FIRSTENERGY CORP
Form 10-K/A
September 11, 2003

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K/A

(MARK ONE)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2002
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE TRANSITION PERIOD FROM _________TO ___________

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.

AMENDMENT NO. 3

333-21011	FIRSTENERGY CORP. (An Ohio Corporation) 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-1843785

SECURITIES REGISTERED PURSUANT TO SECTION 12(B) OF THE ACT:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
FirstEnergy Corp.	Common Stock, $0.10 par value	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(G) OF THE ACT:

None

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

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

Indicate by check mark whether each registrant is an accelerated filer (as defined in Rule 12b-2 of the Act): Yes (X) No ( )

State the aggregate market value of the common stock held by non-affiliates of the registrant: FirstEnergy Corp., $9,920,663,231 as of June 28, 2002; and for all other registrants, none.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date:

CLASS	OUTSTANDING AS OF MARCH 24, 2003
FirstEnergy Corp., $0.10 par value	297,636,276

EXPLANATORY NOTE

We are filing this Amendment No. 3 to our Annual Report on Form 10-K/A for the year ended December 31, 2002 (the "Report") to correct certain typographical and minor computational errors in Item 7 -- Management's Discussion and Analysis of Results of Operations and Financial Condition of the Report (filed originally as part of Exhibit 13 to the Report). This Amendment has no effect on previously reported results of operations or financial position. No changes in the financial statements or other items of the Report as originally filed are necessary.

The complete amended and restated Item 7, which is included in its entirety below, reflects the following corrections:

Under the heading "RESULTS OF OPERATIONS":

In the third sentence of the first paragraph, the decrease in net income of $404.2 million in 2002 should have read $392.9 million.

In the second sentence of the second paragraph, the net reduction in basic and diluted earnings of $0.46 per share in 2002 should have read $0.71.

In the table of "One-time Charges" following the fifth paragraph, under the column labeled "CHANGE", the amount for Avon and Emdersa adjustment of $43.5 million should have read $61.0 million; the total of $274.5 million should have read $292.0 million; the reduction to basic earnings per share of common stock of $0.65 should have read $0.71; and the reduction to diluted earnings per share of common stock of $0.65 should have read $0.71.

Under the subheading "Net Interest Charges", the reference in the first sentence to a net interest charge increase of $406.6 million in 2002 should have read $405.7 million.

Under the heading "RESULTS OF OPERATIONS -BUSINESS SEGMENTS":

Under the subheading "Regulated Services", the reference in the first sentence to an increase in net income of $938 million in 2002 should have read $927 million.

In the sentence following the above sentence, the reference to the decrease in net income in 2002 of $103.7 million should have read $114.3 million.

The "2002 Column" in the table following the paragraph containing the sentence referred to above is corrected as follows:

Regulated Services

Increase(Decrease)	(In millions) As Originally Filed	As Corrected
Revenues.........................	$(529.5)	$(529.5)
Expenses.........................	(232.4)	(223.8)
Income Before Interest and Income Taxes....................	(297.1)	(305.7)
Net interest charges.............	(131.3)	(131.3)
Income taxes.....................	(62.1)	(60.1)
Net Income Change................	$(103.7)	$(114.3)

Under the subheading "Competitive Services", the reference in the first sentence to an increase in net losses of $119.0 million in 2002 should have read $108.1 million.

In the sentence following the above sentence, the reference to the increase in net losses in 2002 of $89.8 million should have read $78.9 million.

The "2002 Column" in the table following the paragraph containing the sentence referred to above is corrected as follows:

Competitive Services

Increase(Decrease)	(In millions) As Originally Filed	As Corrected
Revenues...................................	$211.5	$ 211.5
Expenses...................................	351.1	341.9
Income Before Interest and Income Taxes....	(139.6)	(130.4)

Net interest charges......................	21.9	21.9
Income taxes..............................	(63.2)	(64.9)
Cumulative effect of a change in accounting	8.5	8.5
Net Loss Increase.........................	$ 89.8	$ 78.9

In the third sentence of the second paragraph following the table above, the years 2002 and 2001 should read 2001 and 2000, respectively.

Under the heading "CAPITAL RESOURCES AND LIQUIDITY":

Under the subheading "Cash Flows From Financing Activities", in the sixth sentence of the first paragraph following the table, the total $4.3 billion of preferred stock that could have been issued as of December 31, 2002 should have read $4.5 billion.

Under the heading "IMPLEMENTATION OF RECENT ACCOUNTING STANDARD":

The "Total before adjustment" for revenues and expenses in the chart entitled 2002 IMPACT OF RECORDING ENERGY TRADING NET of $12,515 million and $10,378 million, respectively, should have read $12,499 million and $10,368 million, respectively.

The "Total as reported" for revenues and expenses in the same chart as indicated above of $12,247 million and $10,110 million, respectively, should have read $12,231 million and $10,100 million, respectively.

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* Indicates the items that have not been revised and are not included in this Form 10-K/A. Reference is made to the original 10-K, as previously amended, for the complete text of such items.

THE FOLLOWING ITEM HAS BEEN AMENDED IN THIS AMENDMENT NO. 3:

PART II

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FIRSTENERGY CORP.

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), availability and cost of capital, 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 the fall of 2003, inability to accomplish or realize anticipated benefits from strategic goals, further investigation into the causes of the August 14, 2003, power outage and other similar factors.

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

RESTATEMENTS

As further discussed in Note 2(M) to the Consolidated Financial

Statements, the Company is restating its consolidated financial statements for the year ended December 31, 2002. The revisions principally reflect a change in the method of amortizing the costs being recovered under the Ohio transition plan and recognition of above-market values of certain leased generation facilities.

Transition Cost Amortization

As discussed under Regulatory matters in Note 2(D), FirstEnergy's Ohio electric utilities recover transition costs, including regulatory assets, through an approved transition plan filed under Ohio's electric utility restructuring legislation. The plan, which was approved in July 2000, provides for the recovery of costs from January 1, 2001 through a fixed number of kilowatt-hour sales to all customers that continue to receive regulated transmission and distribution service, which is expected to end in 2006 for OE, 2007 for TE and in 2009 for CEI.

FirstEnergy, OE, CEI and TE amortize these transition costs using the effective interest method. The amortization schedules originally developed at the beginning of the transition plan in 2001 in applying this method were based on total transition revenues, including revenues designed to recover costs which have not yet been incurred or that were recognized on the regulatory financial statements (fair value purchase accounting adjustments), but not in the financial statements prepared under generally accepted accounting principles (GAAP). The Ohio electric utilities have revised their amortization schedules under the effective interest method to consider only revenues relating to transition

regulatory assets recognized on the GAAP balance sheet. The impact of this change will result in higher amortization of these regulatory assets in the first several years of the transition cost recovery period, compared with the method previously applied. The change in method results in no change in total amortization of the regulatory assets recovered under the transition period through the end of 2009.

After giving effect to the restatement, total transition cost amortization including above market leases) is expected to approximate the following for the years from 2003 through 2009 (in millions).

2003..............	$685
2004..............	786
2005..............	913
2006..............	378
2007..............	213
2008..............	163
2009..............	44

Above-Market Lease Costs

In 1997, FirstEnergy was formed through a merger between OE and Centerior Energy Corporation. The merger was accounted for as an acquisition of Centerior, the parent company of CEI and TE, under the purchase accounting rules of Accounting Principles Board (APB) Opinion No. 16. In connection with the reassessment of the accounting for the transition plan, FirstEnergy reassessed its accounting for the Centerior purchase and determined that above-market lease liabilities should have been recorded at the time of the merger. Accordingly, in 2002, FirstEnergy recorded additional adjustments associated with the 1997 merger between OE and Centerior to reflect certain above March 1 market lease liabilities for Beaver Valley Unit 2 and the Bruce Mansfield Plant, for which CEI and TE had previously entered into sale-leaseback arrangements. CEI and TE recorded an increase in goodwill related to the above March 1 market lease costs for Beaver Valley Unit 2 since regulatory accounting for nuclear generating assets had been discontinued prior to the merger date and it was determined that this additional liability would have increased goodwill at the date of the merger. The corresponding impact of the above March 1 market lease liability for the Bruce Mansfield Plant were recorded as regulatory assets because regulatory accounting had not been discontinued at that time for the fossil generating assets and recovery of these liabilities was provided under the transition plan.

The total above-market lease obligation of $722 million associated with Beaver Valley Unit 2 will be amortized through the end of the lease term in 2017 (approximately $37 million per year). The additional goodwill has been recorded on a net basis, reflecting amortization that would have been recorded through 2001, when goodwill amortization ceased with the adoption of Statement of Financial Accounting Standard No.SFAS) 142, "Goodwill and Other Intangible Assets". The total above-market lease obligation of $755 million associated with the Bruce Mansfield Plant is being amortized through the end of 2016 (approximately $48 million per year). Before the start of the transition plan in 2001, the regulatory asset would have been amortized at the same rate as the lease obligation resulting in no impact to net income. Beginning in 2001, the remaining unamortized regulatory asset would have been included in CEI's and TE's amortization schedules for regulatory assets and amortized through the end of the recovery period - approximately 2009 for CEI and 2007 for TE.

