CLEVELAND ELECTRIC ILLUMINATING CO
Form 10-Q
August 19, 2003

FORM 10-Q

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549

(MARK ONE)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2003

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.
333-21011	FIRSTENERGY CORP. (AN OHIO CORPORATION) 76 SOUTH MAIN STREET AKRON, OH 44308 TELEPHONE (800)736-3402	34-1843785
1-2578	OHIO EDISON COMPANY (AN OHIO CORPORATION) 76 SOUTH MAIN STREET AKRON, OH 44308 TELEPHONE (800)736-3402	34-0437786
1-2323	THE CLEVELAND ELECTRIC ILLUMINATING COMPANY (AN OHIO CORPORATION) C/O FIRSTENERGY CORP. 76 SOUTH MAIN STREET AKRON, OH 44308 TELEPHONE (800)736-3402	34-0150020
1-3583	THE TOLEDO EDISON COMPANY (AN OHIO CORPORATION) C/O FIRSTENERGY CORP. 76 SOUTH MAIN STREET AKRON, OH 44308 TELEPHONE (800)736-3402	34-4375005
1-3491	PENNSYLVANIA POWER COMPANY (A PENNSYLVANIA CORPORATION) C/O FIRSTENERGY CORP. 76 SOUTH MAIN STREET AKRON, OH 44308 TELEPHONE (800)736-3402	25-0718810

1-3141	JERSEY CENTRAL POWER & LIGHT COMPANY (A NEW JERSEY CORPORATION) C/O FIRSTENERGY CORP. 76 SOUTH MAIN STREET AKRON, OH 44308 TELEPHONE (800)736-3402	21-0485010
1-446	METROPOLITAN EDISON COMPANY (A PENNSYLVANIA CORPORATION) C/O FIRSTENERGY CORP. 76 SOUTH MAIN STREET AKRON, OH 44308 TELEPHONE (800)736-3402	23-0870160
1-3522	PENNSYLVANIA ELECTRIC COMPANY (A PENNSYLVANIA CORPORATION) C/O FIRSTENERGY CORP. 76 SOUTH MAIN STREET AKRON, OH 44308 TELEPHONE (800)736-3402	25-0718085

Indicate by check mark whether each of the registrants (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 whether each registrant is an accelerated filer (as defined in Rule 12b-2 of the Act):

Yes [X]   No [ ]

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

CLASS	OUTSTANDING AS OF AUGUST 8, 2003
FirstEnergy Corp., $.10 par value	297,636,276
Ohio Edison Company, no par value	100
The Cleveland Electric Illuminating Company, no par value	79,590,689
The Toledo Edison Company, $5 par value	39,133,887
Pennsylvania Power Company, $30 par value	6,290,000
Jersey Central Power & Light Company, $10 par value	15,371,270
Metropolitan Edison Company, no par value	859,500
Pennsylvania Electric Company, $20 par value	5,290,596

FirstEnergy Corp. is the sole holder of Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company common stock. Ohio Edison Company is the sole holder of Pennsylvania Power Company common stock.

This combined Form 10-Q is separately filed by FirstEnergy Corp., Ohio Edison Company, Pennsylvania Power Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. No registrant makes any representation as to information relating to any other registrant, except that information relating to any of the FirstEnergy subsidiary registrants is also attributed to FirstEnergy.

This Form 10-Q 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.

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NOTES TO FINANCIAL STATEMENTS
(UNAUDITED)

1 - FINANCIAL STATEMENTS:

The principal business of FirstEnergy Corp. (FirstEnergy) is the holding, directly or indirectly, of all of the outstanding common stock of its eight principal electric utility operating subsidiaries, Ohio Edison Company (OE), The Cleveland Electric Illuminating Company (CEI), The Toledo Edison Company (TE), Pennsylvania Power Company (Penn), American Transmission Systems, Inc. (ATSI), Jersey Central Power & Light Company (JCP&L), Metropolitan Edison Company (Met-Ed) and Pennsylvania Electric Company (Penelec). These utility subsidiaries are referred to throughout as "Companies." Penn is a wholly owned subsidiary of OE. JCP&L, Met-Ed and Penelec were acquired in a merger (which was effective November 7, 2001) with GPU, Inc., the former parent company of JCP&L, Met-Ed and Penelec. The merger was accounted for by the purchase method of accounting and the applicable effects were reflected on the financial statements of JCP&L, Met-Ed and Penelec as of the merger date. FirstEnergy's consolidated financial statements also include its other principal subsidiaries: FirstEnergy Solutions Corp. (FES); FirstEnergy Facilities Services Group, LLC (FSG); MYR Group, Inc.; MARBEL Energy Corporation; FirstEnergy Nuclear Operating Company (FENOC); GPU Capital, Inc.; GPU Power, Inc.; and FirstEnergy Service Company (FESC). FES provides energy-related products and services and, through its FirstEnergy Generation Corp. (FGCO) subsidiary, operates FirstEnergy's nonnuclear generation business. FENOC operates the Companies' nuclear generating facilities. FSG is the parent company of several heating, ventilating, air conditioning and energy management companies, and MYR is a utility infrastructure construction service company. MARBEL holds FirstEnergy's interest in Great Lakes Energy Partners, LLC. GPU Capital owns and operates electric distribution systems in foreign countries (see Note 3) and GPU Power owns and operates generation facilities in foreign countries. FESC provides legal, financial and other corporate support services to affiliated FirstEnergy companies. Significant intercompany transactions have been eliminated.

