TOLEDO EDISON CO
Form 10-K/A
September 24, 2003

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549

FORM 10-K/A

AMENDMENT NO. 2

(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.
1-3583	THE TOLEDO EDISON COMPANY (AN OHIO CORPORATION) 76 SOUTH MAIN STREET AKRON, OH 44308 TELEPHONE (800)736-3402	34-4375005

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

REGISTRANT	TITLE OF EACH CLASS	NAME OF EACH ON WHICH RE
The Toledo Edison Company	Cumulative Preferred Stock, par value $100 per share:	
	4.25% Series	American Stoc
	Cumulative Preferred Stock, par value $25 per share:	
	$2.365 Series	All series re
	Adjustable Rate, Series A	New York Stoc
	Adjustable Rate, Series B	
	First Mortgage Bonds:	
	8% Series due 2003	New York Stoc

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: None.

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

CLASS	OUTSTANDING AS OF MARCH 24, 2003
The Toledo Edison Company, $5 par value	39,133,887

EXPLANATORY NOTE

We are filing this Amendment No. 2 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 and Item 8 - FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA 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.

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

Under the heading "Restatements":

Under the subheading "Above-Market Lease Costs":

In the table following the sixth paragraph, the total transition cost amortization is corrected as follows:

	(IN MILLIONS) AS ORIGINALLY FILED	AS CORRECTED
2003	$53	$114
2004	71	131
2005	99	151

2006	76	95
2007	75	68

Under the heading "Results of Operations":

In the sixth sentence of the second paragraph, the text "..but revenues from electricity throughput decreased by $11.1 million in 2002 from the prior year due to lower unit prices" should have read "... and revenues from electricity throughput increased by $5.7 million in 2002 from the prior year".

Under the subheading "Operating Expenses and Taxes":

In the second sentence of the first paragraph, the decrease in total 2001 operating expenses and taxes of $18.0 million should have read $35.9 million.

In the fourth sentence of the second paragraph, the increase in other operating costs of $7.3 million should have read $7.2 million.

Under the heading "Capital Resources and Liquidity":

Under the subheading "Cash Flows from Operating Activities":

In the table, 2002 cash earnings and working capital and other is corrected as follows:

	(IN MILLIONS) AS ORIGINALLY FILED	AS CORRECTED
Cash earnings	$111	$142
Working capital and other	45	14

The complete amended and restated Item 8, which is included in its entirety below, reflects the following corrections:

NOTES TO FINANCIAL STATEMENTS:

Under Note 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Under the subheading "(M) RESTATEMENTS":

Under the subheading "Above-Market Lease Costs--":

In the table following the sixth paragraph, the total transition cost amortization is corrected as follows:

	(IN MILLIONS) AS ORIGINALLY FILED	AS CORRECTED
2003	$53	$114

2004	71	131
2005	99	151
2006	76	95
2007	75	68

Under Note 3 - CAPITALIZATION:

Under the subheading "(E) COMPREHENSIVE INCOME":

In the second sentence, the unrealized gains of $(5,997) should have read $1.1 million.

EXHIBIT 12.3 CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

As a result of the restatements, the fixed charge ratios exhibit has been revised.

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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. 2:

PART II

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

THE TOLEDO EDISON COMPANY

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.

CORPORATE SEPARATION

Beginning on January 1, 2001, Ohio customers were able to choose their electricity suppliers as a result of legislation which restructured the electric utility industry. That legislation required unbundling the price for electricity into its component elements - including generation, transmission, distribution and transition charges. Toledo Edison Company (TE) continues to deliver power to homes and businesses through our existing distribution system and maintain the "provider of last resort" (PLR) obligation under our rate plan. As a result of the transition plan, FirstEnergy's electric utility operating companies (EUOC) entered into power supply agreements whereby FirstEnergy Solutions Corp. (FES) purchases all of the EUOC nuclear generation, and leases EUOC fossil generating facilities. We are a "full requirements" customer of FES to enable us to meet our PLR responsibilities in our service area.

The effect on TE's reported results of operations during 2001 from FirstEnergy's corporate separation plan and our sale of transmission assets to American Transmission Systems, Inc. (ATSI) in September 2000, are summarized in the following tables:

CORPORATE RESTRUCTURING - 2001 INCOME STATEMENT EFFECTS
INCREASE (DECREASE)

	CORPORATE SEPARATION	ATSI	TOTAL
		(IN MILLIONS)	
Operating Revenues:			
Power supply agreement with FES	$180.9	$ --	$180.9
Generating units rent	14.0	--	14.0
Ground lease with ATSI	--	(0.2)	(0.2)
TOTAL OPERATING REVENUES EFFECT	$194.9	$ (0.2)	$194.7
Operating Expenses and Taxes:			
Fossil fuel costs	$(39.8)(a)	$ --	$(39.8)
Purchased power costs	388.0(b)	--	388.0
Other operating costs	(21.6)(a)	7.6(d)	(14.0)
Provision for depreciation and amortization	--	(2.7)(e)	(2.7)
General taxes	(2.0)(c)	(3.3)(e)	(5.3)
Income taxes	(50.4)	0.1	(50.3)
TOTAL OPERATING EXPENSES EFFECT	$274.2	$ 1.7	$275.9

OTHER INCOME	$ --	$ 2.0(f)	$ 2.0

(a) Transfer of fossil operations to FirstEnergy Generation Company (FGCO).

(b) Purchased power from power supply agreement (PSA).

(c) Payroll taxes related to employees transferred to FGCO.

(d) Transmission services received from ATSI.

(e) Depreciation and property taxes related to transmission assets sold to ATSI.

(f) Interest on note receivable from ATSI.

RESTATEMENTS

As further discussed in Note 1(M) to the Consolidated Financial Statements, the Company is restating its consolidated financial statements for the three years ended December 31, 2002. The revisions principally reflect a change in the method of amortizing costs being recovered through the Ohio transition plan and recognition of above-market values of certain leased generation facilities.

Transition Cost Amortization

As discussed under Regulatory Plan in Note 1(C) to the Consolidated Financial Statements, TE recovers 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 2007.

The Company amortizes 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, but not in the financial statements prepared under generally accepted accounting principles (GAAP). The Company has revised the 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 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 previously recorded regulatory assets recovered under the transition period through the end of 2007.

Above-Market Lease Costs

In 1997, FirstEnergy Corp. was formed through a merger between Ohio Edison Company (OE) and Centerior Energy Corporation (Centerior). The merger was accounted for as an acquisition of Centerior, the parent company of 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, the Company 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, the Company has restated its financial statements to record additional adjustments associated with the 1997 merger between OE and Centerior to reflect certain above-market lease liability for Beaver Valley Unit 2 and the Bruce Mansfield Plant, for which TE had previously entered into sale-leaseback arrangements. The Company recorded an increase in goodwill related to the above-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 consideration would have increased goodwill at the date of the merger. The corresponding impact of the above-market lease liability for the Bruce Mansfield Plant was recorded as a regulatory asset 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 $111 million associated with Beaver Valley Unit 2 will be amortized through the end of the lease term in 2017 (approximately $5.7 million annually). The additional goodwill has been recorded effective as of the merger date, and amortization has been recorded through 2001, when goodwill amortization ceased with the adoption of Statement of Financial Accounting Standards (SFAS) No. 142 (SFAS 142), "Goodwill and Other Intangible Assets." The total above-market lease obligation of $298 million associated with the Bruce Mansfield Plant is being reversed through the end of 2016 (approximately $18.9 million annually). Before the start of the transition plan in fiscal 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 unamortized regulatory asset will be included in the Company's revised amortization schedule for regulatory assets and amortized through the end of the recovery period in 2007.

The Company has reflected the impact of the accounting for the period from the merger in 1997 through 1999 as a cumulative effect adjustment of $4.3 million to retained earnings as of January 1, 2000. The after-tax effect of these items for the three years ended December 31, 2002 was as follows:

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INCOME STATEMENT EFFECTS
INCREASE (DECREASE)

	TRANSITION COST AMORTIZATION	REVERSAL OF LEASE OBLIGATIONS(1)	TOTAL
		(IN THOUSANDS)	
Year ended December 31, 2002			
Nuclear operating expenses	$ --	$ (5,700)	$ (5,700)
Other operating expenses	--	(18,900)	(18,900)
Provision for depreciation and amortization	28,400	40,200	68,600
Income taxes	(12,559)	(6,372)	(18,931)
Total expense	$ 15,841	$ 9,228	$ 25,069
Net income effect	$(15,841)	$ (9,228)	$(25,069)
Year ended December 31, 2001			

Nuclear operating expenses	$ --	$ (5,700)	$ (5,700)
Other operating expenses	--	(18,900)	(18,900)
Provision for depreciation and amortization	13,600	33,000	46,600
Income taxes	(5,619)	(3,177)	(8,796)
Total expense	$ 7,981	$ 5,223	$ 13,204
Net income effect	$ (7,981)	$ (5,223)	$(13,204)
Year ended December 31, 2000			
Nuclear operating expenses	$ --	$ (5,700)	$ (5,700)
Other operating expenses	--	--	--
Provision for depreciation and amortization	--	1,600	1,600
Income taxes	--	2,371	2,371
Total expense	$ --	$ (1,729)	$ (1,729)
Net income effect	$ --	$ 1,729	$ 1,729

(1) The provision for depreciation and amortization in each of 2001 and 2000 includes goodwill amortization of $1.6 million.

In addition, the impact increased the following balances in the consolidated balance sheet as of January 1, 2000:

	(IN THOUSANDS)
Goodwill	$ 61,990
Regulatory assets	298,000
Total assets	$ 359,990
Other current liabilities	$ 24,600
Deferred income taxes	(41,059)
Other deferred credits	372,100
Total liabilities	$355,641
Retained earnings	$ 4,349

The impact of the adjustments described above for the next five years is expected to reduce net income in 2003 through 2005 and increase net income in 2006 through 2007 as shown below.

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	$(15.5)	$(45.3)	$24.6	$(36.2)	$(21.4)
2004	(7.1)	(52.9)	24.6	(35.4)	(20.9)
2005	9.6	(61.9)	24.6	(27.7)	(16.3)
2006	20.2	(39.3)	24.6	5.5	3.2
2007	33.6	(27.0)	24.6	31.2	18.4

(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.

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 2007 (in millions).

2003..............	$114
2004..............	131
2005..............	151
2006..............	95
2007..............	68

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Other Unrecorded Adjustments

This restatement for the years ended December 31, 2002, 2001 and 2000 also includes adjustments that were not previously recognized that principally related to an adjustment to unbilled revenues in 2001 with the corresponding impact in 2002. The net income impact by year was $7.2 million in 2002, $(7.0) million in 2001 and $(0.8) million in 2000.

The effects of all the changes on the Consolidated Statements of Income previously reported for the three years ended December 31, 2002 are as follows:

	2002		2001	
	AS PREVIOUSLY PRESENTED	RESTATED PRESENTATION	AS PREVIOUSLY PRESENTED	RESTATED PRESENTATION
			(IN THOUSANDS EXCEPT PER SHARE AM	
Revenues	$ 987,645	$ 996,045	$1,094,903	$1,086,503
Expenses	932,467	959,346	989,419	1,000,539
Other income	13,329	13,329	15,652	15,652
Income before net interest charges	68,507	50,028	121,136	101,616
Net interest charges	55,170	55,170	58,225	58,925
Net income	13,337	(5,142)	62,911	42,691
Preferred stock dividend requirements	11,356	10,756	16,135	16,135
Earnings on common stock	$ 1,981	$ (15,898)	$ 46,776	$ 26,556

RESULTS OF OPERATIONS

Earnings on common stock decreased to a loss of $15.9 million in 2002 from $26.6 million in 2001 and $121.9 million in 2000. Excluding the effects of the corporate restructuring shown in the table above, earnings on common stock decreased by 13.2% in 2001 from 2000.

Operating revenues decreased by $90.5 million or 8.3% in 2002, compared with 2001. The lower revenues reflect the effects of a sluggish national economy on our service area, shopping by Ohio customers for alternative energy providers and decreases in wholesale revenues. Retail kilowatt-hour sales declined by 11.4% in 2002 from the prior year, with declines in all customer sectors (residential, commercial and industrial), resulting in a $34.4 million reduction in generation sales revenue. Our lower generation kilowatt-hour sales resulted primarily from customer choice in Ohio. Sales of electric generation by alternative suppliers as a percent of total sales delivered in our franchise area increased to 17.0% in 2002 from 5.6% in 2001. Distribution deliveries increased 0.8% in 2002, compared with 2001 and revenues from electricity throughput increased by $5.7 million in 2002 from the prior year. The higher distribution deliveries resulted from additional residential and commercial demand due to warmer summer weather that was more than offset by the effect that continued sluggishness in the economy had on demand by the industrial customers. Transition plan incentives, provided to customers to encourage switching to alternative energy providers, further reduced operating revenues by $15.0 million in 2002 from the prior year. These revenue reductions are deferred for future recovery under our transition plan and do not materially affect current period earnings. Sales revenues from wholesale customers decreased by $45.1 million in 2002 compared to 2001, due to lower kilowatt-hour sales and a decline in market prices. Reduced wholesale kilowatt-hour sales resulted principally from lower sales to FES reflecting the extended outage at Davis-Besse (see Davis-Besse Restoration).

Excluding the effects shown in the Corporate Restructuring table above, operating revenues decreased by $63.1 million or 6.6% in 2001 from 2000 following a $33.8 million increase in 2000 from the prior year. Customer choice in Ohio and the influence of a declining national economy on our regional business activity combined to lower operating revenues. Sales of electric generation provided by other suppliers in our service area represented 5.6% of total energy delivered in 2001. Retail generation sales declined in all customer categories resulting in an overall 4.0% reduction in kilowatt-hour sales from the prior year. Distribution deliveries increased 1.7% in 2001 from the prior year despite the weaker national economic environment. As part of Ohio's electric utility restructuring law, the implementation of a 5% reduction in generation charges for residential customers reduced operating revenues by approximately $8.0 million in 2001, compared to 2000. Operating revenues were also lower in 2001 from the prior year due to the absence of revenues associated with the low-income payment plan now administered by the Ohio Department of Development; there was also a corresponding reduction in other operating costs associated with that change. Revenues from kilowatt-hour sales to wholesale customers declined by $36.5 million in 2001 from 2000, with a corresponding 37.2% reduction in kilowatt-hour sales.