FirstEnergy has reflected the net impact of the accounting for these items for the period from the merger in 1997 through 2001 in the 2002 financial statements. The cumulative impact to net income recorded in 2002 related to these prior periods increased net income by $5.9 million in the restated 2002 financial statements and is reflected as a reduction in other operating expenses in the accompanying consolidated statement of income. In addition, the impact increased the following balances in the consolidated balance sheet as of January 1, 2002:

Increase (decrease)	(In Thousands)
Goodwill...........................	$ 381,780
Regulatory assets..................	636,100
Total assets.......................	$1,017,880
Other current liabilities...........	84,600
Deferred income taxes...............	(262,580)
Deferred investment tax credits.....	(828)
Other deferred credits..............	1,190,800
Total liabilities..................	$1,011,992
Retained earnings..................	$ 5,888

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The after-tax effect of the actual 2002 impact of these items decreased net income for the year ended December 31, 2002, by $71 million, or $0.24 per share. The effects of these changes on the Consolidated Statement of

Income, Consolidated Balance Sheet and Consolidated Statement of Cash Flows previously reported for December 31, 2002 are described in Note 2(M) to the Consolidated Financial Statements.

The adjustments described above are anticipated to result in a decrease in reported net income through 2005 and an increase in net income for the period 2006 through 2017, the end of the lease term for Beaver Valley Unit 2. The schedule below shows the estimated impact on net income of these adjustments for 2003 through 2008.

Year	Change in Transition Cost Amortization	Regulatory Asset Amortization (a)	Lease Liability Reversal	Effect on Pre-Tax Income	Effect on Net Income
		(in millions)			
2003	$(68)	$(103)	$85	$(86)	$(51)
2004	(40)	(118)	85	(73)	(43)
2005	36	(136)	85	(16)	(9)
2006	33	(83)	85	35	21
2007	64	(77)	85	72	43
2008	106	(56)	85	135	80

(a) This represents the additional amortization related to the regulatory assets recognized in connection with the above-market lease for the Bruce Mansfield Plant discussed above.

Other Adjustments -

FirstEnergy has also included in this restatement certain immaterial adjustments that were not previously recognized in 2002 related to the recognition of a valuation allowance on a tax benefit recognized in 2002 and other adjustments. The impact of these adjustments decreased net income by $11.3 million.

The total after-tax effect of the adjustments in this restatement decreased net income for the year ended December 31, 2002, by $76 million, or $0.26 per share as shown below.

Income Statement Effects

Increase (Decrease)	Transition Cost Amortization	Reversal of Lease Obligations	Other
	(In thousands, except per share am		
Total revenues	$ --	$ --	$ --
Fuel and purchased power	--	--	(10,700)
Other operating expenses	--	(90,688)	14,800
Provision for depreciation and amortization	150,474	50,272	--
Income before interest and income taxes	(150,474)	40,416	(4,100)
Net interest charges	--	--	(3,300)
Income taxes	(30,920)	(13,962)	10,500

Net income effect	$(119,554)	$ 54,378	$(11,300)
Basic earnings per share effect	$(0.42)	$0.20	($0.04)
Diluted earnings per share effect	$(0.42)	$0.20	($0.04)

GPU MERGER

On November 7, 2001, the merger of FirstEnergy and GPU became effective with FirstEnergy being the surviving company. The merger was accounted for using purchase accounting under the guidelines of SFAS 141, "Business Combinations." Under purchase accounting, the results of operations for the combined entity are reported from the point of consummation forward. As a result, our financial statements for 2001 reflect twelve months of operations for our pre-merger organization and seven weeks of operations (November 7, 2001 to December 31, 2001) for the former GPU companies. In 2002, our financial statements include twelve months of operations for both our pre-merger organization and the former GPU companies. Additional goodwill resulting from the merger ($2.3 billion) plus goodwill existing at GPU ($1.9 billion) at the time of the merger is not being amortized, reflecting the application of SFAS 142, "Goodwill and Other Intangible Assets." Goodwill continues to be subject to review for potential impairment (see Significant Accounting Policies - Goodwill). As a result of the merger, we issued nearly 73.7 million shares of our common stock, which are reflected in the calculation of earnings per share of common stock in 2002 and for the seven-week period outstanding in 2001.

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RESULTS OF OPERATIONS

Net income decreased to $552.8 million in 2002, compared to $646.4 million in 2001 and $599.0 million in 2000. Net income in 2001 included the cumulative effect of an accounting change resulting in a net after-tax charge of $8.5 million (see Cumulative Effect of Accounting Changes). Excluding the former GPU companies' results (and related interest expense on acquisition debt), net income decreased to $392.9 million in 2002 from $615.5 million in 2001 due in large part to the incremental costs related to the extended Davis-Besse outage and a number of one-time charges summarized in the table below. In addition, SFAS 142, implemented January 1, 2002, resulted in the cessation of goodwill amortization. In 2001, amortization of goodwill reduced net income by approximately $57 million ($0.25 per share of common stock). Excluding the former GPU companies' results (and related interest expense on acquisition debt), net income increased in 2001 due to reduced depreciation and amortization, general taxes and net interest charges. The benefits of these reductions were offset in part by lower retail electric sales, increased other operating expenses and higher gas costs.

Incremental costs related to the extended outage at the Davis-Besse nuclear plant (see Davis-Besse Restoration) reduced basic and diluted earnings per share of common stock by $0.47 in 2002. In addition, the table below displays one-time charges that resulted in a comparative net reduction to basic and diluted earnings of $0.71 per share of common stock in 2002, compared to

2001.

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

The impact of domestic and world economic conditions on the electric power industry limited our divestiture program during 2002. By the end of 2001, we had successfully completed the sale of our Australian gas transmission companies, had reached agreement with Aquila, Inc. for the sale of our holdings of electric distribution facilities in the United Kingdom (UK) and executed an agreement with NRG Energy Inc. (NRG) for the sale of four coal-fired power plants. However, the UK transaction with Aquila closed on May 8, 2002 and reflected the March 2002 modification of Aquila's initial offer such that Aquila acquired a 79.9 percent equity interest in Avon Energy Partners Holdings (Avon) for approximately $1.9 billion (including the assumption of $1.7 billion of debt). In the fourth quarter of 2002, we recognized a $50 million impairment of our Avon investment. On August 8, 2002, we notified NRG that we were canceling our agreement with them for their purchase of the four fossil plants because NRG had stated that it could not complete the transaction under the original terms of the agreement. We were also actively pursuing the sale of an electric distribution company in Argentina - GPU Empressa Distribuidora Electrica Regional S.A. and its affiliates (Emdersa). With the deteriorating economic conditions in Argentina no sale could be completed by December 31, 2002. (See Note 3 regarding the April 2003 abandonment). Further information on the impact of the changes in accounting related to our divestiture activities is available in the "Change in Previously Reported Income Statement Classifications" section and in the discussion of depreciation charges in the "Expenses" section below.

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

One-time Charges

One-time Charges	2002	2001
	(In millions)	
Investment impairments	$100.7	--
Pennsylvania deferred energy costs	55.8	--
Avon and Emdersa adjustment	61.0	--
Lake Plants - depreciation and sale costs	29.2	--
Long-term derivative contract adjustment	18.1	--
Generation project cancellation	17.1	--
Severance costs - 2002	11.3	--
Uncollectible reserve and contract losses	--	9.2
Early retirement costs - 2001	--	8.8
Estimated claim settlement	16.8	--
	$310.0	$18.0

Reduction to earnings per share of common stock		
Basic	$0.76	$0.05
Diluted	$0.76	$0.05

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Revenues

Total revenues increased $4.2 billion in 2002, which included more than $4.6 billion incremental revenues for the former GPU companies in 2002 (twelve months), compared to 2001 (seven weeks). Excluding results from the former GPU companies, total revenues increased $24.7 million following a $336.7 million increase in 2001. The additional sales in both years resulted from an expansion of our unregulated businesses, which more than offset lower sales from our electric utility operating companies (EUOC). Sources of changes in pre-merger and post-merger companies' revenues during 2002 and 2001, compared to the prior year, are summarized in the following table:

Sources of Revenue Changes	2002	2001
Increase (Decrease)	(In millions)	
Pre-Merger Companies:		
Electric Utilities (Regulated Services):		
Retail electric sales	$(328.5)	$(240.5)
Other revenues	18.4	(22.6)
Total Electric Utilities	(310.1)	(263.1)
Unregulated Businesses (Competitive Services):		
Retail electric sales	136.4	(19.9)
Wholesale electric sales:		
Nonaffiliated	140.0	254.4
Affiliated	345.3	32.7
Gas sales	(171.7)	226.1
Other revenues	(115.2)	106.5
Total Unregulated Businesses	334.8	599.8
Total Pre-Merger Companies	24.7	336.7
Former GPU Companies:		
Electric utilities	3,782.4	570.4
Unregulated businesses	766.0	101.9
Total Former GPU Companies	4,548.4	672.3
Intercompany Revenues	(341.9)	(38.6)

Net Revenue Increase	$4,231.2	$970.4

Electric Sales

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

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

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

Despite the decrease in kilowatt-hour sales by our pre-merger EUOC, total electric generation sales increased by 22.0% in 2002 compared to the prior year as a result of higher kilowatt-hour sales by our competitive services segment. Revenues from the wholesale market increased $501.4 million in 2002 from 2001 and kilowatt-hour sales more than doubled. More than half of the increase resulted from additional affiliated company sales by FES to Met-Ed and Penelec. FES assumed the supply obligation in the third quarter of 2002 for a portion of Met-Ed's and Penelec's provider of last resort (PLR) supply requirements (see State Regulatory Matters - Pennsylvania). The increase also included sales into the

New Jersey market as an alternative supplier for a portion of New Jersey's basic generation service (BGS). Retail sales by our competitive services segment increased by $136.4 million as a result of a 59.0% increase in kilowatt-hour sales in 2002 from 2001. That increase resulted from retail customers switching to FES, our unregulated subsidiary, under Ohio's electricity choice program. The higher kilowatt-hour sales in Ohio were partially offset by lower retail sales in markets outside of Ohio.

