 million, respectively, as the nuclear fuel is consumed.

Contractual Obligations

Our cash contractual obligations as of December 31, 2003 that we consider firm obligations are as follows:

Contractual Obligations	Total	2004	2005-2006	2007-2008	Thereafter
			(In millions)		
Long-term debt	$11,471	$1,256	$1,964	$ 572	$ 7,679
Short-term borrowings	522	522	–	–	–
Preferred stock[1]	19	2	4	13	–
Capital leases[2]	24	6	10	2	6
Operating leases[2]	2,545	182	363	358	1,642
Pension funding[3]	835	–	546	289	–
Purchases[4]	15,145	2,603	3,886	3,325	5,331
Total	$30,561	$4,571	$6,773	$4,559	$14,658

[1] Subject to mandatory redemption.

[2] See Note 4.

[3] Amounts represent our estimate of the contributions necessary to maintain our defined benefit pension plan's funding at a minimum required level as determined by government regulations. Amounts are subject to change based on the performance of the assets in the plan as well as the discount rate used to determine the obligation. We are unable to estimate the projected contributions beyond 2007.

[4] Fuel and power purchases under contracts with fixed or minimum quantities and approximate timing.

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 letters of credit. Some contracts contain ratings contingent collateralization provisions.

As of December 31, 2003, the maximum potential future payments under outstanding guarantees and other assurances totaled approximately $1.9 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure
	(In millions)
FirstEnergy Guarantees of Subsidiaries	
Energy and Energy-Related Contracts[1]	$ 857
Other[2]	174
	1,031
Surety Bonds	161
Letters of Credit[3][4]	678
Total Guarantees and Other Assurances	$1,870

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

[2] Issued for various terms.

[3] Includes letters of credit of $184 million issued for various terms under letter of credit capacity available in FirstEnergy's revolving credit agreement.

[4] Includes unsecured letters of credit of approximately $216 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by CEI and TE (see Note 5(E)), as well as collateralized letters of credit of $278 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE (see Note 4).

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 financing 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 that such parental guarantees will increase amounts otherwise paid by us to meet our obligations incurred in connection with ongoing energy and energy-related contracts is remote.

While these types of guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating-downgrade or "material adverse event" the immediate payment of cash collateral or provision of a letter of credit may be required. The following table summarizes collateral provisions as of December 31, 2003:

Collateral Provisions	Total Exposure	Collateral Paid Cash	Letters of Credit	Remaining Exposure[1]
		(In millions)		
Rating downgrade	$187	$68	$5	$114
Adverse event	235	–	65	170
Total	$422	$68	$70	$284

[1] As of February 11, 2004, we had a remaining exposure of $282 million with $106 million of cash and $87 million of letters of credit provided as collateral.

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.

We have guaranteed the obligations of the operators of the TEBSA project, up to a maximum of $6.0 million (subject to escalation) under the project's operations and maintenance agreement. In connection with the sale of TEBSA in January 2004, the purchaser indemnified FirstEnergy against any loss under this guarantee. We have provided the TEBSA project lenders a $50 million letter of credit (LOC) (under our existing $250 million LOC capacity available as part of our $1.25 billion credit facilities) to obtain TEBSA lender consent as substitute collateral for the release of the assets for us to abandon our Argentina operations, Emdersa (see Note 3). In December 2003, a replacement LOC was issued in the amount of $60 million, which is renewable and declines yearly based upon the senior outstanding debt of TEBSA. This LOC granted us the ability to sell our remaining 20.1% interest in Avon, as well as abandon the Argentina assets in April 2003.

Off-Balance Sheet Arrangements

We have obligations that are not included on our Consolidated Balance Sheets related to the sale and leaseback arrangements involving Perry Unit 1, Beaver Valley Unit 2 and the Bruce Mansfield Plant, which are reflected as part of the operating lease payments disclosed above (see Notes 4 and 9). The present value of these sale and leaseback operating lease commitments, net of trust investments, total $1.4 billion as of December 31, 2003.

CEI and TE sell substantially all of their retail customer receivables to Centerior Funding Corporation (CFC), a wholly owned subsidiary of CEI. CFC subsequently transfers the receivables to a trust (a "qualified special purpose entity") under SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities," under an asset-backed securitization agreement. This provided $200 million of off-balance sheet financing as of December 31, 2003. See Note 2(C) for additional discussion about this arrangement.

As of December 31, 2003, off-balance sheet arrangements include certain statutory business trusts created by CEI, Met-Ed and Penelec to issue trust preferred securities aggregating $285 million. These trusts were included in the consolidated financial statements of FirstEnergy prior to adoption of FASB Interpretation No. 46, "Consolidation of Variable Interest Entities", but have subsequently been deconsolidated under "FIN 46R" (see Note 9 - New Accounting Standards and Interpretations). This has not resulted in any change in outstanding debt.

FirstEnergy has equity ownership interests in certain various businesses that are accounted for using the equity method. There are no undisclosed material contingencies related to these investments. Certain guarantees that we do not expect to have a material current or future effect on our financial condition, liquidity or results of operations are disclosed under contractual obligations above.

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 2003 is summarized in the following table:

Increase (Decrease) in the Fair Value Derivative Contracts	Non-Hedge	Hedge	Total
		(In millions)	
Change in the fair value of commodity derivative contracts			
Outstanding net asset as of January 1, 2003	$ 54	$ 24	$ 78
Additions/Increase in value of existing contracts	8	35	43
Change in techniques/assumptions	9	–	9
Settled contracts	(4)	(47)	(51)
Outstanding net asset as of December 31, 2003[1]	67	12	79
Non-commodity net assets as of December 31, 2003:			
Interest Rate Swaps[2]	–	(6)	(6)
Net Assets - Derivatives Contracts as of December 31, 2003[3]	**$ 67**	**$ 6**	**$ 73**
Impact of Changes in Commodity Derivative Contracts[4]			
Income Statement Effects (Pre-Tax)	$(13)	$ –	$(13)
Balance Sheet Effects:			
OCI (Pre-Tax)	$ –	$(12)	$(12)
Regulatory Liability	$ 26	$ –	$ 26

[1] Includes $61 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 $17 million of derivative contract fair value decrease, 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 are included on the Consolidated Balance Sheet as of December 31, 2003 as follows:

Balance Sheet Classification	Non-Hedge	Hedge	Total
	(In millions)		
Current-			
Other Assets	$13	$2	$15
Other Liabilities	(8)	–	(8)
Non-Current-			
Other Deferred Charges	62	14	76
Other Noncurrent Liabilities	–	(10)	(10)
Net assets	$67	$6	$73

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 commodity derivative contracts by year are summarized in the following table:

Source of Information – Fair Value by Contract Year	2004	2005	2006	2007	Thereafter	Total
			(In millions)			
Prices actively quoted[1]	$11	$1	$ –	$ –	$ –	$12
Other external sources[2]	15	10	–	–	–	25
Prices based on models	-	–	10	9	23	42
Total[3]	**$26**	**$11**	**$10**	**$9**	**$23**	**$79**

[1] Exchange traded.

[2] Broker quote sheets.

[3] Includes $61 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, 2003. We estimate that if energy commodity prices experienced an adverse 10% change, net income for the next twelve months would decrease by approximately $3 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 following table.

Comparison of Carrying Value to Fair Value

Year of Maturity	2004	2005	2006	2007	2008	There-after	Total	Fair Value
Assets				*(Dollars in millions)*				
Investments other than Cash and Cash Equivalents-								
Fixed Income	$326	$64	$82	$77	$57	$1,882	**$2,488**	**$2,597**
Average interest rate	7.5%	7.8%	7.8%	7.9%	7.7%	6.2%	6.6%	
Liabilities								
Long-term Debt and Other Long-Term Obligations:								
Fixed rate[1]	$986	$547	$1,377	$237	$335	$6,644	**$10,126**	**$10,625**
Average interest rate	7.3%	7.3%	5.7%	6.6%	5.3%	6.7%	6.6%	
Variable rate[1]	$270	$40				$1,035	**$1,345**	**$1,345**
Average interest rate	2.4%	2.3%				2.3%	2.4%	
Preferred Stock Subject to Mandatory Redemption	$2	$2	$2	$12	$1		**$19**	**$19**
Average dividend rate	7.5%	7.5%	7.5%	7.6%	7.4%		7.6%	
Short-term Borrowings	$522						**$522**	**$522**
Average interest rate	2.1%						2.1%	

[1] Balances and rates do not reflect the fixed-to-floating interest rate swap agreements discussed 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. While fluctuations in the fair value of our Ohio EUOC decommissioning 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, there is not expected to be an earnings effect from fluctuations in their decommissioning trust balances. As of December 31, 2003, decommissioning trust balances totaled $1.352 billion, with $797 million held by our Ohio EUOC and the balance held by our non-Ohio EUOC. As of year end 2003, trust balances of our Ohio EUOC included 62% of equity securities and 38% of debt instruments.

Interest Rate Swap Agreements

We have entered into various fixed-to-floating interest rate swap agreements, as part of our ongoing effort to manage the interest rate risk of our debt portfolio. 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, fixed interest rates and interest payment dates match those of the underlying obligations. Reductions to interest expense recorded in 2003 and 2002 due to the difference between fixed and variable debt rates totaled $27 million and $17 million, respectively. As of December 31, 2003, the debt underlying the interest rate swaps had a weighted average fixed interest rate of 5.39%, which the swaps have effectively converted to a current weighted average variable interest rate of 2.06%. GPU Power (through a subsidiary) used existing dollar-denominated interest rate swap agreements in 2003. The swaps 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 2003 and 2002. The following summarizes the principal characteristics of the swap agreements:

	December 31, 2003			December 31, 2002		
Interest Rate Swaps	Notional Amount	Maturity Date	Fair Value	Notional Amount	Maturity Date	Fair Value
	(Dollars in millions)					
Fixed to Floating Rate						
(Fair value hedges)	$200	2006	$1			
	50	2008	–			
	100	2010	1			
	100	2011	1			
	350	2013	(1)			
	150	2015	(10)			
	150	2018	1			
	50	2019	1			
	–	–	–	$444	2023	$16
	–	–	–	150	2025	6
Floating to Fixed Rate*						
(Cash flow hedges)	$ 7	2005	$ –	$ 16	2005	$ (1)

* *FirstEnergy no longer had the cash flow hedges as of January 30, 2004 as a result of GPU Power divestiture (see Note 3).*

Equity Price Risk

Included in nuclear decommissioning trusts are marketable equity securities carried at their market value of approximately $779 million and $532 million as of December 31, 2003 and 2002, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges, would result in a $78 million reduction in fair value as of December 31, 2003 (see Note 2(M) – Cash and Financial Instruments).

Foreign Currency Risk

Due to the disposition of foreign operations, we are no longer exposed to foreign currency risk from investments in international business operations. In 2002, we experienced net foreign currency translation losses in connection with our Argentina operations (see Note 3 – Divestitures).

Credit Risk

Credit risk is the risk of an obligor's failure to meet the terms of any investment contract, loan agreement or otherwise perform as agreed. Credit risk arises from all activities in which success depends on issuer, borrower or counterparty performance, whether reflected on or off the balance sheet. We engage in transactions for the purchase and sale of commodities including gas, electricity, coal and emission allowances. These transactions are often with major energy companies within the industry.

We maintain stringent credit policies with respect to our counterparties that management believes minimizes overall credit risk. This includes performing independent risk evaluations, actively monitoring portfolio trends and using collateral and contract provisions to mitigate exposure. As part of our credit program, we aggressively manage the quality of our portfolio of energy contracts evidenced by a current weighted risk S&P rating for energy contract counterparties of "BBB." As of December 31, 2003, the largest credit concentration to any counterparty was 8 percent – which is a currently rated investment grade counterparty.

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 customers in the EUOC's service areas;
- allowing recovery of transition costs (sometimes referred to as stranded investment) not otherwise recoverable in a competitive generation market;
- itemizing (unbundling) the price of electricity into its component elements – including generation, transmission, distribution and transition costs recovery charges;
- deregulating the electric generation businesses;
- continuing regulation of the EUOC's transmission and distribution systems; and
- requiring corporate separation of regulated and unregulated business activities.

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	2003	2002	(Decrease)
		(In millions)	
OE	$1,451	$1,787	$(336)
CEI	1,056	1,145	(89)
TE	459	545	(86)
Penn	28	151	(123)
JCP&L	2,558	3,058	(500)
Met-Ed	1,028	1,179	(151)
Penelec	497	600	(103)
Total	$7,077	$8,465	$(1,388)

Regulatory assets by source are as follows:

Regulatory Assets By Source As of December 31	2003	2002	Increase (Decrease)
		(In millions)	
Regulatory transition charge	$6,427	$7,608	$(1,181)
Customer shopping incentives	371	188	183
Customer receivables for future income taxes	340	394	(54)
Societal benefits charge	81	144	(63)
Loss on reacquired debt	75	74	1
Postretirement benefits	77	88	(11)
Nuclear decommissioning, decontamination and spent fuel disposal costs	(96)	99	(195)
Component removal costs	(321)	(288)	(33)
Property losses and unrecovered plant costs	70	88	(18)
Other	53	70	(17)
Total	$7,077	$8,465	$(1,388)

Ohio

FirstEnergy's transition plan for the Ohio EUOC included approval for recovery of transition costs, including regulatory assets, 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; granting 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 EUOC's retail customers; and freezing customer prices 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 EUOC 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. Subject to approval by the PUCO, recovery will be accomplished by extending the respective transition cost recovery period.

On October 21, 2003, the Ohio EUOC filed an application with the PUCO to establish generation service rates beginning January 1, 2006, in response to expressed concerns by the PUCO about price and supply uncertainty following the end of the market development period. The filing included two options:

- A competitive auction, which would establish a price for generation that customers would be charged during the period covered by the auction, or
- A Rate Stabilization Plan, which would extend current generation prices through 2008, ensuring adequate generation supply at stable prices, and continuing our support of energy efficiency and economic development efforts.

Under the first option, an auction would be conducted to secure generation service for our Ohio EUOC's customers. Beginning in 2006, customers would pay market prices for generation as determined by the auction.

Under the Rate Stabilization Plan option, customers would have price and supply stability through 2008 – three years beyond the end of the market development period – as well as the benefits of a competitive market. Customer benefits would include: customer savings by extending the current five percent discount on generation costs and other customer credits; maintaining current distribution base rates through 2007; market-based auctions that may be conducted annually to ensure that customers pay the lowest available prices; extension of our support of energy-efficiency programs and the potential for continuing the program to give preferred access to nonaffiliated entities to generation capacity if shopping drops below 20%. Under the proposed plan, we are requesting:

- Extension of the transition cost amortization period for OE from 2006 to 2007; for CEI from 2008 to 2009 and for TE from mid-2007 to 2008;
- Deferral of interest costs on the accumulated shopping incentives and other cost deferrals as new regulatory assets; and
- Ability to initiate a request to increase generation rates under certain limited conditions.

On January 7, 2004, the PUCO staff filed testimony on the proposed rate plan generally supporting the Rate Stabilization Plan as opposed to the competitive auction proposal. Hearings began on February 11, 2004. On February 23, 2004, after consideration of PUCO staff comments and testimony as well as those provided by some of the intervening parties, FirstEnergy made certain modifications to the Rate Stabilization Plan. A decision is expected from the PUCO in the Spring of 2004.

On November 25, 2003, the PUCO ordered FirstEnergy to file a plan with the PUCO no later than March 1, 2004, illustrating how FirstEnergy will address certain problems identified by the U.S.-Canada Power System Outage Task Force (in connection with the August 14, 2003 regional power outage) and addressing how FirstEnergy proposes to upgrade its control room computer hardware and software, improve its control room training procedures and improve the training of control room operators to ensure that similar problems do not occur in the future. The PUCO, in consultation with the North American Electric Reliability Council, will review the plan before determining the next steps in the proceeding.

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. JCP&L's two August 2002 rate filings requested increases in base electric rates of approximately $98 million annually and requested the recovery of deferred energy 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 (see Note 5(H)). On July 25, 2003, the NJBPU announced its JCP&L base electric rate proceeding decision which reduced JCP&L's annual revenues by approximately $62 million effective August 1, 2003. The NJBPU decision also provided for an interim return on equity of 9.5% on JCP&L's rate base for the next six to twelve months. During that period, JCP&L will initiate another proceeding to request recovery of additional costs incurred to enhance system reliability. In that proceeding, the NJBPU could increase the return on equity to 9.75% or decrease it to 9.25%, depending on its assessment of the reliability of JCP&L's service. Any reduction would be retroactive to August 1, 2003. The revenue decrease in the decision consists of a $223 million decrease in the electricity delivery charge, a $111 million increase due to the August 1, 2003 expiration of annual customer credits previously mandated by the New Jersey transition legislation, a $49 million increase in the MTC tariff component, and a net $1 million increase in the SBC charge. The MTC allows for the recovery of $465 million in deferred energy costs over the next ten years on an interim basis, thus disallowing $153 million of the $618 million provided for in a preliminary settlement agreement between certain parties. As a result, JCP&L recorded charges to net income for the year ended December 31, 2003, aggregating $185 million ($109 million net of tax) consisting of the $153 million deferred energy costs and other regulatory assets. JCP&L filed a motion for rehearing and reconsideration with the NJBPU on August 15, 2003 with respect to the following issues: (1) the disallowance of the $153 million deferred energy costs; (2) the reduced rate of return on equity; and (3) $42.7 million of disallowed costs to achieve merger savings. On October 10, 2003, the NJBPU held the motion in abeyance until the final NJBPU decision and order is issued. This is expected to occur in the first quarter of 2004.

On July 5, 2003, JCP&L experienced a series of 34.5 kilovolt sub-transmission line faults that resulted in outages on the New Jersey shore. The NJBPU instituted an investigation into these outages, and directed that a Special Reliability Master be hired to oversee the investigation. On December 8, 2003, the Special Reliability Master issued his Interim Report recommending that JCP&L implement a series of actions to improve reliability in the area affected by the outages. The NJBPU adopted the findings and recommendations of the Interim Report on December 17, 2003, and ordered JCP&L to implement the recommended actions on a staggered basis, with initial actions to be completed by March 31, 2004. JCP&L expects to spend $12.5 million implementing these actions during 2004.

Pennsylvania

In June 2001, the Pennsylvania Public Utility Commission (PPUC) approved the Settlement Stipulation with all of the major parties in the combined merger and rate proceedings which approved the FirstEnergy/GPU merger and provided PLR deferred accounting treatment for energy costs, permitting Met-Ed and Penelec to defer, for future recovery, energy costs in excess of amounts reflected in their capped generation rates retroactive to January 1, 2001. This PLR deferral accounting procedure was later reversed in a February 2002 Commonwealth Court of Pennsylvania decision. The court decision affirmed the PPUC decision regarding approval of the merger, remanding the decision to the PPUC only with respect to the issue of merger savings. FirstEnergy established reserves in 2002 for Met-Ed's and Penelec's PLR deferred energy costs which aggregated $287.1 million, reflecting the potential adverse impact of the then pending Pennsylvania Supreme Court decision whether to review the Commonwealth Court decision. We recorded in 2002 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 April 2, 2003, the PPUC remanded the issue relating to merger savings to the Office of Administrative Law Judge (ALJ) for hearings, directed Met-Ed and Penelec to file a position paper on the effect of the Commonwealth Court order on the Settlement Stipulation and allowed other parties to file responses to the position paper. Met-Ed and Penelec filed a letter with the ALJ on June 11, 2003, voiding the Stipulation in its entirety and reinstating Met-Ed's and Penelec's restructuring settlement previously approved by the PPUC.