CHANGES IN KWH SALES	2002	2001

INCREASE (DECREASE)		
Electric Generation:		
Retail	(11.4)%	(4.0)%
Wholesale	(27.6)%	(37.2)%
TOTAL ELECTRIC GENERATION SALES ...	(19.2)%	(11.8)%
Distribution Deliveries:		
Residential	7.5 %	3.4 %
Commercial and industrial	(1.0)%	1.1 %
TOTAL DISTRIBUTION DELIVERIES	0.8 %	1.7 %

Operating Expenses and Taxes

Total operating expenses and taxes decreased by $41.2 million in 2002 and increased by $239.9 million in 2001 from 2000. Excluding the effects of restructuring, total 2001 operating expenses and taxes were $35.9 million lower than the prior year. The following table presents changes from the prior year by expense category excluding the impact of restructuring.

OPERATING EXPENSES AND TAXES - CHANGES	2002	2001
	RESTATED (SEE NOTE 1(M))	
INCREASE (DECREASE)	(IN MILLIONS)	
Fuel and purchased power	$(90.5)	$(49.8)
Nuclear operating costs	96.8	(16.5)
Other operating costs	7.2	(8.9)
TOTAL OPERATION AND MAINTENANCE EXPENSES ...	13.5	(75.2)
Provision for depreciation and amortization ..	(14.7)	73.0
General taxes	(4.6)	(27.7)
Income taxes	(35.4)	(6.0)
TOTAL OPERATING EXPENSES AND TAXES	$(41.2)	$(35.9)

Lower fuel and purchased power costs in 2002, compared to 2001, resulted from a $69.0 million reduction in purchased power from FES, reflecting lower kilowatt-hours purchased due to reduced kilowatt-hour sales and lower unit prices. Nuclear operating costs increased by $96.8 million in 2002, primarily due to approximately $55.9 million of incremental Davis-Besse maintenance costs related to the extended outage (see Davis-Besse Restoration). During 2002, costs also included amounts incurred for refueling outages at two nuclear plants (Beaver Valley Unit 2 and Davis-Besse), compared to only one outage (Perry) in 2001. The $7.2 million increase in other operating costs in 2002 resulted principally from higher employee benefit costs, employee severance costs and uncollectible accounts expense.

The decrease in fuel and purchased power costs in 2001, compared to 2000, reflects the transfer of fossil operations to FGCO with our power requirements being provided under the PSA. There was one less nuclear refueling outage in 2001, compared to 2000, resulting in a $16.5 million decrease in nuclear operating costs from the prior year. Other operating costs decreased by $8.9 million in 2001 from the prior year, due to a reduction in low-income payment plan customer costs, decreased storm damage costs and the absence of costs incurred in 2000 related to the development of a distribution communications system.

Charges for depreciation and amortization decreased by $14.7 million in 2002 from 2001. This decrease reflects higher shopping incentive deferrals and tax-related deferrals under TE's transition plan and the cessation of goodwill amortization beginning January 1, 2002, upon implementation SFAS 142 TE's goodwill amortization in 2001 totaled $14.0 million. Depreciation and amortization increased by $73.0 million in 2001 from the prior year due to incremental transition cost amortization under our transition plan, partially offset by new deferrals for shopping incentives.

General taxes decreased by $4.6 million in 2002 from 2001 due to state tax changes in connection with the Ohio electric industry restructuring.

Net Interest Charges

Net interest charges continued to trend lower decreasing by $3.8 million in 2002 and $5.9 million in 2001, compared to the prior year. We continued to redeem and refinance outstanding debt and preferred stock during 2002 -- net redemptions and refinancing activities totaled $264.1 million and $51.8 million, respectively, and will result in annualized savings of $23.2 million.

CAPITAL RESOURCES AND LIQUIDITY

Through net debt and preferred stock redemptions, we continued to reduce the cost of debt and preferred stock, and improve our financial position in 2002. During 2002, we reduced total debt by approximately $163 million. Our common stockholder's equity as a percentage of capitalization increased to 50% as of December 31, 2002 from 27% at the end of 1997. Over the last five years, we have reduced the average cost of outstanding debt from 9.13% in 1997 to 6.61% in 2002.

Changes in Cash Position

As of December 31, 2002, we had $20.7 million of cash and cash equivalents, which was used to redeem long-term debt in January 2003, compared with $0.3 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 energy services. Net cash provided from operating activities was $156 million in 2002 and $190 million in 2001. Cash flows provided from 2002 and 2001 operating activities are as follows:

OPERATING CASH FLOWS	2002	2001
	(IN MILLIONS)	
Cash earnings (1)	$ 142	$ 236

Working capital and other	14	(46)
Total	$ 156	$ 190

(1) Includes net income, depreciation and amortization, deferred income taxes, investment tax credits and major noncash charges.

Cash Flows From Financing Activities

In 2002, the net cash used for financing activities of $29 million primarily reflects the redemptions of debt and preferred stock shown below. The following table provides details regarding new issues and redemptions during 2002:

SECURITIES ISSUED OR REEDEMED IN 2002

	(IN MILLIONS)
NEW ISSUES	
Pollution Control Notes	$ 20
REDEMPTIONS	
Unsecured Notes	135
Secured Notes	44
Preferred Stock	85
Other, principally redemption premiums	2
	266
Short-term Borrowings, Net	132

In 2001, net cash used for financing activities totaled $97.8 million, primarily due to redemptions of $42 million of long-term debt notes and dividend payments of $30.8 million.

We had about $22.6 million of cash and temporary investments and $149.7 million of short-term indebtedness as of December 31, 2002. Under our first mortgage indenture, as of December 31, 2002, we had the capability to issue $144 million of additional first mortgage bonds on the basis of property additions and retired bonds. Based on our earnings in 2002 under the earnings coverage test contained in our charter, we could not issue additional preferred stock (assuming no additional debt was issued). At the end of 2002, our common equity as a percentage of capitalization, stood at 50% compared to 45% at the end of 2001. The higher common equity percentage in 2002 compared to 2001 resulted from net redemptions of preferred stock and long-term debt and a $100 million equity contribution from FirstEnergy.

Cash Flows From Investing Activities

Net cash used in investing activities totaled $106 million in 2002. The net cash used for investing resulted from property additions. Expenditures for property additions primarily include expenditures supporting our distribution of electricity. In 2001, net cash used in investing activities totaled $93 million, principally due to property additions and the sale of property to affiliates as part of corporate separation and the sale to ATSI discussed above.

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

CONTRACTUAL OBLIGATIONS	TOTAL	LESS THAN 1 YEAR	1-3 YEARS	3-5 YEARS
			(IN MILLIONS)	
Long-term debt..................	$ 730	$116	$215	$ 30
Short-term borrowings...........	150	150	--	--
Preferred stock (1).............	--	--	--	--
Capital leases (2)..............	--	--	--	--
Operating leases (2)............	1,067	75	153	158
Purchases (3)...................	269	30	75	64
Total......................	$ 2,216	$371	$443	$ 252

(1) Subject to mandatory redemption.

(2) Operating lease payments are net of capital trust receipts of $363.3 million (see Note 2).

(3) Fuel and power purchases under contracts with fixed or minimum quantities and approximate timing.

Our capital spending for the period 2003-2007 is expected to be about $169 million (excluding nuclear fuel) of which $54 million applies to 2003. Investments for additional nuclear fuel during the 2003-2007 period are estimated to be approximately $34 million, of which about $12 million relates to 2003. During the same periods, our nuclear fuel investments are expected to be reduced by approximately $40 million and $19 million, respectively, as the nuclear fuel is consumed.

On February 22, 2002, Moody's Investor Service changed its credit rating outlook for FirstEnergy from stable to negative. The change was based upon a decision by the Commonwealth Court of Pennsylvania to remand to the Pennsylvania Public Utility Commission (PPUC) for reconsideration its decision on the mechanism for sharing merger savings and reversed the PPUC's decisions regarding rate relief and accounting deferrals rendered in connection with its approval of the GPU merger. On April 4, 2002, Standard & Poor's (S&P) changed its outlook for FirstEnergy's credit ratings from stable to negative citing recent developments including: damage to the Davis-Besse reactor vessel head, the Pennsylvania Commonwealth Court decision, and deteriorating market conditions for some sales of FirstEnergy's remaining non-core assets. On July 31, 2002, Fitch revised its rating outlook for FirstEnergy to negative from stable. The revised outlook reflected the adverse impact of the unplanned Davis-Besse outage, Fitch's judgment about NRG's financial ability to consummate the purchase of four power plants from FirstEnergy (see Note 6 - Sale of Generating Assets) and Fitch's expectation of subsequent delays in debt reduction. On August 1, 2002, S&P concluded that while NRG's liquidity position added uncertainty to FirstEnergy's sale of power plants to NRG, its ratings would not be affected. S&P found FirstEnergy's cash flows sufficiently stable to support a continued (although delayed) program of debt and preferred stock redemption. S&P noted that it would continue to closely monitor FirstEnergy's progress on various initiatives. On January 21, 2003, S&P indicated its concern about FirstEnergy's disclosure of non-cash charges related to deferred costs in Pennsylvania, pension and other post-retirement benefits, and Emdersa (FirstEnergy's Argentina Operations), which were higher than anticipated in the third quarter of 2002. S&P identified the restart of the Davis-Besse nuclear plant "...without significant delay beyond April 2003..." as key to maintaining its current debt ratings. S&P also identified other issues it would continue to monitor including: FirstEnergy's deleveraging efforts, free cash generated during 2003, the Jersey Central Power & Light Company rate case, successful hedging of its short power position, and continued capture of projected merger savings. While FirstEnergy anticipates being prepared to restart the Davis-Besse plant in the spring of 2003 the Nuclear Regulatory Commission (NRC) must authorize the unit's restart following a formal inspection process prior to its returning the unit to service. Significant delays in the planned date of Davis-Besse's return to service or other factors (identified above) affecting the speed with which FirstEnergy reduces debt could put additional pressure on the Company's credit ratings.

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Other Obligations

Obligations not included on our Consolidated Balance Sheet primarily consist of sale and leaseback arrangements involving the Bruce Mansfield Plant and Beaver Valley Unit 2, which are reflected in the operating lease payments above (see Note 2 - Leases). The present value as of December 31, 2002, of these sale and leaseback operating lease commitments, net of trust investments, total $621 million. We sell substantially all of our retail customer receivables, which provided $52 million of off balance sheet financing as of December 31, 2002.

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 risks related to refinancing maturing debt by issuing new debt securities. As discussed in Note 2, our investment in the Shippingport Capital Trust effectively reduces 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 1 - Utility Plant and Depreciation. 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.

The table below presents principal amounts and related weighted average interest rates by year of maturity for our investment portfolio and debt obligations.

COMPARISON OF CARRYING VALUE TO FAIR VALUE

	2003	2004	2005	2006	2007	THERE-AFTER
				(DOLLARS IN MILLIONS)		
Assets						
Investments other than Cash and Cash Equivalents:						
Fixed Income.................	$ 20	$ 9	$134	$ 12	$ 9	$ 290
Average interest rate.....	7.7%	7.7%	7.8%	7.7%	7.7%	6.8%
Liabilities						
Long-term Debt:						
Fixed rate...................	$116	$215			$ 30	$ 160
Average interest rate	7.7%	7.8%			7.1%	7.8%
Variable rate................						$ 209
Average interest rate.....						3.0%
Short-term Borrowings........	$150					
Average interest rate.....	1.8%					

EQUITY PRICE RISK

Included in our nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $90 million and $90 million as of December 31, 2002 and 2001, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $9 million reduction in fair value as of December 31, 2002 (see Note 1K - Supplemental Cash Flows Information)

OUTLOOK

Our industry continues to transition to a more competitive environment. In 2001, all our customers could select alternative energy suppliers. We continue to deliver power to residential homes and businesses through our existing distribution systems, which remain regulated. Customer rates have been restructured into separate components to support customer choice. We have a continuing responsibility to provide power to our customers not choosing to receive power from an alternative energy supplier subject to certain limits. Adopting new approaches to regulation and experiencing new forms of competition have created new uncertainties.

Regulatory Matters

Beginning on January 1, 2001, Ohio customers were able to choose their electricity suppliers. Ohio customer rates were restructured to establish separate charges for transmission, distribution, transition cost recovery and a generation-related component. When one of our customers elects to obtain power from an alternative supplier, we reduce the customer's bill with a "generation shopping credit," based on the regulated generation component plus an incentive, and the customer receives a generation charge from the alternative supplier. We have continuing responsibility to provide energy to our franchise customers as the PLR through December 31, 2005. Regulatory assets are costs which have been authorized by the Public Utilities Commission of Ohio (PUCO) for recovery from customers in future periods and, without such authorization, would have been charged to income when incurred. All of our regulatory assets are expected to continue to be recovered under the provisions of our transition plan as discussed below. Our regulatory assets are $578.2 million as of December 31, 2002 and $642.2 million as of December 31, 2001.

The transition cost portion of rates provides for recovery of certain amounts not otherwise recoverable in a competitive generation market (such as regulatory assets). Transition costs are paid by all customers whether or not they choose an alternative supplier. Under the PUCO-approved transition plan, we assumed the risk of not recovering up to $80 million of transition revenue if the rate of customers (excluding contracts and full-service accounts) switching from our service to an alternative supplier did not reach 20% for any consecutive twelve-month period by December 31, 2005 - the end of the market development period. That goal was achieved in 2002. Accordingly, TE does not believe that there will be any regulatory action reducing the recoverable transition costs.