In 2001, our pre-merger EUOC retail revenues decreased by $240.5 million compared to 2000, principally due to lower generation sales volume resulting from the first year of customer choice in Ohio. Sales by alternative suppliers increased to 11.3% of total energy delivered compared to 0.8% in 2000. Implementation of a 5% reduction in generation charges for residential customers as part of Ohio's electric utility restructuring in 2001 also contributed $51.2 million to the reduced electric sales revenues. Kilowatt-hour deliveries to franchise customers were down a more moderate 1.7% due in part to the decline in economic conditions, which was a major factor resulting in a 3.1% decrease in kilowatt-hour deliveries to commercial and industrial customers. Other regulated electric revenues decreased by $22.6 million in 2001, compared to the prior year, due in part to reduced customer reservation of transmission capacity.

Total electric generation sales increased by 2.7% in 2001 compared to the prior year with sales to the wholesale market being the largest single factor contributing to this increase. Kilowatt-hour sales to wholesale customers more than doubled from 2000 and revenues increased $287.1 million in 2001 from the prior year. The higher kilowatt-hour sales benefited from increased availability of power to sell into the wholesale market, due to additional internal generation and increased shopping by retail customers from alternative suppliers, which allowed us to take advantage of wholesale market opportunities. Retail kilowatt-hour sales by our competitive services segment increased by 3.6% in 2001, compared to 2000, primarily due to expanding sales within Ohio as a result of retail customers switching to FES under Ohio's electricity choice program. The higher kilowatt-hour sales in Ohio were partially offset by lower sales in markets outside of Ohio as some customers returned to their local distribution companies. Despite an increase in kilowatt-hour sales in Ohio's competitive market, declining sales to higher-priced eastern markets contributed to an overall decline in retail competitive sales revenue in 2001 from the prior year.

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

Changes in KWH Sales	2002	2001
Increase (Decrease)		
Electric Generation Sales:		
Retail -		
Regulated services	(14.2)%	(12.2)%
Competitive services	59.0%	3.6%
Wholesale	122.6%	117.2%
Total Electric Generation Sales	22.0%	2.7%
EUOC Distribution Deliveries:		
Residential	6.3%	1.7%
Commercial and industrial	(3.2)%	(3.1)%
Total Distribution Deliveries	(0.5)%	(1.7)%

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

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

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

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

Nonelectric Sales

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

Expenses

Total expenses increased nearly $3.8 billion in 2002, which included more than $3.7 billion of incremental expenses for the former GPU companies in 2002 (twelve months), compared to 2001 (seven weeks). For our pre-merger companies, total expenses increased $409.9 million in 2002 and $280.4 million in 2001, compared to the respective prior years. Sources of changes in pre-merger and post-merger companies' expenses in 2002 and 2001, compared to the prior year, are summarized in the following table:

Sources of Expense Changes	2002	2001
Increase (Decrease)	(In millions)	
Pre-Merger Companies:		
Fuel and purchased power	$ 431.0	$ 48.7
Purchased gas	(227.9)	266.5
Other operating expenses	102.6	178.2
Depreciation and amortization	75.6	(99.0)
General taxes	28.5	(114.0)

Total Pre-Merger Companies	409.8	280.4
Former GPU Companies	3,730.0	542.4
Intercompany Expenses	(353.9)	(32.6)
Net Expense Increase	$3,785.9	$ 790.2

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

Higher fuel and purchased power costs in 2002 compared to 2001 primarily reflect additional purchased power costs of $352.9 million. The increase resulted from additional volumes to cover supply obligations assumed by FES. These included a portion of Met-Ed's and Penelec's PLR supply requirements (which started in the third quarter of 2002), contract sales including sales to the New Jersey market to provide BGS, and additional supplies required to replace Davis-Besse power during its extended outage (see Davis-Besse Restoration). Fuel expense increased $99.5 million in 2002 from the prior year principally due to additional internal generation (5.4% higher) and an increased mix of coal and natural gas generation in 2002. The extended outage at the Davis-Besse nuclear plant produced a decline in nuclear generation of 14.6% in 2002, compared to 2001. Purchased gas costs decreased by $227.9 million primarily due to lower unit costs of natural gas purchased in 2002 compared to the prior year resulting in a $48.4 million improvement in gas margins.

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

Other operating expenses increased $102.6 million in 2002 from the previous year. The increase principally resulted from several large offsetting factors. Nuclear costs increased $125.3 million primarily due to $115.0 million of incremental Davis-Besse costs related to its extended outage (see Davis-Besse Restoration). One-time charges, discussed above, added $98.3 million and an aggregate increase in administrative and general expenses and non-operating costs of $127.4 million resulted in large part from higher employee benefit expenses. Partially offsetting these higher costs were the elimination in the second half of 2001 of coal trading activities ($95.4 million) and reduced facilities

service business ($58.9 million). The reversal of lease obligations related to the Bruce Mansfield fossil facility and Beaver Valley nuclear facility reduced other operating expenses by $84.8 million in 2002 as compared to 2001.

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

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

Charges for depreciation and amortization increased $75.6 million in 2002 from the preceding year. This increase resulted from several factors: increased amortization under the Ohio transition plan ($201 million). The start up of a new fluidized bed boiler in January 2002, owned by Bayshore Power Company, a wholly owned subsidiary, resulted in higher depreciation expense in 2002. Also, new combustion turbine capacity added in late 2001 and two months of 2001 depreciation recorded in 2002 (for the four fossil plants we chose not to sell) increased depreciation expense in 2002. However, two factors offset a portion of the above increase: shopping incentive deferrals and tax-deferrals under the Ohio transition plan ($108.5 million) and the cessation of goodwill amortization ($56.4 million) beginning January 1, 2002.

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

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

Net Interest Charges

Net interest charges increased $405.7 million in 2002, compared to 2001. These increases included interest on $4 billion of long-term debt issued by FirstEnergy in connection with the merger. Excluding the results associated with the former GPU companies and merger-related financing, net interest charges decreased $57.0 million in 2002, compared to a $39.8 million decrease in 2001 from 2000. Our continued redemption and refinancing of our outstanding debt and preferred stock during 2002, maintained our downward trend in financing costs, before the effects of the GPU merger. Excluding activities related to the former GPU companies, redemption and refinancing activities for 2002 totaled $1.1 billion and $143.4 million, respectively, and are expected to result in annualized savings of $86.0 million. We also exchanged existing fixed-rate payments on outstanding debt (principal amount of $593.5 million at year end 2002) for short-term variable rate payments through interest rate swap transactions (see Market Risk Information - Interest Rate Swap Agreements below). Net interest charges were reduced by $17.4 million in 2002 as a result of these swaps.

Discontinued Operations

In April 2003, FirstEnergy divested its ownership in GPU Empresa Distribuidora Electrica Regional S.A. and affiliates (Emdersa) through the abandonment of its shares in the parent company of the Argentina operation. FirstEnergy has reclassified the results of Emdersa for the year ended December 31, 2002, totaling $87.5 million in discontinued operations.

Cumulative Effect of Accounting Change

In 2001, we adopted SFAS 133, "Accounting for Derivative Instruments and Hedging Activities" resulting in an $8.5 million after-tax charge. (See Note 2J)

Postretirement Plans

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

Postretirement Expenses (Income)	2002	2001	2000
(in millions)			
Pension	$ 16.4	$(11.1)	$(40.6)
OPEB	99.1	86.6	65.5
Total	$115.5	$ 75.5	$ 24.9

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

RESULTS OF OPERATIONS - BUSINESS SEGMENTS

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

Regulated Services

Net income increased to $927 million in 2002, compared to $729.1 million in 2001 and $562.5 million in 2000. Excluding additional net income of $312.7 million associated with the former GPU companies, net income decreased by $114.3 million in 2002. The changes in pre-merger net income are summarized in the following table:

Regulated Services	2002	2001
Increase (Decrease)	(In millions)	
Revenues	$(529.5)	$(116.4)
Expenses	(223.8)	(344.1)
Income Before Interest and Income Taxes	(305.7)	227.7
Net interest charges	(131.3)	(16.8)
Income taxes	(60.1)	132.7
Net Income Change	$(114.3)	$ 111.8

Lower generation sales, additional transition plan incentives and a slight decline in revenue from distribution deliveries combined for a $312.5 million reduction in external revenues in 2002 from the prior year. Shopping by Ohio customers from alternative energy suppliers combined with the effect of a sluggish national economy on our regional business reduced retail electric sales revenues. In addition, a $188.0 million decline in revenues resulted from reduced sales to FES, due to the extended outage of the Davis-Besse nuclear plant, which reduced generation available for sale. The $232.4 million decrease in expenses primarily resulted from three major factors: a $190.5 million decrease in purchased power, a $111.6 million reduction in other operating expenses and a $58.9 million increase in depreciation expense. Lower generation sales reduced the need for purchased power and other operating expenses reflected reduced costs in jobbing and contracting work and decreased uncollectible accounts expense. Higher depreciation and amortization resulted from $201 million higher incremental transition costs partially offset by $108.5 million of new deferred regulatory assets under the Ohio transition plan and the cessation of goodwill amortization beginning January 1, 2002.