On October 2, 2003, the PPUC issued an order concluding that the Commonwealth Court reversed the PPUC's June 20, 2001 order in its entirety. The PPUC directed Met-Ed and Penelec to file tariffs within thirty days of the order to reflect the competitive transition charge (CTC) rates and shopping credits that were in effect prior to the June 21, 2001 order to be effective upon one day's notice. In response to that order, Met-Ed and Penelec filed these supplements to their tariffs to become effective October 24, 2003.

On October 8, 2003, Met-Ed and Penelec filed a petition for clarification relating to the October 2, 2003 order on two issues: to establish June 30, 2004 as the date to fully refund the NUG trust and to clarify that the ordered accounting treatment regarding the CTC rate/shopping credit swap should follow the ratemaking, and that the PPUC's findings would not impair their rights to recover all of their stranded costs. On October 9, 2003, ARIPPA (an intervenor in the proceedings) petitioned the PPUC to direct Met-Ed and Penelec to reinstate accounting for the CTC rate/shopping credit swap retroactive to January 1, 2002. Several other parties also filed petitions. On October 16, 2003, the PPUC issued a reconsideration order granting the date requested by Met-Ed and Penelec for the NUG trust refund and, denying Met-Ed's and Penelec's other clarification requests and granting ARIPPA's petition with respect to the retroactive accounting treatment of the changes to the CTC rate/shopping credit swap. On October 22, 2003, Met-Ed and Penelec filed an Objection with the Commonwealth Court asking that the Court reverse the PPUC's finding that requires Met-Ed and Penelec to treat the stipulated CTC rates that were in effect from January 1, 2002 on a retroactive basis. Met-Ed and Penelec are considering filing an appeal to the Commonwealth Court on the PPUC orders as well.

On October 27, 2003, one Commonwealth Court judge issued an Order denying Met-Ed's and Penelec's objection without explanation. Due to the vagueness of the Order, Met-Ed and Penelec, on October 31, 2003, filed an Application for Clarification with the judge. Concurrent with this filing, Met-Ed and Penelec, in order to preserve their rights, also filed with the Commonwealth Court both a Petition for Review of the PPUC's October 16 and October 22 Orders, and an application for reargument, if the judge, in his clarification order, indicates that Met-Ed's and Penelec's objection was intended to be denied on the merits. In addition to these findings, Met-Ed and Penelec, in compliance with the PPUC's Orders, filed revised PPUC quarterly reports for the twelve months ended December 31, 2001 and 2002, and for the first two quarters of 2003, reflecting balances consistent with the PPUC's findings in their Orders.

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 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 assumed the supply obligation and the 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 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 a fixed price 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 on-peak obligation through 2004 and a portion of 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 current market prices.

In late 2003, the PPUC issued a Tentative Order implementing new reliability benchmarks and standards. In connection therewith, the PPUC commenced a rulemaking procedure to amend the Electric Service Reliability Regulations to implement these new benchmarks, and create additional reporting on reliability. Although neither the Tentative Order nor the Reliability Rulemaking has been finalized, the PPUC ordered all Pennsylvania utilities to begin filing quarterly reports on November 1, 2003. The comment period for both the Tentative Order and the Proposed Rulemaking Order has closed. We are currently awaiting the PPUC to issue a final order in both matters. The order will determine (1) the standards and benchmarks to be utilized, and (2) the details required in the quarterly and annual reports. It is expected that these Orders will be finalized in March 2004.

On January 16, 2004, the PPUC initiated a formal investigation of Met-Ed's, Penelec's and Penn's levels of compliance with the Public Utility Code and the PPUC's regulations and orders with regard to reliable electric service. Hearings will be held in August in this investigation and the ALJ has been directed to issue a Recommended Decision by September 30, 2004, in order to allow the PPUC time to issue a Final Order before December 16, 2004. We are unable to predict the outcome of the investigation or the impact of the PPUC Order.

FERC Regulatory Matters

On December 19, 2002, the FERC granted unconditional Regional Transmission Organization status to PJM Interconnection, LLC which includes JCP&L, Met-Ed and Penelec as transmission owners. The FERC also 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. Effective October 1, 2003, MISO received operational control of ATSI's transmission facilities. Transmission service over the facilities of ATSI is now provided under the MISO Open Access Transmission Tariff. A settlement of all rate matters related to ATSI's integration into MISO was filed with the FERC on December 18, 2003 and has been certified to the Commission as an uncontested settlement.

PJM and MISO were ordered by the FERC to develop a common market between the regions by October 31, 2004. The FERC also initiated a Section 206 investigation into the reasonableness of the "through-and-out" transmission rates charged by PJM and MISO. By order issued November 17, 2003, MISO, PJM and certain unaffiliated transmission owners in the Midwest were directed to eliminate rates for point-to-point service between the two RTOs effective April 1, 2004. A settlement judge has been appointed by the FERC to resolve compliance filings by the affected transmission providers. AEP, Commonwealth Edison and other utilities have appealed the FERC's November 17, 2003 order to the federal court of appeals for the District of Columbia.

Environmental Matters

We believe we are in material compliance with 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 from the Companies' Ohio and Pennsylvania facilities. Various regulatory and judicial actions have since sought to further define NOx reduction requirements (see Note 7(D) – Environmental Matters). We continue to evaluate our compliance plans and other compliance options.

Clean Air Act Compliance

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 the 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.

W. H. Sammis Plant

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. The NOV and complaint allege violations of the Clean Air Act based on operation and maintenance of the W. H. 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. On August 7, 2003, the United States District Court for the Southern District of Ohio ruled that 11 projects undertaken at the W. H. Sammis Plant between 1984 and 1998 required pre-construction permits under the Clean Air Act. The ruling concludes the liability phase of the case, which deals with applicability of Prevention of Significant Deterioration provisions of the Clean Air Act. The remedy phase, which is currently scheduled to be ready for trial beginning July 19, 2004, will address civil penalties and what, if any, actions should be taken to further reduce emissions at the plant. In the ruling, the Court indicated that the remedies it "may consider and impose involved a much broader, equitable analysis, requiring the Court to consider air quality, public health, economic impact, and employment consequences. The Court may also consider the less than consistent efforts of the EPA to apply and further enforce the Clean Air Act." The potential penalties that may be imposed, as well as the capital expenditures necessary to comply with substantive remedial measures that may be required, could have a material adverse impact on the Company's financial condition and results of operations. Management is unable to predict the ultimate outcome of this matter and no liability has been accrued as of December 31, 2003.

Regulation of Hazardous Waste

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 subsequently determined 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 EUOC 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, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2003, 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 a non-bypassable societal benefits charge. The Companies have total accrued liabilities aggregating approximately $65 million as of December 31, 2003.

Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol (Protocol), to address global warming by reducing the amount of man-made greenhouse gases emitted by developed countries by 5.2% from 1990 levels between 2008 and 2012. The United States signed the Protocol in 1998 but failed to receive the two-thirds vote of the U.S. Senate required for ratification. However, the Bush administration has committed the United States to a voluntary climate change strategy to reduce domestic greenhouse gas intensity – the ratio of emissions to economic output – by 18% through 2012.

We cannot currently estimate the financial impact of climate change policies although the potential restrictions on carbon dioxide (CO_2) emissions could require significant capital and other expenditures. However, the CO_2 emissions per kilowatt-hour of electricity generated by FirstEnergy is lower than many regional competitors due to FirstEnergy's diversified generation sources which includes the low or non-CO_2 emitting gas-fired and nuclear generators.

Other Legal Matters

A number of legal and regulatory proceedings have been filed against FirstEnergy in connection with, among other things, the restatements of earnings, the August 14th regional outage described above, and the extended outage at Davis-Besse, alleging violations of federal securities laws, breaches of fiduciary duties by its directors and officers or damages as a result of one or more of those events. All shareholder derivative actions filed in federal court have been consolidated into one action, as have all federal securities actions. Three tort actions seeking damages allegedly caused by the August 14th power outage were filed in Ohio state court and were dismissed on jurisdictional grounds. Two of those decisions have been appealed and the third case was refiled at the PUCO. We were also named as a respondent in two regulatory proceedings initiated at the PUCO in response to complaints alleging failure to provide reasonable and adequate service. Two tort actions relating to the power outage were preliminarily commenced in New York State court, but have not been pursued to date. We intend to defend all of these actions vigorously, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be instituted against us. In particular, if we were ultimately determined to have legal liability in connection with any of these proceedings, it could have a material adverse effect on our financial condition and results of operations.

FENOC recently received a subpoena from a grand jury sitting in the United States District Court for the Northern District of Ohio, Eastern Division requesting the production of certain documents and records relating to the inspection and maintenance of the reactor vessel head at the Davis-Besse plant. We are unable to predict the outcome of this investigation. In addition, FENOC remains subject to possible civil enforcement action by the NRC in connection with the events leading to the Davis-Besse outage. If it were ultimately determined that FirstEnergy has legal liability or is otherwise made subject to regulatory or civil enforcement action with respect to the Davis-Besse outage, it could have a material adverse effect on FirstEnergy's financial condition and results of operations.

Critical 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.

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 – $7.1 billion as of December 31, 2003. 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 a significant number of commodity contracts, as well as interest rate swaps, which increase the impact of derivative accounting judgments.

Revenue Recognition

We follow the accrual method of accounting for revenues, recognizing revenue for electricity that has been delivered to customers 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 Kilowatt - hour usage by residential, commercial and industrial customers
- Kilowatt - hour usage 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 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 are also 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 for pension and OPEB costs.

Plan amendments to retirement health care benefits in 2003 and 2002, related to changes in benefits provided and cost-sharing provisions, reduced FirstEnergy's obligation by $123 million and $121 million, respectively. In early 2004, FirstEnergy announced that it would amend the benefit provisions of its health care benefits plan and both employees and retirees would share in more of the benefit 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 recent declines in corporate bond yields and interest rates in general, we reduced the assumed discount rate as of December 31, 2003 to 6.25% from 6.75% and 7.25% used as of December 31, 2002 and 2001, respectively.

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. In 2003, 2002 and 2001, plan assets actually earned 24.0%, (11.3)% and (5.5)%, respectively. Our pension costs in 2003 were computed assuming a 9.0% rate of return on plan assets based upon projections of future returns and our pension trust investment allocation of approximately 70% equities, 27% bonds, 2% real estate and 1% cash.

As a result of the increased market value of our pension plan assets, we reduced our minimum liability as prescribed by SFAS 87 as of December 31, 2003 by $253 million, recording a decrease of $6 million in an intangible asset and crediting OCI by $145 million (offsetting previously recorded deferred tax benefits by $102 million). The remaining balance in OCI of $299 million will reverse in future periods to the extent the fair value of trust assets exceeds the accumulated benefit obligation. The accrued pension cost was reduced to $438 million as of December 31, 2003.

Based on pension assumptions and pension plan assets as of December 31, 2003, we will not be required to fund our pension plans in 2004. However, health care cost trends have significantly increased and will affect future OPEB costs. Pension and OPEB expenses in 2004 are expected to decrease by $38 million and $34 million, respectively. These reductions reflect the actual performance of pension plan assets and amendments to the health care benefits plan announced in early 2004 which result in employees and retirees sharing more of the benefit costs. The reduction in OPEB costs for 2004 does not reflect the impact of the new Medicare law signed by President Bush in December 2003 due to uncertainties regarding some of its new provisions (see Note 2(K)). The 2003 and 2002 composite health care trend rate assumptions are approximately 10%-12% gradually decreasing to 5% 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 pension and OPEB 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	$ 5	$ 15
Long-term return on assets	Decrease by 0.25%	$ 8	$ 1	$9
Health care trend rate	Increase by 1%	na	$26	$ 26
Increase in Minimum Liability				
Discount rate	Decrease by 0.25%	$104	na	$104

Ohio Transition Cost Amortization

In connection with FirstEnergy's restructuring plan, the PUCO determined allowable transition costs based on amounts recorded on the regulatory books of the Ohio electric utilities. These costs exceeded those deferred or capitalized on FirstEnergy's balance sheet prepared under GAAP since they included certain costs which have not yet been incurred or that were recognized on the regulatory financial statements (fair value purchase accounting adjustments). FirstEnergy uses an effective interest method for amortizing its transition costs, often referred to as a "mortgage-style" amortization. The interest rate under this method is equal to the rate of return authorized by the PUCO in the transition plan for each respective company. In computing the transition cost amortization, FirstEnergy includes only the portion of the transition revenues associated with transition costs included on the balance sheet prepared under GAAP. Revenues collected for the off-balance sheet costs and the return associated with these costs are recognized as income when received.

Long-Lived Assets

In accordance with SFAS 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 might 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 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).

The calculation of future cash flows is based on assumptions, estimates and judgement about future events. The aggregate amount of cash flows determines whether an impairment is indicated. The timing of the cash flows is critical in determining the amount of the impairment.

Nuclear Decommissioning

In accordance with SFAS 143, we recognize an ARO for the future decommissioning of our nuclear power plants. The ARO liability represents an estimate of the fair value of our current obligation related to nuclear decommissioning and the retirement of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. We used an expected cash flow approach (as discussed in FASB Concepts Statement No. 7, "Using Cash Flow Information and Present Value in Accounting Measurements") to measure the fair value of the nuclear decommissioning ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plants' current license and settlement based on an extended license term.

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 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), the goodwill is tested for impairment. When impairment is indicated we 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 2003. As a result of that review, a non-cash goodwill impairment charge of $122 million was recognized in the third quarter of 2003, reducing the carrying value of FSG. Of this amount, $117 million is reported as an operating expense and $5 million is included, net of tax, in the loss from discontinued operations. The impairment charge reflects the continued slow down in the development of competitive retail markets and depressed economic conditions that affect the value of FSG. 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. The impairment analysis includes a significant source of cash representing the EUOC recovery of transition costs as described in Note 2(D). A summary of the changes in our goodwill for the twelve months ended December 31, 2003 is shown below:

	Segments		
	Regulated	Competitive	Total
		(In millions)	
Balance as of December 31, 2002	$5,993	$285	$6,278
Impairment charges	–	(122)	(122)
FSG divestitures	–	(41)	(41)
Other	–	13	13
Balance as of December 31, 2003	$5,993	$135	$6,128

New Accounting Standards and Interpretations Adopted

FIN 46 (revised December 2003), "Consolidation of Variable Interest Entities"

In December 2003, the FASB issued a revised interpretation of Accounting Research Bulletin No. 51, "Consolidated Financial Statements", referred to as FIN 46R, which requires the consolidation of a VIE by an enterprise if that enterprise is determined to be the primary beneficiary of the VIE. As required, FirstEnergy adopted FIN 46R for interests in VIEs or potential VIEs commonly referred to as special-purpose entities effective December 31, 2003. We will adopt FIN 46R for all other types of entities effective March 31, 2004.

FirstEnergy currently has transactions with entities in connection with sale and leaseback arrangements which fall within the scope of this interpretation and which meet the definition of a VIE in accordance with FIN 46R. Upon adoption of FIN 46R effective December 31, 2003, FirstEnergy consolidated the PNBV Capital Trust (PNBV) and the Shippingport Capital Trust (Shippingport) which were created in 1996 and 1997, respectively, to refinance debt in connection with sale and leaseback transactions. Consolidation of PNBV changed the trust investment of $361 million to an investment in collateralized lease bonds of $372 million. The $11 million increase represents the minority interest in the total assets of the trust. Prior to the adoption of FIN 46R, the assets and liabilities of Shippingport were included on a proportionate basis in the financial statements of CEI and TE. Adoption of FIN 46R did not impact FirstEnergy with respect to this trust, but did result in recording all of the trust assets and liabilities on CEI's financial statements.

As described in Note 5(G), CEI, Met-Ed and Penelec created statutory business trusts to issue trust preferred securities in the aggregate of $285 million. Application of the guidance in FIN 46R resulted in the holders of the preferred securities being considered the primary beneficiaries of these trusts. Therefore, FirstEnergy has deconsolidated the trusts and recognized an equity investment in the trusts of $9 million ($3 million each for CEI, Met-Ed and Penelec) and subordinated debentures to the trusts of $294 million ($103 million for CEI, $96 million for Met-Ed and $95 million for Penelec) as of December 31, 2003.

In August 1995, Los Amigos Leasing Company, Ltd. (Los Amigos) was formed as a consolidated subsidiary of GPU Power to own and lease to TEBSA equipment comprised of an 895 megawatt plant constructed and operated by TEBSA. Upon application of FIN 46R, Los Amigos met the criteria of a VIE and FirstEnergy was determined not to be its primary beneficiary. Therefore, effective December 31, 2003 Los Amigos was deconsolidated, resulting in the removal of approximately $243 million of total assets (primarily unbilled lease receivable) and liabilities (primarily senior and subordinated debt) from FirstEnergy's Consolidated Balance Sheets. Los Amigos was sold as part of the TEBSA divestiture on January 30, 2004.

We have evaluated numerous entities with which the Companies have contractual, ownership, or other financial interests and we continue to evaluate other entities that meet the deferral criteria and may be subject to consolidation under FIN 46R as of March 31, 2004. See Note 9 for further discussion of FIN 46R.

SFAS 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity"

In May 2003, the FASB issued SFAS 150, which establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. In accordance with the standard, certain financial instruments that embody obligations for the issuer are required to be classified as liabilities. SFAS 150 was effective immediately for financial instruments entered into or modified after May 31, 2003 and effective at the beginning of the first interim period beginning after June 15, 2003 for all other financial instruments.

Upon adoption of SFAS 150, effective July 1, 2003, FirstEnergy reclassified as debt the preferred stock of consolidated subsidiaries subject to mandatory redemption with a carrying value of approximately $18.5 million ($5.0 million for CEI and $13.5 million for Penn) as of December 31, 2003. Adoption of SFAS 150 had no impact on FirstEnergy's Consolidated Statements of Income because the preferred dividends were previously included in net interest charges and required no reclassification.

SFAS 143, "Accounting for Asset Retirement Obligations"

In January 2003, FirstEnergy implemented SFAS 143 which provides accounting standards for retirement obligations associated with tangible long-lived assets. This statement requires recognition of the fair value of a liability for an asset retirement obligation in the period in which it is incurred. See "Cumulative Effect of Accounting Change" and "Earnings Effect of SFAS 143" discussed above and Notes 2(F) and 2(J) for further discussions of SFAS 143.