As part of our Ohio transition plan we are obligated to supply electricity to customers who do not choose an alternative supplier. We are also required to provided 160 megawatts (MW) of low cost supply to unaffiliated alternative suppliers that serve customers within our service area. Our competitive retail sales affiliate, FES, acts as an alternate supplier for a portion of our load. In 2003, the total peak load forecasted for customers electing to stay with us, including the 160 MW of low cost supply and the load served by our affiliate is 2,020 MW.

Davis-Besse Restoration

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

Restart activities include both hardware and management issues. In addition to refurbishment and installation work at the plant, we have made significant management and human performance changes with the intent of establishing the proper safety culture throughout the workforce. Work was completed on the reactor head during 2002 and is continuing on efforts designed to enhance the unit's reliability and performance. FENOC is also accelerating maintenance work that had been planned for future refueling and maintenance outages. At a meeting with the NRC in November 2002, FENOC 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. FENOC anticipates that the unit will be ready for restart in the fall of 2003 after completion of the additional maintenance work and regulatory reviews. The NRC must authorize restart of the plant following its formal inspection process before the unit can be returned to service. While the additional maintenance work has delayed our plans to reduce post-merger debt levels we believe such investments in the unit's future safety, reliability and performance to be essential. Significant delays in Davis-Besse's return to service, which depends on the successful resolution of the management and technical issues as well as

NRC approval could trigger an evaluation for impairment of our investment in the plant (see Significant Accounting Policies below).

The actual costs (capital and expense) associated with the extended Davis-Besse outage (TE share - 48.62%) in 2002 and estimated costs in 2003 are:

COSTS OF DAVIS-BESSE EXTENDED OUTAGE	100%
	(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

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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. 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.

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 5 - Environmental Matters). We continue to evaluate our compliance plans and other compliance options.

Violations of federally approved SO_2 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 SO(2) 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 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.

We have been named as a "potentially responsible party" (PRP) 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. Federal law provides that all PRPs for a particular site be held liable on a joint and several basis. We have accrued a liability of $0.2 million as of December 31, 2002, based on estimates of the total costs of cleanup, the proportionate responsibility of other PRPs for such costs and the financial ability of other PRPs to pay. We believe that waste disposal costs will not have a material adverse effect on our financial condition, cash flows, or results of operations.

The effects of compliance on the Company 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.

SIGNIFICANT ACCOUNTING POLICIES

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

Regulatory Accounting

We are subject to regulation that sets the prices (rates) we are permitted to charge our customers based on our 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 Ohio, significant amounts of regulatory assets have been recorded -- $578.2 million as of December 31, 2002. We continually 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.

Revenue Recognition

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

- Net energy generated or purchased for retail load
- Losses of energy over distribution lines
- Allocations to distribution companies within the FirstEnergy system
- Mix of kilowatt-hour usage by residential, commercial and industrial customers
- Kilowatt-hour usage of customers receiving electricity from alternative suppliers

Pension and Other Postretirement Benefits Accounting

Our reported costs of providing non-contributory defined pension benefits and postemployment benefits other than pensions (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. 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 obligation. 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
		(IN MILLIONS)	
Discount rate	Decrease by 0.25%	$0.2	$0.2
Long-term return on assets	Decrease by 0.25%	0.1	--
Health care trend rate	Increase by 1%	na	0.5
INCREASE IN MINIMUM PENSION LIABILITY			
Discount rate	Decrease by 0.25%	4.4	na

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 $18.7 million and established a minimum liability of $25.0 million, recording an intangible asset of $7.6 million and reducing OCI by $21.1 million (recording a related deferred tax benefit of $15.0 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 $3 million and $1 million, respectively - a total of $4 million in 2003 as compared to 2002.

Ohio Transition Cost Amortization

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

Long-Lived Assets

In accordance with SFAS 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 regulations in the jurisdictions in which TE operates do not provide for recovery of goodwill. As a result, no amortization of goodwill 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. 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 approximately $504.5 million of goodwill.

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 $123.2 million were recorded as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $15.0 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 $172 million. As of December 31, 2002, the Company had recorded decommissioning liabilities of $179.6 million. The change in the estimated liabilities resulted from changes in methodology and various assumptions, including changes in the projected dates for decommissioning.

The 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 $115.2 million increase to income ($67.3 million net of tax). The 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 $115.2 million increase to income ($67.3 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.

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

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

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

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

TE currently has transactions 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. TE currently consolidates the majority of these entities and believes it will continue to consolidate following the adoption of FIN 46. One of these entities TE is currently consolidating is the Shippingport Capital Trust, which reacquired a portion of the off-balance sheet debt issued in connection with the sale and leaseback of its interest in the Bruce Mansfield Plant. Ownership of the trust includes a 4.85 percent interest by nonaffiliated parties and a 0.34 percent equity interest by Toledo Edison Capital Corp., a majority owned subsidiary.

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.

TE 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, TE 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.

THE FOLLOWING ITEM HAS BEEN AMENDED IN THIS AMENDMENT NO. 2:

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

THE TOLEDO EDISON COMPANY

CONSOLIDATED STATEMENTS OF INCOME (RESTATED*)

FOR THE YEARS ENDED DECEMBER 31,	2002	2001
		(IN THOUSAND
OPERATING REVENUES (a) (NOTE 1)................................	$996,045	$1,086,503
OPERATING EXPENSES AND TAXES:		
Fuel and purchased power (Note 1)............................	366,932	457,444
Nuclear operating costs (Note 1).............................	252,608	155,832
Other operating costs (Note 1)...............................	141,997	134,744
Total operation and maintenance expenses...................	761,537	748,020
Provision for depreciation and amortization..................	162,082	176,796
General taxes..	53,223	57,810

Income taxes	(17,496)	17,913
Total operating expenses and taxes	959,346	1,000,539
OPERATING INCOME	36,699	85,964
OTHER INCOME (NOTE 1)	13,329	15,652
INCOME BEFORE NET INTEREST CHARGES	50,028	101,616
NET INTEREST CHARGES:		
Interest on long-term debt	58,120	66,463
Allowance for borrowed funds used during construction	(2,502)	(3,848
Other interest expense (credit)	(448)	(3,690
Net interest charges	55,170	58,925
NET INCOME (LOSS)	(5,142)	42,691
PREFERRED STOCK DIVIDEND REQUIREMENTS	10,756	16,135
EARNINGS (LOSS) ON COMMON STOCK	$(15,898)	$ 26,556

*See Note 1(M).

(a) Includes electric sales to associated companies of $232.2 million, $277.9 million and $142.3 million in 2002, 2001 and 2000, respectively.

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

THE TOLEDO EDISON COMPANY

CONSOLIDATED BALANCE SHEETS (RESTATED*)

AS OF DECEMBER 31,	2002	2001
	(IN THOUSANDS)	
ASSETS		
UTILITY PLANT:		
In service	$ 1,600,860	$ 1,578,943
Less-Accumulated provision for depreciation	706,772	645,865
	894,088	933,078
Construction work in progress-		
Electric plant	104,091	40,220
Nuclear fuel	33,650	19,854

	137,741	60,074
	1,031,829	993,152
OTHER PROPERTY AND INVESTMENTS:		
Shippingport Capital Trust (Note 2)	240,963	262,131
Nuclear plant decommissioning trusts	174,514	156,084
Long-term notes receivable from associated companies	162,159	162,347
Other	2,236	4,248
	579,872	584,810
CURRENT ASSETS:		
Cash and cash equivalents	20,688	302
Receivables-		
Customers	4,711	5,922
Associated companies	55,245	64,667
Other	6,778	1,309
Notes receivable from associated companies	1,957	7,607
Materials and supplies, at average cost-		
Owned	13,631	13,996
Under consignment	22,997	17,050
Prepayments and other	3,455	14,580
	129,462	125,433
DEFERRED CHARGES:		
Regulatory assets	578,243	642,246
Goodwill	504,522	504,522
Property taxes	23,429	23,836
Other	14,257	1,909
	1,120,451	1,172,513
	$ 2,861,614	$ 2,875,908

CAPITALIZATION AND LIABILITIES

CAPITALIZATION (See Consolidated Statements of Capitalization):		
Common stockholder's equity	$ 681,195	$ 629,805
Preferred stock not subject to mandatory redemption	126,000	126,000
Long-term debt	557,265	646,174
	1,364,460	1,401,979
CURRENT LIABILITIES:		
Currently payable long-term debt and preferred stock	189,355	347,593
Accounts payable-		
Associated companies	171,862	53,960
Other	9,338	29,818
Notes payable to associated companies	149,653	17,208
Accrued taxes	34,676	35,355
Accrued interest	16,377	19,918
Deferred lease costs	24,600	24,600
Other	57,462	41,622
	653,323	570,074
DEFERRED CREDITS:		
Accumulated deferred income taxes	158,279	170,364

Accumulated deferred investment tax credits	29,255	31,266
Nuclear plant decommissioning costs	179,587	151,226
Pensions and other postretirement benefits	82,553	120,561
Deferred lease costs	317,200	341,800
Other	76,957	88,638
	843,831	903,855
COMMITMENTS AND CONTINGENCIES (Notes 2 and 5)		
	$ 2,861,614	$ 2,875,908

*See Note 1(M).

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

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THE TOLEDO EDISON COMPANY

CONSOLIDATED STATEMENTS OF CAPITALIZATION (RESTATED*)

AS OF DECEMBER 31,	2002
(DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)	
COMMON STOCKHOLDER'S EQUITY:	
Common stock, $5 par value, authorized 60,000,000 shares 39,133,887 shares outstanding	$ 195,670
Other paid-in capital	428,559
Accumulated other comprehensive loss (Note 3E)	(20,012)
Retained earnings (Note 3A)	76,978
Total common stockholder's equity	681,195

	NUMBER OF SHARES OUTSTANDING		OPTIONAL REDEMPTION PRICE		
	2002	2001	PER SHARE	AGGREGATE	2002
PREFERRED STOCK (NOTE 3C):					
Cumulative, $100 par value-					
Authorized 3,000,000 shares					
Not Subject to Mandatory Redemption:					
$ 4.25	160,000	160,000	$104.63	$ 16,740	16,000
$ 4.56	50,000	50,000	101.00	5,050	5,000
$ 4.25	100,000	100,000	102.00	10,200	10,000
$ 8.32	--	100,000	--	--	--
$ 7.76	--	150,000	--	--	--
$ 7.80	--	150,000	--	--	--

$ 10.00..........................	--	190,000	--	--	--
	310,000	900,000		31,990	31,000
Redemption Within One Year					--
	310,000	900,000		31,990	31,000
Cumulative, $25 par value-					
Authorized 12,000,000 shares					
Not Subject to Mandatory Redemption:					
$2.21............................	--	1,000,000	--	--	--
$2.365...........................	1,400,000	1,400,000	27.75	38,850	35,000
Adjustable Series A..............	1,200,000	1,200,000	25.00	30,000	30,000
Adjustable Series B..............	1,200,000	1,200,000	25.00	30,000	30,000
	3,800,000	4,800,000		98,850	95,000
Redemption Within One Year...........					--
	3,800,000	4,800,000		98,850	95,000
Total Not Subject to Mandatory Redemption.................	4,110,000	5,700,000		$ 130,840	126,000

	2002
LONG-TERM DEBT (NOTE 3D):	
First mortgage bonds:	
8.000% due 2003..	33,725
7.875% due 2004..	145,000
Total first mortgage bonds...	178,725
Unsecured notes and debentures:	
8.700% due 2002..	--
10.000% due 2003-2010..	910
* 4.850% due 2030..	34,850
* 4.000% due 2033..	5,700
* 4.500% due 2033..	31,600
* 5.580% due 2033..	18,800
Total unsecured notes and debentures.....................................	91,860

*See Note 1(M).

THE TOLEDO EDISON COMPANY

CONSOLIDATED STATEMENTS OF CAPITALIZATION (RESTATED*) (CONT'D)

AS OF DECEMBER 31,	2002
	(IN THOUSAN
LONG-TERM DEBT (CONT'D):	
Secured notes:	
8.180% due 2002	--
8.620% due 2002	--
8.650% due 2002	--
7.760% due 2003	5,000
7.780% due 2003	1,000
7.820% due 2003	38,400
7.850% due 2003	15,000
7.910% due 2003	3,000
7.670% due 2004	70,000
7.130% due 2007	30,000
7.625% due 2020	45,000
7.750% due 2020	54,000
9.220% due 2021	15,000
10.000% due 2021	--
6.875% due 2023	20,200
8.000% due 2023	30,500
** 1.700% due 2024	67,300
6.100% due 2027	10,100
5.375% due 2028	3,751
** 1.400% due 2033	30,900
** 1.350% due 2033	20,200
Total secured notes	459,351
Capital lease obligations (Note 2)	--
Net unamortized premium on debt	16,684
Long-term debt due within one year	(189,355)
Total long-term debt	557,265
TOTAL CAPITALIZATION	$1,364,460

*   See Note 1(M).

** Denotes variable rate issue with December 31, 2002 interest rate shown.

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

THE TOLEDO EDISON COMPANY

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

OTH

	COMPREHENSIVE INCOME (LOSS) RESTATED (SEE NOTE 1(M))	NUMBER OF SHARES	PAR VALUE	PAID CAPI
			(DOLLARS IN T	
Balance, January 1, 2000		39,133,887	$195,670	$328
Cumulative effect for restatement (see Note 1 (m)				
Restated balance at January 1, 2000				
Net income	$ 138,144			
Cash dividends on preferred stock				
Cash dividends on common stock				
Balance, December 31, 2000		39,133,887	195,670	328
Net income	$ 42,691			
Unrealized gain on investments, net of $4,800 of income taxes	7,100			
Comprehensive income	$ 49,791			
Cash dividends on preferred stock				
Cash dividends on common stock				
Balance, December 31, 2001		39,133,887	195,670	328
Net income (loss)	$ (5,142)			
Unrealized loss on investments, net of $(4,034)of income taxes	(5,997)			
Minimum liability for unfunded retirement benefits, net of $(15,042,000) of income taxes	(21,115)			
Comprehensive loss	$ (32,254)			
Equity contribution from parent				100
Cash dividends on preferred stock				
Cash dividends on common stock				
Preferred stock redemption premiums				
Balance, December 31, 2002		39,133,887	$195,670	$428

CONSOLIDATED STATEMENTS OF PREFERRED STOCK

	NOT SUBJECT TO MANDATORY REDEMPTION	
	NUMBER OF SHARES	VALUE
	(DOLLARS IN THOUSANDS)	
Balance, January 1, 2000	5,700,000	$ 210,000
Balance, December 31, 2000	5,700,000	210,000
Balance, December 31, 2001	5,700,000	210,000

Redemptions		
$ 8.32 . Series	(100,000)	(10,000)
$ 7.76 . Series	(150,000)	(15,000)
$ 7.80 . Series	(150,000)	(15,000)
$10.00 Series	(190,000)	(19,000)
$ 2.21 . Series	(1,000,000)	(25,000)
Balance, December 31, 2002	4,110,000	$ 126,000

* See Note 1(M) to the Consolidated Financial Statements.