The Companies follow the accounting policies and practices prescribed by the Securities and Exchange Commission (SEC), the Public Utilities Commission of Ohio (PUCO), the Pennsylvania Public Utility Commission (PPUC), the New Jersey Board of Public Utilities (NJBPU) and the Federal Energy Regulatory Commission (FERC). The condensed unaudited financial statements of FirstEnergy and each of the Companies reflect all normal recurring adjustments that, in the opinion of management, are necessary to fairly present results of operations for the interim periods. These statements should be read in conjunction with the financial statements and notes included in the combined Annual Report on Form 10-K, as amended where applicable, for the year ended December 31, 2002 for FirstEnergy and the Companies. 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 disclosure of contingent assets and liabilities. Actual results could differ from those estimates. The reported results of operations are not indicative of results of operations for any future period. Certain prior year amounts have been reclassified to conform with the current year presentation, as discussed further in Note 5, as well as restated as discussed below.

Preferred Securities

The sole assets of the CEI subsidiary trust that is the obligor on the preferred securities included in FirstEnergy's and CEI's Capitalizations are $103.1 million aggregate principal amount of 9% junior subordinated debentures of CEI due December 31, 2006. CEI has effectively provided a full and unconditional guarantee of the trust's obligations under the preferred securities.

Met-Ed and Penelec each formed statutory business trusts for the issuance of $100 million each of preferred securities due 2039 and included in FirstEnergy's, Met-Ed's and Penelec's respective capitalizations. Ownership of the respective Met-Ed and Penelec trusts is through separate wholly-owned limited partnerships, of which a wholly-owned subsidiary of each company is the sole general partner. In these transactions, the sole assets and sources of revenues of

each trust are the preferred securities of the applicable limited partnership, whose sole assets are the 7.35% and 7.34% subordinated debentures (aggregate principal amount of $103.1 million each) of Met-Ed and Penelec, respectively. In each case, the applicable parent company has effectively provided a full and unconditional guarantee of the trust's obligations under the preferred securities.

Securitized Transition Bonds

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

JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on each of FirstEnergy's and JCP&L's Consolidated Balance Sheet. The transition bonds represent obligations only of the Issuer and are collateralized solely by the equity and assets of the Issuer, which consist primarily of bondable transition property. The bondable transition property is solely the property of the Issuer.

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

Pension and Other Postretirement Benefits

As a result of GPU Service Inc. merging with FESC in the second quarter of 2003, operating company employees of GPU Service were transferred to JCP&L, Met-Ed and Penelec. Accordingly, FirstEnergy requested an actuarial study to update the pension and other post-employment benefit (OPEB) assets and liabilities for each of its subsidiaries. Based on the actuary's report, the accrued pension and OPEB costs for FirstEnergy and its subsidiaries as of June 30, 2003 increased (decreased) by the following amounts:

	PENSION	OPEB
	(In thousands)	
OE	$ 50,937	$ 48,775
CEI	(16,699)	(49,526)
TE	(3,439)	(24,476)
Penn	15,851	9,751
JCP&L	78,549	86,333
Met-Ed	47,219	59,405
Penelec	70,693	87,314
Other subsidiaries	(243,111)	(217,576)
Total FirstEnergy	$ --	$ --

The corresponding adjustment related to these changes increased (decreased) other comprehensive income, deferred income taxes and receivables from/to associated companies in the respective operating company's financial statements.