CONSOLIDATED STATEMENTS OF INCOME

(In thousands, except per share amounts)

For the Years Ended December 31,	2003	2002	2001
		(See Note 2(I))	
Revenues:			
Electric utilities	**$8,978,021**	$9,165,805	$5,729,036
Unregulated businesses	**3,329,026**	2,881,543	2,270,326
Total revenues	**12,307,047**	12,047,348	7,999,362
Expenses:			
Fuel and purchased power	**4,567,859**	3,670,844	1,421,525
Purchased gas	**586,799**	587,860	820,031
Other operating expenses	**3,643,575**	3,725,587	2,727,794
Provision for depreciation and amortization	**1,281,690**	1,298,290	889,550
Goodwill impairment (Note 2(L))	**116,988**	—	—
General taxes	**638,465**	649,898	455,340
Total expenses	**10,835,376**	9,932,479	6,314,240
Claim Settlement (Note 3)	**167,937**	—	—
Income Before Interest and Income Taxes	**1,639,608**	2,114,869	1,685,122
Net Interest Charges:			
Interest expense	**801,184**	906,970	519,131
Capitalized interest	**(31,900)**	(24,474)	(35,473)
Subsidiaries' preferred stock dividends	**42,369**	75,647	72,061
Net interest charges	**811,653**	958,143	555,719
Income Taxes	**405,959**	524,059	474,457
Income Before Discontinued Operations and Cumulative Effect of Accounting Changes	**421,996**	632,667	654,946
Discontinued operations (net of income taxes (benefit) of ($1,499,000) and $4,635,000, respectively) (Note 2(I))	**(101,379)**	(79,863)	—
Cumulative effect of accounting change (net of income taxes (benefit) of $72,516,000 and ($5,839,000), respectively) (Note 2(J))	**102,147**	—	(8,499)
Net Income	**$ 422,764**	$ 552,804	$ 646,447
Basic Earnings Per Share of Common Stock:			
Income before discontinued operations and cumulative effect of accounting changes	**$ 1.39**	$ 2.16	$ 2.85
Discontinued operations (Note 2(I))	**(0.33)**	(0.27)	—
Cumulative effect of accounting changes (Note 2(J))	**0.33**	—	(0.03)
Net income	**$ 1.39**	$ 1.89	$ 2.82
Weighted Average Number of Basic Shares Outstanding	**303,582**	293,194	229,512
Diluted Earnings Per Share of Common Stock:			
Income before discontinued operations and cumulative effect of accounting changes	**$ 1.39**	$ 2.15	$ 2.84
Discontinued operations (Note 2(I))	**(0.33)**	(0.27)	—
Cumulative effect of accounting changes (Note 2(J))	**0.33**	—	(0.03)
Net income	**$ 1.39**	$ 1.88	$ 2.81
Weighted Average Number of Diluted Shares Outstanding	**304,972**	294,421	230,430
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,	2003	2002
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 113,975**	$ 196,301
Receivables-		
Customers (less accumulated provisions of $50,247,000 and $52,514,000 respectively, for uncollectible accounts)	**1,000,259**	1,153,486
Other (less accumulated provisions of $18,283,000 and $12,851,000 respectively, for uncollectible accounts)	**505,241**	469,606
Materials and supplies, at average cost-		
Owned	**325,303**	253,047
Under consignment	**95,719**	174,028
Prepayments and other	**202,814**	203,630
	2,243,311	2,450,098
Property, Plant and Equipment:		
In service	**21,594,746**	20,372,224
Less – Accumulated provision for depreciation	**9,105,303**	8,264,075
	12,489,443	12,108,149
Construction work in progress	**779,479**	859,016
	13,268,922	12,967,165
Investments:		
Nuclear plant decommissioning trusts	**1,351,650**	1,049,560
Investments in lease obligation bonds (Note 4)	**989,425**	1,079,435
Letter of credit collateralization (Note 4)	**277,763**	277,763
Other	**878,853**	918,874
	3,497,691	3,325,632
Deferred Charges:		
Regulatory assets	**7,076,923**	8,464,549
Goodwill	**6,127,883**	6,278,072
Other	**695,218**	900,837
	13,900,024	15,643,458
	$32,909,948	$34,386,353
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Currently payable long-term debt and preferred stock	**$ 1,754,197**	$ 1,702,822
Short-term borrowings (Note 6)	**521,540**	1,092,817
Accounts payable	**725,239**	906,468
Accrued taxes	**669,529**	455,121
Lease market valuation liability	**84,800**	84,800
Other	**716,862**	1,009,215
	4,472,167	5,251,243
Capitalization (See Consolidated Statements of Capitalization):		
Common stockholders' equity	**8,289,341**	7,050,661
Preferred stock of consolidated subsidiaries –		
Not subject to mandatory redemption	**335,123**	335,123
Subject to mandatory redemption	**—**	18,521
Subsidiary-obligated mandatorily redeemable preferred securities	**—**	409,867
Long-term debt and other long-term obligations –		
Preferred stock of consolidated subsidiaries subject to mandatory redemption	**16,764**	—
Subordinated debentures to affiliated trusts	**294,324**	—
Other	**9,477,978**	10,872,216
	18,413,530	18,686,388
Noncurrent Liabilities:		
Accumulated deferred income taxes	**2,178,075**	2,069,682
Asset retirement obligations (Note 2(F))	**1,179,493**	—
Nuclear plant decommissioning costs	**—**	1,243,558
Power purchase contract loss liability	**2,727,892**	3,136,538
Retirement benefits	**1,591,006**	1,564,930
Lease market valuation liability	**1,021,000**	1,105,800
Other	**1,326,785**	1,328,214
	10,024,251	10,448,722
Commitments, Guarantees and Contingencies (Notes 4 and 7)		
	$32,909,948	$34,386,353

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

(Dollars in thousands, except per share amounts)

As of December 31,					2003	2002
Common Stockholders' Equity:						
Common stock, $0.10 par value - authorized 375,000,000 shares- 329,836,276 and 297,636,276 shares outstanding, respectively					**$ 32,984**	$ 29,764
Other paid-in capital					**7,062,825**	6,120,341
Accumulated other comprehensive loss (Note 5(I))					**(352,649)**	(656,148)
Retained earnings (Note 5(A))					**1,604,385**	1,634,981
Unallocated employee stock ownership plan common stock- 2,896,951 and 3,966,269 shares, respectively (Note 5(B))					**(58,204)**	(78,277)
Total common stockholders' equity					**8,289,341**	7,050,661
	Number of Shares Outstanding		***Optional* Redemption Price**			
	2003	**2002**	**Per Share**	**Aggregate**		
Preferred Stock of Consolidated Subsidiaries (Note 5(D)):						
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
Total Not Subject to Mandatory Redemption	609,650	609,650		$63,893	**60,965**	60,965
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	100.00	25,000	**25,000**	25,000
Total Not Subject to Mandatory Redemption	391,049	391,049		$39,614	**39,105**	39,105
Subject to Mandatory Redemption (Note 5(F)):						
7.625%*	–	142,500				14,250
Redemption Within One Year*						(750)
Total Subject to Mandatory Redemption*	–	142,500				13,500
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
Adjustable Series L	474,000	474,000	100.00	47,400	**46,404**	46,404
Total Not Subject to Mandatory Redemption	974,000	974,000		$97,900	**96,404**	96,404
Subject to Mandatory Redemption (Note 5(F)):						
$7.35 Series C*	–	60,000				6,021
Redemption Within One Year*						(1,000)
Total Subject to Mandatory Redemption*	–	60,000				5,021

(Dollars in thousands, except per share amounts)

As of December 31,	Number of Shares Outstanding 2003	Number of Shares Outstanding 2002	Optional Redemption Price Per Share	Optional Redemption Price Aggregate	2003	2002
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
	310,000	310,000		31,990	**31,000**	31,000
Cumulative, $25 par value-						
Authorized 12,000,000 shares						
Not Subject to Mandatory Redemption:						
$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	3,800,000		98,850	**95,000**	95,000
Total Not Subject to Mandatory Redemption	4,110,000	4,110,000		$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
Subsidiary-Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trust or Limited Partnership Holding Solely Subordinated Debentures of Subsidiaries (NOTE 5(G)):						
Cleveland Electric Illuminating Co.						
Cumulative, $25 stated value-						
Authorized 4,000,000 shares						
9.00%	–	4,000,000			**–**	100,000
Jersey Central Power & Light Co.						
Cumulative, $25 stated value-						
Authorized 5,000,000 shares						
8.56%	–	5,000,000			**–**	125,244
Metropolitan Edison Co.						
Cumulative, $25 stated value-						
Authorized 4,000,000 shares						
7.35%	–	4,000,000			**–**	92,409
Pennsylvania Electric Co.						
Cumulative, $25 stated value-						
Authorized 4,000,000 shares						
7.34%	–	4,000,000			**–**	92,214

Long-Term Debt (Note 5(E)) (Interest rates reflect weighted average rates) *(In thousands)*

	First Mortgage Bonds			Secured Notes			Unsecured Notes			Total	
As of December 31,		**2003**	**2002**		**2003**	**2002**		**2003**	**2002**	**2003**	**2002**
Ohio Edison Co. -											
Due 2003-2008	6.88%	$80,000	$230,000	5.62%	$227,761	$189,264	3.95%	$526,725	$441,725		
Due 2009-2013	—	—	—	6.98%	2,752	2,753	—	—	—		
Due 2014-2018	—	—	—	5.01%	59,000	59,000	5.45%	150,000	—		
Due 2019-2023	7.99%	—	219,460	7.01%	60,443	60,443	—	—	—		
Due 2024-2028	—	—	—	5.38%	13,522	13,522	—	—	—		
Due 2029-2033	—	—	—	3.10%	308,012	308,012	—	—	—		
Total-Ohio Edison		80,000	449,460		671,490	632,994		676,725	441,725	**$1,428,215**	$1,524,179
Cleveland Electric Illuminating Co. -											
Due 2003-2008	6.86%	125,000	525,000	6.78%	470,905	680,205	5.58%	27,700	27,700		
Due 2009-2013	—	—	—	7.43%	151,580	151,580	5.72%	378,700	78,700		
Due 2014-2018	—	—	—	6.03%	412,630	300,000	—	—	—		
Due 2019-2023	9.00%	—	150,000	6.67%	186,660	216,660	—	—	—		
Due 2024-2028	—	—	—	7.59%	148,843	148,843	—	—	—		
Due 2029-2033	—	—	—	1.45%	30,000	30,000	9.00%	103,093	—		
Total-Cleveland Electric		125,000	675,000		1,400,618	1,527,288		509,493	106,400	**2,035,111**	2,308,688
Toledo Edison Co. -											
Due 2003-2008	7.88%	145,000	178,725	7.51%	100,000	229,700	4.88%	85,250	91,130		
Due 2009-2013	—	—	—	—	—	—	10.00%	—	730		
Due 2019-2023	—	—	—	7.92%	144,500	164,700	—	—	—		
Due 2024-2028	—	—	—	5.90%	13,851	13,851	—	—	—		
Due 2029-2033	—	—	—	1.43%	51,100	51,100	—	—	—		
Total-Toledo Edison		145,000	178,725		309,451	459,351		85,250	91,860	**539,701**	729,936
Pennsylvania Power Co. -											
Due 2003-2008	6.88%	39,370	80,344	2.59%	10,300	10,300	3.40%	19,700	19,700		
Due 2009-2013	9.74%	4,870	4,870	5.40%	1,000	1,000	—	—	—		
Due 2014-2018	9.74%	4,870	4,870	4.00%	45,325	45,325	—	—	—		
Due 2019-2023	8.37%	34,757	34,757	3.62%	27,182	27,182	—	—	—		
Due 2024-2028	—	—	—	5.79%	22,934	22,934	—	—	—		
Due 2029-2033	—	—	—	5.95%	238	238	—	—	—		
Total-Penn Power		83,867	124,841		106,979	106,979		19,700	19,700	**210,546**	251,520
Jersey Central Power & Light Co. -											
Due 2003-2008	7.01%	251,575	442,989	5.75%	217,336	241,135	7.69%	99	115		
Due 2009-2013	7.13%	4,725	4,725	5.64%	130,024	130,024	7.69%	144	144		
Due 2014-2018	7.10%	12,200	12,200	5.34%	248,841	98,841	7.69%	208	208		
Due 2019-2023	7.75%	205,000	241,586	—	—	—	7.69%	302	302		
Due 2024-2028	7.18%	200,000	200,000	—	—	—	7.69%	437	437		
Due 2029-2033	—	—	—	—	—	—	7.69%	633	633		
Due 2034-2038	—	—	—	—	—	—	7.69%	917	917		
Due 2039-2043	—	—	—	—	—	—	7.69%	228	228		
Total-Jersey Central		673,500	901,500		596,201	470,000		2,968	2,984	**1,272,669**	1,374,484
Metropolitan Edison Co. -											
Due 2003-2008	6.44%	128,265	208,700	5.79%	150,000	150,000	7.69%	199	230		
Due 2009-2013	—	—	—	4.75%	250,000	—	7.69%	288	288		
Due 2014-2018	—	—	—	—	—	—	7.69%	417	417		
Due 2019-2023	6.10%	28,500	208,500	—	—	—	7.69%	603	604		
Due 2024-2028	5.95%	13,690	13,690	—	—	—	7.69%	874	874		
Due 2029-2033	—	—	—	—	—	—	7.69%	1,266	1,266		
Due 2034-2038	—	—	—	—	—	—	7.69%	1,834	1,834		
Due 2039-2043	—	—	—	—	—	—	7.98%	96,166	455		
Total-Metropolitan Edison		170,455	430,890		400,000	150,000		101,647	5,968	**672,102**	586,858

Long-Term Debt (Interest rates reflect weighted average rates) (Cont'd) *(In thousands)*

	First Mortgage Bonds			Secured Notes			Unsecured Notes			Total	
As of December 31,		**2003**	**2002**		**2003**	**2002**		**2003**	**2002**	**2003**	**2002**
Pennsylvania Electric Co. -											
Due 2003-2008	6.13%	$3,700	$3,905	—	$ —	$ —	5.86%	$133,099	$133,115		
Due 2009-2013	5.35%	24,310	24,310	—	—	—	6.55%	135,144	135,144		
Due 2014-2018	—	—	—	—	—	—	7.69%	208	208		
Due 2019-2023	5.80%	20,000	20,000	—	—	—	6.63%	125,302	125,302		
Due 2024-2028	6.05%	25,000	25,000	—	—	—	7.69%	437	437		
Due 2029-2033	—	—	—	—	—	—	7.69%	633	633		
Due 2034-2038	—	—	—	—	—	—	7.69%	917	917		
Due 2039-2043	—	—	—	—	—	—	7.98%	95,748	228		
Total-Pennsylvania Electric		73,010	73,215		—	—		491,488	395,984	**564,498**	469,199
FirstEnergy Corp. -											
Due 2003-2008	—	—	—	—	—	—	5.58%	1,570,000	1,695,000		
Due 2009-2013	—	—	—	—	—	—	6.45%	1,500,000	1,500,000		
Due 2029-2033	—	—	—	—	—	—	7.38%	1,500,000	1,500,000		
Total-FirstEnergy		—	—		—	—		4,570,000	4,695,000	**4,570,000**	4,695,000
Bay Shore Power		—	—	6.24%	140,600	143,200	—	—	—	**140,600**	143,200
Facilities Services Group		—	—	6.72%	7,754	13,205	—	—	—	**7,754**	13,205
FirstEnergy Generation		—	—	—	—	—	5.00%	15,000	15,000	**15,000**	15,000
FirstEnergy Properties		—	—	7.89%	9,438	9,679	—	—	—	**9,438**	9,679
Warrenton River Terminal		—	—	5.00%	410	634	—	—	—	**410**	634
First Communications		—	—	—	—	—	6.21%	5,407	—	**5,407**	—
GPU Capital		—	—	—	—	—	5.78%		101,467	—	101,467
GPU Power		—	—	7.14%	—	174,760	11.87%	—	67,372	—	242,132
Total		$1,350,832	$2,833,631		$3,642,941	$3,688,090		$6,477,678	$5,943,460	**11,471,451**	12,465,181
Preferred stock subject to mandatory redemption*										**18,514**	—
Capital lease obligations										**13,313**	15,761
Net unamortized premium on debt										**39,985**	92,346
Long-term debt due within one year*										**(1,754,197)**	(1,701,072)
Total long-term debt*										**9,789,066**	10,872,216
Total Capitalization*										**$18,413,530**	$18,686,388

** The December 31, 2003 balance for Preferred Stock Subject to Mandatory Redemption is classified as debt under SFAS 150 (see Note 9).*

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, 2001		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		
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	$552,804					552,804	
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 $(3,796,000) of income taxes	(5,269)				(5,269)		
Currency translation adjustments	(91,448)				(91,448)		
Comprehensive income	$ 65,659						
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	(656,148)	1,634,981	(78,277)
Net income	$422,764					422,764	
Minimum liability for unfunded retirement benefits, net of $101,950,000 of income taxes	144,236				144,236		
Unrealized loss on derivative hedges, net of $(241,000) of income taxes	(347)				(347)		
Unrealized gain on investments, net of $53,451,000 of income taxes	68,162				68,162		
Currency translation adjustments	91,448				91,448		
Comprehensive income	$726,263						
Stock options exercised				(3,502)			
Common stock issued		32,200,000	3,220	930,918			
Allocation of ESOP shares				15,068			20,073
Cash dividends on common stock						(453,360)	
Balance, December 31, 2003		329,836,276	$32,984	$7,062,825	$(352,649)	$1,604,385	$ (58,204)

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, 2001	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
Redemptions-				
7.625% Series			(7,500)	(750)
$7.35 Series C			(10,000)	(1,000)
8.56% Series			(5,000,000)	(125,242)
FIN 46 Deconsolidation-				
9.00% Series			(4,000,000)	(100,000)
7.35% Series			(4,000,000)	(92,618)
7.34% Series			(4,000,000)	(92,428)
Amortization of fair market value adjustments-				
$7.35 Series C				(7)
8.56% Series				(2)
7.35% Series				209
7.34% Series				214
Balance, December 31, 2003	6,209,699	$335,123	185,000	$18,514*

** The December 31, 2003 balance for Preferred Stock Subject to Mandatory Redemption is classified as debt under SFAS 150 (see Note 9).*

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,	2003	2002	2001
Cash Flows From Operating Activities:			
Net Income	**$ 422,764**	$ 552,804	$ 646,447
Adjustments to reconcile net income to net cash from operating activities:			
Provision for depreciation and amortization	**1,281,690**	1,298,290	889,550
Nuclear fuel and capital lease amortization	**66,072**	80,507	98,178
Other amortization and accruals, net (Note 2(M))	**(16,278)**	(16,593)	(11,927)
Deferred costs recoverable as regulatory assets	**(216,829)**	(362,956)	(31,893)
Goodwill impairment (Note 2(L))	**116,988**	—	—
Disallowed purchased power costs	**152,500**	—	—
Investment impairments (Note 3)	**43,803**	50,000	—
Deferred income taxes, net	**80,043**	103,293	31,625
Investment tax credits, net	**(26,404)**	(26,507)	(22,545)
Cumulative effect of accounting change	**(174,663)**	—	14,338
Loss from discontinued operations (see Note 2(I))	**101,379**	79,863	—
Receivables	**66,311**	(73,392)	53,099
Materials and supplies	**5,399**	(29,134)	(50,052)
Accounts payable	**(169,652)**	218,226	(84,572)
Deferred lease costs	**(119,398)**	(84,800)	—
Other (Note 10)	**338,737**	125,686	(250,564)
Net cash provided from operating activities	**1,952,462**	1,915,287	1,281,684
Cash Flows From Financing Activities:			
New Financing-			
Common stock	**934,138**	—	—
Preferred stock	**—**	—	96,739
Long-term debt	**1,027,312**	668,676	4,338,080
Short-term borrowings, net	**—**	478,520	—
Redemptions and Repayments-			
Common stock	**—**	—	(15,308)
Preferred stock	**(127,087)**	(522,223)	(85,466)
Long-term debt	**(2,128,567)**	(1,308,814)	(394,017)
Short-term borrowings, net	**(575,391)**	—	(1,641,484)
Common Stock Dividend Payments	**(453,360)**	(439,628)	(334,633)
Net cash provided from (used for) financing activities	**(1,322,955)**	(1,123,469)	1,963,911
Cash Flows From Investing Activities:			
GPU acquisition, net of cash	**—**	—	(2,013,218)
Property additions	**(856,316)**	(997,723)	(852,449)
Proceeds from sale of assets	**78,743**	155,034	—
Avon cash and cash equivalents (Note 3)	**—**	31,326	—
Net assets held for sale	**—**	(31,326)	—
Cash investments (Note 2(M))	**52,884**	81,349	24,518
Other (Note 10)	**12,856**	(54,355)	(233,526)
Net cash used for investing activities	**(711,833)**	(815,695)	(3,074,675)
Net increase (decrease) in cash and cash equivalents	**(82,326)**	(23,877)	170,920
Cash and cash equivalents at beginning of year	**196,301**	220,178	49,258
Cash and cash equivalents at end of year*	**$ 113,975**	$ 196,301	$ 220,178
Supplemental Cash Flows Information:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	**$ 730,277**	$ 881,515	$ 425,737
Income taxes	**$ 161,915**	$ 389,180	$ 433,640