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

Competitive Services

Net losses increased to $108.1 million in 2002, compared to $31.8 million in 2001 and net income of $39.1 million in 2000. Excluding additional net income of $2.6 million associated with the former GPU companies, net losses increased by $78.9 million in 2002. The changes to pre-merger earnings are summarized in the following table:

Competitive Services	2002	2001
Increase (Decrease)	(In millions)	
Revenues	$211.5	$289.3
Expenses	341.9	392.5
Income Before Interest and Income Taxes	(130.4)	(103.2)
Net interest charges	21.9	13.5
Income taxes	(64.9)	(51.3)
Cumulative effect of a change in accounting	8.5	(8.5)
Net Loss Increase	$ 78.9	$ 73.9

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

In 2001, sales to nonaffiliates increased $523.2 million, compared to the prior year, with electric revenues contributing $299.8 million, natural gas revenues adding $226.1 million and the balance of the change from energy-related services. Reduced power requirements by the regulated services segment reduced internal revenues by $267.8 million. Expenses increased $392.5 million in 2001 from 2000 primarily due to a $266.5 million increase in purchased gas costs and increases resulting from additional fuel and purchased power costs (see Results of Operations above) as well as higher expenses for energy-related services. Reduced margins for both major competitive product areas - electricity and natural gas - contributed to the reduction in net income, along with higher interest charges and the cumulative effect of the SFAS 133 accounting change. Margins for electricity and gas sales were both adversely affected by higher fuel costs.

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CAPITAL RESOURCES AND LIQUIDITY

Changes in Cash Position

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

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

Cash Flows From Operating Activities

Our consolidated net cash from operating activities is provided by our regulated and competitive energy services businesses (see Results of Operations - Business Segments above). Net cash flows from operating activities in 2002 reflect twelve months of cash flows for the former GPU companies while

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

Operating Cash Flows	2002	2001
	(in millions)	
Pre-merger Companies:		
Cash earnings (1)	$1,059	$1,551
Working capital and other	405	21
Total pre-merger companies	1,464	1,572
Former GPU companies	563	166
Eliminations	(112)	(456)
Total	$1,915	$1,282

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

Excluding the former GPU companies, cash flows from operating activities totaled $1.464 billion in 2002 primarily due to cash earnings and to a lesser extent working capital and other changes. In 2001, cash flows from operating activities totaled $1.572 billion principally due to cash earnings.

Cash Flows From Financing Activities

In 2002, the net cash used for financing activities of $1.123 billion primarily reflects the redemptions of debt and preferred stock shown below. In 2001, net cash provided from financing activities totaled $1.964 billion, primarily due to $4 billion of long-term debt issued in connection with the GPU acquisition, which was partially offset by $2.1 billion of redemptions and refinancings. The following table provides details regarding new issues and redemptions during 2002:

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Securities Issued or Redeemed	2002
	(In millions)
New Issues	
Pollution Control Notes	$ 143
Transition Bonds (See Note 5H)	320
Unsecured Notes	210
Other, principally debt discounts	(4)
	$ 669

Redemptions	
First Mortgage Bonds	$ 728
Pollution Control Notes	93
Secured Notes	278
Unsecured Notes	189
Preferred Stock	522
Other, principally redemption premiums	21
	$1,831
Short-term Borrowings, Net	$ 479

We had approximately $1.093 billion of short-term indebtedness at the end of 2002 compared to $614.3 million at the end of 2001. Available borrowing capability included $177 million under the $1.5 billion revolving lines of credit and $64 million under bilateral bank facilities. At the end of 2002, OE, CEI, TE and Penn had the aggregate capability to issue $2.1 billion of additional first mortgage bonds (FMB) on the basis of property additions and retired bonds. JCP&L, Met-Ed and Penelec will no longer issue FMB other than as collateral for senior notes, since their senior note indentures prohibit them (subject to certain exceptions) from issuing any debt which is senior to the senior notes. As of December 31, 2002, JCP&L, Met-Ed and Penelec had the aggregate capability to issue $474 million of additional senior notes based upon FMB collateral. Based upon applicable earnings coverage tests and their respective charters, OE, Penn, TE and JCP&L could issue a total of $4.5 billion of preferred stock (assuming no additional debt was issued) as of the end of 2002. CEI, Met-Ed and Penelec have no restrictions on the issuance of preferred stock (see Note 5G - Long-Term Debt for discussion of debt covenants).

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

Cash Flows From Investing Activities

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

Summary of 2002 Cash Flows Used for Investing Activities	Property Additions	Investments	Other	T
Sources (Uses)		(in millions)		
Regulated Services	$(490)	$ 87	$ (21)	$(4
Competitive Services	(403)	--	10	(3
Other	(105)	149*	(54)	(

Eliminations	--	--	11	
Total	$(998)	$236	$ (54)	$(8

In 2001, net cash flows used in investing activities totaled $3.075 billion, principally due to the GPU acquisition ($2.013 billion) and property additions ($852 million).

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

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Contractual Obligations	Total	Less than 1 Year	1-3 Years	3-5 Years
			(in millions)	
Long-term debt	$12,465	$1,073	$2,210	$1,654
Short-term borrowings	1,093	1,093	--	--
Preferred stock (1)	445	2	4	14
Capital leases (2)	31	5	11	7
Operating leases (2)	2,697	153	365	349
Purchases (3)	13,156	2,149	2,902	2,634
Total	$29,887	$4,475	$5,492	$4,658

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

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

2003). In the fourth quarter of 2002, we recorded a $50 million charge to reduce the carrying value of our remaining Avon 20.1 percent equity investment. On August 8, 2002, we notified NRG that we were canceling a November 2001 agreement to sell four fossil plants for approximately $1.5 billion ($1.355 billion in cash and $145 million in debt assumption) to NRG because NRG had stated it could not complete the transaction under the original terms of the agreement. In December 2002, we announced that we would retain ownership of the plants after reviewing subsequent bids from other potential buyers. As a result of this decision, we recorded an aggregate charge of $74 million ($43 million, net of tax) in the fourth quarter of 2002, consisting of $57 million ($33 million, net of tax) in non-cash depreciation charges that were not recorded while the plants were pending sale and $17 million ($10 million, net of tax) of transaction-related fees (see Note 3). in the 2001 merger with GPU. On April 18, 2003, we divested our ownership interest in Emdersa, our Argentina operations, resulting in a charge of $87.5 million in the restated year ended December 31, 2002 Consolidated Statement of Income as "Discontinued Operations (See Note 2M).

On August 14, 2003, Moody's Investors Service placed the debt ratings of FirstEnergy and all of its subsidiaries under review for possible downgrade. Moody's stated that the review was prompted by: (1) weaker than expected operating performance and cash flow generation; (2) less progress than expected in reducing debt; (3) continuing high leverage relative to its peer group; and (4) negative impact on cash flow and earnings from the continuing nuclear plant outage at Davis-Besse. Moody's further stated that, in anticipation of Davis-Besse returning to service in the near future and FirstEnergy's continuing to significantly reduce debt and improve its financial profile, "Moody's does not expect that the outcome of the review will result in FirstEnergy's senior unsecured debt rating falling below investment-grade."

On July 25, 2003, Standard & Poor's (S&P) issued comments on FirstEnergy's debt ratings in light of the latest extension of the Davis-Besse outage and the NJBPU decision on the JCP&L rate case. S&P noted that additional costs from the Davis-Besse outage extension, the NJBPU ruling on recovery of deferred energy costs and additional capital investments required to improve reliability in the New Jersey shore communities will adversely affect FirstEnergy's cash flow and deleveraging plans. S&P noted that it continues to assess FirstEnergy's plans to determine if projected financial measures are adequate to maintain its current rating.

On August 7, 2003, S&P affirmed its "BBB" corporate credit rating for FirstEnergy. However, S&P stated that although FirstEnergy generates substantial free cash, that its strategy for reducing debt had deviated substantially from the one presented to S&P around the time of the GPU merger when the current rating was assigned. S&P further noted that their affirmation of FirstEnergy's corporate credit rating was based on the assumption that FirstEnergy would take appropriate steps quickly to maintain its investment grade ratings including the issuance of equity and possible sale of assets. Key issues being monitored by S&P included reaudit of CEI and TE by PricewaterhouseCoopers LLP, restart of Davis-Besse, FirstEnergy's liquidity position, its ability to forecast provider-of-last-resort load and the performance of its hedged portfolio, and capture of merger synergies.