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

THE TOLEDO EDISON COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS (RESTATED*)

FOR THE YEARS ENDED DECEMBER 31,	2002	2001	2000
	(IN THOUSANDS)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (Loss)	$ (5,142)	$ 42,691	$ 138,144
Adjustments to reconcile net income (loss) to net cash from operating activities:			
Provision for depreciation and amortization	162,082	176,796	106,514
Nuclear fuel and lease amortization	11,866	22,222	23,881
Deferred income taxes, net	(24,821)	(1,383)	22,165
Investment tax credits, net	(1,851)	(3,832)	(1,827)
Receivables	5,164	(1,437)	(6,671)
Materials and supplies	(5,582)	8,336	4,093
Accounts payable	40,801	22,144	13,997
Accrued taxes	(4,881)	(17,671)	(223)
Accrued interest	(3,541)	(28)	(2,015)
Prepayments and other	11,125	12,571	(1,220)
Deferred lease costs	(24,600)	(24,600)	(5,700)
Other	(5,082)	(45,953)	(33,322)
Net cash used for operating activities	155,538	189,856	257,816
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	19,580	--	96,405
Short-term borrowings, net	132,445	--	8,060
Equity contributions from parent	100,000	--	--
Redemptions and Repayments-			
Preferred stock	(85,299)	--	--
Long-term debt	(180,368)	(42,265)	(200,633)
Short-term borrowings, net	--	(24,728)	--
Dividend Payments-			
Common stock	(5,600)	(14,700)	(67,100)
Preferred stock	(10,057)	(16,135)	(16,247)

Net cash used for financing activities	(29,299)	(97,828)	(179,515)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(105,510)	(112,451)	(92,860)
Loans to associated companies	--	(123,438)	(63,838)
Loan payments from associated companies	5,838	25,185	--
Capital trust investments	21,168	17,705	15,618
Sale of assets to associated companies	--	123,438	81,014
Other	(27,349)	(23,550)	(17,162)
Net cash used for investing activities	(105,853)	(93,111)	(77,228)
Net increase (decrease) in cash and cash equivalents	20,386	(1,083)	1,073
Cash and cash equivalents at beginning of year	302	1,385	312
Cash and cash equivalents at end of year	$ 20,688	$ 302	$ 1,385
SUPPLEMENTAL CASH FLOWS INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	$ 61,498	$ 63,159	$ 71,009
Income taxes	$ 3,561	$ 33,210	$ 65,553

*See Note 1(M).

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

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THE TOLEDO EDISON COMPANY

CONSOLIDATED STATEMENTS OF TAXES (RESTATED*)

FOR THE YEARS ENDED DECEMBER 31,	2002	2001	2000
		(IN THOUSANDS)	
GENERAL TAXES:			
Real and personal property	$ 22,737	$ 23,624	$ 46,302
Ohio kilowatt-hour excise**	28,046	19,576	--
State gross receipts**	--	12,789	36,813
Social security and unemployment	1,684	1,128	7,220
Other	756	693	502
Total general taxes	$ 53,223	$ 57,810	$ 90,837
PROVISION FOR INCOME TAXES:			
Currently payable-			
Federal	$ 12,845	$ 22,244	$ 56,631
State	3,983	4,840	1,811

	16,828	27,084	58,442
Deferred, net-			
Federal	(19,091)	4,725	22,216
State	(5,570)	(1,539)	(51)
	(24,661)	3,186	22,165
Investment tax credit amortization	(2,011)	(3,908)	(1,827)
Total provision for income taxes	$ (9,844)	$ 26,362	$ 78,780
INCOME STATEMENT CLASSIFICATION OF PROVISION FOR INCOME TAXES:			
Operating income	$ (17,496)	$ 17,913	$ 74,183
Other income	7,652	8,449	4,597
Total provision for income taxes	$ (9,844)	$ 26,362	$ 78,780
RECONCILIATION OF FEDERAL INCOME TAX EXPENSE AT STATUTORY RATE TO TOTAL PROVISION FOR INCOME TAXES:			
Book income before provision for income taxes	$ (14,986)	$ 69,053	$ 216,924
Federal income tax expense at statutory rate	$ (5,245)	$ 24,169	$ 75,923
Increases (reductions) in taxes resulting from-			
State income taxes, net of federal income tax benefit	(1,031)	2,146	1,144
Amortization of investment tax credits	(2,011)	(3,908)	(1,827)
Amortization of tax regulatory assets	(2,362)	(2,563)	(1,737)
Amortization of goodwill	--	4,911	4,894
Other, net	805	1,607	383
Total provision for income taxes	$ (9,844)	$ 26,362	$ 78,780
ACCUMULATED DEFERRED INCOME TAXES AT DECEMBER 31:			
Property basis differences	$ 177,262	$ 171,976	$ 163,537
Competitive transition charge	196,812	239,088	192,444
Unamortized investment tax credits	(11,414)	(12,184)	(16,689)
Unused alternative minimum tax credits	--	--	(5,100)
Deferred gain for asset sale to affiliated company	14,186	16,305	15,330
Other comprehensive income	(14,276)	4,800	--
Above market leases	(140,399)	(150,634)	(160,868)
Retirement benefits	(9,768)	(35,126)	(28,656)
Other	(54,124)	(63,861)	(2,334)
Net deferred income tax liability	$ 158,279	$ 170,364	$ 157,664

* See Note 1(M).

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

The consolidated financial statements include The Toledo Edison Company (Company) and its 90% owned subsidiary, The Toledo Edison Capital Corporation (TECC). The subsidiary was formed in 1997 to make equity investments in a business trust in connection with the financing transactions related to the Bruce Mansfield Plant sale and leaseback (see Note 2). The Cleveland Electric Illuminating Company (CEI), an affiliate, has a 10% interest in TECC. All significant intercompany transactions have been eliminated. The Company is a wholly owned subsidiary of FirstEnergy Corp. FirstEnergy holds directly all of the issued and outstanding common shares of its principal electric utility operating subsidiaries, including, the Company, CEI, Ohio Edison Company (OE), American Transmission Systems, Inc. (ATSI), Jersey Central Power & Light Company (JCP&L), Metropolitan Edison Company (Met-Ed) and Pennsylvania Electric Company (Penelec). JCP&L, Met-Ed and Penelec were formerly wholly owned subsidiaries of GPU, Inc. which merged with FirstEnergy on November 7, 2001.

The Company follows the accounting policies and practices prescribed by the Securities and Exchange Commission (SEC), the Public Utilities Commission of Ohio (PUCO) and the Federal Energy Regulatory Commission (FERC). The preparation of financial statements in conformity with accounting principles generally accepted in the United States (GAAP) requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates.

(A) CONSOLIDATION-

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

(B) REVENUES-

The Company's principal business is providing electric service to customers in northwestern Ohio. The Company's retail customers are metered on a cycle basis. Revenue is recognized for unbilled electric service through the end of the year.

Receivables from customers include sales to residential, commercial and industrial customers located in the Company's service area and sales to wholesale customers. There was no material concentration of receivables at December 31, 2002 or 2001, with respect to any particular segment of the Company's customers.

The Company and CEI sell substantially all of their retail customers' receivables to Centerior Funding Corporation (CFC), a wholly owned subsidiary of CEI. CFC subsequently transfers the receivables to a trust (a SFAS 140 "qualified special purpose entity") under an asset-backed securitization agreement. Transfers are made in return for an interest in the trust (41% as of December 31, 2002), which is stated at fair value, reflecting adjustments for anticipated credit losses. The average collection period for billed receivables is 28 days. Given the short collection period after billing, the fair value of CFC's interest in the trust approximates the stated value of its retained interest in underlying receivables after adjusting for anticipated credit losses. Accordingly, subsequent measurements of the retained interest under SFAS 115 (as an available-for-sale financial instrument) result in no material change in value. Sensitivity analyses reflecting 10% and 20% increases in the rate of anticipated credit losses would not have significantly affected the Company's retained interest in the pool of receivables through the trust. Of the $272 million sold to the trust and outstanding as of December 31, 2002, FirstEnergy had a retained interest in $111 million of the receivables included as other receivables on the Consolidated Balance Sheets. Accordingly, receivables recorded on the Consolidated Balance Sheets were reduced by approximately $161 million due to these sales. Collections of receivables previously transferred to the trust and used for the purchase of new receivables from CFC during 2002, totaled approximately $2.2 billion. The Company processed receivables for the trust and received servicing fees of approximately $1.3 million in 2002. Expenses associated with the factoring discount related to the sale of receivables were $4.7 million in 2002.

(C) REGULATORY PLAN-

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

In July 2000, the PUCO approved FirstEnergy's transition plan for the Company, OE and CEI as modified by a settlement agreement with major parties to the transition plan. The application of SFAS 71, "Accounting for the Effects of Certain Types of Regulation" to the Company's nonnuclear generation business was discontinued with the issuance of the PUCO transition plan order, as described further below. Major provisions of the settlement agreement consisted of approval of recovery of generation-related transition costs as filed of $0.8 billion net of deferred income taxes and transition costs related to regulatory assets as filed of $0.5 billion net of deferred income taxes, with recovery through no later than mid-2007 for the Company, except where a longer period of recovery is provided for in the settlement agreement. The generation-related transition costs include $0.3 billion of impaired generating assets recognized as regulatory assets as described further below, $1.0 billion, net of deferred income taxes, of above-market operating lease costs (see Note 1(M)) and $0.3 billion, net of deferred income taxes, of additional plant costs that were reflected on the Company's regulatory financial statements.

Also as part of the settlement agreement, FirstEnergy is giving preferred access over its subsidiaries to nonaffiliated marketers, brokers and aggregators to 160 megawatts (MW) of generation capacity through 2005 at established prices for sales to the Company's retail customers. Customer prices are frozen through the five-year market development period except for certain limited statutory exceptions, including the 5% reduction referred to above. In February 2003, the Company was authorized increases in annual revenues aggregating approximately $5 million to recover its higher tax costs resulting from the Ohio deregulation legislation.

The Company's 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 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 period could have been shortened for the Company to reduce recovery by as much as $80 million. The Company has achieved its required 20% customer shopping goals in 2002. Accordingly, the Company believes that there will be no regulatory action reducing the recoverable transition costs.

The application of SFAS 71 has been discontinued with respect to the Company's generation operations. The SEC issued interpretive guidance regarding asset impairment measurement that concluded any supplemental regulated cash flows such as a competitive transition charge should be excluded from the cash flows of assets in a portion of the business not subject to regulatory accounting practices. If those assets are impaired, a regulatory asset should be established if the costs are recoverable through regulatory cash flows. Consistent with the SEC guidance $53 million of impaired plant investments were recognized by the Company as regulatory assets recoverable as transition costs through future regulatory cash flows. Net assets included in utility plant relating to the operations for which the application of SFAS 71 was discontinued, were $559 million as of December 31, 2002. See Note 1(M) for further discussion of the Ohio transition plan.

(D) UTILITY PLANT AND DEPRECIATION-

Utility plant reflects the original cost of construction (except for the Company's nuclear generating units which were adjusted to fair value in connection with the purchase accounting and impairment tests prepared in connection with the transition plan), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs. The Company's accounting policy for planned major maintenance projects is to recognize liabilities as they are incurred.

The Company provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The annualized composite rate was approximately 3.9% in 2002, 3.5% in 2001 and 3.4% in 2000.

Annual depreciation expense includes approximately $28.5 million for future decommissioning costs applicable to the Company's ownership interests in three nuclear generating units (Beaver Valley Unit 2, Davis-Besse Unit 1 and Perry Unit 1). The Company's share of the future obligation to decommission these units is approximately $475 million in current dollars and (using a 4.0% escalation rate) approximately $1.0 billion in future dollars. The estimated obligation and

the escalation rate were developed based on site specific studies. Payments for decommissioning are expected to begin in 2016, when actual decommissioning work begins. The Company has recovered approximately $192 million for decommissioning through its electric rates from customers through December 31, 2002. The Company has also recognized an estimated liability of approximately $4.8 million related to decontamination and decommissioning of nuclear enrichment facilities operated by the United States Department of Energy, as required by the Energy Policy Act of 1992.

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

The Company has identified applicable legal obligations as defined under the new standard, principally for nuclear power plant decommissioning. Upon adoption of SFAS 143, asset retirement costs of $123 million were recorded as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $15 million. Due to the increased carrying amount, the related long-lived assets were tested for impairment in accordance with SFAS 144, "Accounting for Impairment or Disposal of Long-Lived Assets". No impairment was indicated.

The asset retirement liability at the date of adoption will be $172 million. As of December 31, 2002, the Company had recorded decommissioning liabilities of $179.6 million. The change in the estimated liabilities resulted from changes in methodology and various assumptions, including changes in the projected dates for decommissioning.

The 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 will be a $115 million increase to income ($67 million net of tax).