** 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,	2003	2002	2001
General Taxes:			
Real and personal property	**$ 183,694**	$ 218,683	$ 176,916
State gross receipts*	**130,244**	132,622	102,335
Kilowatt-hour excise*	**228,216**	219,970	117,979
Social security and unemployment	**68,019**	46,345	44,480
Other	**28,292**	32,709	13,630
Total general taxes	**$ 638,465**	$ 650,329	$ 455,340
Provision For Income Taxes:			
Currently payable-			
Federal	**$ 306,347**	$ 326,417	$ 375,108
State	**118,155**	104,867	84,322
Foreign	**(1,165)**	20,624	108
	423,337	451,908	459,538
Deferred, net-			
Federal	**71,910**	81,934	37,888
State	**8,133**	7,759	(6,177)
Foreign	**—**	13,600	(86)
	80,043	103,293	31,625
Investment tax credit amortization	**(26,404)**	(26,507)	(22,545)
Total provision for income taxes	**$ 476,976**	$ 528,694	$ 468,618
Reconciliation of Federal Income Tax Expense at Statutory Rate To Total Provision for Income Taxes:			
Book income before provision for income taxes	**$ 899,740**	$1,081,498	$1,115,065
Federal income tax expense at statutory rate	**$ 314,909**	$ 378,524	$ 390,273
Increases (reductions) in taxes resulting from-			
Amortization of investment tax credits	**(26,404)**	(26,507)	(22,545)
State income taxes, net of federal income tax benefit	**82,088**	73,207	50,794
Amortization of tax regulatory assets	**31,909**	29,296	30,419
Amortization of goodwill	**—**	—	18,416
Preferred stock dividends	**7,202**	13,634	19,733
Reserve for foreign operations	**44,305**	48,587	—
Other, net	**22,967**	11,953	(18,472)
Total provision for income taxes	**$ 476,976**	$ 528,694	$ 468,618
Accumulated Deferred Income Taxes at December 31:			
Property basis differences	**$2,293,209**	$2,052,594	$1,996,937
Customer receivables for future income taxes	**139,335**	144,073	178,683
Regulatory transition charge	**1,084,871**	1,408,232	1,289,438
Deferred sale and leaseback costs	**(95,474)**	(99,647)	(77,099)
Nonutility generation costs	**(221,063)**	(228,476)	(178,393)
Unamortized investment tax credits	**(70,054)**	(78,227)	(86,256)
Other comprehensive income	**(243,743)**	(398,883)	(115,395)
Lease market valuation liability	**(455,074)**	(490,698)	—
Other (Note 10)	**(253,932)**	(239,286)	(323,696)
Net deferred income tax liability**	**$2,178,075**	$2,069,682	$2,684,219

** 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.

1. GENERAL:

The consolidated financial statements include FirstEnergy Corp., a registered 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 operating 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; First Communications, LLC; FirstEnergy Nuclear Operating Company (FENOC); GPU Capital, Inc.; GPU Power, Inc.; and FirstEnergy Service Company (FESC). 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 holds FirstEnergy's interest in Great Lakes Energy Partners, LLC. First Communications provides local and long-distance phone service. GPU Capital owned and operated electric distribution systems in foreign countries and GPU Power owned and operated generation facilities in foreign countries. FESC provides legal, financial and other corporate support services to affiliated FirstEnergy companies.

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. FirstEnergy's consolidated financial statements for the year ended December 31, 2002 were restated to reflect a change in the method of amortizing costs being recovered under the Ohio transition plan, recognition of above-market liabilities of certain leased generation facilities, Ohio transition plan regulatory assets and goodwill.

Certain prior year amounts have been reclassified to conform with the current year presentation, as described further in Notes 2(F), 2(I) and 8.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

(A) Consolidation-

FirstEnergy consolidates all majority-owned subsidiaries over which the Company exercises control and, when applicable, entities for which the Company has a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation. Investments in nonconsolidated affiliates (20-50 percent owned companies, joint ventures and partnerships) over which the Company has the ability to exercise significant influence, but not control, are accounted for on the equity basis.

(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 2003, 2002 and 2001, stock-based awards to purchase shares of common stock totaling 3.3 million, 3.4 million and 0.1 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 Discontinued Operations and Cumulative Effect of Accounting Changes 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, 2003	2002	2001
	(In thousands)		
Denominator for basic earnings per share (weighted average shares actually outstanding)	303,582	293,194	229,512
Assumed exercise of dilutive securities or agreements to issue common stock	1,390	1,227	918
Denominator for diluted earnings per share	304,972	294,421	230,430

(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 10 – 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, 2003 or 2002, with respect to any particular segment of FirstEnergy's customers. Total customer receivables were \$1.0 billion (billed – \$664 million and unbilled – \$336 million) and \$1.2 billion (billed – \$808 million and unbilled – \$345 million) as of December 31, 2003 and 2002, respectively.

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 (a "qualified special purpose entity") under Statement of Financial Accounting Standards (SFAS) No. 140 "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities," under an asset-backed securitization agreement. Transfers are made in return for an interest in the trust (19% as of December 31, 2003), 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, "Accounting for Certain Investments in Debt and Equity Securities," (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 $250 million sold to the trust and outstanding as of December 31, 2003, FirstEnergy's retained interests in $48 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 $202 million due to these sales. Collections of receivables previously transferred to the trust and used for the purchase of new receivables from CFC during 2003 totaled approximately $2.4 billion. CEI and TE processed receivables for the trust and received servicing fees of approximately $3.6 million in 2003. Expenses associated with the factoring discount related to the sale of receivables were $3.5 million, $4.7 million and $12.0 million in 2003, 2002 and 2001.

(D) Regulatory Matters-

In Ohio, New Jersey and Pennsylvania, laws applicable to electric industry deregulation contain 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 transition costs (sometimes referred to as stranded investment);
- itemizing (unbundling) the price of electricity into its component elements – including generation, transmission, distribution and transition costs recovery charges;
- deregulating the Companies' electric generation businesses;
- continuing regulation of the Companies' transmission and distribution systems; and
- requiring corporate separation of regulated and unregulated business activities.

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 recovery period extension is related to the customer shopping incentives recovery discussed below. 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 OE, CEI and TE (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, net of deferred income taxes, (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 gives 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, which runs through the end of 2005, 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. Subject to approval by the PUCO, recovery will be accomplished by extending the respective transition cost recovery period.

On October 21, 2003, the Ohio Companies filed an application with the PUCO to establish generation service rates beginning January 1, 2006, in response to expressed concerns by the PUCO about price and supply uncertainty following the end of the market development period. The filing included two options:

- A competitive auction, which would establish a price for generation that customers would be charged during the period covered by the auction, or
- A Rate Stabilization Plan, which would extend current generation prices through 2008, ensuring adequate supply and continuing our support of energy efficiency and economic development efforts.

Under the first option, an auction would be conducted to secure generation service, including PLR responsibility, for the Ohio Companies' customers. Beginning in 2006, customers would pay market prices for generation as determined by the auction.

Under the Rate Stabilization Plan option, customers would have price and supply stability through 2008 – three years beyond the end of the market development period – as well as the benefits of a competitive market. Customer benefits would include: customer savings by extending the current five percent discount on generation costs and other customer credits; maintaining current distribution base rates through 2007; market-based auctions that may be conducted annually to ensure that customers pay the lowest available prices; extension of the Ohio Companies' support of energy-efficiency programs and the potential for continuing the program to give preferred access to non-affiliated entities to generation capacity if shopping drops below 20%. Under the proposed plan, we are requesting:

- Extension of the transition cost amortization period for OE from 2006 to 2007; for CEI from 2008 to 2009 and for TE from mid-2007 to 2008;
- Deferral of interest costs on the accumulated shopping incentives and other cost deferrals as new regulatory assets; and
- Ability to initiate a request to increase generation rates under certain limited conditions.

On January 7, 2004, the PUCO staff filed testimony on the proposed rate plan generally supporting the Rate Stabilization Plan as opposed to the competitive auction proposal. Hearings began on February 11, 2004. On February 23, 2004, after consideration of PUCO Staff comments and testimony as well as those provided by some of the intervening parties, FirstEnergy made certain modifications to the Rate Stabilization Plan. A decision is expected from the PUCO in the Spring of 2004.

On November 25, 2003. the PUCO ordered FirstEnergy to file a plan with the PUCO no later than March 1, 2004, illustrating how FirstEnergy will address certain problems identified by the U.S./Canada Power Outage Task Force (in connection with the August 14, 2003 regional power outage) and addressing how FirstEnergy proposes to upgrade its control room computer hardware and software, improve its control room training procedures and improve the training of control room operators to ensure that similar problems do not occur in the future. The PUCO, in consultation with the North American Electric Reliability Council, will review the plan before determining the next steps in the proceeding.

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 had been 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 and there would be an adjustment to goodwill.

In addition, the Final Order provided for the ability to securitize stranded costs associated with the divested Oyster Creek Nuclear Generating Station. Under NJBPU authorization in 2002, JCP&L issued through its wholly owned subsidiary, JCP&L Transition Funding LLC, $320 million of transition bonds (recognized on the Consolidated Balance Sheet) which securitized the recovery of these costs and which provided for a usage-based non-bypassable transition bond charge (TBC) and for the transfer of the bondable transition property to another entity.

Prior to August 1, 2003, JCP&L's PLR obligation to provide basic generation service (BGS) to non-shopping customers was 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, 2003, the accumulated deferred cost balance totaled approximately $440 million, after the charge discussed below. 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. JCP&L's two August 2002 rate filings requested increases in base electric rates of approximately $98 million annually and requested the recovery of 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. On July 25, 2003, the NJBPU announced its JCP&L base electric rate proceeding decision, which reduced JCP&L's annual revenues by approximately $62 million effective August 1, 2003. The NJBPU decision also provided for an interim return on equity of 9.5% on JCP&L's rate base for six to twelve months. During that period, JCP&L will initiate another proceeding to request recovery of additional costs incurred to enhance system reliability. In that proceeding, the NJBPU could increase the return on equity to 9.75% or decrease it to 9.25%, depending on its assessment of the reliability of JCP&L's service. Any reduction would be retroactive to August 1, 2003. The net revenue decrease from the NJBPU's decision consists of a $223 million decrease in the electricity delivery charge, a $111 million increase due to the August 1, 2003 expiration of annual customer credits previously mandated by the New Jersey transition legislation, a $49 million increase in the MTC tariff component, and a net $1 million increase in the SBC charge. The MTC allows for the recovery of $465 million in deferred energy costs over the next ten years on an interim basis, thus disallowing $153 million of the $618 million provided for in a preliminary settlement agreement between certain parties. As a result, JCP&L recorded charges to net income for the year ended December 31, 2003, aggregating $185 million ($109 million net of tax) consisting of the $153 million of disallowed deferred energy costs and other regulatory assets. JCP&L filed a motion for rehearing and reconsideration with the NJBPU on August 15, 2003 with respect to the following issues: (1) the disallowance of the $153 million deferred energy costs; (2) the reduced rate of return on equity; and (3) $42.7 million of disallowed costs to achieve merger savings. On October 10, 2003, the NJBPU held the motion in abeyance until the final NJBPU decision and order which is expected to be issued in the first quarter of 2004.

JCP&L's BGS obligation for the twelve month period beginning August 1, 2003 was auctioned in February 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 sells all self-supplied energy (NUGs and owned generation) to the wholesale market with offsetting credits to its deferred energy balances. The BGS auction for the subsequent period was completed in February 2004. The NJBPU adjusted the generation component of JCP&L's retail rates on August 1, 2003 to reflect the results of the BGS auction.

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 and would be an adjustment to goodwill.

In June 2001, the PPUC approved the Settlement Stipulation with all of the major parties in the combined merger and rate relief proceedings which approved the FirstEnergy/GPU merger and provided PLR deferred accounting treatment for energy costs, permitting Met-Ed and Penelec to defer, for future recovery, energy costs in excess of amounts reflected in their capped generation rates retroactive to January 1, 2001. This PLR deferral accounting procedure was later denied in a February 2002 Commonwealth Court of Pennsylvania decision. The court decision also affirmed the PPUC decision regarding approval of the merger, remanding the decision to the PPUC only with respect to the issue of merger savings. FirstEnergy established reserves in 2002 for Met-Ed's and Penelec's PLR deferred energy costs which aggregated $287.1 million, reflecting the potential adverse impact of the then pending Pennsylvania Supreme Court decision whether to review the Commonwealth Court decision. As a result, FirstEnergy recorded in 2002 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 April 2, 2003, the PPUC remanded the issue relating to merger savings to the Office of Administrative Law for hearings, directed Met-Ed and Penelec to file a position paper on the effect of the Commonwealth Court order on the Settlement Stipulation and allowed other parties to file responses to the position paper. Met-Ed and Penelec filed a letter with the Administrative Law Judge (ALJ) on June 11, 2003, voiding the Stipulation in its entirety and reinstating Met-Ed's and Penelec's restructuring settlement previously approved by the PPUC.

On October 2, 2003, the PPUC issued an order concluding that the Commonwealth Court reversed the PPUC's June 20, 2001 order in its entirety. The PPUC directed Met-Ed and Penelec to file tariffs within thirty days of the order to reflect the competitive transition charge (CTC) rates and shopping credits that were in effect prior to the June 21, 2001 order to be effective upon one day's notice. In response to that order, Met-Ed and Penelec filed these supplements to their tariffs to become effective October 24, 2003.

On October 8, 2003, Met-Ed and Penelec filed a petition for clarification relating to the October 2, 2003 order on two issues: to establish June 30, 2004 as the date to fully refund the NUG trust fund and to clarify that the ordered accounting treatment regarding the CTC rate/shopping credit swap should follow the ratemaking, and that the PPUC's findings would not impair their rights to recover all of their stranded costs. On October 9, 2003, ARIPPA (an intervenor in the proceedings) petitioned the PPUC to direct Met-Ed and Penelec to reinstate accounting for the CTC rate/shopping credit swap retroactive to January 1, 2002. Several other parties also filed petitions. On October 16, 2003, the PPUC issued a reconsideration order granting the date requested by Met-Ed and Penelec for the NUG trust fund refund, denying Met-Ed's and Penelec's other clarification requests and granting ARIPPA's petition with respect to the accounting treatment of the changes to the CTC rate/shopping credit swap. On October 22, 2003, Met-Ed and Penelec filed an Objection with the Commonwealth Court asking that the Court reverse the PPUC's finding that requires Met-Ed and Penelec to treat the stipulated CTC rates that were in effect from January 1, 2002 on a retroactive basis. Met-Ed and Penelec are considering filing an appeal to the Commonwealth Court on the PPUC orders as well.

On October 27, 2003, a Commonwealth Court judge issued an Order denying Met-Ed's and Penelec's objection without explanation. Due to the vagueness of the Order, Met-Ed and Penelec, on October 31, 2003, filed an Application for Clarification with the judge. Concurrent with this filing, Met-Ed and Penelec, in order to preserve their rights, also filed with the Commonwealth Court both a

Petition for Review of the PPUC's October 16 and October 22 Orders, and an application for reargument, if the judge, in his clarification order, indicates that Met-Ed's and Penelec's objection was intended to be denied on the merits. In addition to these findings, Met-Ed and Penelec, in compliance with the PPUC's Orders, filed revised PPUC quarterly reports for the twelve months ended December 31, 2001 and 2002, and for the first two quarters of 2003, reflecting balances consistent with the PPUC's findings in their Orders.

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 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 assumed the supply obligation and the 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 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 a fixed price 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 on-peak obligation through 2004 and a portion of 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 current market prices.

In late 2003, the PPUC issued a Tentative Order implementing new reliability benchmarks and standards. In connection therewith, the PPUC commenced a rulemaking procedure to amend the Electric Service Reliability Regulations to implement these new benchmarks, and create additional reporting on reliability. Although neither the Tentative Order nor the Reliability Rulemaking has been finalized, the PPUC ordered all Pennsylvania utilities to begin filing quarterly reports on November 1, 2003. The comment period for both the Tentative Order and the Proposed Rulemaking Order has closed. Met-Ed, Penelec and Penn are currently awaiting the PPUC to issue a final order in both matters. The order will determine (1) the standards and benchmarks to be utilized, and (2) the details required in the quarterly and annual reports. It is expected that these Orders will be finalized in March of 2004.

On January 16, 2004, the PPUC initiated a formal investigation of Met-Ed's, Penelec's and Penn's levels of compliance with the Public Utility Code and the PPUC's regulations and orders with regard to reliable electric service. Hearings will be held in August in this investigation and the ALJ has been directed to issue a Recommended Decision by September 30, 2004, in order to allow the PPUC time to issue a Final Order before December 16, 2004. FirstEnergy is unable to predict the outcome of the investigation or the impact of the PPUC order.

Transition Cost Amortization -

OE, CEI and TE amortize transition costs (see Regulatory Matters – Ohio) using the effective interest method. Under the current Ohio transition plan, total transition cost amortization is expected to approximate the following for 2004 through 2009.

	(In millions)
2004	$794
2005	922
2006	371
2007	208
2008	164
2009	46

The decrease in amortization beginning in 2006 results from the termination of generation-related transition cost recovery under the Ohio transition plan.

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. Regulatory assets which do not earn a current return totaled approximately $625 million as of December 31, 2003.

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

	2003	2002
	(In millions)	
Regulatory transition charge	$6,427	$7,608
Customer shopping incentives	371	188
Customer receivables for future income taxes	340	394
Societal benefits charge	81	144
Loss on reacquired debt	75	74
Employee postretirement benefit costs	77	88
Nuclear decommissioning, decontamination and spent fuel disposal costs	(96)	99
Component removal costs	(321)	(288)
Property losses and unrecovered plant costs	70	88
Other	53	70
Total	$7,077	$8,465

Regulatory Accounting for Generation Operations-

The application of SFAS 71 was discontinued with respect to the Companies' generation operations. The SEC's interpretive guidance regarding asset impairment measurement providing 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, 2003.