OTHER OBLIGATIONS

Obligations not included on our Consolidated Balance Sheet primarily consist of sale and leaseback arrangements involving Perry Unit 1, Beaver Valley

Unit 2 and the Bruce Mansfield Plant, which are reflected in the operating lease payments disclosed above (see Note 4). The present value as of December 31, 2002, of these sale and leaseback operating lease commitments, net of trust investments, total $1.5 billion. CEI and TE sell substantially all of their retail customer receivables, which provided $170 million of off-balance sheet financing as of December 31, 2002 (see Note 2 - Revenues).

GUARANTEES AND OTHER ASSURANCES

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

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

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

(1) Issued for a one-year term, with a 10-day termination right by FirstEnergy.
(2) Includes parental guarantees of subsidiary debt and lease financing including our letters of credit supporting subsidiary debt.
(3) Issued for various terms.
(4) Estimated net liability under contracts subject to rating-contingent collateralization provisions.

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

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

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

MARKET RISK INFORMATION

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

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Commodity Price Risk

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

Increase (Decrease) in the Fair Value of Commodity Derivative Contracts	Non-Hedge	Hedge	Total
		(In millions)	
Outstanding net asset (liability) as of January 1, 2002	$ 9.9	$(76.3)	$(66.4)
New contract value when entered	--	2.2	2.2
Additions/Increase in value of existing contracts	55.5	73.9	129.4
Change in techniques/assumptions	(20.1)	--	(20.1)
Settled contracts	8.5	24.3	32.8
Outstanding net asset as of December 31, 2002 (1)	53.8	24.1	77.9
Non-commodity net assets as of December 31, 2002:			
Interest Rate Swaps (2)	--	20.5	20.5
Net Assets - Derivatives Contracts as of December 31, 2002 (3)	$ 53.8	$ 44.6	$ 98.4
Impact of Changes in Commodity Derivative Contracts (4)			
Income Statement Effects (Pre-Tax)	$ 13.9	$ --	$ 13.9
Balance Sheet Effects:			
Other Comprehensive Income (OCI) (Pre-Tax)	$ --	$ 98.2	$ 98.2

Regulatory Liability	$ 30.0	$ --	$ 30.0

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

	Non-Hedge	Hedge	Total
	(In millions)		
Current-			
Other Assets	$ 31.2	$14.9	$ 46.1
Other Liabilities	(16.2)	(8.8)	(25.0)
Non-Current-			
Other Deferred Charges	39.6	39.4	79.0
Other Deferred Credits	(0.8)	(0.9)	(1.7)
Net assets	$ 53.8	$44.6	$ 98.4

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

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Source of Information - Fair Value by Contract Year	2003	2004	2005	2006	Thereafter
			(In millions)		
Prices actively quoted(1)	$16.0	$1.5	$ --	$--	$--
Other external sources(2) -	22.2	2.1	(0.9)	--	--
Prices based on models	--	--	--	5.5	31.5
Total(3)	$38.2	$3.6	$(0.9)	$5.5	$31.5

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

Interest Rate Risk

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

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

Comparison of Carrying Value to Fair Value

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

Interest Rate Swap Agreements

During 2002, FirstEnergy entered into fixed-to-floating interest rate swap agreements, to increase the variable-rate component of its debt portfolio from 16% to approximately 20% at year end. These derivatives are treated as fair value hedges of fixed-rate, long-term debt issues - protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. Swap maturities, call options and interest payment dates match those of the underlying obligations. During the fourth quarter of 2002, in a period of steadily declining market interest rates, we

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unwound swaps with a total notional amount of $400 million that we had entered into during the second and third quarters of 2002. Under fair-value accounting, the swaps' fair value ($19.9 million asset) was added to the carrying value of the hedged debt and will be amortized to maturity. Offsets to interest expense recorded in 2002 due to the difference between fixed and variable debt rates totaled $17.4 million. As of December 31, 2002, the debt underlying FirstEnergy's outstanding interest rate swaps had a weighted average fixed interest rate of 7.76%, which the swaps have effectively converted to a current weighted average variable interest rate of 3.04%. GPU Power (through a subsidiary) used dollar-denominated interest rate swap agreements in 2002. In 2001, Penelec, GPU Power (through a subsidiary) and GPU Electric, Inc. (through GPU Power UK) used interest rate swaps denominated in dollars and sterling. All of the agreements of the former GPU companies convert variable-rate debt to fixed-rate debt to manage the risk of increases in variable interest rates. GPU Power's swaps had a weighted average fixed interest rate of 6.68% in 2002 and 6.99% in 2001. The following summarizes the principal characteristics of the swap agreements:

Interest Rate Swaps

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

Equity Price Risk

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

Foreign Currency Risk

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

OUTLOOK

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

Business Organization

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

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Optimizing the Use of Assets

Upon completion of its merger with GPU, FirstEnergy accepted an October 2001 offer from Aquila, Inc. (formerly UtiliCorp United) to purchase Avon, FirstEnergy's wholly owned holding company for Midlands Electricity plc, for $2.1 billion (including the assumption of $1.7 billion of debt). The transaction closed on May 8, 2002 and reflected the March 2002 modification of Aquila's initial offer such that Aquila acquired a 79.9 percent equity interest in Avon for approximately $1.9 billion (including the assumption of $1.7 billion of debt). Proceeds to FirstEnergy included $155 million in cash and a note receivable for approximately $87 million (representing the present value of $19 million per year to be received over six years beginning in 2003) from Aquila for its 79.9 percent interest. FirstEnergy and Aquila together own all of the outstanding shares of Avon through a jointly owned subsidiary, with each company having an ownership voting interest. Originally, in accordance with applicable accounting guidance, the earnings of those foreign operations were not recognized in current earnings from the date of the GPU acquisition. However, as a result of the decision to retain an ownership interest in Avon in the quarter ended March 31, 2002, EITF Issue No. 90-6, "Accounting for Certain Events Not Addressed in Issue No. 87-11 relating to an Acquired Operating Unit to be Sold" required FirstEnergy to reallocate the purchase price of GPU based on amounts as of the purchase date as if Avon had never been held for sale, including reversal of the effects of having applied EITF Issue No. 87-11, to the transaction. The effect of reallocating the purchase price and reversal of the effects of EITF Issue No. 87-11, including the allocation of capitalized interest, has been reflected in the Consolidated Statement of Income for the six months ended June 30, 2002 by reclassifying certain revenue and expense amounts related to activity during the quarter ended March 31, 2002 to their respective income statement classifications for the six-month 2002 period. See Note 1 for the effects of the change in classification. In the fourth quarter of 2002, FirstEnergy recorded a $50 million charge to reduce the carrying value of its remaining 20.1 percent interest.

On May 22, 2003, FirstEnergy announced it reached an agreement to sell its 20.1 percent interest in Avon to Scottish and Southern Energy plc; that agreement also includes Aquila's 79.9 percent interest. Under terms of the agreement, Scottish and Southern will pay FirstEnergy and Aquila an aggregate $70 million (FirstEnergy's share would be approximately $14 million). Midland's debt will remain with that company. FirstEnergy also recognized in the second quarter of 2003 an impairment of $12.6 million ($8.2 million net of tax) related to the carrying value of the note FirstEnergy had with Aquila from the initial sale of a 79.9 percent interest in Avon that occurred in May 2002. After receiving the first annual installment payment of $19 million in May 2003, FirstEnergy sold the remaining balance of its note receivable in a secondary market and received $63.2 million in proceeds on July 28, 2003.

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

State Regulatory Matters

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

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

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

Regulatory Assets as of December 31,

Company	2002
(In millions)	
OE	$1,848.7
CEI	1,191.8
TE	578.2
Penn	156.9
JCP&L	3,199.0
Met-Ed	1,179.1
Penelec	599.7
Total	$8,753.4

Ohio

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

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

New Jersey

Under New Jersey transition legislation, all electric distribution companies were required to file rate cases to determine the level of unbundled rate components to become effective August 1, 2003. JCP&L submitted two rate filings with the NJBPU in August 2002. The first filing requested increases in base electric rates of approximately $98 million annually. The second filing was a request to recover deferred costs that exceeded amounts being recovered under the current MTC and SBC rates; one proposed method of recovery of these costs is the securitization of the deferred balance. This securitization methodology is similar to the Oyster Creek securitization. On July 25, 2003, the NJBPU announced its JCP&L base electric rate proceeding decision which reduces 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 percent on JCP&L's rate base for the next 6 to 12 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 percent or decrease it to 9.25 percent, 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 would allow for the recovery of $465 million in deferred energy costs over the next ten years on an interim basis, thus disallowing $152.5 million. JCP&L also announced on July 25, 2003 that it is reviewing the NJBPU decision and will decide on its appropriate course of action, which could include filing an appeal for reconsideration with the NJBPU and possibly an appeal to the Appellate Division of the Superior Court of New Jersey.