The FASB approved SFAS 142, "Goodwill and Other Intangible Assets," on June 29, 2001. Under SFAS 142, amortization of existing goodwill ceased January 1, 2002. Instead, goodwill is tested for impairment at least on an annual basis - based on the results of the transition analysis and the 2002 annual analysis, no impairment of the Company's goodwill is required. As described above under "Regulatory Plan" the Company recovers transition costs that represent a significant source of cash. The Company is unable to predict how completion of transition cost recovery will affect future goodwill impairment analyses. Prior to the adoption of SFAS 142, the Company amortized about $14 million of goodwill annually. The goodwill balance as of December 31, 2002 and 2001 was $505 million.

The following table shows what net income would have been if goodwill amortization had been excluded from prior periods:

	2002	2001	2000
	RESTATED	RESTATED	RESTATED

	(IN THOUSANDS)		
Reported net income (loss)	$ (5,142)	$ 42,691	$ 138,114
Add back goodwill amortization	--	14,032	13,984
Adjusted net income (loss)	$ (5,142)	$ 56,723	$ 152,098

(E) COMMON OWNERSHIP OF GENERATING FACILITIES-

The Company, together with CEI and OE and its wholly owned subsidiary, Pennsylvania Power Company (Penn), own and/or lease, as tenants in common, various power generating facilities. Each of the companies is obligated to pay a share of the costs associated with any jointly owned facility in the same proportion as its interest. The Company's portion of operating expenses associated with jointly owned facilities is included in the corresponding operating expenses on the Consolidated Statements of Income. The amounts reflected on the Consolidated Balance Sheet under utility plant at December 31, 2002 include the following:

GENERATING UNITS	UTILITY PLANT IN SERVICE	ACCUMULATED PROVISION FOR DEPRECIATION	CONSTRUCTION WORK IN PROGRESS	OWNERSHIP/ LEASEHOLD INTEREST
		(IN MILLIONS)		
Bruce Mansfield Units 2 and 3	$ 46.0	$ 16.9	$ 21.0	18.61%
Beaver Valley Unit 2	3.2	0.2	8.8	19.91%
Davis-Besse	222.6	48.9	54.4	48.62%
Perry	338.7	59.9	3.6	19.91%
Total	$ 610.5	$ 125.9	$ 87.8	

The Bruce Mansfield Plant and Beaver Valley Unit 2 are being leased through sale and leaseback transactions (see Note 2) and the above-related amounts represent construction expenditures subsequent to the transaction.

(F) NUCLEAR FUEL-

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

(G) STOCK-BASED COMPENSATION-

FirstEnergy applies the recognition and measurement principles of Accounting Principles Board Opinion No. 25 (APB 25), "Accounting for Stock Issued to Employees" and related Interpretations in accounting for its stock-based compensation plans (see Note 3B). No material stock-based employee compensation expense is reflected in net income as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the grant date, resulting in substantially no intrinsic value.

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

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

The effects of applying fair value accounting to FirstEnergy's stock options would not materially effect the Company's net income.

(H) INCOME TAXES-

Details of the total provision for income taxes are shown on the Consolidated Statements of Taxes. Deferred income taxes result from timing differences in the recognition of revenues and expenses for tax and accounting purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. The liability method is used to account for deferred income taxes. Deferred income tax liabilities related to tax and accounting basis differences are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. The Company is included in FirstEnergy's consolidated federal income tax return. The consolidated tax liability is allocated on a "stand-alone" company basis, with the Company recognizing any tax losses or credits it contributed to the consolidated return.

(I) RETIREMENT BENEFITS-

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

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

As a result of the reduced market value of FirstEnergy's pension plan assets, it was required to recognize an additional minimum liability as prescribed by SFAS 87 and SFAS 132, "Employers' Disclosures about Pension and Postretirement Benefits," as of December 31, 2002. FirstEnergy's accumulated benefit obligation of $3.438 billion exceeded the fair value of plan assets ($2,889 billion) resulting in a minimum pension liability of $548.6 million. FirstEnergy eliminated its prepaid pension asset of $286.9 million (Company - $18.7 million) and established a minimum liability of $548.6 million (Company - $25.0 million), recording an intangible asset of $78.5 million (Company - $7.6 million) and reducing OCI by $444.2 million (Company - $21.1 million) (recording a related deferred tax asset of $312.8 million (Company - $15.0 million)). The charge to OCI will reverse in future periods to the extent the fair value of trust assets exceed the accumulated benefit obligation. The amount of pension liability recorded as of December 31, 2002, increased due to the lower discount rate and asset returns assumed as of December 31, 2002.

The following sets forth the funded status of the plans and amounts recognized on FirstEnergy's Consolidated Balance Sheets as of December 31:

	PENSION BENEFITS		OTHER POSTRETIREMENT BENEFITS	
	2002	2001	2002	2001
	(IN MILLIONS)			
Change in benefit obligation:				
Benefit obligation as of January 1............	$3,547.9	$1,506.1	$ 1,581.6	$ 752.0
Service cost..................................	58.8	34.9	28.5	18.3
Interest cost.................................	249.3	133.3	113.6	64.4
Plan amendments...............................	--	3.6	(121.1)	--
Actuarial loss................................	268.0	123.1	440.4	73.3
Voluntary early retirement program............	--	--	--	2.3
GPU acquisition...............................	(11.8)	1,878.3	110.0	716.9
Benefits paid.................................	(245.8)	(131.4)	(83.0)	(45.6)
Benefit obligation as of December 31..........	3,866.4	3,547.9	2,070.0	1,581.6
Change in fair value of plan assets:				
Fair value of plan assets as of January 1.....	3,483.7	1,706.0	535.0	23.0
Actual return on plan assets..................	(348.9)	8.1	(57.1)	12.7
Company contribution..........................	--	--	37.9	43.3
GPU acquisition...............................	--	1,901.0	--	462.0
Benefits paid.................................	(245.8)	(131.4)	(42.5)	(6.0)
Fair value of plan assets as of December 31...	2,889.0	3,483.7	473.3	535.0
Funded status of plan.........................	(977.4)	(64.2)	(1,596.7)	(1,046.6)
Unrecognized actuarial loss...................	1,185.8	222.8	751.6	212.8
Unrecognized prior service cost...............	78.5	87.9	(106.8)	17.7
Unrecognized net transition obligation........	--	--	92.4	101.6
Net amount recognized.........................	$ 286.9	$ 246.5	$ (859.5)	$ (714.5)
Consolidated Balance Sheets classification:				
Prepaid (accrued) benefit cost................	$ (548.6)	$ 246.5	$ (859.5)	$ (714.5)

Intangible asset............................	78.5	--	--	--
Accumulated other comprehensive loss..........	757.0	--	--	--
Net amount recognized.......................	$ 286.9	$ 246.5	$ (859.5)	$ (714.5)
Company's share of net amount recognized......	$ 18.7	$ 1.6	$ (56.2)	$ (119.1)
Assumptions used as of December 31:				
Discount rate................................	6.75%	7.25%	6.75%	7.25%
Expected long-term return on plan assets......	9.00%	10.25%	9.00%	10.25%
Rate of compensation increase................	3.50%	4.00%	3.50%	4.00%

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

	PENSION BENEFITS			O POSTRETIR	
	2002	2001	2000	2002	
			(IN MILLIONS)		
Service cost.................................	$ 58.8	$ 34.9	$ 27.4	$ 28.5	$
Interest cost................................	249.3	133.3	104.8	113.6	
Expected return on plan assets................	(346.1)	(204.8)	(181.0)	(51.7)	
Amortization of transition obligation (asset)..	--	(2.1)	(7.9)	9.2	
Amortization of prior service cost............	9.3	8.8	5.7	3.2	
Recognized net actuarial loss (gain)..........	--	--	(9.1)	11.2	
Voluntary early retirement program............	--	6.1	17.2	--	
Net periodic benefit cost (income)............	$ (28.7)	$ (23.8)	$ (42.9)	$ 114.0	$
Company's share of net benefit cost...........	$ 0.7	$ (0.7)	$ (12.7)	$ 4.4	$

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

(J) TRANSACTIONS WITH AFFILIATED COMPANIES-

Operating revenues, operating expenses and other income include transactions with affiliated companies, primarily CEI, OE, Penn, ATSI, FirstEnergy Solutions Corp. (FES) and FirstEnergy Service Company (FECO). The Ohio transition plan, as discussed in the "Regulatory Plans" section, resulted in the corporate separation of FirstEnergy's regulated and unregulated operations in 2001. Unregulated operations under FES now operate the generation businesses of the Company, CEI, OE and Penn. As a result, the Company entered into power supply agreements (PSA) whereby FES purchases all of the Company's nuclear generation and the generation from leased fossil generating facilities and the Company purchases its power from FES to meet its "provider of last resort" obligations. CFC serves as the transferor in connection with the accounts receivable securitization for the Company and CEI. The primary affiliated companies transactions, including the effects of the PSA beginning in 2001, the sale and leaseback of the Company's transmission assets to ATSI in September 2000 and FirstEnergy's providing support services at cost, are as follows:

	2002	2001	2000
		(IN MILLIONS)	
OPERATING REVENUES:			
PSA revenues with FES...........	$128.2	$180.9	$ --
Generating units rent with FES..	14.0	14.0	--
Electric sales to CEI...........	104.0	97.0	106.8
Ground lease with ATSI..........	1.7	1.7	1.9
OPERATING EXPENSES:			
Purchased power under PSA.......	319.0	388.0	--
Transmission expenses (including ATSI rent)...................	22.5	17.0	9.4
FirstEnergy support services....	26.2	23.8	36.0
OTHER INCOME:			
Interest income from ATSI.......	3.0	3.0	1.0
Interest income from FES........	9.7	9.7	--

FirstEnergy does not bill directly or allocate any of its costs to any subsidiary company. Costs are allocated to the Company from its affiliates, GPU Service, Inc. and FirstEnergy Service Company, both subsidiaries of FirstEnergy Corp. and both "mutual service companies" as defined in Rule 93 of the 1935 Public Utility Holding Company Act (PUHCA). The majority of costs are directly billed or assigned at no more than cost as determined by PUHCA Rule 91. The remaining costs are for services that are provided on behalf of more than one company, or costs that cannot be precisely identified and are allocated using formulas that are filed annually with the SEC on Form U-13-60. The current allocation or assignment formulas used and their bases include multiple factor formulas; the ratio of each company's amount of FirstEnergy's aggregate direct payroll, number of employees, asset balances, revenues, number of customers and other factors; and specific departmental charge ratios. Management believes that these allocation methods are reasonable.

The Company is selling 150 megawatts of its Beaver Valley Unit 2 leased capacity entitlement to CEI. Operating revenues for this transaction were $104.0 million, $97.0 million and $104.0 million in 2002, 2001 and 2000, respectively. This sale is expected to continue through the end of the lease period. (See Note 2.)

(K) SUPPLEMENTAL CASH FLOWS INFORMATION-

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. As of

December 31, 2002, cash and cash equivalents included $30 million used to redeem long-term debt in January 2003. Noncash financing and investing activities included capital lease transactions amounting to $1.0 million and $36.1 million in 2001 and 2000, respectively. There were no capital lease transactions in 2002.

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

	2002		2001	
	CARRYING VALUE	FAIR VALUE	CARRYING VALUE	FA VAL
	(IN MILLIONS)			
Long-term debt	$730	$772	$889	$9
Investments other than cash and cash equivalents:				
Debt securities				
- Maturity (5-10 years)	$123	$127	$123	$1
- Maturity (more than 10 years)	278	303	299	2
Equity securities	2	2	2	
All other	175	175	157	1
	$578	$607	$581	$5

The fair value of long-term debt reflects the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective year. The yields assumed were based on securities with similar characteristics offered by a corporation with credit ratings similar to the Company's ratings.

The fair value of investments other than cash and cash equivalents represent cost (which approximates fair value) or the present value of the cash inflows based on the yield to maturity. The yields assumed were based on financial instruments with similar characteristics and terms. Investments other than cash and cash equivalents include decommissioning trust investments. The Company has no securities held for trading purposes.

The investment policy for the nuclear decommissioning trust funds restricts or limits the ability to hold certain types of assets including private or direct placements, warrants, securities of the Company, investments in companies owning nuclear power plants, financial derivatives, preferred stocks, securities convertible into common stock and securities of the trust fund's custodian or managers and their parents or subsidiaries. The investments that are held in the decommissioning trusts (included as "All other" in the table above) consist of equity securities, government bonds and corporate bonds. Unrealized gains and losses applicable to the decommissioning trusts have been recognized in OCI in accordance with SFAS 115. Realized gains (losses) are recognized as additions (reductions) to trust asset balances. For the year 2002, net realized losses were approximately $5.0 million and interest and dividend income totaled approximately $5.9 million.

(L) REGULATORY ASSETS-

The Company recognizes, as regulatory assets, costs which the FERC and PUCO have authorized for recovery from customers in future periods. Without such authorization, the costs would have been charged to income as incurred. All regulatory assets will continue to be recovered from customers under the Company's transition plan. Based on that plan, the Company continues to bill and collect cost-based rates for its transmission and distribution services, which will remain regulated; accordingly, it is appropriate that the Company continues the application of SFAS 71 to those operations.

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

	2002	2001
	REVISED (SEE NOTE 1(M))	
	(IN MILLIONS)	
Regulatory transition costs.....................	$582.1	$648.1
Loss on reacquired debt.........................	3.0	3.2
Other...	(6.9)	(9.1)
Total....................................	$578.2	$642.2

(M) RESTATEMENTS-

The Company is restating its financial statements for the three years ended December 31, 2002. The primary modifications include revisions to reflect a change in the method of amortizing costs being recovered through the Ohio transition plan and recognition of above-market values of certain leased generation facilities. In addition, certain other immaterial previously unrecorded adjustments are now reflected in results for the three years ended December 31, 2002.

Transition Cost Amortization -

The Company amortizes transition costs, described in Note 1(C) above, 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, but not in the financial statements prepared under GAAP. TE has revised the amortization schedule 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 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 previously recorded regulatory assets recovered under the transition period through the end of 2007.