Derivative Accounting

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

FirstEnergy uses derivatives to hedge the risk of price and interest rate fluctuations. FirstEnergy's primary ongoing hedging activity involves cash flow hedges of electricity and natural gas purchases. The maximum periods over which the variability of electricity and natural gas cash flows are hedged are two and three years, respectively. Gains and losses from hedges of commodity price risks are included in net income when the underlying hedged commodities are delivered. Also, gains and losses are included in net income when ineffectiveness occurs on certain natural gas hedges. FirstEnergy entered into interest rate derivative transactions during 2001 to hedge a portion of the anticipated interest

payments on debt related to the GPU acquisition. Gains and losses from hedges of anticipated interest payments on acquisition debt will be included in net income over the periods that hedged interest payments are made - 5, 10 and 30 years.

Gains and losses from derivative contracts are included in other operating expenses. The current net deferred loss of $110.8 million included in Accumulated Other Comprehensive Loss (AOCL) as of June 30, 2003, for derivative hedging activity, as compared to the March 31, 2003 balance of $105.8 million in net deferred losses, resulted from a $7.7 million reduction related to current hedging activity and a $12.7 million increase due to net hedge gains included in earnings during the three months ended June 30, 2003. Approximately $25.3 million (after tax) of the current net deferred loss on derivative instruments in AOCL is expected to be reclassified to earnings during the next twelve months as hedged transactions occur. However, the fair value of these derivative instruments will fluctuate from period to period based on various market factors and will generally be more than offset by the margin on related sales and revenues.

FirstEnergy also entered into fixed-to-floating interest rate swap agreements during 2002 and 2003 to increase the variable-rate component of its debt portfolio. These derivatives are treated as fair value hedges of fixed-rate, long-term debt issues protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. Swap maturities, call options and interest payment dates match those of the underlying obligations resulting in no ineffectiveness in these hedge positions. The swap agreements consummated in the second quarter of 2003 are based on a notional principal amount of $200 million. As of June 30, 2003, the notional amount of FirstEnergy's fixed-for-floating rate interest rate swaps totaled $550 million.

Comprehensive Income

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholders' equity, except those resulting from transactions with common stockholders. As of June 30, 2003, FirstEnergy's AOCL was approximately $534.1 million as compared to the December 31, 2002 balance of $656.1 million. A reconciliation of net income to comprehensive income for the three months and six months ended June 30, 2003 and 2002, is shown below:

	THREE MONTHS ENDED JUNE 30,		SIX
	2003	2002	2003
		RESTATED (SEE NOTE 1)	RESTATE (SEE NOTE
	(IN THOUSANDS)		(IN
Net income (loss)................................	$(57,888)	$207,898	$160,51
Other comprehensive income, net of tax:			
Derivative hedge transactions..................	(4,917)	535	(57
Currency transactions (1)......................	89,790	--	91,46
Available for sale securities..................	38,454	(2,140)	38,26
Comprehensive income............................	$ 65,439	$206,293	$289,66

(1) See Note 3 - International Operations (Emdersa Abandonment).

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. No material stock-based employee compensation expense is reflected in net income as all options granted under those plans have exercise prices equal to the market value of the underlying common stock on the respective grant dates, 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 effects of applying fair value accounting to FirstEnergy's stock options would be reductions to net income and earnings per share. The following table summarizes those effects.

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	THREE MONTHS ENDED JUNE 30,		SIX
	2003	2002	2003
		RESTATED (SEE NOTE 1)	RESTATE (SEE NOTE
	(IN THOUSANDS)		(IN
Net income (loss), as reported	$(57,588)	$207,898	$160,51
Add back compensation expense reported in net income, net of tax (based on APB 25)	49	44	9
Deduct compensation expense based upon estimated fair value, net of tax	(3,731)	(2,556)	(6,71
Adjusted net income (loss)	$(61,270)	$205,386	$153,89
Earnings (Loss) Per Share of Common Stock -			
Basic			
As Reported	$ (0.20)	$ 0.74	$ 0.5
Adjusted	$ (0.21)	$ 0.73	$ 0.5
Diluted			
As Reported	$ (0.20)	$ 0.73	$ 0.5
Adjusted	$ (0.21)	$ 0.72	$ 0.5

Changes in Previously Reported Income Statement Classifications

FirstEnergy recorded an increase to income during the first quarter of 2002 of $31.7 million (net of income taxes of $13.6 million) relative to a decision to retain an interest in the Avon Energy Partners Holdings (Avon) business previously classified as held for sale - see Note 3. This amount represents the aggregate results of operations of Avon for the period this business was held for sale. It was previously reported on the Consolidated Statement of Income as the cumulative effect of a change in accounting. In April 2003, it was determined that this amount should instead have been classified in operations. As further discussed in Note 3, the decision to retain Avon was made in the first quarter of 2002 and Avon's results of operations for that quarter have been classified in their respective revenue and expense captions on the Consolidated Statement of Income. This change in classification had no effect on previously reported net income. The effects of this change on the Consolidated Statement of Income previously reported for the six months ended June 30, 2002 are reflected in the restatements shown below.