Pennsylvania

Effective September 1, 2002, Met-Ed and Penelec assigned their PLR responsibility to FES through a wholesale power sale which expires in December 2003 and may be extended for each successive calendar year. Under the terms of the wholesale agreement, FES assumed the supply obligation and the supply profit and loss risk, for the portion of power supply requirements not self-supplied by Met-Ed and Penelec under their NUG contracts and other existing power contracts with nonaffiliated third party suppliers. This arrangement reduces Met-Ed's and Penelec's exposure to high wholesale power prices by providing power at or below the shopping credit for their uncommitted PLR energy costs during the term of the agreement to FES. FES has hedged most of Met-Ed's and Penelec's unfilled on-peak PLR obligation through 2004 and a portion of 2005. Met-Ed and Penelec will continue to defer those cost differences between NUG contract rates and the rates reflected in their capped generation rates.

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

On April 2, 2003, the PPUC remanded the merger savings issue to the Office of Administrative Law for hearings and directed Met-Ed and Penelec to file a position paper on the effect of the Commonwealth Court's order on the Settlement Stipulation by May 2, 2003 and for the other parties to file their responses to the Met-Ed and Penelec position paper by June 2, 2003. In summary, the Met-Ed and Penelec position paper essentially stated the following:

- Because no stay of the PPUC's June 2001 order approving the Settlement Stipulation was issued or sought, the Stipulation remained in effect until the Pennsylvania Supreme Court denied all appeal applications in January 2003,

- As of January 16, 2003, the Supreme Court's Order became final and the portions of the PPUC's June 2001 Order that were inconsistent with the Supreme Court's findings were reversed,

- The Supreme Court's finding effectively amended the Stipulation to remove the PLR cost recovery and deferral provisions and reinstated the GENCO Code of Conduct as a merger condition, and

- All other provisions included in the Stipulation unrelated to these three issues remain in effect.

The other parties' responses included significant disagreement with the position paper and disagreement among the other parties themselves, including the Stipulation's original signatory parties. Some parties believe that no portion of the Stipulation has survived the Commonwealth Court's Order. Because of these disagreements, Met-Ed and Penelec filed a letter on June 11, 2003 with the Administrative Law Judge assigned to the remanded case voiding the Stipulation in its entirety pursuant to the termination provisions. They believe this will significantly simplify the issues in the pending action by reinstating Met-Ed's and Penelec's Restructuring Settlement previously approved by the PPUC. In addition, they have agreed to voluntarily continue certain Stipulation provisions including funding for energy and demand side response programs and to cap distribution rates at current levels through 2007. This voluntary distribution rate cap is contingent upon a finding that Met-Ed and Penelec have satisfied the "public interest" test applicable to mergers and that any rate impacts of merger savings will be dealt with in a subsequent rate case. Based upon this letter, Met-Ed and Penelec believe that the remaining issues before the Administrative Law Judge are the appropriate treatment of merger savings issues and whether their accounting and related tariff modifications are consistent with the Court Order.

FERC Regulatory Matters

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

Supply Plan

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

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

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

Davis-Besse Restoration

On April 30, 2002, the 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 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, FirstEnergy has made significant management and human performance changes with the intent of establishing the proper safety culture throughout the workforce. Work was completed on the reactor head during 2002 and is continuing on efforts designed to enhance the unit's reliability and performance. FirstEnergy is also accelerating maintenance work that had been planned for future refueling and maintenance outages. At a meeting with the NRC in November 2002, FirstEnergy discussed plans to test the bottom of the reactor for leaks and to install a state-of-the-art leak-detection system around the reactor. The additional maintenance work being performed has expanded the previous estimates of restoration work. FirstEnergy anticipates that the unit will be ready for restart in the fall of 2003. The NRC must authorize restart of the plant following its formal inspection process before the unit can be returned to service. While the additional maintenance work has delayed FirstEnergy's plans to reduce post-merger debt levels FirstEnergy believes such investments in the unit's future safety, reliability and performance to be essential. Significant delays in Davis-Besse's return to service, which depends on the successful resolution of the management and technical issues as well as NRC approval, could trigger an evaluation for impairment of the nuclear plant (see Significant Accounting Policies below).

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

Costs of Davis-Besse Extended Outage	(In millions)
2002 - Actual	
Capital Expenditures:	
Reactor head and restart	$ 63.3
Incremental Expenses (pre-tax):	
Maintenance	115.0
Fuel and purchased power	119.5
Total	$234.5
2003 - Estimated	
Primarily operating expenses (pre-tax):	
Maintenance (including acceleration of programs)	$50
Replacement power per month	$12-18

We have fully hedged the on-peak replacement energy supply for Davis-Besse for the expected length of the outage.

Environmental Matters

We believe we are in compliance with the current sulfur dioxide (SO_2) and nitrogen oxide (NO_x) reduction requirements under the Clean Air Act Amendments of 1990. In 1998, the Environmental Protection Agency (EPA) finalized regulations requiring additional NO_x reductions in the future from our Ohio and Pennsylvania facilities. Various regulatory and judicial actions have since sought to further define NO_x reduction requirements (see Note 7D - Environmental Matters). We continue to evaluate our compliance plans and other compliance options.

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

In 1999 and 2000, the EPA issued Notices of Violation (NOV) or a Compliance Order to nine utilities covering 44 power plants, including the W. H. Sammis Plant. In addition, the U.S. Department of Justice filed eight civil complaints against various investor-owned utilities, which included a complaint against OE and Penn in the U.S. District Court for the Southern District of Ohio. The NOV and complaint allege violations of the Clean Air Act based on operation and maintenance of the Sammis Plant dating back to 1984. The civil 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 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 March 15, 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, may have a material adverse impact on the Company's financial condition and results or operations. Management is unable to predict the ultimate outcome of this matter.

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

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

The Companies have been named as "potentially responsible parties" (PRPs) at waste disposal sites which may require cleanup under the Comprehensive Environmental Response, Compensation and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site be held liable on a joint and several basis.

Therefore, potential environmental liabilities have been recognized on the Consolidated Balance Sheet as of December 31, 2002, based on estimates of the total costs of cleanup, the Companies' proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay. In addition, JCP&L has accrued liabilities for environmental remediation of former manufactured gas plants in New Jersey; those costs are being recovered by JCP&L through the SBC. The Companies have total accrued liabilities aggregating approximately $54.3 million as of December 31, 2002.

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

Legal Matters

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

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

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

It is FirstEnergy's understanding that, as of August 18, 2003, five individual described herein shareholder-plaintiffs have filed separate complaints against FirstEnergy Corp. alleging various securities law violations in connection with the restatement of earnings described herein. Most of these complaints have not yet been officially served on the Company. Moreover, FirstEnergy is still reviewing the suits that have been served in preparation for a responsive pleading. FirstEnergy is however, aware that in each case, the plaintiffs are seeking certification from the court to represent a class of similarly situated shareholders.

Power Outage

On August 14, 2003, eight states and southern Canada experienced a widespread power outage. That outage affected approximately 1.4 million customers in FirstEnergy's service area. The cause of the outage has not been determined. Having restored service to its customers, FirstEnergy is now in the process of accumulating data and evaluating the status of its electrical system prior to and during the outage event and would expect that the same effort Is under way at utilities and regional transmission operators across the region.

As of August 18, 2003, the following facts about FirstEnergy's system were known. Early in the afternoon of August 14, hours before the event, Unit 5 of the Eastlake Plant in Eastlake, Ohio tripped off. Later in the afternoon, three FirstEnergy transmission lines and one owned by American Electric Power and FirstEnergy tripped out of service. The

Midwest Independent System Operator (MISO), which oversees the regional transmission grid, indicated that there were a number of other transmission line trips in the region outside of FirstEnergy's system. FirstEnergy customers experienced no service interruptions resulting from these conditions. Indications to FirstEnergy were that the Company's system was stable. Therefore, no isolation of FirstEnergy's system was called for. In addition, FirstEnergy determined that its computerized system for monitoring and controlling its transmission and generation system was operating, but the alarm screen function was not. However, MISO's monitoring system was operating properly. FirstEnergy believes that extensive data needs to be gathered and analyzed in order to determine with any degree of certainty the circumstances that led to the outage. This is a very complex situation, far broader than the power line outages FirstEnergy experienced on its system. From the preliminary data that has been gathered, FirstEnergy believes that the transmission grid in the Eastern Interconnection, not just within FirstEnergy's system, was experiencing unusual electrical conditions at various times prior to the event. These included unusual voltage and frequency fluctuations and load swings on the grid. FirstEnergy is committed to working with the North American Electric Reliability Council and others involved to determine exactly what events in the entire affected region led to the outage. There is no timetable as to when this entire process will be completed. It is, however, expected to last several weeks, at a minimum.