	SFAS 71 Discontinued Net Assets	Total Assets
	(In millions)	
OE	$976	$6,591
CEI	1,429	6,773
TE	561	2,855
Penn	92	879
JCP&L	42	7,579
Met-Ed	15	3,474

(E) Property, Plant and Equipment-

Property, plant and equipment reflects original cost (except for nuclear generating assets which were adjusted to fair value), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. JCP&L holds a 50% ownership interest in Yards Creek Pumped Storage Facility – its net book value was approximately $20.7 million as of December 31, 2003. FirstEnergy also had shared ownership interests in various foreign properties – all such assets were divested by January 30, 2004. 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 2003, 2002 and 2001 (post-merger periods only for JCP&L, Met-Ed and Penelec) are shown in the following table:

Annual Composite Depreciation Rate	2003	2002	2001
OE	2.8%	2.7%	2.7%
CEI	3.0	3.4	3.2
TE	3.0	3.9	3.5
Penn	2.6	2.9	2.9
JCP&L	2.8	3.5	3.4
Met-Ed	2.7	3.0	3.0
Penelec	2.7	3.0	2.9

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.

(F) Asset Retirement Obligation-

In January 2003, FirstEnergy implemented SFAS 143, "Accounting for Asset Retirement Obligations,"which provides accounting standards for retirement obligations associated with tangible long-lived assets. This statement requires recognition of the fair value of a liability for an asset retirement obligation (ARO) 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 instead if the criteria for such treatment are met. Upon retirement, a gain or loss would be recognized if the cost to settle the retirement obligation differs from the carrying amount.

FirstEnergy identified applicable legal obligations as defined under the new standard for nuclear power plant decommissioning, reclamation of a sludge disposal pond related to the Bruce Mansfield Plant, and closure of two coal ash disposal sites. The ARO liability as of the date of adoption of SFAS 143 was $1.107 billion, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. The ARO liability was $1.179 billion as of December 31, 2003 and included $1.166 billion for nuclear decommissioning of the Beaver Valley, Davis-Besse, Perry, and Three Mile Island Unit 2 (TMI-2) nuclear generating facilities (discussed below). The Companies' share of the obligation to decommission these units was developed based on site specific studies performed by an independent engineer. FirstEnergy utilized an expected cash flow approach (as discussed in FASB Concepts Statement No. 7, "Using Cash Flow Information and Present Value in Accounting Measurements") to measure the fair value of the nuclear decommissioning ARO. The Companies maintain nuclear decommissioning trust funds that are legally restricted for purposes of settling the nuclear decommissioning ARO. As of December 31, 2003, the fair value of the decommissioning trust assets was $1.352 billion. Payments for decommissioning of the nuclear generating units are expected to begin in 2014, when actual decommissioning work is expected to begin.

The following table provides the beginning and ending aggregate carrying amount of the total ARO and the changes to the balance during 2003.

ARO Reconciliation	2003
	(In millions)
Beginning balance as of January 1, 2003	$1,107
Liabilities incurred	–
Liabilities settled	–
Accretion in 2003	72
Revisions in estimated cash flows	–
Ending balance as of December 31, 2003	**$1,179**

The following table provides the year-end balance of the ARO for 2002, as if SFAS 143 had been adopted on January 1, 2002.

Adjusted ARO Reconciliation	2002
	(In millions)
Beginning balance as of January 1, 2002	$1,042
Accretion in 2002	65
Ending balance as of December 31, 2002	**$1,107**

In addition to the nuclear decommissioning ARO, FirstEnergy has also recognized estimated liabilities for post defueling monitored storage at TMI-2 of $26 million and decontamination and decommissioning of nuclear enrichment facilities of $28 million. Under terms of the NRC license, FirstEnergy is required to monitor and maintain TMI-2 to ensure that there is no deterioration of the facility. As required by the Energy Policy Act of 1992, FirstEnergy participates in the decontamination and decommissioning of nuclear enrichment facilities operated by the United States Department of Energy.

In accordance with SFAS 143, FirstEnergy ceased the accounting practice of depreciating non-regulated generation assets using a cost of removal component in the depreciation rates. That practice recognized accumulated depreciation in excess of the historical cost of an asset because the removal cost would exceed the estimated salvage value. Beginning in 2003, the cost of removal related to non-regulated generation assets is charged to expense rather than to the accumulated provision for depreciation. In accordance with SFAS 71, the cost of removal on regulated plant assets continues to be accounted for as a component of depreciation rates and is recognized as a regulatory liability.

The following table provides the effect on income as if SFAS 143 had been applied during 2002 and 2001.

Effect of the Change in Accounting Principle Applied Retroactively	2002	2001
	(In millions, except per share amounts)	
Reported net income	$553	$646
Increase (Decrease):		
Elimination of decommissioning expense	88	88
Depreciation of asset retirement cost	(3)	(3)
Accretion of ARO liability	(38)	(35)
Non-regulated generation cost of removal component, net	15	11
Income tax effect	(25)	(25)
Net earnings increase	37	36
Net income adjusted	$590	$682
Basic earnings per share of common stock:		
Net income as previously reported	$1.89	$2.82
Adjustment for effect of change in accounting principle applied retroactively	0.12	0.16
Net income adjusted	$2.01	$2.98
Diluted earnings per share of common stock:		
Net income as previously reported	$1.88	$2.81
Adjustment for effect of change in accounting principle applied retroactively	0.12	0.16
Net income adjusted	$2.00	$2.97

(G) Stock-based Compensation-

FirstEnergy applies the recognition and measurement principles of Accounting Principles Board Opinion No. 25 (APB 25), "Accounting for Stock Issued to Employees" and related Interpretations in accounting for its stock-based compensation plans (see Note 5(C)). 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 First Energy had elected to account for employee stock options under the fair value method (as provided under SFAS 123, "Accounting for Stock-Based Compensation") 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:

	2003	2002	2001
Valuation assumptions:			
Expected option term (years)	7.9	8.1	8.3
Expected volatility	26.91%	23.31%	23.45%
Expected dividend yield	5.09%	4.36%	5.00%
Risk-free interest rate	3.67%	4.60%	4.67%
Fair value per option	$5.09	$6.45	$4.97

If fair value accounting were applied to FirstEnergy's stock options, net income and earnings per share would be reduced as summarized below.

	2003	2002	2001
	(In thousands, except per share amounts)		
Net Income, as reported	$422,764	$552,804	$646,447
Add back compensation expense reported in net income, net of tax (based on APB 25)	163	166	25
Deduct compensation expense based upon estimated fair value, net of tax	(12,354)	(8,825)	(3,748)
Adjusted net income	$410,573	$544,145	$642,724
Earnings Per Share of Common Stock –			
Basic			
As Reported	$1.39	$1.89	$2.82
Adjusted	$1.35	$1.86	$2.80
Diluted			
As Reported	$1.39	$1.88	$2.81
Adjusted	$1.35	$1.85	$2.79

(H) Income Taxes-

Details of the total provision for income taxes are shown on the Consolidated Statements of Taxes. The Company records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the next tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid.

FirstEnergy has capital loss carryforwards of approximately $1.1 billion, most of which expire in 2007. The deferred tax assets associated with these capital loss carryforwards ($374 million) are fully offset by a valuation allowance as of December 31, 2003, since management is unable to predict whether sufficient capital gains will be generated to utilize all of these capital loss carryforwards. Any ultimate utilization of capital loss carryforwards for which valuation allowances were established through purchase accounting would adjust goodwill.

The Company has also recorded valuation allowances of $92 million for deferred tax assets associated with impairment losses related to certain domestic assets and the divestiture of international assets acquired through the merger with GPU (see Note 12).

FirstEnergy has net operating loss carryforwards for state and local income tax purposes of approximately $693 million. A valuation allowance of $5 million has been recorded against the associated deferred tax assets of $30 million. These losses expire as follows:

Expiration Period	Amount
	(in millions)
2004-2008	$102
2009-2013	147
2014-2018	130
2019-2022	314
	$693

(I) Discontinued Operations-

FirstEnergy has included in "Discontinued Operations" on the Consolidated Statements of Income for the years ended December 31, 2003 and 2002 operating income and losses on sales of its international operations in Argentina and Bolivia and certain domestic subsidiaries of FSG and MARBEL, all of which were sold in 2003. Discontinued operations in 2003 of $(101) million, net of tax benefits of $2 million, included operating results of $2 million (revenues of $52 million and pre-tax income of $2 million) and losses on sales or abandonments of $103 million. A net operating loss of $80 million (revenues of $284 million and pre-tax loss of $75 million) attributable to these entities was included in discontinued operations in 2002. The 2001 results of the divested entities were not significant and the 2001 Consolidated Statement of Income was not reclassified to separately report discontinued operations.

On April 18, 2003, FirstEnergy divested its ownership in Emdersa through the abandonment of its shares in Emdersa's parent company, GPU Argentina Holdings, Inc. The abandonment was accomplished by relinquishing FirstEnergy's shares to the independent Board of Directors of GPU Argentina Holdings, relieving FirstEnergy of all rights and obligations relative to this business. FirstEnergy included in discontinued operations Emdersa's net income of $7 million and a $67 million charge for the abandonment in the second quarter of 2003 (no income tax benefit was recognized). An after-tax loss of $87 million (including $109 million in currency transaction losses arising principally from U.S. dollar denominated debt) was included in discontinued operations in 2002.

In December 2003, Empresa Guaracachi S.A. (EGSA), GPU Power's Bolivia subsidiary, was sold to Bolivia Integrated Energy Limited. FirstEnergy included in discontinued operations a $33 million loss on the sale of EGSA in the fourth quarter of 2003 (no income tax benefit was realized) and an operating loss for the year of $2 million. Discontinued operations in 2002 include EGSA's operating income of $6 million.

The FSG subsidiaries, Colonial Mechanical and Webb Technologies, were sold in January 2003 and Ancoma, Inc. was sold in December 2003; the MARBEL subsidiary, Northeast Ohio Natural Gas Corp. was sold in June 2003. The 2003 and 2002 results for these divested business operations included in discontinued operations for the years ended December 2003 and 2002 totaled $(3) million and $2 million, respectively.

The following table summarizes major assets and liabilities for all of these divestitures included in FirstEnergy's Consolidated Balance Sheets as of December 31, 2002.

As of December 31	2002
	(In millions)
Current assets	$106
Property and investments	175
Deferred charges	44
Total assets	$325
Current liabilities	$ 64
Capitalization	205
Noncurrent liabilities	56
Total liabilities and capitalization	$325

(J) Cumulative Effect of Accounting Change-

As a result of adopting SFAS 143 in January 2003, asset retirement costs were recorded in the amount of $602 million as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $415 million. The ARO liability on the date of adoption was $1.107 billion, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. The remaining cumulative effect adjustment for unrecognized depreciation and accretion, offset by the reduction in the existing decommissioning liabilities and the reversal of accumulated estimated removal costs for non-regulated generation assets, was a $175 million increase to income, $102 million net of tax, or $0.33 per share of common stock (basic and diluted) in the year ended December 31, 2003 (see Note 9).

On January 1, 2001, FirstEnergy adopted SFAS 133 as amended, "Accounting for Derivative Instruments and Hedging Activities." The cumulative effect to January 1, 2001 was a charge of $9 million (net of $6 million of income taxes) or $0.03 per share of common stock.

(K) Pension and Other Postretirement Benefit Plans

FirstEnergy provides noncontributory defined benefit pension plans that cover substantially all of its employees. The trusteed plans provide defined benefits based on years of service and compensation levels. The Company's funding policy is based on actuarial computations using the projected unit credit method. No pension contributions were required during the three years ended December 31, 2003.

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. The Company 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.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans, and earnings on plan assets. Such factors may be further affected by business combinations (such as the merger with GPU, Inc. in November 2001), which impact employee demographics, plan experience and other factors. Pension and OPEB costs may also be affected by changes in 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. FirstEnergy uses a December 31 measurement date for the majority of its plans.

Plan amendments to retirement health care benefits in 2003 and 2002, relate to changes in benefits provided and cost-sharing provisions, which reduced the Company's obligation by $123 million and $121 million, respectively. In early 2004, the Company announced that it would amend the benefit provisions of its health care benefits plan and both employees and retirees would share in more of the benefit costs.

On December 8, 2003, President Bush signed into law a bill that expands Medicare, primarily adding a prescription drug benefit for Medicare-eligible retirees starting in 2006. FirstEnergy anticipates that the benefits it pays after 2006 will be lower as a result of the new Medicare provisions. Due to uncertainties surrounding some of the new Medicare provisions and a lack of authoritative accounting guidance about these issues, FirstEnergy deferred the recognition of the impact of the new Medicare provisions as provided by FASB Staff Position 106-1. The final accounting guidance could require changes to previously reported information.

Obligations and Funded Status As of December 31	Pension Benefits 2003	Pension Benefits 2002	Other Benefits 2003	Other Benefits 2002
	(In millions)			
Change in benefit obligation				
Benefit obligation at beginning of year	$3,866	$3,548	$2,077	$1,582
Service cost	66	59	43	28
Interest cost	253	249	136	114
Plan participants' contributions	—	—	6	—
Plan amendments	—	—	(123)	(121)
Actuarial loss	222	268	323	440
GPU acquisition (Note 12)	—	(12)	—	110
Benefits paid	(245)	(246)	(94)	(76)
Benefit obligation at end of year	$4,162	$3,866	$2,368	$2,077
Change in fair value of plan assets				
Fair value of plan assets at beginning of year	$2,889	$3,484	$473	$535
Actual return on plan assets	671	(349)	88	(57)
Company contribution	—	—	68	31
Plan participants' contribution	—	—	2	—
Benefits paid	(245)	(246)	(94)	(36)
Fair value of plan assets at end of year	$3,315	$2,889	$537	$473
Funded status	$(847)	$(977)	$(1,831)	(1,604)
Unrecognized net actuarial loss	919	1,186	994	752
Unrecognized prior service cost (benefit)	72	78	(221)	(107)
Unrecognized net transition obligation	—	—	83	92
Net asset (liability) recognized	$144	$287	$(975)	$(867)
Amounts Recognized in the Consolidated Balance Sheets As of December 31				
Accrued benefit cost	$(438)	$(548)	$(975)	$(867)
Intangible assets	72	78	—	—
Accumulated other comprehensive loss	510	757	—	—
Net amount recognized	$144	$287	$(975)	$(867)
Increase (decrease) in minimum liability included in other comprehensive income (net of tax)	$(145)	$444	—	—
Assumptions Used to Determine Benefit Obligations As of December 31				
Discount rate	6.25%	6.75%	6.25%	6.75%
Rate of compensation increase	3.50%	3.50%		
Allocation of Plan Assets As of December 31				
Asset Category				
Equity securities	70%	61%	71%	58%
Debt securities	27	35	22	29
Real estate	2	2	—	—
Cash	1	2	7	13
Total	100%	100%	100%	100%

Information for Pension Plans With an Accumulated Benefit Obligation in Excess of Plan Assets	2003	2002
	(In millions)	
Projected benefit obligation	$4,162	$3,866
Accumulated benefit obligation	3,753	3,438
Fair value of plan assets	3,315	2,889

Components of Net Periodic Benefit Costs	Pension Benefits 2003	Pension Benefits 2002	Pension Benefits 2001	Other Benefits 2003	Other Benefits 2002	Other Benefits 2001
			(In millions)			
Service cost	$66	$59	$35	$43	$29	$18
Interest cost	253	249	133	137	114	65
Expected return on plan assets	(248)	(346)	(205)	(43)	(52)	(10)
Amortization of prior service cost	9	9	8	(9)	3	3
Amortization of transition obligation (asset)	—	—	(2)	9	9	9
Recognized net actuarial loss	62	—	—	40	11	5
Voluntary early retirement program	—	—	6	—	—	2
Net periodic cost (income)	$142	$(29)	$(24)	$177	$114	$92

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31	Pension Benefits 2003	Pension Benefits 2002	Pension Benefits 2001	Other Benefits 2003	Other Benefits 2002	Other Benefits 2001
Discount rate	6.75%	7.25%	7.75%	6.75%	7.25%	7.75%
Expected long-term return on plan assets	9.00%	10.25%	10.25%	9.00%	10.25%	10.25%
Rate of compensation increase	3.50%	4.00%	4.00%			

In selecting an assumed discount rate, FirstEnergy considers 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. The assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by the Company's pension trusts. The long-term rate of return is developed considering the portfolio's asset allocation strategy.

Assumed Health Care Cost Trend Rates As of December 31	2003	2002
Health care cost trend rate assumed for next year (pre/post-Medicare)	10%-12%	10%-12%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5%	5%
Year that the rate reaches the ultimate trend rate (pre/post-Medicare)	2009-2011	2008-2010

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on total of service and interest cost	$26	$(19)
Effect on postretirement benefit obligation	$233	$(212)

FirstEnergy employs a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, and small and large capitalizations. Other assets such as real estate are used to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives are not used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on a continuing basis through periodic investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

As a result of the increased market value of its pension plan assets, FirstEnergy reduced its minimum liability as prescribed by SFAS 87 as of December 31, 2003 by $253 million, recording a decrease of $6 million in an intangible asset and crediting OCI by $145 million (offsetting previously recorded deferred tax benefits by $102 million). The remaining balance in OCI of $299 million will reverse in future periods to the extent the fair value of trust assets exceeds the accumulated benefit obligation. The accrued pension cost was reduced to $438 million as of December 31, 2003.

FirstEnergy does not expect to contribute to its pension plans in 2004 and expects to contribute $16 million to its other postretirement benefit plans in 2004.

(L) 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. Under SFAS 142, "Goodwill and Other Intangible Assets," amortization of existing goodwill ceased January 1, 2002. Instead, FirstEnergy evaluates goodwill for impairment at least annually and makes 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), the goodwill is tested for impairment. When impairment is indicated, FirstEnergy recognizes a loss – calculated as the difference between the implied fair value of a reporting unit's goodwill and the carrying value of the goodwill. FirstEnergy's annual review was completed in the third quarter of 2003. As a result of that review, a non-cash goodwill impairment charge of $122 million was recognized in the third quarter of 2003, reducing the carrying value of FSG. Of this amount, $117 million is reported as an operating expense and $5 million is included, net of tax, in the loss from discontinued operations. The impairment charge reflects the continued slow down in the development of competitive retail markets and depressed economic conditions that affect the value of FSG. The fair value of FSG was estimated using primarily the expected discounted future cash flows. The forecasts used in FirstEnergy's evaluations of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on FirstEnergy's future evaluations of goodwill. As of December 31, 2003, FirstEnergy had $6.1 billion of goodwill that primarily relates to its regulated services segment. The impairment analysis includes a significant source of cash representing the Companies' recovery of transition costs as described above under Note 2 (D). FirstEnergy does not believe that completion of transition cost recovery will result in an impairment of goodwill relating to its regulated business segment.

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

	2003	2002	2001
	(In thousands, except per share amounts)		
Reported net income	$422,764	$552,804	$646,447
Goodwill amortization (net of tax)	—	—	54,584
Adjusted net income	$422,764	$552,804	$701,031
Basic earnings per common share:			
Reported earnings per share	$1.39	$1.89	$2.82
Goodwill amortization	—	—	0.23
Adjusted earnings per share	$1.39	$1.89	$3.05
Diluted earnings per common share:			
Reported earnings per share	$1.39	$1.88	$2.81
Goodwill amortization	—	—	0.23
Adjusted earnings per share	$1.39	$1.88	$3.04

A summary of the changes in FirstEnergy's goodwill for the years ended December 31, 2002 and 2003 is shown below:

	2003	2002
	(In millions)	
Balance as of January 1	$6,278	$5,983
Impairment charges	(122)	—
FSG divestitures	(41)	—
GPU acquisition (see Note 12)	—	286
Other	13	9
Balance as of December 31	$6,128	$6,278

(M) Cash and Financial Instruments-

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. Cash and cash equivalents as of December 31, 2003 included $32 million received in December 2003 which was included in the NRG settlement claim sold in January 2004 (see Note 3). Cash and cash equivalents as of December 31, 2002 included $50 million used for the redemption of long-term debt in January 2003. Noncash financing and investing activities in 2001 included $2.6 billion of common stock issued for the GPU acquisition and capital lease transactions amounting to $3 million. There were no capital lease transactions in 2003 or 2002. Net losses on foreign currency exchange transactions reflected on FirstEnergy's 2002 Consolidated Statement of Income consisted of approximately $104 million from FirstEnergy's Argentina operations (see Note 3 – Divestitures).