As a result of FirstEnergy's divestiture of its ownership in GPU Empresa Distribuidora Electrica Regional S.A. and affiliates (Emdersa) in April 2003 through the abandonment of its shares in the parent company of the Argentina operation (as further described in Note 3), FirstEnergy recorded a $67.4 million charge in the second quarter of 2003 on the Consolidated Statement of Income as "Discontinued Operations". This divestiture caused Emdersa's first quarter 2003 net income of approximately $6.9 million, which had been previously classified in its respective revenues and expense captions on the Consolidated Statement of Income, to be also reclassified as Discontinued Operations. Accordingly, Emdersa's Discontinued Operations reflect a $60.5 million net loss for the six months ended June 30, 2003 which included $6.9 million of after-tax earnings from the Argentina operation from the first quarter of 2003 - previously reported as $10.7 million of revenue, $0.1 million of expenses and $3.7 million of income taxes.

The following table summarizes Emdersa's major assets and liabilities included in FirstEnergy's Consolidated Balance Sheet as of December 31, 2002:

	(IN THOUSANDS)
ASSETS ABANDONED:	
Current Assets	$ 17,344
Property, plant and equipment	61,980
Other	8,737
Total Assets	$ 88,061
LIABILITIES RELATED TO ASSETS ABANDONED:	
Current Liabilities	$ 12,777
Long-term debt	100,202
Other	10,548
Total Liabilities	$ 123,527

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RESTATEMENTS OF PREVIOUSLY REPORTED RESULTS

FirstEnergy, OE, CEI and TE have restated their financial statements for the year ended December 31, 2002; for the three months ended March 31, 2003 and 2002; the six months ended June 30, 2003 and the three and six months ended June 30, 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 adjustments recorded in the first quarter of 2003 that related to 2002 are now reported in results for the earlier periods. The net impact of these adjustments decreased net income by $6.2 million in the first quarter of 2003. Included in the adjustments are the impact in the first and second quarters of 2003 of recognizing revenue on the deferred costs incurred subsequent to the merger associated with this Company's rate matter in Pennsylvania (see Note 4). The impact of this restatement increased net income in the first quarter, 2002 by $12 million and decreased net income in the second quarter 2002 by $8 million. See note 2(M) of the FirstEnergy, OE, CEI and TE Form 10-K/A for further discussion of the restatements. Since the results for the quarter ended March 31, 2003 have been restated as discussed above and the results of operations for the six months ended June 30, 2003 reflect these restated results, the June 30, 2003 amounts are restated.

Transition Cost Amortization

As discussed in Regulatory Matters in Note 4, FirstEnergy, OE, CEI and TE amortize transition costs using the effective interest method. The amortization schedules originally developed at the beginning of the transition plan in 2001 in applying this method were based on total transition revenues, including revenues designed to recover costs which have not yet been incurred or that were recognized on the regulatory financial statements (fair value purchase accounting adjustments) but not in the financial statements prepared under GAAP. The Ohio electric utilities have 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 in the first several years of the transition cost recovery period, compared with the method previously applied. The change in method results in no change in total amortization of the regulatory assets recovered under the transition plan through the end of 2009. The following table summarizes the previously reported transition cost amortization and the restated amounts under the revised method for the three months and six months ended June 30, 2002:

	THREE MONTHS ENDED JUNE 30, 2002		SIX MO JUNE
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSL REPORTED
	(IN THOUSANDS)		
OE....................................	$75,026	$ 82,326	$151,202
CEI...................................	11,655	36,455	24,796
TE....................................	6,325	23,925	14,217
Total FirstEnergy..................	$93,006	$142,706	$190,215

Above-Market Lease Costs

In 1997, FirstEnergy was formed through a merger between OE and Centerior Energy Corp. The merger was accounted for as an acquisition of Centerior, the parent company of CEI and TE, under the purchase accounting rules of Accounting Principles Board (APB) Opinion No. 16. In connection with the reassessment of the accounting for the transition plan, FirstEnergy reassessed its accounting for the Centerior purchase and determined that above market lease liabilities should have been recorded at the time of the merger. Accordingly, as of 2002, FirstEnergy recorded 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 CEI and TE had previously entered into sale-leaseback arrangements. CEI and TE 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 liability would have increased goodwill at the date of the merger. The corresponding impact of the above market lease liabilities for the Bruce Mansfield Plant were recorded as regulatory assets because regulatory accounting had not been discontinued at that time for the fossil generating assets and recovery of these liabilities was provided for under the transition plan.