IMPLEMENTATION OF RECENT ACCOUNTING STANDARD

In June 2002, the Emerging Issues Task Force (EITF) reached a partial consensus on Issue No. 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." Based on the EITF's partial consensus position, for periods after July 15, 2002, mark-to-market revenues and expenses and their related kilowatt-hour (KWH) sales and purchases on energy trading contracts must be shown on a net basis in the Consolidated Statements of Income. We have previously reported such contracts as gross revenues and purchased power costs. Comparative quarterly disclosures and the Consolidated Statements of Income for revenues and expenses have been reclassified for 2002 only to conform with the revised presentation (see Note 11 - Summary of Quarterly Financial Data). In addition, the related KWH sales and purchases statistics described above under Results of Operations were reclassified (7.2 billion KWH in 2002 and 3.7 KWH billion in 2001). The following table displays the impact of changing to a net presentation for our energy trading operations.

2002 Impact of Recording Energy Trading Net	Revenues	Expenses
	Restated (See Notes 2(L) and 2(M)) (in millions)	
Total before adjustment	$12,499	$10,368
Adjustment	(268)	(268)
Total as reported	$12,231	$10,100

SIGNIFICANT ACCOUNTING POLICIES

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

Purchase Accounting - Acquisition of GPU

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

Regulatory Accounting

Our regulated services segment is subject to regulation that sets the prices (rates) it is permitted to charge its customers based on costs that the regulatory agencies determine we are permitted to recover. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by an unregulated company. This rate-making process results in the recording of regulatory assets based on anticipated future cash inflows. As a result of the changing regulatory framework in each state in which we operate, a significant amount of regulatory assets have been recorded - $8.8 billion as of December 31, 2002. We regularly review these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future.

Derivative Accounting

Determination of appropriate accounting for derivative transactions requires the involvement of management representing operations, finance and risk assessment. In order to determine the appropriate accounting for derivative transactions, the provisions of the contract need to be carefully assessed in accordance with the authoritative accounting literature and management's intended use of

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

Revenue Recognition

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

o Net energy generated or purchased for retail load

o Losses of energy over transmission and distribution lines

o Mix of KWH usage by residential, commercial and industrial customers

o KWH 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 (OPEB) are dependent upon numerous factors resulting from actual plan experience and certain assumptions.

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

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

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

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

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

Increase in Costs from Adverse Changes in Key Assumptions

Assumption	Adverse Change	Pension	OPEB	Total
			(In millions)	

Discount rate	Decrease by 0.25%	$10.3	$ 7.4	$17.7
Long-term return on assets	Decrease by 0.25%	$ 6.9	$ 1.2	$ 8.1
Health care trend rate	Increase by 1%	na	$ 20.7	$20.7
Increase in Minimum Liability				
Discount rate	Decrease by 0.25%	$99.4	na	$99.4

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

Long-Lived Assets

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

Goodwill

The regulators in the jurisdictions that the Companies operate in do not provide recovery at goodwill. As a result, no amortization has been recorded subsequent to the adoption of SFAS 142. In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by SFAS 142, we evaluate our goodwill for impairment at least annually and would make such an evaluation more frequently if indicators of impairment should arise. In accordance with the accounting standard, if the fair value of a reporting unit is less than its carrying value including goodwill, an impairment for goodwill must be recognized in the financial statements. If impairment were to occur we would recognize a loss - calculated as the difference between the implied fair value of a reporting unit's goodwill and the carrying value of the goodwill. Our annual review was completed in the third quarter of 2002. The results of that review indicated no impairment of goodwill -- fair value was higher than carrying value for each of our reporting units. The forecasts used in our evaluations of goodwill reflect operations consistent with our general business assumptions. Unanticipated changes in those assumptions could have a significant effect on our future evaluations of goodwill. As of December 31, 2002, we had $6.3 billion of goodwill that primarily relates to our regulated services segment.

RECENTLY ISSUED ACCOUNTING STANDARDS NOT YET IMPLEMENTED

SFAS 143, "Accounting for Asset Retirement Obligations"

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

We have identified applicable legal obligations as defined under the new standard, principally for nuclear power plant decommissioning. Upon adoption of SFAS 143 in January 2003, asset retirement costs of $602 million were recorded as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $415 million. Due to the increased carrying amount, the related long-lived assets were tested for impairment in accordance with SFAS 144. No impairment was indicated. The asset retirement liability at the date of adoption was $1.109 billion. As of December 31, 2002, FirstEnergy had recorded decommissioning liabilities of $1.232 billion, including unrealized gains on decommissioning trust funds of $12 million. The change in the estimated liabilities resulted from changes in methodology and various assumptions, including changes in the projected dates for decommissioning.

Management expects that substantially all nuclear decommissioning costs for Met-Ed, Penelec, JCP&L and Penn will be recoverable through their regulated rates. Therefore, we recognized a regulatory liability of $185 million upon adoption of SFAS 143 for the transition amounts related to establishing the asset retirement obligations for nuclear decommissioning. The remaining cumulative effect adjustment to recognize the undepreciated asset retirement cost and the asset retirement liability offset by the reversal of the previously recorded decommissioning liabilities was a $175 million increase to income ($102 million net of tax).

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

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

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

Disclosure"

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

FASB Interpretation (FIN) No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others - an interpretation of FASB Statements No. 5, 57, and 107 and rescission of FASB Interpretation No. 34"

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

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

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

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

FirstEnergy currently consolidates the majority of these entities and believes it will continue to consolidate following the adoption of FIN 46. In addition to the entities FirstEnergy is currently consolidating FirstEnergy believes that the PNBV Capital Trust, which reacquired a portion of the off-balance sheet debt issued in connection with the sale and leaseback of OE's interest in the Perry Plant and Beaver Valley Unit 2, would require consolidation. Ownership of the trust includes a three-percent equity interest by a nonaffiliated party and a three-percent equity interest by OES Ventures, a wholly owned subsidiary of OE. Full consolidation of the trust under FIN 46 would change the characterization of the PNBV trust investment to a lease obligation bond investment. Also, consolidation of the outside minority interest would be required, which would increase assets and liabilities by $11.6 million.

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 is effective for financial instruments entered into or modified after May 31, 2003 and is effective at the beginning of the first interim period beginning after June 15, 2003 (FirstEnergy's third quarter of 2003) for all other financial instruments.

FirstEnergy did not enter into or modify any financial instruments within the scope of SFAS 150 during June 2003. Upon adoption of SFAS 150, effective July 1, 2003, FirstEnergy expects to classify as debt the preferred stock of consolidated subsidiaries subject to mandatory redemptions with a carrying value of approximately $19 million as of June 30, 2003. Subsidiary preferred dividends on FirstEnergy's Consolidated Statements of Income are currently included in net interest charges. Therefore, the application of SFAS 150 will not require the reclassification of such preferred dividends to net interest charges.

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 which would correspond to FirstEnergy's fourth quarter of 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 in a contract of a general index, such as the Consumer Price Index, would prevent that contract from qualifying for the normal purchases and normal sales (NPNS) exception under SFAS 133, as amended, and therefore exempt from the mark-to-market treatment of certain contracts. DIG Issue C20 is to be applied prospectively to all existing contracts as of its effective date and for all future transactions. If it is determined under DIG Issue C20 guidance that the NPNS exception was claimed for an existing contract that was not eligible for this exception, the contract will be recorded at fair value, with a corresponding adjustment of net income as the cumulative effect of a change in accounting principle in the fourth quarter of 2003. FirstEnergy is currently assessing the new guidance and has not yet determined the impact on its financial statements.

EITF Issue No. 01-08, "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 will be applied prospectively to arrangements committed to, modified or acquired through a business combination, beginning in the third quarter of 2003. FirstEnergy is currently assessing the new EITF consensus and has not yet determined the impact on its financial position or results of operations following adoption.

PART IV

3. Exhibits - FirstEnergy

Exhibit Number		
3-1	--	Articles of Incorporation constituting FirstEnergy Corp.'s Articles of Incorporation, dated September 17, 1996. (September 17, 1996 Form 8-K, Exhibit C)
3-1(a)	--	Amended Articles of Incorporation of FirstEnergy Corp. (Registration No. 333-21011, Exhibit (3)-1)
3-2	--	Regulations of FirstEnergy Corp. (September 17, 1996 Form 8-K, Exhibit D)
3-2(a)	--	FirstEnergy Corp. Amended Code of Regulations. (Registration No. 333-21011, Exhibit (3)-2)
4-1	--	Rights Agreement (December 1, 1997 Form 8-K, Exhibit 4.1)
4-2	--	FirstEnergy Corp. to The Bank of New York, Supplemental Indenture, dated November 7, 2001. (2001 Form 10-K, Exhibit 4-2)
10-1	--	FirstEnergy Corp. Executive and Director Incentive Compensation Plan, revised November 15, 1999. (1999 Form 10-K, Exhibit 10-1)
10-2	--	Amended FirstEnergy Corp. Deferred Compensation Plan for Directors, revised November 15, 1999. (1999 Form 10-K, Exhibit 10-2)
10-3	--	Employment, severance and change of control agreement between FirstEnergy Corp. and executive officers. (1999 Form 10-K, Exhibit 10-3)
10-4	--	FirstEnergy Corp. Supplemental Executive Retirement Plan, amended January 1, 1999. (1999 Form 10-K, Exhibit 10-4)
10-5	--	FirstEnergy Corp. Executive Incentive Compensation Plan. (1999 Form 10-K, Exhibit 10-5)
10-6	--	Restricted stock agreement between FirstEnergy Corp. and A. J. Alexander. (1999 Form 10-K, Exhibit 10-6)
10-7	--	FirstEnergy Corp. Executive and Director Incentive Compensation Plan. (1998 Form 10-K, Exhibit 10-1)