On the Consolidated Statements of Cash Flows, the amounts included in "Cash investments" under Cash Flows From Investing Activities primarily consist of changes in investments in collateralized lease bonds (see Note 4) of $85 million and other cash investments of $(32) million in 2003 and changes in investments in collateralized lease bonds of $87 million and other cash investments of $(6) million in 2002. The amounts included in "Other amortization and accruals, net" under Cash Flows From Operating Activities include 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:

	2003 Carrying Value	2003 Fair Value	2002 Carrying Value	2002 Fair Value
	(In millions)			
Long-term debt	$11,471	$11,970	$12,465	$12,761
Preferred stock*	$ 19	$ 19	$ 445	$ 454
Investments other than cash and cash equivalents:				
Debt securities:				
-Maturity (5-10 years)	$ 452	$ 427	$ 502	$ 471
-Maturity (more than 10 years)	871	1,005	927	1,030
Equity securities	–	–	15	15
All other	1,944	1,944	1,668	1,669
	$ 3,267	$ 3,376	$ 3,112	$ 3,185

** The December 31, 2003 amount is classified as debt under SFAS 150.*

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 10 for discussion of SFAS 115 activity related to available-for-sale securities.

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, ($779 million) and fixed income securities ($573 million) as of December 31, 2003. In 2001, unrealized gains and losses applicable to all of FirstEnergy's decommissioning trusts were recognized in the trust investment with a corresponding change to the decommissioning liability. In 2003 and 2002, unrealized gains and losses applicable to the decommissioning trusts of FirstEnergy's Ohio Companies were reclassified to OCI in accordance with SFAS 115, as fluctuations in the fair value of these trust balances will eventually affect earnings. Realized gains (losses) are recognized as additions (reductions) to trust asset balances. For 2003 and 2002, net realized gains (losses) were approximately $6.0 million and $(15.6) million and interest and dividend income totaled approximately $37.0 million and $33.2 million, respectively.

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, FirstEnergy repurchased and retired 550,000 shares (average price of $27.82 per share).

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 2003 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 are 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. Accumulated Other Comprehensive Loss (AOCL) as of December 31, 2003 includes a net deferred loss of $111 million for derivative hedging activity. The $1 million increase from the December 31, 2002 balance of $110 million includes a $3 million reduction related to current hedging activity and a $4 million increase due to net hedge gains included in earnings during the year. Approximately $22 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.

During 2003, FirstEnergy and OE executed fixed-for-floating interest rate swap agreements with notional values of $950 million and $200 million, respectively, whereby FE and OE receive fixed cash flows based on the fixed coupons of the hedged securities and pay variable cash flows based on short-term variable market interest rates (6 month LIBOR index). 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, fixed interest rates received, and interest payment dates match those of the underlying obligations. FirstEnergy entered into interest rate swap agreements on a $950 million notional amount of its and its subsidiaries' senior notes and first mortgage bonds with a weighted average fixed interest rate of 5.46%. OE entered into interest rate swap agreements on a $200 million notional amount of its senior notes with a weighted average fixed interest rate of 5.09%. In addition, the cancellation options (options with strike prices equivalent to that of the options embedded in the call feature of the securities), on $593.5

million notional amount of cancelable interest rate swaps on callable first mortgage bonds were exercised by swap counterparties. As a result of the counterparties exercising these options, FirstEnergy received $20.2 million in cash swap cancellation premiums during 2003. The amount of the cash premiums will be recognized over the remaining maturity of each respective hedged security. As of December 31, 2003 interest rate swap agreements with notional values totaling $1.15 billion were outstanding.

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.

3. DIVESTITURES:

International Operations-

FirstEnergy completed the sale of its international assets subsequent to December 31, 2003 with the sales of its remaining 20.1 percent interest in Avon (parent of Midlands Electricity in the United Kingdom) on January 16, 2004, and its 28.67 percent interest in Termobarranquilla S.A., Empresa de Servicios Publicos (TEBSA) for $12 million on January 30, 2004. An impairment loss of $26 million related to TEBSA was recorded in December 2003 in Other Operating Expenses on the 2003 Consolidated Statement of Income and no gain or loss was recognized upon the sale in 2004. Avon, TEBSA and other international assets sold in 2003 were acquired as part of FirstEnergy's November 2001 merger with the former GPU, Inc. FirstEnergy no longer has ownership interests in international operating assets.

The divestiture in 2003 of international operations in Bolivia and Argentina included the sale of FirstEnergy's wholly owned subsidiary, Guaracachi America, Inc., a holding company with a 50.001 percent interest in EGSA, on December 11, 2003, and its ownership in Emdersa through the abandonment of its shares in Emdersa's parent company, GPU Argentina Holdings, Inc. on April 18, 2003 (see Note 2 (I)). This resulted in a loss on sale of $33 million recognized in Discontinued Operations in the Consolidated Statement of Income for the year ended December 31, 2003.

FirstEnergy had sold a 79.9 percent equity interest in Avon on May 8, 2002 to Aquila, Inc. (formerly UtiliCorp United) 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. After reaching agreement to sell its remaining 20.1 percent interest in the fourth quarter of 2003, FirstEnergy recorded a $5 million after-tax charge to reduce the carrying value. In the fourth quarter of 2002, FirstEnergy recorded a $50 million after-tax charge to reduce the carrying value of its remaining 20.1 percent interest.

In the second quarter of 2003, FirstEnergy recognized an impairment of $13 million ($8 million net of tax) related to the carrying value of the note FirstEnergy had with Aquila from the 2002 sale of the 79.9 percent interest in Avon. The changes in the fourth quarter of 2002 and second quarter of 2003 are included in Other Operating Expenses on the Consolidated Statements of Income for the years ended December 31, 2002 and 2003, respectively. After receiving the first annual installment payment of $19 million in May 2003, FirstEnergy sold the remaining balance of its note receivable in the secondary market and received $63 million in proceeds on July 28, 2003.

Through 2002, FirstEnergy was unsuccessful in divesting of GPU's former Argentina operations and made the decision to abandon its interest in Emdersa in early 2003. A number of economic events occurred in Argentina that hindered FirstEnergy's ability to realize Emdersa's estimated fair value. These events included currency devaluation, restrictions on repatriation of cash, and the anticipation of future asset sales in that region by competitors. The abandonment was accomplished by relinquishing FirstEnergy's shares to the independent Board of Directors of GPU Argentina Holdings, relieving FirstEnergy of all rights and obligations relative to this business. As a result of the abandonment, FirstEnergy recognized a one-time, non-cash charge of $67 million, or $0.23 per share of common stock in the second quarter of 2003. This charge is the result of realizing the currency translation adjustment (CTA) losses through current period earnings ($90 million, or $0.30 per share), partially offset by the gain recognized from abandoning FirstEnergy's investment in Emdersa ($23 million, or $0.07 per share). Since FirstEnergy had previously recorded $90 million of CTA adjustments in OCI, the net effect of the $67 million charge was an increase in common stockholders' equity of $23 million. In addition, FirstEnergy reflected Emdersa's 2002 results of an after-tax loss of $87 million (including $109 million in currency transaction losses arising principally from U.S. dollar denominated debt) as discontinued operations in the Consolidated Statement of Income for the year ended December 31, 2002. FirstEnergy also recognized a CTA of $91 million in 2002 which reduced FirstEnergy's common stockholders' equity. This adjustment represented the impact of translating Emdersa's financial statements from its functional currency to the U.S. dollar for GAAP financial reporting.

The $67 million after-tax charge in 2003 does not include the expected income tax benefits related to the abandonment, which were fully reserved during the second quarter of 2003. FirstEnergy expects tax benefits of approximately $129 million, of which $50 million would increase net income in the period that it becomes probable those benefits will be realized. The remaining $79 million of tax benefits would reduce goodwill recognized in connection with the acquisition of GPU.

Generation 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. NRG filed voluntary bankruptcy petitions in May 2003; subsequently FirstEnergy reached an agreement for settlement of its claim against NRG. Under NRG's proposed Plan of Reorganization, FirstEnergy, as an unsecured creditor, could receive an estimated settlement of approximately $198 million, with payment in the form of cash (12%), notes (15.2%) and new NRG common stock (72.8%). FirstEnergy sold its entire claim (including $32 million of cash proceeds received in December 2003) for $170 million in January 2004.

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 Statements of Income.

Other Domestic Operations-

Sales of domestic assets in 2003 included three FSG subsidiaries – Ancoma, Inc., a mechanical contracting company based in Rochester, New York, and Virginia-based Colonial Mechanical and Webb Technologies - and a MARBEL subsidiary – Northeast Ohio Natural Gas (see Note 2(I)).

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, 2003 are summarized as follows:

	2003	2002	2001
		(In millions)	
Operating leases			
Interest element	$181	$188	$194
Other	150	136	120
Capital leases			
Interest element	2	2	8
Other	2	3	36
Total rentals	$335	$329	$358

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 (see Note 9).

The future minimum lease payments as of December 31, 2003, are:

	Capital Leases	Operating Leases: Lease Payments	Operating Leases: Capital Trusts	Operating Leases: Net
		(In millions)		
2004	$6	$294	$112	$182
2005	5	313	130	183
2006	5	322	142	180
2007	1	300	131	169
2008	1	294	105	189
Years thereafter	6	2,514	872	1,642
Total minimum lease payments	24	$4,037	$1,492	$2,545
Executory costs	5			
Net minimum lease payments	19			
Interest portion	6			
Present value of net minimum lease payments	13			
Less current portion	2			
Noncurrent portion	$11			

FirstEnergy has recorded above-market lease liabilities for Beaver Valley Unit 2 and the Bruce Mansfield Plant associated with the 1997 merger between OE and Centerior. The total above-market lease obligation of $722 million associated with Beaver Valley Unit 2 is being amortized on a straight-line basis through the end of the lease term in 2017 (approximately $37 million per year). The total above-market lease obligation of $755 million associated with the Bruce Mansfield Plant is being amortized on a straight-line basis through the end of 2016 (approximately $48 million per year). As of December 31, 2003 the above-market lease liabilities for Beaver Valley Unit 2 and the Bruce Mansfield Plant totaled $1.1 billion, of which $85 million is current.

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 (ESOP) -

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 2003, 2002 and 2001, 1,069,318 shares, 1,151,106 shares and 834,657 shares, respectively, were allocated to employees with the corresponding expense recognized based on the shares allocated method. The fair value of 2,896,951 shares unallocated as of December 31, 2003, was approximately $102.0 million. Total ESOP-related compensation expense was calculated as follows:

	2003	2002	2001
		(In millions)	
Base compensation	$35.1	$34.2	$25.1
Dividends on common stock held by the ESOP and used to service debt	(9.1)	(7.8)	(6.1)
Net expense	$26.0	$26.4	$19.0

(C) Stock Compensation Plans-

In 2001, FirstEnergy assumed responsibility for two 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:

	2003	2002	2001
Restricted common shares granted	–	36,922	133,162
Weighted average market price	n/a [1]	$36.04	$35.68
Weighted average vesting period (years)	n/a [1]	3.2	3.7
Dividends restricted	n/a [1]	Yes	– [2]

[1] Not applicable since no restricted stock was granted.

[2] 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, 2003, there were 410,399 stock units outstanding. See Note 10(D) 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, 2001	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
Options granted	3,981,100	29.71
Options exercised	455,986	25.94
Options forfeited	311,731	29.09
Balance, December 31, 2003	13,648,869	29.27
(1,919,662 options exercisable)		29.67

As of December 31, 2003, the weighted average remaining contractual life of outstanding stock options was 7.6 years.

Options outstanding by plan and range of exercvise price as of December 31, 2003 were as follows:

FirstEnergy Programs	Range of Exercise Prices	Options Outstanding
FE plan	$19.31 - $29.87	9,904,861
	$30.17 - $35.15	3,214,601
Plans acquired through merger:		
GPU plan	$23.75 - $35.92	501,734
Other plans		27,673
Total		13,648,869

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 2(G) – Stock-Based Compensation.

(D) Preferred and Preference Stock-

All 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) Long-Term Debt-

Each of the Companies has a first mortgage indenture under which it issues 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 exist 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, 2003, the Companies' annual sinking fund requirements for all bonds issued under the various mortgage indentures of the Companies amounts to $61.9 million. OE and Penn expect to deposit funds with their respective mortgage bond trustees in 2004 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 fund obligations 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)
2004	$1,750
2005	683
2006	1,377
2007	237
2008	385

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 $494 million, $97 million and $50 million in 2004, 2005 and 2008, 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 $220 million and noncancelable municipal bond insurance policies of $482 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 1.125% to 1.50% 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 $270 million as of December 31, 2003, under its $500 million revolving credit facility agreement which expires November 29, 2004. FirstEnergy currently pays an annual facility fee of 0.425% on the total credit facility amount. FirstEnergy had no borrowings as of December 31, 2003 under a new $375 million long-term revolving credit facility agreement which expires October 23, 2006. FirstEnergy currently pays an annual facility fee of 0.50% on the total credit facility amount. The fees are subject to change based on changes to FirstEnergy's credit ratings.

OE had unsecured borrowings of $40 million as of December 31, 2003 under a $250 million long-term revolving credit facility agreement which expires May 12, 2005. OE currently pays an annual facility fee of 0.20% on the total credit facility amount. OE had no unsecured borrowings as of December 31, 2003 under a $125 million long-term revolving credit facility which expires October 23, 2006. OE currently pays an annual facility fee of 0.25% on the total credit facility amount. The fees are subject to change based on changes to OE's credit ratings.

CEI and TE have unsecured letters of credit of approximately $216 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).

(F) Long-Term Debt: Preferred Stock Subject to Mandatory Redemption-

Effective July 1, 2003, upon adoption of SFAS 150 (see Note 9), FirstEnergy reclassified as debt the preferred stock of consolidated subsidiaries subject to mandatory redemption. Prior year amounts were not reclassified.

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

	Series	Shares	Redemption Price Per Share
CEI	$7.35C	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 2004 through 2006, $12.3 million in 2007 and $1.0 million in 2008.

(G) Long-Term Debt: Subordinated Debentures to Affiliated Trusts-

CEI formed a wholly owned statutory business trust to sell preferred securities and invest the gross proceeds in the 9.00% subordinated debentures of CEI. 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 the trust's preferred securities. The trust's 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 to those of CEI. However, ownership of the respective Met-Ed and Penelec trusts is through separate wholly owned limited partnerships. In these transactions, each trust invested the gross proceeds from the sale of its 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, Met-Ed and Penelec has effectively provided a full and unconditional guarantee of obligations under the trust's preferred securities. The trust's 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.

In each of these transactions, interest on the subordinated debentures (and therefore distributions on the trust's preferred securities) may be deferred for up to 60 months, but CEI, Met-Ed and Penelec 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.

Upon adoption of FASB Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51" (FIN 46R), the limited partnerships and statutory business trusts discussed above are not consolidated on the financial statements of FirstEnergy, CEI, Met-Ed and Penelec as of December 31, 2003 (see Note 9).

The following table displays information regarding preferred securities of statutory business trusts outstanding as of December 31, 2003:

	Maturity	Rate	Stated Value	Subordinated Debentures
			(In millions)	
Cleveland Electric Financing Trust [a]	2031	9.00%	$100.0	$103.1
Met-Ed Capital Trust [b]	2039	7.35%	$100.0	$103.1
Penelec Capital Trust [b]	2039	7.34%	$100.0	$103.1

[a] *The sole assets of the trust are CEI's subordinated debentures with the same rate and maturity date as the preferred securities.*

[b] *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 subordinated debentures of Met-Ed and Penelec, respectively, with the same rate and maturity date as the preferred securities.*

(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 Consolidated Balance Sheet. 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 TBC, 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 TBC, pursuant to a servicing agreement with the Issuer. JCP&L is entitled to a quarterly servicing fee of $100,000 that is payable from TBC 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, 2003, accumulated other comprehensive income (loss) consisted of a minimum liability for unfunded retirement benefits of $306 million, unrealized gains on investments in securities available for sale of $64 million, and unrealized losses on derivative instrument hedges of $111 million. Other comprehensive income (loss) reclassified to net income in 2003, 2002 and 2001 totaled $29 million, $(10) million and $31 million, respectively. These amounts were net of income taxes in 2003, 2002 and 2001 of $20 million, $(7) million and $22 million, respectively.

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

Short-term borrowings outstanding as of December 31, 2003, consisted of $372 million of bank borrowings and $150 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 0.50% on the amount of the entire finance limit. The receivables financing agreement expires in October 2004.

FirstEnergy and its subsidiaries have various credit facilities (including a FirstEnergy $375 million short-term revolving credit facility) with domestic and foreign banks that provide for borrowings of up to $604 million 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 0.20% to 0.375%. These lines expire at various times during 2004. The weighted average interest rates on short-term borrowings outstanding as of December 31, 2003 and 2002 were 2.14% and 2.41%, respectively.

7. COMMITMENTS, GUARANTEES AND CONTINGENCIES:

(A) Capital Expenditures-

FirstEnergy's current forecast reflects expenditures of approximately $2.3 billion for property additions and improvements from 2004-2006, of which approximately $713 million is applicable to 2004. Investments for additional nuclear fuel during the 2004-2006 period are estimated to be approximately $323 million, of which approximately $90 million applies to 2004. During the same periods, the Companies' nuclear fuel investments are expected to be reduced by approximately $285 million and $93 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 $10.9 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 $402 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 $64 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 ratings contingent collateralization provisions. As of December 31, 2003, outstanding guarantees and other assurances aggregated approximately $1.9 billion.

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 $1.0 billion (included in the $1.9 billion discussed above) as of December 31, 2003 will increase amounts otherwise to be paid by FirstEnergy to meet its obligations incurred in connection with financings and ongoing energy and energy-related activities is remote.

While guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating-downgrade or "material adverse event" the immediate payment of cash collateral or provision of a letter of credit may be required. The following table summarizes collateral provisions as of December 31, 2003:

Collateral Provisions	Exposure	Collateral Paid: Cash	Collateral Paid: Letters of Credit	Remaining Exposure[1]
		(In millions)		
Rating downgrade	$187	$68	$5	$114
Adverse Event	235	–	65	170
Total	$422	$68	$70	$284

[1] *As of February 11, 2004, we had a remaining exposure of $282 million with $106 million of cash and $87 million of letters of credit provided as collateral.*

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related FirstEnergy guarantees of $161 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.