Above-Market Lease Costs -

In 1997, FirstEnergy Corp. was formed through a merger between OE and Centerior. The merger was accounted for as an acquisition of Centerior, the parent company of TE, under the purchase accounting rules of APB 16. In connection with the reassessment of the accounting for the transition plan, the 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, the Company has restated its financial statements to record additional adjustments associated with the 1997 merger between OE and Centerior to reflect certain above-market lease liabilities for Beaver Valley Unit 2 and the Bruce Mansfield Plant, for which TE had previously entered into sale-leaseback arrangements. The Company recorded an increase in goodwill related to the above-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 consideration would have increased goodwill at the date of the merger. The corresponding impact of the above-market lease liability for the Bruce Mansfield Plant was recorded as a regulatory asset because regulatory accounting had not been discontinued at that time for the fossil generating assets and recovery of these liabilities was provided under the Company, Regulatory Plan in effect at the time of the merger and subsequently under the transition plan.

The total above-market lease obligation of $111 million associated with Beaver Valley Unit 2 will be amortized through the end of the lease term in 2017 (approximately $5.7 million annually). The additional goodwill has been recorded effective as of the merger date, and amortization has been recorded through 2001, when goodwill amortization ceased with the adoption of SFAS 142. The total above-market lease obligation of $298 million associated with the Bruce Mansfield Plant is being amortized through the end of 2016 (approximately $18.9 million annually). 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 unamortized regulatory asset has been included in the Company's revised amortization schedule for regulatory assets and amortized through the end of the recovery period in 2007.

The Company has reflected the impact of the accounting for the above market lease obligations for the period from the merger in 1997 through 1999 as a cumulative effect adjustment of $4.3 million to retained earnings as of January 1, 2000. The after-tax effect of these items in the years ended December 31, 2002, 2001 and 2000 was as follows:

INCOME STATEMENT EFFECTS	TRANSITION COST AMORTIZATION	REVERSAL OF LEASE OBLIGATIONS(1)	TOTAL
INCREASE (DECREASE)		(IN THOUSANDS)	
Year ended December 31, 2002			
Nuclear operating expenses	$ --	$ (5,700)	$ (5,700)
Other operating expenses	--	(18,900)	(18,900)
Provision for depreciation and amortization	28,400	40,200	68,600
Income taxes	(12,559)	(6,372)	(18,931)
Total expense	$ 15,841	$ 9,228	$ 25,069

Net income effect	$(15,841)	$ (9,228)	$(25,069)
Year ended December 31, 2001			
Nuclear operating expenses	$ --	$ (5,700)	$ (5,700)
Other operating expenses	--	(18,900)	(18,900)
Provision for depreciation and amortization	13,600	33,000	46,600
Income taxes	(5,619)	(3,177)	(8,796)
Total expense	$ 7,981	$ 5,223	$ 13,204
Net income effect	$ (7,981)	$ (5,223)	$(13,204)
Year ended December 31, 2000			
Nuclear operating expenses	$ --	$ (5,700)	$ (5,700)
Other operating expenses	--	--	--
Provision for depreciation and amortization	--	1,600	1,600
Income taxes	--	2,371	2,371
Total expense	$ --	$ (1,729)	$ (1,729)
Net income effect	$ --	$ 1,729	$ 1,729

(1) The provision for depreciation and amortization in 2001 and 2000 includes goodwill amortization of $1.6 million.

In addition, the impact of the above market lease obligations increased the following balances in the consolidated balance sheet as of January 1, 2000:

	(in thousands)
Goodwill	$ 61,990
Regulatory assets	298,000
Total assets	$ 359,990
Other current liabilities	$ 24,600
Deferred income taxes	(41,059)
Other deferred credits	372,100
Total liabilities	$ 355,641
Retained earnings	$ 4,349

The net impact of the adjustments described above for the next five years is expected to reduce net income in 2003 through 2005 and increase net income in 2006 through 2007.

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 2007 (in millions).

	(IN MILLIONS)
2003...........	$ 114
2004...........	131
2005...........	151
2006...........	95
2007...........	68

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Other Unrecorded Adjustments

This restatement for the years ended December 31, 2002, 2001 and 2000 also includes adjustments that were not previously recognized that principally related to an adjustment to unbilled revenue in 2001 with a corresponding impact in 2002. The net income impact by year was $7.2 million in 2002, $(7.0) million in 2001 and $(0.8) million in 2000.

The effects of all of the changes in this restatement on the previously reported Consolidated Balance Sheet as of December 31, 2002 and 2001, and the Consolidated Statements of Income and Consolidated Statements of Cash Flows for the years ended December 31, 2002, 2001 and 2000 are as follows:

	2002		2001	
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSLY REPORTED	RE
			(IN THOUSANDS)	
CONSOLIDATED STATEMENTS OF INCOME				
OPERATING REVENUES:	$ 987,645	$ 996,045	$1,094,903	$1,
EXPENSES:				
Fuel and purchased power	366,932	366,932	457,444	
Nuclear operating costs	258,308	252,608	161,532	
Other operating costs	163,267	141,997	151,244	
Total operation and maintenance expenses	788,507	761,537	770,220	
Provision for depreciation and amortization	93,482	162,082	130,196	
General taxes	53,223	53,223	57,810	
Income taxes	(2,745)	(17,496)	31,193	
Total expenses	932,467	959,346	989,419	1,
OPERATING INCOME	55,178	36,699	105,484	
OTHER INCOME	13,329	13,329	15,652	
INCOME BEFORE NET INTEREST CHARGES	68,507	50,028	121,136	

NET INTEREST CHARGES	55,170	55,170	58,225	
NET INCOME (LOSS)	13,337	(5,142)	62,911	
PREFERRED STOCK DIVIDEND REQUIREMENT	11,356	10,756	16,135	
EARNINGS (LOSS) ON COMMON STOCK	$ 1,981	$ (15,898)	$ 46,776	$

	2002		2001	
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSLY REPORTED	R
			(IN THOUSAND	
CONSOLIDATED BALANCE SHEETS				
ASSETS				
CURRENT ASSETS	$ 129,462	$ 129,462	$ 133,833	$
PROPERTY, PLANT AND EQUIPMENT	1,031,829	1,031,829	993,152	
INVESTMENTS	579,872	579,872	584,810	
DEFERRED CHARGES:				
Regulatory assets	392,643	578,243	388,846	
Goodwill	445,732	504,522	445,732	
Other	37,686	37,686	25,745	
	876,061	1,120,451	860,323	1
	$2,617,224	$2,861,614	$2,572,118	$2
LIABILITIES AND CAPITALIZATION				
CURRENT LIABILITIES	$ 628,084	$ 653,323	$ 546,167	$
CAPITALIZATION				
Common stockholders' equity	712,931	681,195	637,665	
Preferred stock not subject to mandatory redemption	126,000	126,000	126,000	
Long-term debt	557,265	557,265	646,174	
	1,396,196	1,364,460	1,409,839	1
DEFERRED CREDITS:				
Accumulated deferred income taxes	223,087	158,279	213,145	
Accumulated deferred investment tax credits	29,491	29,255	31,342	
Nuclear plant decommissioning costs	180,856	179,587	162,426	
Other	159,510	476,710	209,199	

	592,944	843,831	616,112	--
	$2,617,224	$2,861,614	$2,572,118	$2

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CONSOLIDATED STATEMENTS OF CASH FLOWS

CASH FLOWS FROM OPERATING ACTIVITIES:				
Net Income	$ 13,337	$ (5,142)	$ 62,911	$ 4
Adjustments to reconcile net income to net cash from operating activities:				
Provision for depreciation and amortization	93,482	162,082	130,196	17
Nuclear fuel and lease amortization	11,866	11,866	22,222	2
Deferred income taxes, net	(5,868)	(24,821)	11,897	(
Investment tax credits, net	(1,851)	(1,851)	(3,832)	(
Receivables	13,564	5,164	(9,837)	(
Materials and supplies	(5,582)	(5,582)	8,336	
Accounts payable	42,501	40,801	19,744	2
Deferred rents and sale/leaseback	--	(24,600)	--	(2
Other	(5,911)	(2,379)	(51,781)	(5
Net cash provided from operating activities	$ 155,538	$ 155,538	$ 189,856	$ 18
CASH FLOWS FROM FINANCING ACTIVITIES	$ (29,299)	$ (29,299)	$ (97,828)	$ (9
CASH FLOWS FROM INVESTING ACTIVITIES	$(105,853)	$(105,853)	$ (93,111)	$ (9

2. LEASES:

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

The Company and CEI sold their ownership interests in Bruce Mansfield Units 1, 2 and 3 and the Company sold a portion of its ownership interest in Beaver Valley Unit 2. In connection with these sales, which were completed in 1987, the Company and CEI entered into operating leases for lease terms of approximately 30 years as co-lessees. During the terms of the leases, the Company and CEI continue to be responsible, to the extent of their combined ownership and leasehold interest, for costs associated with the units including construction expenditures, operation and maintenance expenses, insurance, nuclear fuel, property taxes and decommissioning. The Company and CEI have the right, at the end of the respective basic lease terms, to renew the leases. The Company and CEI also have the right to purchase the facilities at the expiration of the basic lease term or any renewal term at a price equal to the fair market value of the facilities.

As co-lessee with CEI, the Company is also obligated for CEI's lease payments. If CEI is unable to make its payments under the Bruce Mansfield Plant lease, the Company would be obligated to make such payments. No such payments have been made on behalf of CEI. (CEI's future minimum lease payments as of December 31, 2002 were approximately $0.2 billion, net of trust cash receipts.)

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

	2002	2001	2000
	(IN MILLIONS)		
Operating leases			
Interest element..............	$ 52.6	$ 55.7	$ 58.7
Other.........................	58.6	52.4	46.2
Capital leases			
Interest element..............	--	2.5	3.9
Other.........................	0.3	14.1	24.1
Total rentals.................	$111.5	$124.7	$132.9

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

	OPERATING LEASES		
	LEASE PAYMENTS	CAPITAL TRUST	NET
	(IN MILLIONS)		
2003..................................	$ 111.7	$ 36.6	$ 75.1
2004..................................	97.9	24.6	73.3
2005..................................	104.8	25.3	79.5
2006..................................	107.8	26.0	81.8
2007..................................	99.2	22.6	76.6
Years thereafter......................	908.7	228.2	680.5
Total minimum lease payments...........	$1,430.1	$ 363.3	$1,066.8

The Company and CEI refinanced high-cost fixed obligations related to their 1987 sale and leaseback transaction for the Bruce Mansfield Plant through a lower cost transaction in June and July 1997. In a June 1997 offering (Offering), the two companies pledged $720 million aggregate principal amount ($145 million for the Company and $575 million for CEI) of first mortgage bonds due through 2007 to a trust as security for the issuance of a like principal amount of secured notes due through 2007. The obligations of the two companies under these secured notes are joint and several. Using available cash, short-term borrowings and the net proceeds from the Offering, the two companies invested $906.5 million ($337.1 million for the Company and $569.4 million for CEI) in a business trust, in June 1997. The trust used these funds in July 1997 to purchase lease notes and redeem all $873.2 million aggregate principal amount of 10-1/4% and 11-1/8% secured lease obligations bonds (SLOBs) due 2003 and 2016. The SLOBs were issued by a special-purpose funding corporation in 1988 on behalf of lessors in the two companies' 1987 sale and leaseback transaction. The Shippingport Capital Trust arrangement effectively reduces lease costs related to that transaction.

3. CAPITALIZATION:

(A) RETAINED EARNINGS-

The Company has a provision in its mortgage that requires common stock dividends to be paid out of its total balance of retained earnings.

(B) STOCK COMPENSATION PLANS-

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

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

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

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

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

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

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

STOCK OPTION ACTIVITIES	NUMBER OF OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE
Balance, January 1, 2000..............	2,153,369	$25.32
(159,755 options exercisable)..........		24.87
Options granted.....................	3,011,584	23.24
Options exercised...................	90,491	26.00
Options forfeited...................	52,600	22.20
Balance, December 31, 2000...........	5,021,862	24.09
(473,314 options exercisable)..........		24.11
Options granted.....................	4,240,273	28.11
Options exercised...................	694,403	24.24
Options forfeited...................	120,044	28.07
Balance, December 31, 2001............	8,447,688	26.04
(1,828,341 options exercisable)........		24.83
Options granted.....................	3,399,579	34.48
Options exercised...................	1,018,852	23.56
Options forfeited...................	392,929	28.19
Balance, December 31, 2002...........	10,435,486	28.95
(1,400,206 options exercisable)........		26.07

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

No material stock-based employee compensation expense is reflected in net income for stock options granted under the above plans since the exercise price was equal to the market value of the underlying common stock on the grant date. The effect of applying fair value accounting to FirstEnergy's stock options is summarized in Note 1G - "Stock-Based Compensation."

(C) PREFERRED AND PREFERENCE STOCK-

Preferred stock may be redeemed by the Company in whole, or in part, with 30-90 days' notice.

The preferred dividend rates on the Company's Series A and Series B shares fluctuate based on prevailing interest rates and market conditions. The dividend rates for both issues averaged 7% in 2002.

The Company has five million authorized and unissued shares of $25 par value preference stock.

(D) LONG-TERM DEBT-

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

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

	(IN MILLIONS)
2003................................	$189.4
2004................................	268.7
2005................................	31.6
2006................................	--
2007................................	30.0

Included in the table above are amounts for various variable interest rate long-term debt which have provisions by which individual debt holders have the option to "put back" or require the respective debt issuer to redeem their debt at those times when the interest rate may change prior to its maturity date. These amounts are $73 million, $54 million and $32 million in 2003, 2004 and 2005, respectively, which represents the next date at which the debt holders may exercise this provision.

The Company's obligations to repay certain pollution control revenue bonds are secured by several series of first mortgage bonds. Certain pollution control revenue bonds are entitled to the benefit of irrevocable bank letters of

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credit of $68.0 million and a noncancelable municipal bond insurance policy of $51.1 million to pay principal of, or interest on, the pollution control revenue bonds. To the extent that drawings are made under the letters of credit or policy, the Company is entitled to a credit against its obligation to repay those bonds. The Company pays an annual fee of 1.00% of the amounts of the letters of credit to the issuing bank and is obligated to reimburse the bank for any drawings thereunder.