10-8	--	Amended FirstEnergy Corp. Deferred Compensation Plan for Directors, amended February 15, 1999. (1998 Form 10-K, Exhibit 10-2)
10-9	--	Restricted stock agreement between FirstEnergy Corp. and A. J. Alexander. (2000 Form 10-K, Exhibit 10-9)
10-10	--	Restricted stock agreement between FirstEnergy Corp. and H. P. Burg. (2000 Form 10-K, Exhibit 10-10)
10-11	--	Stock option agreement between FirstEnergy Corp. and officers dated November 22, 2000. (2000 Form 10-K, Exhibit 10-11)
10-12	--	Stock option agreement between FirstEnergy Corp. and officers dated March 1, 2000. (2000 Form 10-K, Exhibit 10-12)
10-13	--	Stock option agreement between FirstEnergy Corp. and director dated January 1, 2000. (2000 Form 10-K, Exhibit 10-13)
10-14	--	Stock option agreement between FirstEnergy Corp. and two directors dated January 1, 2001. (2000 Form 10-K, Exhibit 10-14)

10-15	--	Executive and Director Incentive Compensation Plan dated May 15, 2001. (2001 Form 10-K, Exhibit 10-15)
10-16	--	Amended FirstEnergy Corp. Deferred Compensation Plan for Directors, revised September 18, 2000. (2001 Form 10-K, Exhibit 10-16)
10-17	--	Stock Option Agreements between FirstEnergy Corp. and Officers dated May 16, 2001. (2001 Form 10-K, Exhibit 10-17)
10-18	--	Restricted Stock Agreements between FirstEnergy Corp. and Officers dated February 20, 2002. (2001 Form 10-K, Exhibit 10-18)
10-19	--	Stock Option Agreements between FirstEnergy Corp. and One Director dated January 1, 2002. (2001 Form 10-K, Exhibit 10-19)
10-20	--	FirstEnergy Corp. Executive Deferred Compensation Plan. (2001 Form 10-K, Exhibit 10-20)
10-21	--	Executive Incentive Compensation Plan-Tier 2. (2001 Form 10-K, Exhibit 20-21)
10-22	--	Executive Incentive Compensation Plan-Tier 3. (2001 Form 10-K, Exhibit 20-22)
10-23	--	Executive Incentive Compensation Plan-Tier 4. (2001 Form 10-K, Exhibit 10-23)
10-24	--	Executive Incentive Compensation Plan-Tier 5. (2001

		Form 10-K, Exhibit 10-24)
10-25	--	Amendment to GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries, effective April 5, 2001. (2001 Form 10-K, Exhibit 10-25)
10-26	--	Form of Amendment, effective November 7, 2001, to GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries, Deferred Remuneration Plan for Outside Directors of GPU, Inc., and Retirement Plan for Outside Directors of GPU, Inc. (2001 Form 10-K, Exhibit 10-26)
10-27	--	GPU, Inc. Stock Option and Restricted Stock Plan for MYR Group, Inc. Employees. (2001 Form 10-K, Exhibit 10-27)
10-28	--	Executive and Director Stock Option Agreement dated June 11, 2002.
10-29	--	Director Stock Option Agreement.
10-30	--	Executive and Director Executive Incentive Compensation Plan, Amendment dated May 21, 2002.
10-31	--	Directors Deferred Compensation Plan, Revised Nov. 19, 2002.
10-32	--	Executive Incentive Compensation Plan 2002.
10-33	--	GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries as amended and restated to reflect amendments through June 3, 1999. (1999 Form 10-K, Exhibit 10-V, File No. 1-6047, GPU, Inc.)
10-34	--	Form of 1998 Stock Option Agreement under the GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries. (1997 Form 10-K, Exhibit 10-Q, File No. 1-6047, GPU, Inc.)
10-35	--	Form of 1999 Stock Option Agreement under the GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries. (1999 Form 10-K, Exhibit 10-W, File No. 1-6047, GPU, Inc.)
10-36	--	Form of 2000 Stock Option Agreement under the GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries. (2000 Form 10-K, Exhibit 10-W, File No. 1-6047, GPU, Inc.)
10-37	--	Deferred Remuneration Plan for Outside Directors of GPU, Inc. as amended and restated effective August 8, 2000. (2000 Form 10-K, Exhibit 10-O, File No. 1-6047, GPU, Inc.)

10-38	--	Retirement Plan for Outside Directors of GPU, Inc. as amended and restated as of August 8, 2000. (2000 Form 10-K, Exhibit 10-N, File No. 1-6047, GPU, Inc.)

	10-39	--	Forms of Estate Enhancement Program Agreements entered into by certain former GPU directors. (1999 Form 10-K, Exhibit 10-JJ, File No. 1-6047, GPU, Inc.)
*	12.1	--	Consolidated fixed charge ratios.
*	13	--	FirstEnergy 2002 Annual Report to Stockholders, as revised. (Only those portions expressly incorporated by reference in this Form 10-K/A are to be deemed "filed" with the SEC.)
	21	--	List of Subsidiaries of the Registrant at December 31, 2002.
*	23	--	Consent of Independent Auditors.
*	31.1	--	Certification letter from chief executive officer, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act.
*	31.2	--	Certification letter from chief financial officer, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act.
*	32	--	Certification letter from chief executive officer and chief financial officer, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act.

* Indicates revised exhibits included in this Form 10-K/A in electronic format. Reference is made to the original 10-K for the other exhibits filed with it.

Reports on Form 8-K

FIRSTENERGY-

FirstEnergy filed twenty-four reports on Form 8-K since September 30, 2002. A report dated October 7, 2002 reported updated cost and schedule estimates associated with efforts to return Davis-Besse Nuclear Power Station to service. A report dated October 31, 2002 reported updated information associated with Davis-Besse restoration efforts. A report dated December 2, 2002 reported the merger of the GPU Employees Savings Plan into the FirstEnergy System Savings Plan. A report dated December 3, 2002 reported updated FirstEnergy 2003 earnings guidance. A report dated December 20, 2002 reported that FirstEnergy subsidiaries would retain ownership of four power plants previously planned to be sold. A report dated January 17, 2003 reported updated information related with efforts to prepare Davis-Besse for a safe and reliable return to service and the updated schedule for JCP&L rate proceedings. A report dated January 21, 2003 reported that the Pennsylvania Supreme Court denied further appeals of the February 21, 2002 Pennsylvania Commonwealth Court decision, which effectively affirmed the Pennsylvania Public Utility Commission's order approving the FirstEnergy and GPU merger, let stand the Commonwealth Court's denial of PLR relief for Met-Ed and Penelec and remanded the merger savings issue back to the PPUC. A report dated March 11, 2003 reported updated Davis-Besse information including the installation of the new reactor head on the reactor vessel. A report dated March 17, 2003 reported updated Davis-Besse information, the filing of a $2 billion shelf registration with the SEC and the status of the JCP&L rate proceedings. A report dated March 18, 2003 reported NJBPU audit results of JCP&L restructuring-related deferrals. A report dated April 16, 2003 reported updated Davis-Besse information. A report dated April 18, 2003 reported FirstEnergy's divestiture of its Argentina operations through the abandonment of its investment resulting in a second quarter 2003 charge to net income of $63 million. A report dated May 1, 2003 reported FirstEnergy's first quarter 2003 results and other updated information including Davis-Besse updated ready for restart schedule. A report dated May 9, 2003 reported updated Davis-Besse information and a JCP&L rate proceedings update. A report dated May 9, 2003, reported the filing of the Form 10-K/A Amendment No. 1. A report dated May 22, 2003, reported an agreement to sell FirstEnergy's 20.1% interest in United Kingdom-based Aquila Sterling Limited, the owner of Midlands Electricity. A report dated June 5, 2003 reported updated Davis-Besse information. A report dated June 11, 2003, reported a letter filed with a Pennsylvania Public Utility Commission Administrative Law Judge which voids a prior stipulation. A report dated June 27, 2003, reported JCP&L's signing of a settlement agreement with certain parties in its base rate case proceeding. A report dated July 24, 2003, reported updates to the schedule and cost estimates for Davis-Besse. A reported dated July 25, 2003 reported the New Jersey Board of Public Utilities decision on JCP&L's rate proceedings. A report dated August 5, 2003 reported FirstEnergy's second quarter 2003 earnings results and other information. A report dated August 5, 2003 reported the pending restatement of 2002 FE, OE, CEI and TE financial statements and restatement and reaudit of 2001 CEI and TE financial statements. A report dated August 7, 2003 reported the pending restatement and reaudit of 2000 CEI and TE financial statements. A report dated August 8, 2003 reported a U.S. District Court ruling with respect to the W. H. Sammis Plant under the Clean Air Act.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

FIRSTENERGY CORP.

Registrant

/s/Harvey L. Wagner

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

Date: September 11, 2003