FirstEnergy has also guaranteed the obligations of the operators of the TEBSA project, up to a maximum of $6 million (subject to escalation) under the project's operations and maintenance agreement. In connection with the sale of TEBSA in January 2004, the purchaser indemnified FirstEnergy against any loss under this guarantee. FirstEnergy had provided the TEBSA project lenders a $50 million letter of credit (LOC) (under FirstEnergy's existing $250 million LOC capacity available as part of a $1.25 billion FirstEnergy credit facility) to obtain TEBSA lender consent as substitute collateral for the release of the assets for FirstEnergy to abandon its Argentina operations, Emdersa (see Note 3). In December 2003, a replacement LOC was issued in the amount of $60 million, which is renewable and declines yearly based upon the senior outstanding debt of TEBSA. This LOC granted FirstEnergy the ability to sell its remaining 20.1% interest in Avon, as well as abandon the Argentina assets in April 2003.

(D) Environmental Matters-

Various federal, state and local authorities regulate the Companies with regard to air and water quality and other environmental matters. 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 that 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. Overall, FirstEnergy believes it is in material compliance with existing regulations but is unable to predict future change in regulatory policies and what, if any, the effects of such change would be. FirstEnergy estimates additional capital expenditures for environmental compliance of approximately $91 million for 2004 through 2006, which is included in the $2.3 billion of forecasted capital expenditures for 2004 through 2006 (see Note 7(A)). Additional estimated capital expenditures forecast of $481 million relating to proposed environment laws could be required after 2006.

Clean Air Act Compliance

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 are complying with SO2 reduction requirements under the Clean Air Act Amendments of 1990 by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NOx reductions required by the 1990 Amendments 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 (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia 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. New Jersey and Pennsylvania submitted a SIP that required compliance with the NOx budgets at the Companies' New Jersey and Pennsylvania facilities by May 1, 2003. Michigan and Ohio submitted a SIP that requires compliance with the NOx budgets at the Companies' Michigan and Ohio facilities by May 31, 2004.

National Ambient Air Quality Standards

In July 1997, the EPA promulgated changes in the National Ambient Air Quality Standard (NAAQS) for ozone and proposed a new NAAQS for fine particulate matter. On December 17, 2003, the EPA proposed the "Interstate Air Quality Rule" covering a total of 29 states (including New Jersey, Ohio and Pennsylvania) and the District of Columbia based on proposed findings that air pollution emissions from 29 eastern states and the District of Columbia significantly contribute to nonattainment of the NAAQS for fine particles and/or the "8-hour" ozone NAAQS in other states. The EPA has proposed the Interstate Air Quality Rule to "cap-and-trade" NOx and SO2 emissions in two phases (Phase I in 2010 and Phase II in 2015). According to the EPA, SO2 emissions would be reduced by approximately 3.6 million tons in 2010, across states covered by the rule, with reductions ultimately reaching more than 5.5 million tons annually. NOx emission reductions would measure about 1.5 million tons in 2010 and 1.8 million tons in 2015. The future cost of compliance with these proposed regulations may be substantial and will depend on whether and how they are ultimately implemented by the states in which the Companies operate affected facilities.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. On December 15, 2003, the EPA proposed two different approaches to reduce mercury emissions from coal-fired power plants. The first approach would require plants to install controls known as "maximum achievable control technologies" (MACT) based on the type of coal burned. According to the EPA, if implemented, the MACT proposal would reduce nationwide mercury emissions from coal-fired power plants by fourteen tons to approximately thirty-four tons per year. The second approach proposes a cap-and-trade program that would reduce mercury emissions in two distinct phases. Initially, mercury emissions would be reduced by 2010 as a "co-benefits" from implementation of SO2 and NOx emission caps under the EPA's proposed Interstate Air Quality Rule. Phase II of the mercury cap-and-trade program would be implemented in 2018 to cap nationwide mercury emissions from coal-fired power plants at fifteen tons per year. The EPA has agreed to choose between these two options and issue a final rule by December 15, 2004. The future cost of compliance with these regulations may be substantial.

W. H. Sammis Plant

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. The NOV and complaint allege violations of the Clean Air Act based on operation and maintenance of the W. H. 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. On August 7, 2003, the United States District Court for the Southern District of Ohio ruled that 11 projects undertaken at the W. H. Sammis Plant between 1984 and 1998 required pre-construction permits under the Clean Air Act. The ruling concludes the liability phase of the case, which deals with applicability of Prevention of Significant Deterioration provisions of the Clean Air Act. The remedy phase, which is currently scheduled to be ready for trial beginning July 19, 2004, will address civil penalties and what, if any, actions should be taken to further reduce emissions at the plant. In the ruling, the Court indicated that the remedies it "may consider and impose involved a much broader, equitable analysis, requiring the Court to consider air quality, public health, economic impact, and employment consequences. The Court may also consider the less than consistent efforts of the EPA to apply and further enforce the Clean Air Act." The potential penalties that may be imposed, as well as the capital expenditures necessary to comply with substantive remedial measures that may be required, could have a material adverse impact on FirstEnergy's financial condition and results of operations. Management is unable to predict the ultimate outcome of this matter and no liability has been accrued as of December 31, 2003.

Regulation of Hazardous Waste

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 subsequently determined 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, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2003, 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 a non-bypassable societal benefits charge. Included in Current Liabilities and Other Noncurrent Liabilities are accrued liabilities aggregating approximately $65 million as of December 31, 2003. The Companies accrue environmental liabilities only when they can conclude that it is probable that they have an obligation for such costs and can reasonably determine the amount of such costs. Unasserted claims are reflected in the Companies' determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol (Protocol), to address global warming by reducing the amount of man-made greenhouse gases emitted by developed countries by 5.2% from 1990 levels between 2008 and 2012. The United States signed the Protocol in 1998 but it failed to receive the two-thirds vote of the U.S. Senate required for ratification. However, the Bush administration has committed the United States to a voluntary climate change strategy to reduce domestic greenhouse gas intensity – the ratio of emissions to economic output – by 18% through 2012.

The Companies cannot currently estimate the financial impact of climate change policies although the potential restrictions on carbon dioxide (CO_2) emissions could require significant capital and other expenditures. However, the CO_2 emissions per kilowatt-hour of electricity generated by the Companies is lower than many regional competitors due to the Companies' diversified generation sources which includes low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal Clean Water Act and its amendments, apply to the Companies' plants. In addition, Ohio, New Jersey and Pennsylvania have water quality standards applicable to the Companies' operations. As provided in the Clean Water Act, authority to grant federal National Pollutant Discharge Elimination System water discharge permits can be assumed by a state. Ohio, New Jersey and Pennsylvania have assumed such authority.

(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 not otherwise discussed above are described below.

Power Outages

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.

Since July 1999, this litigation has involved a substantial amount of legal discovery including interrogatories, request for production of documents, preservation and inspection of evidence, and depositions of the named plaintiffs and many JCP&L employees. In addition, there have been many motions filed and argued by the parties involving issues such as the primary jurisdiction and findings of the NJBPU, consumer fraud by JCP&L, strict product liability, class decertification, and the damages claimed by the plaintiffs. In January 2000, the NJ Appellate Division determined that the trial court has proper jurisdiction over this litigation. In August 2002, the trial court granted partial summary judgment to JCP&L and dismissed the plaintiffs' claims for consumer fraud, common law fraud, negligent misrepresentation, and strict products liability. In November 2003, the trial court granted JCP&L's motion to decertify the class and denied plaintiffs' motion to permit into evidence their class-wide damage model indicating damages in excess of $50 million. These class decertification and damage rulings have been appealed to the Appellation Division and oral argument is scheduled for May 2004. FirstEnergy is unable to predict the outcome of these matters and no liability has been accrued as of December 31, 2003.

On August 14, 2003, various states and parts of southern Canada experienced a widespread power outage. That outage affected approximately 1.4 million customers in FirstEnergy's service area. FirstEnergy continues to accumulate data and evaluate the status of its electrical system prior to and during the outage event, and continue to cooperate with the U.S.-Canada Power System Outage Task Force (Task Force) investigating the August 14th outage. The interim report issued by the Task Force on November 18, 2003 concluded that the problems leading to the outage began in FirstEnergy's service area. Specifically, the interim report concludes, among other things, that the initiation of the August 14th outage resulted from the coincidence on that afternoon of the following events: (1) inadequate situational awareness at FirstEnergy; (2) FirstEnergy's failure to adequately manage tree growth in its transmission rights of way; and (3) failure of the interconnected grid's reliability organizations (Midwest Independent System Operator and PJM Interconnection) to provide effective diagnostic support. FirstEnergy believes that the interim report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14th outage and that it does not adequately address the underlying causes of the outage. FirstEnergy remains convinced that the outage cannot be explained by events on any one utility's system. On November 25, 2003, the PUCO ordered FirstEnergy to file a plan with the PUCO no later than March 1, 2004, illustrating how FirstEnergy will correct problems identified by the Task Force as events contributing to the August 14th outage and addressing how FirstEnergy proposes to upgrade its control room computer hardware and software and improve the training of control room operators to ensure that similar problems do not occur in the future. The PUCO, in consultation with the North American Electric Reliability Council, will review the plan before determining the next steps in the proceeding. On December 24, 2003, the FERC ordered FirstEnergy to pay for an independent study of part of Ohio's power grid. The study is to examine the stability of the grid in critical points in the Cleveland and Akron areas; the status of projected power reserves during summer 2004 through 2008; and the need for new transmission lines or other grid projects. The FERC ordered the study to be completed within 120 days. At this time, it is unknown what the cost of such study will be, or the impact of the results.

Davis-Besse

FENOC recently received a subpoena from a grand jury sitting in the United States District Court for the Northern District of Ohio, Eastern Division requesting the production of certain documents and records relating to the inspection and maintenance of the reactor vessel head at the David-Besse plant. We are unable to predict the outcome of this investigation. In addition, FENOC remains subject to possible civil enforcement action by the NRC in connection with the events leading to the Davis-Besse outage. If it were ultimately determined that FirstEnergy has legal liability or is otherwise made subject to regulatory or civil enforcement action with respect to the Davis-Besse outage, it could have a material adverse effect on FirstEnergy's financial condition and results of operations.

Other Legal Matters

Various legal proceedings have been filed against FirstEnergy in connection with, among other things, the restatements in August 2003, by FirstEnergy and its Ohio utility subsidiaries of previously reported results, the August 14th power outage described above, and the extended outage at Davis-Besse Nuclear Power Station. Depending upon the particular proceeding, the issues raised include alleged violations of federal securities laws, breaches of fiduciary duties under state law by FirstEnergy directors and officers, and damages as a result of one or more of the noted events. The securities cases have been consolidated into one action pending in federal court in Akron. The derivative actions filed in federal court likewise have been consolidated as a separate matter, also in federal court in Akron. There are also pending derivative actions in state court. FirstEnergy's Ohio utility subsidiaries also were named as respondents in two regulatory proceedings initiated at the PUCO in response to complaints alleging failure to provide reasonable and adequate service stemming primarily from the August 14th power outage. FirstEnergy is vigorously defending these actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be instituted against them. In particular, if FirstEnergy were ultimately determined to have legal liability in connections with these proceedings, it could have a material adverse effect on its financial condition and results of operations.

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, whose operations include the regulated sale of electricity and distribution and transmission services by its eight electric utility operating companies in Ohio, Pennsylvania and New Jersey (OE, CEI, TE, Penn, JCP&L, Met-Ed, Penelec and ATSI). The competitive services business segment consists of the subsidiaries (FES, FSG, MYR, MARBEL and First Communications) that operate unregulated energy and energy-related businesses, including the operation of generation facilities of OE, CEI, TE and Penn resulting from the deregulation of the Companies' electric generation business (see Note 2(D) – Regulatory Matters).

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 2002 has been adjusted to reflect the reclassification of revenue, expense, interest expense and tax amounts of divested businesses reflected as discontinued operations (see Note 2(I)).

Segment Financial Information

	Regulated Services	Competitive Services	Other	Reconciling Adjustments	Consolidated
			(In millions)		
2003					
External revenues	$8,978	$3,234	$ 71	$ 24 (a)	$12,307
Internal revenues	1,092	2,168	547	(3,807) (b)	—
Total revenues	10,070	5,402	618	(3,783)	12,307
Depreciation and amortization	1,209	33	40	—	1,282
Goodwill impairment	—	117	—	—	117
Net interest charges	499	44	344	(75) (b)	812
Income taxes	650	(126)	(118)	—	406
Income before discontinued operations and cumulative effect of accounting change	885	(205)	(258)	—	422
Discontinued operations	—	(6)	(95)	—	(101)
Cumulative effect of accounting change	101	1	—	—	102
Net income	986	(210)	(353)	—	423
Total assets	29,789	2,335	786	—	32,910
Total goodwill	5,993	135	—	—	6,128
Property additions	434	345	77	—	856
2002					
External revenues	$9,166	$2,482	$ 386	$ 13 (a)	$12,047
Internal revenues	1,052	2,044	478	(3,574) (b)	—
Total revenues	10,218	4,526	864	(3,561)	12,047
Depreciation and amortization	1,235	28	35	—	1,298
Net interest charges	588	44	384	(58) (b)	958
Income taxes	698	(87)	(87)	—	524
Income before discontinued operations	928	(111)	(184)	—	633
Discontinued operations	—	2	(82)	—	(80)
Net income	928	(109)	(266)	—	553
Total assets	30,494	2,281	1,611	—	34,386
Total goodwill	5,993	285	—	—	6,278
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 accounting change	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

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)	
2003	$10,267	$624	$766
2002	9,697	613	904
2001	6,078	792	693

Geographic Information*	2003 Revenues	2003 Assets	2002 Revenues	2002 Assets
		(In millions)		
United States	$12,282	$32,826	$11,753	$33,628
Foreign countries*	25	84	294	758
Total	$12,307	$32,910	$12,047	$34,386

** See Note 3 for discussion of divestitures of business operations and Note 2(I) for discussion of discontinued operations.*

9. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

FASB Staff Position (FSP) 106-1 "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003"

Issued Janaury 12, 2004, FSP 106-1 permits a sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Company has elected to defer the effects of the Act due to the lack of specific guidance. Any measure of the accumulated postretirement benefit obligation or net periodic postretirement benefit cost in the financial statements or the accompanying notes do not reflect the impact of the Act on the plans. At this time, specific authoritative guidance on the accounting for the federal subdsidy provided by the Act is pending and that guidance could require the Company to change previously reported information.

FIN 46 (revised December 2003), "Consolidation of Variable Interest Entities"

In December 2003, the FASB issued this revised interpretation of Accounting Research Bulletin No. 51, "Consolidated Financial Statements". This Interpretation, referred to below as "FIN 46R", requires the consolidation of a VIE by an enterprise if that enterprise either absorbs a majority of the VIE's expected losses or receives a majority of the VIE's expected residual returns as a result of ownership, contractual or other financial interests in the VIE. Prior to FIN 46R, entities were generally consolidated by an enterprise that had a controlling financial interest through ownership of a majority voting interest in the entity.

FIN 46R defines a VIE as an entity in which equity investors do not have the characteristics of a controlling financial interest nor have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support. Adoption of FIN 46R is required of public entities that have interests in VIEs or potential VIEs commonly referred to as special-purpose entities for periods ending after December 15, 2003. Adoption by public entities for all other types of entities is required for periods ending after March 15, 2004 (FirstEnergy's first quarter of 2004).

FirstEnergy currently has transactions with entities in connection with sale and leaseback arrangements which fall within the scope of this interpretation and which meet the definition of a VIE in accordance with FIN 46R. Upon adoption of FIN 46R effective December 31, 2003, FirstEnergy consolidated two VIEs; the PNBV Capital Trust (PNBV) and the Shippingport Capital Trust were created in 1996 and 1997, respectively, to refinance debt in connection with these sale and leaseback transactions.

PNBV issued equity and notes to fund the acquisition of a portion of the collateralized lease bonds that had been issued by certain owner trusts in connection with the sale and leaseback in 1987 of a portion of OE's interest in the Perry Plant and Beaver Valley Unit 2. OE used debt and available funds to purchase the notes issued by the PNBV Capital Trust. Ownership of the trust includes a three-percent equity interest by a nonaffiliated third party and a three-percent equity interest held by OES Ventures, a wholly owned subsidiary of OE. Consolidation of the trust as of December 31, 2003 changed the PNBV trust investment of $361 million to an investment in collateralized lease bonds of $372 million. The increase in $11 million represents the minority interest in the total assets of the trust.

Shippingport was established to purchase all of the lease obligation bonds issued by the owner trusts in the Bruce Mansfield Plant sale and leaseback transactions in 1987. CEI and TE acquired all of the notes issued by Shippingport Capital Trust. Upon adoption of FIN 46R, this entity was consolidated on the books of CEI; the obligation to the trusts was previously recorded on the books of both CEI and TE. Consolidation of this entity therefore had no impact on the financial statements of FirstEnergy.

In addition to the two entities created to refinance debt discussed above, the Company evaluated its interest in the owner trusts that acquired the interests in the Perry Plant, Beaver Valley Unit 2 and the Bruce Mansfield Plant. FirstEnergy concluded that the operating companies (OE, CEI and TE) were not the primary beneficiaries of these owner trusts and were therefore not required to consolidate these entities. The leases are accounted for as operating leases in accordance with GAAP and their related obligations are disclosed in Note 4. The combined purchase price of $3.1 billion for all of the interests acquired by the owner trusts in 1987 was funded with debt of $2.5 billion and equity of $600 million.

FirstEnergy is exposed to losses under the sale-leaseback agreements upon the occurrence of certain contingent events that we consider unlikely to occur. The Company's maximum exposure to loss is currently estimated to be $2.0 billion, which represents the net amount of casualty value payments upon the occurrence of specified casualty events that render the plants worthless. Under the sale and leaseback agreements, FirstEnergy has minimum undiscounted net lease payments of $2.6 billion that would not be payable if the casualty value payments are made. In addition, the Company has recorded above market lease obligations of $1.1 billion, of which $85 million is current, related to the Bruce Mansfield Plant and Beaver Valley Unit 2 as of December 31, 2003 related to the acquisition by FirstEnergy of CEI and TE.

As described in Note 5(G), CEI, Met-Ed and Penelec created statutory business trusts to issue trust preferred securities in the aggregate of $285 million. Prior to the adoption of FIN 46R, these trusts had been consolidated by FirstEnergy and the respective operating company. Application of the guidance in FIN 46R resulted in the holders of the preferred securities being considered the primary beneficiaries of these trusts. Therefore, FirstEnergy, CEI, Met-Ed and Penelec have deconsolidated the trusts. As of December 31, 2003, FirstEnergy reported subordinated debentures to the respective trusts of $294 million ($103 million for CEI, $96 million for Met-Ed and $95 million for Penelec) within the balance sheet liability caption "Subordinated debentures to affiliated trusts" and the equity investment in the trusts of $9 million ($3 million each for CEI, Met-Ed and Penelec) within the balance sheet asset caption "Investments – Other."

In August 1995, Los Amigos Leasing Company, Ltd. (Los Amigos) was formed as a consolidated subsidiary of GPU Power to own and lease to TEBSA equipment comprised of an 895 megawatt plant constructed and operated by TEBSA. Upon application of FIN 46R, Los Amigos met the criteria of a VIE and FirstEnergy was determined not to be its primary beneficiary. Therefore, effective December 31, 2003 Los Amigos was deconsolidated, resulting in the removal of approximately $243 million of total assets (primarily unbilled lease receivable) and liabilities (primarily senior and subordinated debt) from FirstEnergy's Consolidated Balance Sheets. Los Amigos was sold as part of the TEBSA divestiture on January 30, 2004.