The total above market lease obligation of $722 million (CEI - $611 million; TE - $111 million) associated with Beaver Valley Unit 2 will be amortized through the end of the lease term in 2017. The additional goodwill has been recorded on a net basis, reflecting amortization that would have been recorded through 2001 when goodwill amortization ceased with the adoption of SFAS No. 142. The total above market lease obligation of $755 million (CEI - $457 million, TE - $298 million) associated with the Bruce Mansfield Plant is being amortized through the end of 2016. Before the start of the transition plan in 2001, the regulatory asset would have been amortized at the same rate as the lease obligation. Beginning in 2001, the remaining unamortized regulatory asset would have been included in CEI's and TE's amortization schedules for regulatory assets and amortized through the end of the recovery period - approximately 2009 for CEI and 2007 for TE.

The effects of these changes on the Consolidated Statement of Income previously reported for the three months ended March 31, 2003, were disclosed in Amendment No. 1 on Form 10-Q/A for the quarter ended March 31, 2003. The effects of these changes on the Consolidated Statements of Income previously reported for the three months and six months ended June 30, 2002 are as follows:

FIRSTENERGY

	THREE MONTHS ENDED JUNE 30, 2002		SIX M JUN
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSL REPORTED
	(IN THOUSANDS, EXCEPT PER SHARE AMOU		
Revenues	$2,898,573	$2,898,573	$ 5,751,851
Expenses	2,230,409	2,272,659	4,594,043
Income before interest and income taxes	668,164	625,914	1,157,808
Net interest charges	250,282	250,282	529,004
Income taxes	184,572	167,734	279,001
Net income	$ 233,310	$ 207,898	$ 349,803
Basic earnings per share of common stock	$ .80	$ .71	$ 1.19
Diluted earnings per share of common stock	$ .79	$ .71	$ 1.19

OE

	THREE MONTHS ENDED JUNE 30, 2002		SIX MO JUNE
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSL REPORTED
		(IN THOUSANDS)	
Operating revenues	$744,550	$744,550	$1,452,349
Operating expenses and taxes	605,946	611,069	1,216,681
Operating income	138,604	133,481	235,668
Other income	15,087	15,087	15,599
Net interest charges	35,856	35,856	77,081
Net income	117,835	112,712	174,186
Preferred stock dividend requirements	2,597	2,597	5,193
Earnings on common stock	$115,238	$110,115	$ 168,993

CEI

	THREE MONTHS ENDED JUNE 30, 2002		SIX MO JUNE
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSL REPORTED
		(IN THOUSANDS)	
Operating revenues	$462,874	$462,874	$ 887,851
Operating expenses and taxes	350,120	355,799	719,775
Operating income	112,754	107,075	168,076
Other income	3,356	3,356	8,597
Net interest charges	46,750	46,750	94,617
Net income	69,360	63,681	82,056
Preferred stock dividend requirements	3,054	3,054	11,310
Earnings on common stock	$ 66,306	$ 60,627	$ 70,746

TE

	THREE MONTHS ENDED JUNE 30, 2002		SIX M JUNE
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSL REPORTED
		(IN THOUSANDS)	
Operating revenues	$ 250,307	$250,307	$ 494,474
Operating expenses and taxes	216,148	222,658	450,657

Operating income	34,159	27,649	43,817
Other income	3,743	3,743	8,086
Net interest charges	14,859	14,859	29,568
Net income	23,043	16,533	22,335
Preferred stock dividend requirements	2,210	2,210	6,934
Earnings on common stock	$ 20,833	$ 14,323	$ 15,401

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The effects of these changes on net cash provided from operating activities on the Consolidated Statement of Cash Flows previously reported for the three months ended March 31, 2003, were disclosed in Amendment No. 1 on Form 10-Q/A for the quarter ended March 31, 2003. The effects of these changes on the Consolidated Statements of Cash Flows previously reported for the three months and six months ended June 30, 2002 are as follows:

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	THREE MONTHS ENDED JUNE 30, 2002		SIX M JUN
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSL REPORTED
		(IN THOUSANDS)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 233,310	$ 207,898	$ 349,803
Adjustments to reconcile net income to net cash from operating activities:			
Provision for depreciation and amortization	250,705	300,405	513,533
Nuclear fuel and lease amortization	19,598	19,598	40,563
Other amortization	(4,386)	(4,386)	(7,923)
Deferred costs recoverable as regulatory assets	(68,936)	(55,136)	(139,070)
Deferred income taxes	50,355	33,517	43,421
Investment tax credits	(6,967)	(6,967)	(13,713)
Cumulative effect of accounting change (Note 5)	--	--	(45,300)
Receivables	(150,157)	(150,157)	(83,567)
Materials and supplies	(21,742)	(21,742)	(3,579)
Accounts payable	47,766	47,766	37,774
Accrued taxes	4,422	4,422	86,719
Accrued interest	(106,136)	(106,136)	(19,557)
Deferred rents & sale/leaseback	(121,642)	(142,892)	(50,204)
Prepayments & other	(128,937)	(128,937)	(19,386)
Other	264,870	264,870	36,693
Net cash provided from operating schedules	$ 262,123	$ 262,123	$ 726,207

OE

	THREE MONTHS ENDED JUNE 30, 2002		SIX MO JUNE
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSL REPORTED
	(IN THOUSANDS)		
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$117,835	$112,712	$174,186
Adjustments to reconcile net income to net cash from operating activities:			
Provision for depreciation and amortization	91,521	98,821	183,651
Nuclear fuel and lease amortization	12,133	12,133	23,535
Deferred income taxes	(8,886)	(11,386)	(22,056)
Investment tax credits	(3,762)	(3,439)	(7,535)
Receivables	(31,345)	(31,345)	32,803
Materials and supplies	(3,158)	(3,158)	(4,800)
Accounts payable	(1,166)	(1,166)	(19,461)
Accrued taxes	149,376	149,376	206,260
Accrued interest	(8,200)	(8,200)	(1,963)
Deferred rents & sale/leaseback	(31,865)	(31,865)	(182)
Prepayments & other	15,178	15,178	31,273
Other	(4,232)	(4,232)	(34,771)
Net cash provided from operating schedules	$293,429	$293,429	$560,940

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CEI

	THREE MONTHS ENDED JUNE 30, 2002		SIX MO JUNE
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSL REPORTED
	(IN THOUSANDS)		
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 69,360	$ 63,681	$ 82,056
Adjustments to reconcile net income to net cash from operating activities:			
Provision for depreciation and amortization	28,333	53,133	56,804
Nuclear fuel and lease amortization	4,794	4,794	10,784
Other amortization	(4,275)	(4,275)	(8,167)
Deferred income taxes	5,904	2,084	13,100
Investment tax credits	(1,129)	(1,270)	(2,031)
Receivables	(38,473)	(38,473)	(31,657)
Materials and supplies	(1,840)	(1,840)	(3,206)
Accounts payable	8,057	8,057	26,379

Other	(27,779)	(42,879)	(13,588)
Net cash provided from operating schedules	$ 42,952	$ 42,952	$130,474

TE

	THREE MONTHS ENDED JUNE 30, 2002		SIX MO JUNE
	AS PREVIOUSLY REPORTED	AS RESTATED	AS PREVIOUSL REPORTED
	(IN THOUSANDS)		
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 23,043	$ 16,533	$ 22,335
Adjustments to reconcile net income to net cash from operating activities:			
Provision for depreciation and amortization	19,748	37,348	41,116
Nuclear fuel and lease amortization	2,671	2,671	6,244
Deferred income taxes	578	(4,322)	5,892
Investment tax credits	(487)	(527)	(973)
Receivables	(18,762)	(18,762)	1,260
Materials and supplies	(1,169)	(1,169)	(1,820)
Accounts payable	(9,210)	(9,210)	(6,349)
Other	(40,885)	(47,035)	(26,413)
Net cash provided from operating activities	$(24,473)	$(24,473)	$ 41,292

2 - COMMITMENTS, GUARANTEES AND CONTINGENCIES:

Capital Expenditures

FirstEnergy's current forecast reflects expenditures of approximately $3.1 billion (OE-$268 million, CEI-$312 million, TE-$169 million, Penn-$123 million, JCP&L-$462 million, Met-Ed-$288 million, Penelec-$328 million, ATSI-$131 million, FES-$823 million and other subsidiaries-$147 million) for property additions and improvements from 2003-2007, of which approximately $733 million (OE-$85 million, CEI-$99 million, TE-$56 million, Penn-$53 million, JCP&L-$112 million, Met-Ed-$51 million, Penelec-$49 million, ATSI-$25 million, FES-$124 million and other subsidiaries-$79 million) is applicable to 2003. Investments for additional nuclear fuel during the 2003-2007 period are estimated to be approximately $481 million (OE-$59 million, CEI-$51 million, TE-$31 million, Penn-$39 million and FES-$301 million), of which approximately $76 million (OE-$28 million, CEI-$17 million, TE-$12 million and Penn-$19 million) applies to 2003.