The Company and CEI have unsecured letters of credit of approximately $215.9 million in connection with the sale and leaseback of Beaver Valley Unit 2 that expire in April 2005. The Company and CEI are jointly and severally liable for the letters of credit (see Note 2).

(E) COMPREHENSIVE INCOME-

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholder's equity except those resulting from transactions with FirstEnergy. As of December 31, 2002, accumulated other comprehensive loss consisted of a minimum liability for unfunded retirement benefits of $21.1 million and unrealized gains of $1.1 million.

4. SHORT-TERM -BORROWINGS:

The Company may borrow from its affiliates on a short-term basis. As of December 31, 2002, the Company had total short-term borrowings of $149.7 million from its affiliates. The average interest rate on short-term borrowings outstanding as of December 31, 2002 and 2001, were 1.8% and 3.6%, respectively.

5. COMMITMENTS AND CONTINGENCIES:

(A) CAPITAL EXPENDITURES-

The Company's current forecast reflects expenditures of approximately $169 million for property additions and improvements from 2003-2007, of which approximately $54 million is applicable to 2003. Investments for additional nuclear fuel during the 2003-2007 period are estimated to be approximately $34 million, of which approximately $12 million applies to 2003. During the same periods, the Company's nuclear fuel investments are expected to be reduced by approximately $40 million and $19 million, respectively, as the nuclear fuel is consumed.

(B) NUCLEAR INSURANCE-

The Price-Anderson Act limits the public liability relative to a single incident at a nuclear power plant to $9.5 billion. The amount is covered by a combination of private insurance and an industry retrospective rating plan. Based on its ownership and leasehold interests in Beaver Valley Unit 2, the Davis Besse Station and the Perry Plant, the Company's maximum potential assessment under the industry retrospective rating plan (assuming the other affiliate co-owners contribute their proportionate shares of any assessments under the retrospective rating plan) would be $77.9 million per incident but not more than $8.8 million in any one year for each incident.

The Company is also insured as to its respective interests in Beaver Valley Unit 2, Davis-Besse and Perry under policies issued to the operating company for each plant. Under these policies, up to $2.75 billion is provided for property damage and decontamination and decommissioning costs. The Company has also obtained approximately $263.4 million of insurance coverage for replacement power costs for its respective interests in Beaver Valley Unit 2, Davis-Besse and Perry. Under these policies, the Company can be assessed a maximum of approximately $14.6 million for incidents at any covered nuclear facility occurring during a policy year which are in excess of accumulated funds available to the insurer for paying losses.

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

(C) ENVIRONMENTAL MATTERS-

Various federal, state and local authorities regulate the Company with regard to air and water quality and other environmental matters. In accordance with the Ohio transition plan discussed in "Regulatory Plans" in Note 1, generation operations and any related additional capital expenditures for environmental compliance are the responsibility of FirstEnergy's competitive services business unit.

The Company is required to meet federally approved sulfur dioxide (SO_2) regulations. Violations of such regulations can result in shutdown of the generating unit involved and/or civil or criminal penalties of up to $31,500 for each day the unit is in violation. The Environmental Protection Agency (EPA) has an interim enforcement policy for SO_2 regulations in Ohio that allows for compliance based on a 30-day averaging period. The Company cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The Company believes it is in compliance with the current SO_2 and nitrogen oxides (NO_x) reduction requirements under the Clean Air Act Amendments of 1990. SO_2 reductions are being achieved by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NO_x reductions are being achieved through combustion controls and the generation of more electricity at lower-emitting plants. In September 1998, the EPA finalized regulations requiring additional NO_x reductions from the Company's Ohio and Pennsylvania facilities. The EPA's NO_x Transport Rule imposes uniform reductions of NO_x emissions (an approximate 85% reduction in utility plant NO_x emissions from projected 2007 emissions) across a region of nineteen states and the District of Columbia, including Ohio and Pennsylvania, based on a conclusion that such NO_x emissions are contributing significantly to ozone pollution in the eastern United States. State Implementation Plans (SIP) must comply by May 31, 2004 with individual state NO_x budgets established by the EPA. Pennsylvania submitted a SIP that requires compliance with the NO_x budgets at the Company's Pennsylvania facilities by May 1, 2003 and Ohio submitted a SIP that requires compliance with the NO_x budgets at the Company's Ohio facilities by May 31, 2004.

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

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. On April 25, 2000, the EPA announced that it will develop national standards regulating disposal of coal ash under its authority to regulate nonhazardous waste.

The Company has been named as a "potentially responsible party" (PRP) 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 Company's proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay. The Company has total accrued liabilities aggregating approximately $0.2 million as of December 31, 2002.

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

(D) OTHER LEGAL PROCEEDINGS-

Various lawsuits, claims and proceedings related to the Company's normal business operations are pending against FirstEnergy and its subsidiaries. The most significant applicable to the Company are described above.

6. SALE OF GENERATING ASSETS:

In November 2001, FirstEnergy reached an agreement to sell four coal-fired power plants totaling 2,535 MW to NRG Energy Inc. The proposed sale had included the 648 MW Bay Shore Plant owned by the Company. On

August 8, 2002, FirstEnergy notified NRG that it was canceling the agreement because NRG stated that it could not complete the transaction under the original terms of the agreement. FirstEnergy also notified NRG that FirstEnergy reserves the right to pursue legal action against NRG, its affiliate and its parent, Xcel Energy, for damages, based on the anticipatory breach of the agreement. On February 25, 2003, the U.S. Bankruptcy Court in Minnesota approved FirstEnergy's request for arbitration against NRG.

In December 2002, FirstEnergy decided to retain ownership of these plants after reviewing other bids it subsequently received from other parties who had expressed interest in purchasing the plants. Since FirstEnergy did not execute a sales agreement by year-end, the Company reflected approximately $13 million ($8 million net of tax) of previously unrecognized depreciation and other transaction costs in the fourth quarter of 2002 related to these plants from November 2001 through December 2002 on its Consolidated Statement of Income.

7. RECENTLY ISSUED ACCOUNTING STANDARDS:

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

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

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

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

TE currently has transactions 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. TE currently consolidates the majority of these entities and believes it will continue to consolidate following the adoption of FIN 46. One of these entities TE is currently consolidating is the Shippingport Capital Trust, which reacquired a portion of the off-balance sheet debt issued in connection with the sale and leaseback of its interest in the Bruce Mansfield Plant. Ownership of the trust includes a 4.85 percent interest by nonaffiliated parties and a 0.34 percent equity interest by Toledo Edison Capital Corp., a majority owned subsidiary.

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 (TE's third quarter of 2003) for all other financial instruments.

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

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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. TE is currently assessing the new EITF consensus and has not yet determined the impact on its financial position or results of operations following adoption.

8. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED):

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

THREE MONTHS ENDED	MARCH 31, 2002(a)		JUNE 30, 2002(a)		SEPTEMBER 30,
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSLY REPORTED
				(IN MILLIONS)	
Operating Revenues	$ 244.1	$ 252.6	$ 250.3	$ 250.3	$ 269.9
Operating Expenses and Taxes	234.5	241.9	216.2	222.7	244.8
Operating Income (Loss)	9.6	10.7	34.1	27.6	25.1
Other Income	4.4	4.3	3.7	3.7	4.0
Net Interest Charges	14.7	14.7	14.8	14.9	14.5
Net Income (Loss)	$ (0.7)	$ 0.3	$ 23.0	$ 16.4	$ 14.6
Earnings (Loss) Applicable to Common Stock	$ (5.4)	$ (4.4)	$ 20.8	$ 14.3	$ 12.4

THREE MONTHS ENDED	MARCH 31, 2001(a)		JUNE 30, 2001(a)		SEPTEMBER 30, 2	
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSLY REPORTED	R

(IN MILLIONS, EXCEPT PER SHARE AMOUNT

Operating Revenues	$ 271.6	$ 271.6	$ 263.0	$ 263.0	$ 306.5	$
Operating Expenses and Taxes	243.3	246.6	229.6	232.9	278.9	
Operating Income	28.3	25.0	33.4	30.1	27.6	
Other Income	3.8	3.8	2.2	2.2	3.9	
Net Interest Charges	15.9	15.9	12.6	12.6	15.1	
Net Income (Loss)	$ 16.2	$ 12.9	$ 23.0	$ 19.7	$ 16.4	$
Earnings on common Stock	$ 12.2	$ 8.9	$ 18.9	$ 15.6	$ 12.4	$

(a) See Note 1(M) for discussion of restated financial data. The changes are principally based on the impact of the revised transition cost amortization and above market rates. In addition, the other adjustments discussed in Note 1(M) increased (decreased) net income for the quarterly periods as follows: (in millions)

	2002	2001
March 31......................	6.9	--
December 31...................	0.3	(7.0)

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PART IV

3. EXHIBITS - COMMON EXHIBITS TO CEI AND TE

EXHIBIT NUMBER		
2(a)	--	Agreement and Plan of Merger between Ohio Edison and Centerior Energy dated as of September 13, 1996 (Exhibit (2)-1, Form S-4 File No. 333-21011, filed by FirstEnergy).
2(b)	--	Merger Agreement by and among Centerior Acquisition Corp., FirstEnergy and Centerior (Exhibit (2)-3, Form S-4 File No. 333-21011, filed by FirstEnergy).
4(a)	--	Rights Agreement (Exhibit 4, June 25, 1996 Form 8-K, File Nos. 1-9130, 1-2323 and 1-3583).
4(b)(1)	--	Form of Note Indenture between Cleveland Electric, Toledo Edison and The Chase Manhattan Bank, as Trustee dated as of June 13, 1997 (Exhibit 4(c), Form S-4 File No. 333-35931, filed by Cleveland Electric and Toledo Edison).
4(b)(2)	--	Form of First Supplemental Note Indenture between Cleveland Electric, Toledo Edison and The Chase Manhattan Bank, as Trustee dated as of June 13, 1997 (Exhibit 4(d), Form S-4 File No. 333-35931, filed by Cleveland Electric and Toledo Edison).
10b(1)(a)	--	CAPCO Administration Agreement dated November 1, 1971, as of

		September 14, 1967, among the CAPCO Group members regarding the organization and procedures for implementing the objectives of the CAPCO Group (Exhibit 5(p), Amendment No. 1, File No. 2-42230, filed by Cleveland Electric).
10b(1)(b)	--	Amendment No. 1, dated January 4, 1974, to CAPCO Administration Agreement among the CAPCO Group members (Exhibit 5(c)(3), File No. 2-68906, filed by Ohio Edison).
10b(2)	--	CAPCO Transmission Facilities Agreement dated November 1, 1971, as of September 14, 1967, among the CAPCO Group members regarding the installation, operation and maintenance of transmission facilities to carry out the objectives of the CAPCO Group (Exhibit 5(q), Amendment No. 1, File No. 2-42230, filed by Cleveland Electric).
10b(2)(1)	--	Amendment No. 1 to CAPCO Transmission Facilities Agreement, dated December 23, 1993 and effective as of January 1, 1993, among the CAPCO Group members regarding requirements for payment of invoices at specified times, for payment of interest on non-timely paid invoices, for restricting adjustment of invoices after a four-year period, and for revising the method for computing the Investment Responsibility charge for use of a member's transmission facilities (Exhibit 10b(2)(1), 1993 Form 10-K, File Nos. 1-9130, 1-2323 and 1-3583).
10b(3)	--	CAPCO Basic Operating Agreement As Amended January 1, 1993 among the CAPCO Group members regarding coordinated operation of the members' systems (Exhibit 10b(3), 1993 Form 10-K, File Nos. 1-9130, 1-2323 and 1-3583).
10b(4)	--	Agreement for the Termination or Construction of Certain Agreement By and Among the CAPCO Group members, dated December 23, 1993 and effective as of September 1, 1980 (Exhibit 10b(4), 1993 Form 10-K, File Nos. 1-9130, 1-2323 and 1-3583).
10b(5)	--	Construction Agreement, dated July 22, 1974, among the CAPCO Group members and relating to the Perry Nuclear Plant (Exhibit 5 (yy), File No. 2-52251, filed by Toledo Edison).
10b(6)	--	Contract, dated as of December 5, 1975, among the CAPCO Group members for the construction of Beaver Valley Unit No. 2 (Exhibit 5 (g), File No. 2-52996, filed by Cleveland Electric).
10b(7)	--	Amendment No. 1, dated May 1, 1977, to Contract, dated as of December 5, 1975, among the CAPCO Group members for the construction of Beaver Valley Unit No. 2 (Exhibit 5(d)(4), File No. 2-60109, filed by Ohio Edison).

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10d(1)(a)	--	Form of Collateral Trust Indenture among CTC Beaver Valley Funding Corporation, Cleveland Electric, Toledo Edison and Irving Trust Company, as Trustee (Exhibit 4(a), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(1)(b)	--	Form of Supplemental Indenture to Collateral Trust Indenture constituting Exhibit 10d(1)(a) above, including form of

Secured Lease Obligation bond (Exhibit 4(b), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).

10d(1)(c) -- Form of Collateral Trust Indenture among Beaver Valley II Funding Corporation, The Cleveland Electric Illuminating Company and The Toledo Edison Company and The Bank of New York, as Trustee (Exhibit (4)(a), File No. 33-46665, filed by Cleveland Electric and Toledo Edison).

10d(1)(d) -- Form of Supplemental Indenture to Collateral Trust Indenture constituting Exhibit 10d(1)(c) above, including form of Secured Lease Obligation Bond (Exhibit (4)(b), File No. 33-46665, filed by Cleveland Electric and Toledo Edison).

10d(2)(a) -- Form of Collateral Trust Indenture among CTC Mansfield Funding Corporation, Cleveland Electric, Toledo Edison and IBJ Schroder Bank & Trust Company, as Trustee (Exhibit 4(a), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).

10d(2)(b) -- Form of Supplemental Indenture to Collateral Trust Indenture constituting Exhibit 10d(2)(a) above, including forms of Secured Lease Obligation bonds (Exhibit 4(b), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).