FirstEnergy is evaluating other entities that meet the deferral criteria and may be subject to consolidation under FIN 46 as of March 31, 2004. Included in this analysis are non-utility generators in which we have neither debt nor equity investments but are generally the sole purchaser of their power.

SFAS 132 (revised December 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits – An amendment of FASB Statements No. 87, 88, and 106

Issued by the FASB in December 2003 and effective for financial statements with fiscal years ending after December 15, 2003, this revision to SFAS 132 revises employers' disclosures about pension plans and other postretirement benefits plans. SFAS 132 (as revised) does not change the measurement or recognition of those plans as required by FASB Statements No. 87, 88, and 106, but requires additional disclosures about the assets, obligations, cash flows, and net periodic benefit cost of defined benefit pension plans and other defined benefit postretirement plans. FirstEnergy has included the additional disclosure requirements in Note 2(K) – Pension and Other Postretirement Benefit Plans.

EITF Issue No. 03-1 "The Meaning of Other-Than Temporary Impairment and its Application to Certain Investments"

In November 2003, the EITF reached consensus that certain quantitative and qualitative disclosures are required for debt and equity securities classified as available-for-sale or held-to-maturity. The guidance requires the disclosure of the aggregate amount of unrealized losses and the aggregate related fair value for investments with unrealized losses that have not been recognized as other-than-temporary impairments. FirstEnergy has adopted the disclosure requirements of EITF Issue No. 03-1 as of December 31, 2003 (See Note 10(E)).

EITF Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to SFAS No 133, Accounting for Derivative Instruments and Hedging Activities, and Not "Held for Trading Purposes" as Defined in EITF Issue 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities."

In July 2003, the EITF reached a consensus that determining whether realized gains and losses on physically settled derivative contracts not "held for trading purposes" should be reported in the income statement on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. The consideration of the facts and circumstances, including economic substance, should be made in the context of the various activities of the entity rather than based solely on the terms of the individual contracts. The Company adopted this consensus effective January 1, 2004. The impact on operating revenues and operating expenses has not been determined but is not expected to be material. The adoption of EITF C3-11 will have no impact on net income.

DIG Implementation Issue No. C20 for SFAS 133, "Scope Exceptions: Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) Regarding Contracts with a Price Adjustment Feature"

In June 2003, the FASB cleared DIG Issue C20 for implementation in fiscal quarters beginning after July 10, 2003. The issue supersedes earlier DIG Issue C11, "Interpretation of Clearly and Closely Related in Contracts That Qualify for the Normal Purchases and Normal Sales Exception." DIG Issue C20 provides guidance regarding when the presence of a general index, such as the Consumer Price Index, in a contract would prevent that contract from qualifying for the normal purchases and normal sales exception under SFAS 133, as amended, and therefore exempt from the mark-to-market treatment of certain contracts. Adoption of DIG Issue C20 did not have a material impact on the Companies' financial statements.

EITF Issue No. 01-8, "Determining Whether an Arrangement Contains a Lease"

In May 2003, the EITF reached a consensus regarding when arrangements contain a lease. Based on the EITF consensus, an arrangement contains a lease if: (1) it identifies specific property, plant or equipment (explicitly or implicitly); and (2) the arrangement transfers the right to the purchaser to control the use of the property, plant or equipment. The consensus is to be applied prospectively to arrangements committed to, modified or acquired through a business combination after the effective date of the consensus. The adoption of this consensus as of July 1, 2003 did not affect FirstEnergy's financial statements.

SFAS 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity"

In May 2003, the FASB issued SFAS 150, which establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. In accordance with the standard, certain financial instruments that embody obligations for the issuer are required to be classified as liabilities. SFAS 150 was effective immediately for financial instruments entered into or modified after May 31, 2003 and effective at the beginning of the first interim period beginning after June 15, 2003 for all other financial instruments.

Upon adoption of SFAS 150, effective July 1, 2003, FirstEnergy reclassified as debt the preferred stock of consolidated subsidiaries subject to mandatory redemption with a carrying value of approximately $19 million ($5 million for CEI and $14 million for Penn) as of December 31, 2003. Adoption of SFAS 150 had no impact on FirstEnergy's Consolidated Statements of Income because the preferred dividends were previously included in net interest charges and required no reclassification.

SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"

Issued by the FASB in April 2003, SFAS 149 further clarifies and amends accounting and reporting for derivative instruments. The statement amends SFAS 133 for decisions made by the Derivative Implementation Group (DIG), as well as issues raised in connection with other FASB projects and implementation issues. The statement was effective for contracts entered into or modified after June 30, 2003 except for implementation issues that were effective for reporting periods beginning before June 15, 2003, that continue to be applied based on their original effective dates. Adoption of SFAS 149 did not have a material impact on the Companies' financial statements.

SFAS 143, "Accounting for Asset Retirement Obligations"

The Company adopted SFAS 143 effective January 1, 2003. The impact of this new accounting standard is discussed above under Notes 2(F) and 2(J).

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 was applicable on a prospective basis to guarantees issued or modified after December 31, 2002. Adoption of FIN 45 for guarantees issued during 2003 did not have a material impact on FirstEnergy's financial statements.

10. OTHER INFORMATION:

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

(A) Consolidated Statements of Cash Flows

	2003	2002	(Unaudited) 2001
		(In Thousands)	
Other Cash Flows From Operating Activities:			
Accrued taxes	$219,936	$ 35,108	$ 8,915
Accrued interest	(57,509)	(27,420)	117,520
Retail rate refund obligation payments	(71,984)	(43,016)	—
Interest rate hedge	—	—	(132,376)
Prepayments and other	(31,155)	133,677	(146,741)
Accrued retirement benefit obligations	282,804	124,678	19,797
Accrued compensation, net	(74,401)	(92,197)	(118,325)
Tax refund related to pre-merger period	51,073	—	—
Energy derivative transactions	(70,498)	(8,682)	—
Asset retirement obligation	97,820	—	—
All other	(7,349)	3,538	646
Total-Other	$338,737	$125,686	$(250,564)
Other Cash Flows from Investing Activities:			
Retirements and transfers	$ 37,580	$ 29,619	$ 40,106
Nonutility generation trusts withdrawals	66,327	49,044	—
Contributions to nuclear decommissioning trusts	(101,218)	(103,143)	(90,995)
Nuclear decommissioning trust investments	(143,493)	16,922	17,614
Long-term notes receivable	82,250	(91,335)	—
Other investments	29,137	(7,944)	(165,938)
All other	42,273	52,482	(34,313)
Total-Other	$ 12,856	$ (54,355)	$(233,526)

(B) Consolidated Statements of Taxes

	2003	2002	(Unaudited) 2001
		(In Thousands)	
Other Accumulated Deferred Income Taxes as of December 31:			
Retirement Benefits	$(359,038)	$(223,065)	$(133,282)
Oyster Creek securitization (Note 5(H))	193,558	202,447	—
Loss carryforwards	(495,254)	(507,690)	(486,495)
Loss carryforwards valuation reserve	470,813	482,061	459,170
Purchase accounting basis differences	(2,657)	(2,657)	(147,450)
Sale of generating assets	(11,785)	(11,786)	207,787
Provision for rate refund	—	(29,370)	(46,942)
All other	(49,569)	(149,226)	(176,484)
Total-Other	$(253,932)	$(239,286)	$(323,696)

(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, 2003, are summarized as follows:

	2003	2002	(Unaudited) 2001
		(In millions)	
Sales	$990	$453	$142
Purchases	1,019	687	204

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 (2001 Unaudited)

Stock-based employee compensation expense recognized for the FirstEnergy Programs' restricted stock during 2003, 2002 and 2001 totaled $1,747,000, $2,259,000 and $1,342,000, respectively. In addition, stock-based employee compensation expense of $2,312,000, $206,000 and $1,637,000 during 2003, 2002 and 2001, respectively, was recognized for EDCP stock units (see Note 5(C) for further discussion).

(E) SFAS 115 Activity

Investments other than cash and cash equivalents in the table in Note 2(M) – Cash and Financial Instruments include available-for-sale securities, at fair value, with the following net results:

	2003*	2002*	(Unaudited) 2001
		(In millions)	
Unrealized gains (losses)	$116	$(48)	$2
Proceeds from sales	516	421	–
Realized gains (losses)	3	(15)	–

** Includes the available-for-sale securities of FirstEnergy's Ohio Companies' decommissioning trusts.*

As of December 31, 2003 accumulated other comprehensive income (loss) for available-for-sale securities consisted of investments with net unrealized gains of $153 million and net unrealized losses of $45 million. The following table provides details for the available-for-sale securities with net unrealized losses as of December 31, 2003.

	Less Than 12 Months		12 Months or More		Total	
Security Type	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
			(In millions)			
Equity Securities	$17	$5	$43	$40	$60	$45
Debt Securities	33	–	–	–	33	–
Total	$50	$5	$43	$40	$93	$45

All of the aggregate unrealized losses related to available-for-sale securities in the table above are considered to be temporary in nature. These securities are primarily held by the nuclear decommissioning trusts of FirstEnergy's Ohio Companies. FirstEnergy has the ability and intent to hold these securities for the period necessary to fund their cost.

11. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED):

The following summarizes certain consolidated operating results by quarter for 2003 and 2002.

Three Months Ended (a)	March 31 2003	June 30 2003	Sept. 30 2003	Dec. 31 2003
	(In millions, except per share amounts)			
Revenues	$3,221	$2,853	$3,434	$2,799
Expenses	2,806	2,619	2,947	2,463
Claim Settlement (Note 3)	–	–	–	168
Income Before Interest and Income Taxes	415	234	487	504
Net Interest Charges	206	205	201	200
Income Taxes	94	19	135	158
Income Before Discontinued Operations and Cumulative Effect of Accounting Change	115	10	151	146
Discontinued Operations (Net of Income Taxes)	2	(68)	1	(36)
Cumulative Effect of Accounting Change (Net of Income Taxes)	102	–	–	–
Net Income (Loss)	$219	$(58)	$152	$110
Basic Earnings (Loss) Per Share of Common Stock:				
Before Discontinued Operations and Cumulative Effect of Accounting Change	$0.39	$0.03	$0.51	$0.44
Discontinued Operations	–	(0.23)	–	(0.11)
Cumulative Effect of Accounting Change	0.35	–	–	–
Basic Earnings (Loss) Per Share of Common Stock	$0.74	$(0.20)	$0.51	$0.33
Diluted Earnings (Loss) Per Share of Common Stock:				
Before Discontinued Operations and CumulativeEffect of Accounting Change	$0.39	$0.03	$0.50	$0.44
Discontinued Operations	–	(0.23)	–	(0.11)
Cumulative Effect of Accounting Change	0.35	–	–	–
Diluted Earnings (Loss) Per Share of Common Stock	$0.74	$(0.20)	$0.50	$0.33

Three Months Ended (a)	March 31 2003	June 30 2003	Sept. 30 2003	Dec. 31 2003
	(In millions, except per share amounts)			
Revenues	$2,810	$2,854	$3,407	$2,976
Expenses	2,322	2,232	2,684	2,694
Income Before Interest and Income Taxes	488	622	723	282
Net Interest Charges	278	249	220	211
Income Taxes	93	167	220	44
Income Before Discontinued Operations	117	206	283	27
Discontinued Operations (Net of Income Taxes)	1	2	2	(85)
Net Income (Loss)	$118	$208	$285	$(58)
Basic Earnings (Loss) Per Share of Common Stock:				
Before Discontinued Operations	$0.40	$0.71	$0.96	$0.09
Discontinued Operations	–	–	0.01	(0.29)
Basic Earnings (Loss) Per Share of Common Stock	$0.40	$0.71	$0.97	$(0.20)
Diluted Earnings (Loss) Per Share of Common Stock:				
Before Discontinued Operations	$0.40	$0.70	$0.96	$0.09
Discontinued Operations	–	–	0.01	(0.29)
Diluted Earnings (Loss) Per Share of Common Stock	$0.40	$0.70	$0.97	$(0.20)

(a) Revenues, expenses, net interest charges and income taxes have been revised to reflect reclassifications of the results of discontinued operations.

Net income for the three months ended December 31, 2003, was increased by $7.4 million due to adjustments relating to the first nine months of 2003. After-tax income of $16.3 million resulted from adjustments for costs charged to expense in prior quarters of 2003 that were subsequently capitalized to regulated segment construction projects in the fourth quarter, partially offset by after-tax charges of $8.9 million for adjustments relating to prior quarters for the competitive segment. Management concluded that these adjustments were not material to the reported consolidated results of operations for any quarter of 2003 (after-tax amounts of $3.1 million, $0.6 million and $3.7 million for the first three quarters of 2003, respectively). However, the adjustments relating to the regulated segment were material to the separate reported results of JCP&L, Penelec and TE; accordingly, the reported results of operations for the first three quarters of 2003 for those subsidiaries will be restated in their separate financial statements. The impact of these adjustments was not material to FirstEnergy's consolidated balance sheets or consolidated statements of cash flows for any quarter of 2003.

The net loss for the second quarter of 2003 included a charge resulting from the NJBPU's decision to disallow recovery by JCP&L of $153 million in deferred energy costs and a $67 million non-cash charge (no tax benefit recognized) from the abandonment of operations in Argentina.

Results for the fourth quarter of 2003 included a $33 million after-tax loss from the divestiture of assets in Bolivia included in discontinued operations and a $26 million impairment of the equity TEBSA investment in Columbia included in continuing operations. The fourth quarter results also include a $170 million gain ($168 million net of expenses) from the NRG Energy Inc. settlement claim.

The operating results in 2002 related to assets sold in 2003 have been reclassified as discontinued operations. The fourth quarter discontinued operations include an $88 million loss from operations of the Argentina assets.

12. GPU MERGER (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 represented 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 occurred in 2003 as merger-related transition assignments were completed.

The merger greatly expanded the size and scope of FirstEnergy's 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 is classified as goodwill and amounts to $3.8 billion as of December 31, 2003. 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 and other minor adjustments, goodwill increased by approximately $286 million as of December 31, 2002. The increase was attributable to the regulated services segment.

The following pro forma combined condensed statement of income of FirstEnergy give effect to the FirstEnergy/GPU merger as if it had been consummated on January 1, 2001, with the purchase accounting adjustments actually recognized in the business combination. 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

	(In millions, except per share amounts)
Revenues	$12,108
Expenses	9,768
Income Before Interest and Income Taxes	2,340
Net Interest Charges	941
Income Taxes	561
Net Income	$838
Earnings per Share of Common Stock	$2.87

CONSOLIDATED FINANCIAL AND PRO FORMA COMBINED OPERATING STATISTICS (UNAUDITED)

(Dollars in thousands)

	2003	2002	2001	2000	1999	1998	1993
		(see Note 2(I))					
GENERAL FINANCIAL INFORMATION							
Revenues	**$12,307,047**	$12,047,348	$7,999,362	$7,028,961	$6,319,647	$5,874,906	$2,399,794
Net Income	**$422,764**	$552,804	$646,447	$598,970	$568,299	$410,874	$59,017
SEC Ratio of Earnings to Fixed Charges	**1.72**	1.90	2.22	2.10	2.01	1.77	1.12
Capital Expenditures	**$791,834**	$903,606	$887,929	$568,711	$474,118	$305,577	$263,179
Total Capitalization(a)	**$18,413,530**	$18,686,388	$21,339,001	$11,204,674	$11,469,795	$11,756,422	$5,656,295
Capitalization Ratios (a):							
Common Stockholders' Equity	**45.0%**	37.7%	34.7%	41.5%	39.8%	37.9%	39.7%
Preferred and Preference Stock:							
Not Subject to Mandatory Redemption	**1.8**	1.8	2.2	5.8	5.7	5.6	5.8
Subject to Mandatory Redemption	—	2.3	2.8	1.4	2.2	2.5	0.8
Long-Term Debt	**53.2**	58.2	60.3	51.3	52.3	54.0	53.7
Total Capitalization	**100.0%**	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Average Capital Costs:							
Preferred and Preference Stock	**6.47%**	7.50%	7.90%	7.92%	7.99%	8.01%	6.86%
Long-Term Debt	**6.08%**	6.56%	6.98%	7.84%	7.65%	7.83%	8.27%
COMMON STOCK DATA							
Earnings per Share (b):							
Basic	**$1.39**	$2.16	$2.85	$2.69	$2.50	$1.95	$1.82
Diluted	**$1.39**	$2.15	$2.84	$2.69	$2.50	$1.95	$1.82
Return on Average Common Equity (b)	**5.6%**	8.4%	12.9%	13.0%	12.7%	10.3%	11.4%
Dividends Paid per Share	**$1.50**	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
Dividend Payout Ratio (b)	**108%**	69%	53%	56%	60%	77%	82%
Dividend Yield	**4.3%**	4.5%	4.3%	4.8%	6.6%	4.6%	6.6%
Price/Earnings Ratio (b)	**25.3**	15.3	12.3	11.7	9.1	16.7	12.5
Book Value per Share	**$25.35**	$24.01	$25.29	$21.29	$20.22	$19.37	$14.70
Market Price per Share	**$35.20**	$32.97	$34.98	$31.56	$22.69	$32.56	$22.75
Ratio of Market Price to Book Value	**139%**	137%	138%	148%	112%	168%	155%
OPERATING STATISTICS (c)							
Generation Kilowatt-Hour Sales (Millions):							
Residential	**31,322**	31,937	32,708	32,519	32,616	31,220	29,709
Commercial	**32,310**	32,892	32,170	33,139	30,311	31,033	27,012
Industrial	**32,451**	32,726	33,024	31,140	30,422	36,683	33,261
Other	**554**	531	536	522	566	611	1,422
Total Retail	**96,637**	98,086	98,438	97,320	93,915	99,547	91,404
Total Wholesale	**42,062**	30,007	20,240	13,761	14,631	9,910	11,953
Total Sales	**138,699**	128,093	118,678	111,081	108,546	109,457	103,357
Customers Served:							
Residential	**3,874,052**	3,868,499	3,833,013	3,798,716	3,767,534	3,735,308	3,582,998
Commercial	**496,253**	471,440	464,053	472,410	455,919	447,087	415,637
Industrial	**10,871**	18,416	18,652	18,996	19,549	19,902	21,920
Other	**5,635**	5,716	5,762	6,001	5,992	5,876	7,512
Total	**4,386,811**	4,364,071	4,321,480	4,296,123	4,248,994	4,208,173	4,028,067
Number of Employees	**15,905**	17,560	18,700	18,912	19,470	20,392	24,689

(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 discontinued operations in 2002 and 2003, accounting changes in 2003 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 *www.firstenergycorp.com/ir.*

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	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 2004 are:

Ex-Dividend Date	Record Date	Payment Date
February 4	February 6	March 1
May 5	May 7	June 1
August 4	August 6	September 1
November 3	November 5	December 1

All dividends are subject to declaration by the Board of Directors in its discretion.

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. Contact Investor Services to receive an authorization form.

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. Contact Investor Services to receive an enrollment form.

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. Shareholders also should 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 2004 Annual Meeting of Shareholders on Tuesday, May 18, at 10 a.m. Eastern time, at the John S. Knight Center, 77 East Mill Street, in Akron, Ohio. Registered shareholders 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 23, 2004.

FirstEnergy®
76 South Main Street, Akron, OH 44308-1890
www.firstenergycorp.com

2003 ANNUAL REPORT