Guarantees and Other Assurances

As part of normal business activities, FirstEnergy enters into various agreements on behalf of its subsidiaries to provide financial or performance assurances to third parties. Such agreements include contract guarantees, surety bonds and ratings contingent collateralization provisions. As of June 30, 2003, outstanding guarantees and other assurances aggregated $1.050

billion.

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy marketing activities - principally to facilitate normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of subsidiary financing principally for the acquisition of property, plant and equipment. These agreements legally obligate FirstEnergy and its subsidiaries to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financing where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, FirstEnergy's guarantee enables the counterparty's legal claim to be satisfied by other FirstEnergy assets. The likelihood that such parental guarantees of $918.2 million as of June 30, 2003 will increase amounts otherwise to be paid by FirstEnergy to meet its obligations incurred in connection with financings and ongoing energy and energy-related activities is remote.

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related FirstEnergy guarantees of $24.5 million provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction jobs, environmental commitments and various retail transactions.

Various energy supply contracts contain credit enhancement provisions in the form of cash collateral or letters of credit in the event of a reduction in credit rating below investment grade. These provisions vary and typically require more than one rating reduction to fall below investment grade by Standard & Poor's or Moody's Investors Service to trigger additional collateralization by FirstEnergy. As of June 30, 2003, rating-contingent collateralization totaled $106.8 million. FirstEnergy monitors these collateralization provisions and updates its total exposure monthly.

Environmental Matters

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

The Companies are required to meet federally approved sulfur dioxide (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 Companies cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The Companies believe they are in compliance with the current 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 Companies' Ohio and Pennsylvania facilities. The EPA's NO_x

Transport Rule imposes uniform reductions of NOx emissions (an approximate 85% reduction in utility plant NOx emissions from projected 2007 emissions) across a region of nineteen states and the District of Columbia, including New Jersey, Ohio and Pennsylvania, based on a conclusion that such NOx emissions are contributing significantly to ozone pollution in the eastern United States. State Implementation Plans (SIP) must comply by May 31, 2004 with individual state NOx budgets established by the EPA. Pennsylvania submitted a SIP that required compliance with the NOx budgets at the Companies' Pennsylvania facilities by May 1, 2003 and Ohio submitted a SIP that requires compliance with the NOx budgets at the Companies' Ohio facilities by May 31, 2004.

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

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In 1999 and 2000, the EPA issued Notices of Violation (NOV) or a Compliance Order to nine utilities covering 44 power plants, including the W. H. Sammis Plant. In addition, the U.S. Department of Justice filed eight civil complaints against various investor-owned utilities, which included a complaint against OE and Penn in the U.S. District Court for the Southern District of Ohio. The NOV and complaint allege violations of the Clean Air Act based on operation and maintenance of the Sammis Plant dating back to 1984. The complaint requests permanent injunctive relief to require the installation of "best available control technology" and civil penalties of up to $27,500 per day of violation. On August 7, the United States District Court for the Southern District of Ohio ruled that 11 projects undertaken at the Sammis Plant between 1984 and 1998 required pre-construction permits under the Clean Air Act. The ruling concludes the liability phase of the case, which deals with applicability of Prevention of Significant Deterioration provisions of the Clean Air Act. The remedy phase, which is currently scheduled to be ready for trial beginning March 15, 2004, will address civil penalties and what, if any, actions should be taken to further reduce emissions at the plant. In the ruling, the Court indicated that the remedies it "may consider and impose involved a much broader, equitable analysis, requiring the Court to consider air quality, public health, economic impact, and employment consequences. The Court may also consider the less than consistent efforts of the EPA to apply and further enforce the Clean Air Act." The potential penalties that may be imposed, as well as the capital expenditures necessary to comply with substantive remedial measures they may be required, may have a material adverse impact on the Company's financial condition and results of operations. Management is unable to predict the ultimate outcome of this matter.