10d(3)(a) -- Form of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, Lessor, and Cleveland Electric and Toledo Edison, Lessee (Exhibit 4(c), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).

10d(3)(b) -- Form of Amendment No. 1 to Facility Lease constituting Exhibit 10d(3)(a) above (Exhibit 4(e), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).

10d(4)(a) -- Form of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the corporate Owner Participant named therein, Lessor, and Cleveland Electric and Toledo Edison, Lessees (Exhibit 4(d), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).

10d(4)(b) -- Form of Amendment No. 1 to Facility Lease constituting Exhibit 10d(4)(a) above (Exhibit 4(f), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).

10d(5)(a) -- Form of Facility Lease dated as of September 30, 1987 between Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Lessor, and Cleveland Electric and Toledo Edison, Lessees (Exhibit 4(c), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).

10d(5)(b) -- Form of Amendment No. 1 to the Facility Lease constituting Exhibit 10d(5)(a) above (Exhibit 4(f), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).

10d(6)(a) -- Form of Participation Agreement dated as of September 15, 1987 among the limited partnership Owner Participant named therein, the Original Loan Participants listed in Schedule 1 thereto, as Original Loan Participants, CTC Beaver Valley Fund Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee, and Cleveland Electric and Toledo Edison, as Lessees (Exhibit 28(a), File No. 33-18755, filed by Cleveland Electric And Toledo Edison).

10d(6)(b)	--	Form of Amendment No. 1 to Participation Agreement constituting Exhibit 10d(6)(a) above (Exhibit 28(c), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(7)(a)	--	Form of Participation Agreement dated as of September 15, 1987 among the corporate Owner Participant named therein, the Original Loan Participants listed in Schedule 1 thereto, as Owner Loan Participants, CTC Beaver Valley Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee, and

Cleveland Electric and Toledo Edison, as Lessees (Exhibit 28(b), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).

10d(7)(b)	--	Form of Amendment No. 1 to Participation Agreement constituting Exhibit 10d(7)(a) above (Exhibit 28(d), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(8)(a)	--	Form of Participation Agreement dated as of September 30, 1987 among the Owner Participant named therein, the Original Loan Participants listed in Schedule II thereto, as Owner Loan Participants, CTC Mansfield Funding Corporation, Meridian Trust Company, as Owner Trustee, IBJ Schroder Bank & Trust Company, as Indenture Trustee, and Cleveland Electric and Toledo Edison, as Lessees (Exhibit 28(a), File No. 33-0128, filed by Cleveland Electric and Toledo Edison).
10d(8)(b)	--	Form of Amendment No. 1 to the Participation Agreement constituting Exhibit 10d(8)(a) above (Exhibit 28(b), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(9)	--	Form of Ground Lease dated as of September 15, 1987 between Toledo Edison, Ground Lessor, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the Owner Participant named therein, Tenant (Exhibit 28(e), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(10)	--	Form of Site Lease dated as of September 30, 1987 between Toledo Edison, Lessor, and Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Tenant (Exhibit 28(c), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(11)	--	Form of Site Lease dated as of September 30, 1987 between

Cleveland Electric, Lessor, and Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Tenant (Exhibit 28(d), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).

10d(12)	--	Form of Amendment No. 1 to the Site Leases constituting Exhibits 10d(10) and 10d(11) above (Exhibit 4(f), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(13)	--	Form of Assignment, Assumption and Further Agreement dated as of September 15, 1987 among The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the Owner Participant named therein, Cleveland Electric, Duquesne, Ohio Edison, Pennsylvania Power and Toledo Edison (Exhibit 28(f), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(14)	--	Form of Additional Support Agreement dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the Owner Participant named therein, and Toledo Edison (Exhibit 28(g), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(15)	--	Form of Support Agreement dated as of September 30, 1987 between Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Toledo Edison, Cleveland Electric, Duquesne, Ohio Edison and Pennsylvania Power (Exhibit 28(e), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(16)	--	Form of Indenture, Bill of Sale, Instrument of Transfer and Severance Agreement dated as of September 30, 1987 between Toledo Edison, Seller, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the Owner Participant named therein, Buyer (Exhibit 28(h), File No. 33-18755, filed by Cleveland Electric and Toledo Edison).
10d(17)	--	Form of Bill of Sale, Instrument of Transfer and Severance Agreement dated as of September 30, 1987 between Toledo Edison, Seller, and Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Buyer (Exhibit 28(f), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).

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10d(18)	--	Form of Bill of Sale, Instrument of Transfer and Severance Agreement dated as of September 30, 1987 between Cleveland Electric, Seller, and Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Buyer (Exhibit 28(g), File No. 33-20128, filed by Cleveland Electric and Toledo Edison).
10d(19)	--	Forms of Refinancing Agreement, including exhibits thereto, among the Owner Participant named therein, as Owner

		Participant, CTC Beaver Valley Funding Corporation, as Funding Corporation, Beaver Valley II Funding Corporation, as New Funding Corporation, The Bank of New York, as Indenture Trustee, The Bank of New York, as New Collateral Trust Trustee, and The Cleveland Electric Illuminating Company and The Toledo Edison Company, as Lessees (Exhibit (28)(e)(i), File No. 33-46665, filed by Cleveland Electric and Toledo Edison).
10d(20)(a)	--	Form of Amendment No. 2 to Facility Lease among Citicorp Lescaman, Inc., Cleveland Electric and Toledo Edison (Exhibit 10(a), Form S-4 File No. 333-47651, filed by Cleveland Electric).
10d(20)(b)	--	Form of Amendment No. 3 to Facility Lease among Citicorp Lescaman, Inc., Cleveland Electric and Toledo Edison (Exhibit 10(b), Form S-4 File No. 333-47651, filed by Cleveland Electric).
10d(21)(a)	--	Form of Amendment No. 2 to Facility Lease among US West Financial Services, Inc., Cleveland Electric and Toledo Edison (Exhibit 10(c), Form S-4 File No. 333-47651, filed by Cleveland Electric).
10d(21)(b)	--	Form of Amendment No. 3 to Facility Lease among US West Financial Services, Inc., Cleveland Electric and Toledo Edison (Exhibit 10(d), Form S-4 File No. 333-47651, filed by Cleveland Electric).
10d(22)	--	Form of Amendment No. 2 to Facility Lease among Midwest Power Company, Cleveland Electric and Toledo Edison (Exhibit 10(e), Form S-4 File No. 333-47651, filed by Cleveland Electric).
10e(1)	--	Centerior Energy Corporation Equity Compensation Plan (Exhibit 99, Form S-8, File No. 33-59635).

3. EXHIBITS - TOLEDO EDISON (TE)

EXHIBIT NUMBER		
3a	--	Amended Articles of Incorporation of TE, as amended effective October 2, 1992 (Exhibit 3a, 1992 Form 10-K, File No. 1-3583).
3b	--	Amended and Restated Code of Regulations, dated March 15, 2002. (2001 Form 10-K, Exhibit 3b)
(B)4b(1)	--	Indenture, dated as of April 1, 1947, between TE and The Chase National Bank of the City of New York (now The Chase Manhattan Bank (National Association)) (Exhibit 2(b), File No. 2-26908).
4b(2)	--	September 1, 1948 (Exhibit 2(d), File No. 2-26908).
4b(3)	--	April 1, 1949 (Exhibit 2(e), File No. 2-26908).
4b(4)	--	December 1, 1950 (Exhibit 2(f), File No. 2-26908).
4b(5)	--	March 1, 1954 (Exhibit 2(g), File No. 2-26908).

4b(6)	--	February 1, 1956 (Exhibit 2(h), File No. 2-26908).
4b(7)	--	May 1, 1958 (Exhibit 5(g), File No. 2-59794).
4b(8)	--	August 1, 1967 (Exhibit 2(c), File No. 2-26908).
4b(9)	--	November 1, 1970 (Exhibit 2(c), File No. 2-38569).
4b(10)	--	August 1, 1972 (Exhibit 2(c), File No. 2-44873).
4b(11)	--	November 1, 1973 (Exhibit 2(c), File No. 2-49428).
4b(12)	--	July 1, 1974 (Exhibit 2(c), File No. 2-51429).
4b(13)	--	October 1, 1975 (Exhibit 2(c), File No. 2-54627).
4b(14)	--	June 1, 1976 (Exhibit 2(c), File No. 2-56396).
4b(15)	--	October 1, 1978 (Exhibit 2(c), File No. 2-62568).

4b(16)	--	September 1, 1979 (Exhibit 2(c), File No. 2-65350).
4b(17)	--	September 1, 1980 (Exhibit 4(s), File No. 2-69190).
4b(18)	--	October 1, 1980 (Exhibit 4(c), File No. 2-69190).
4b(19)	--	April 1, 1981 (Exhibit 4(c), File No. 2-71580).
4b(20)	--	November 1, 1981 (Exhibit 4(c), File No. 2-74485).
4b(21)	--	June 1, 1982 (Exhibit 4(c), File No. 2-77763).
4b(22)	--	September 1, 1982 (Exhibit 4(x), File No. 2-87323).
4b(23)	--	April 1, 1983 (Exhibit 4(c), March 31, 1983, Form 10-Q, File No. 1-3583).
4b(24)	--	December 1, 1983 (Exhibit 4(x), 1983 Form 10-K, File No. 1-3583).
4b(25)	--	April 1, 1984 (Exhibit 4(c), File No. 2-90059).
4b(26)	--	October 15, 1984 (Exhibit 4(z), 1984 Form 10-K, File No. 1-3583).
4b(27)	--	October 15, 1984 (Exhibit 4(aa), 1984 Form 10-K, File No. 1-3583).
4b(28)	--	August 1, 1985 (Exhibit 4(dd), File No. 33-1689).
4b(29)	--	August 1, 1985 (Exhibit 4(ee), File No. 33-1689).
4b(30)	--	December 1, 1985 (Exhibit 4(c), File No. 33-1689).
4b(31)	--	March 1, 1986 (Exhibit 4b(31), 1986 Form 10-K, File No. 1-3583).
4b(32)	--	October 15, 1987 (Exhibit 4, September 30, 1987 Form 10-Q, File No. 1-3583).

4b(33)	--	September 15, 1988 (Exhibit 4b(33), 1988 Form 10-K, File No. 1-3583).
4b(34)	--	June 15, 1989 (Exhibit 4b(34), 1989 Form 10-K, File No. 1-3583).
4b(35)	--	October 15, 1989 (Exhibit 4b(35), 1989 Form 10-K, File No. 1-3583).
4b(36)	--	May 15, 1990 (Exhibit 4, June 30, 1990 Form 10-Q, File No. 1-3583).
4b(37)	--	March 1, 1991 (Exhibit 4(b), June 30, 1991 Form 10-Q, File No. 1-3583).
4b(38)	--	May 1, 1992 (Exhibit 4(a)(3), File No. 33-48844).
4b(39)	--	August 1, 1992 (Exhibit 4b(39), 1992 Form 10-K, File No. 1-3583).
4b(40)	--	October 1, 1992 (Exhibit 4b(40), 1992 Form 10-K, File No. 1-3583).
4b(41)	--	January 1, 1993 (Exhibit 4b(41), 1992 Form 10-K, File No. 1-3583).
4b(42)	--	September 15, 1994 (Exhibit 4(b), September 30, 1994 Form 10-Q, File No. 1-3583).
4b(43)	--	May 1, 1995 (Exhibit 4(d), September 30, 1995 Form 10-Q, File No. 1-3583).
4b(44)	--	June 1, 1995 (Exhibit 4(e), September 30, 1995 Form 10-Q, File No. 1-3583).
4b(45)	--	July 14, 1995 (Exhibit 4(f), September 30, 1995 Form 10-Q, File No. 1-3583).
4b(46)	--	July 15, 1995 (Exhibit 4(g), September 30, 1995 Form 10-Q, File No. 1-3583).
4b(47)	--	August 1, 1997 (Exhibit 4b(47), 1998 Form 10-K, File No. 1-3583).
4b(48)	--	June 1, 1998 (Exhibit 4b (48), 1998 Form 10-K, File No. 1-3583).
4b(49)	--	January 15, 2000 (Exhibit 4b(49), 1999 Form 10-K, File No. 1-3583).
4b(50)	--	May 1, 2000 (Exhibit 4b(50), 2000 Form 10-K, File No. 1-3583).
4b(51)	--	September 1, 2000
4b(52)	--	October 1, 2002
* 12.4	--	Consolidated fixed charge ratios.
* 13.3	--	TE 2002 Annual Report to Stockholders. (Only those portions expressly incorporated by reference in this Form 10-K/A are

to be deemed "filed" with the SEC.)

	21.3	--	List of Subsidiaries of the Registrant at December 31, 2002.
*	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 therewith.

REPORTS ON FORM 8-K

TE

TE filed fourteen 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 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. 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. A report dated April 16, 2003 reported updated Davis-Besse information. 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. A report dated June 5, 2003 reported updated Davis Besse information. A report dated July 24, 2003, reported updates to the schedule and cost estimates for Davis Besse. 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 September 12, 2003 reported that FE, OE, CEI and TE have received an informal data request from the Securities and Exchange Commission related to the recent restatement of their 2002 financial statements.

REPORT OF INDEPENDENT AUDITORS ON
FINANCIAL STATEMENT SCHEDULES

To the Stockholders and Board of Directors of The Toledo Edison Company:

Our audits of the consolidated financial statements referred to in our report dated August 18, 2003 appearing in the restated 2002 Annual Report to Shareholders of The Toledo Edison Company (which report and consolidated financial statements are incorporated by reference in this Form 10-K/A) also included an audit of the financial statement schedules listed in Item 15(a)(2) of this Form 10-K/A. In our opinion, these financial statement schedules present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP
Cleveland, Ohio
August 18, 2003

SIGNATURES

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

THE TOLEDO EDISON COMPANY

Registrant

/s/ Harvey L. Wagner

Harvey L. Wagner
Vice President and Controller
Chief Accounting Officer

Date: September 24, 2003