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

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

The Companies have been named as "potentially responsible parties" (PRPs) at waste disposal sites which may require cleanup under the Comprehensive Environmental Response, Compensation and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site be held liable on a joint and several basis. Therefore, potential environmental liabilities have been recognized on the Consolidated Balance Sheet as of June 30, 2003, based on estimates of the total costs of cleanup, the Companies' proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay. In addition, JCP&L has accrued liabilities for environmental remediation of former manufactured gas plants in New Jersey; those costs are being recovered by JCP&L through a non-bypassable societal benefits charge. The Companies have total accrued liabilities aggregating approximately $53.8 million (JCP&L-$47.1 million, CEI-$2.5 million, TE-$0.2 million, Met-Ed-$0.2 million, Penelec-$0.3 million and other-$3.5 million) as of June 30, 2003.

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

Other Commitments and Contingencies

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

EI Barranquilla, a wholly owned subsidiary of GPU Power, is a 28.67% equity investor in Termobarranquilla S.A., Empresa de Servicios Publicos (TEBSA), which owns a Colombian independent power generation project. GPU Power is committed through September 30, 2003, under certain circumstances, to make additional standby equity contributions to TEBSA of $21.3 million, which FirstEnergy has guaranteed. The total outstanding senior debt of the TEBSA project is $226 million as of June 30, 2003. The lenders include the Overseas Private Investment Corporation, US Export Import Bank and a commercial bank syndicate. FirstEnergy has also guaranteed the obligations of the operators of the TEBSA project, up to a maximum of $6.0 million (subject to escalation) under the project's operations and maintenance agreement. FirstEnergy provided the TEBSA project lenders a $50 million letter of credit (LOC) (under FirstEnergy's existing $250 million LOC capacity available as part of a $1.5 billion FirstEnergy credit facility) to obtain TEBSA lender consent as substitute collateral for the release of the assets for FirstEnergy to abandon its Argentina operations, Emdersa (see Note 3 below).

Power Outage

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

As of August 18, 2003, the following facts about FirstEnergy's system were known. Early in the afternoon of August 14, hours before the event, Unit 5 of the Eastlake Plant in Eastlake, Ohio tripped off. Later in the afternoon, three FirstEnergy transmission lines and one owned by American Electric Power and FirstEnergy tripped out of service. The Midwest Independent System Operator (MISO), which oversees the regional transmission grid, indicated that there were a number of other transmission line trips in the region outside of FirstEnergy's system. FirstEnergy customers experienced no service interruptions resulting from these conditions. Indications to FirstEnergy were that the Company's system was stable. Therefore, no isolation of FirstEnergy's system was called for. In addition, FirstEnergy determined that its computerized system for monitoring and controlling its transmission and generation system was operating, but the alarm screen function was not. However, MISO's monitoring system was operating properly. FirstEnergy believes that extensive data needs to be gathered and analyzed in order to determine with any degree of certainty the circumstances that led to the outage. This is a very complex situation, far broader than the power line outages FirstEnergy experienced on its system. From the preliminary data that has been gathered, FirstEnergy believes that the transmission grid in the Eastern Interconnection, not just within FirstEnergy's system, was experiencing unusual electrical conditions at various times prior to the event. These included unusual voltage and frequency fluctuations and load swings on the grid. FirstEnergy is committed to working with the North American Electric Reliability Council and others involved to determine exactly what events in the entire affected region led to the outage. There is no timetable as to when this entire process will be completed. It is, however, expected to last several weeks, at a minimum.

Legal Matters

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

Various lawsuits, claims and proceedings related to FirstEnergy's normal business operations are pending against it, the most significant of which are described herein.

3 - DIVESTITURES:

INTERNATIONAL OPERATIONS-

FirstEnergy had identified certain former GPU international operations for divestiture within one year of the merger. These operations constitute individual "lines of business" as defined in APB Opinion (APB) No. 30, "Reporting the Results of Operations - Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions," with physically and operationally separable activities. Application of Emerging Issues Task Force (EITF) Issue No. 87-11, "Allocation of Purchase Price to Assets to Be Sold," required that expected, pre-sale cash flows, including incremental interest costs on related acquisition debt, of these operations be considered part of the purchase price allocation. Accordingly, subsequent to the merger date, results of operations and incremental interest costs related to these international subsidiaries were not included in FirstEnergy's 2001 Consolidated Statement of Income. Additionally, assets and liabilities of these international operations had been segregated under separate captions on the Consolidated Balance Sheet as of December 31, 2001 as "Assets Pending Sale" and "Liabilities Related to Assets Pending Sale."

Upon completion of its merger with GPU, FirstEnergy accepted an October 2001 offer from Aquila, Inc. (formerly UtiliCorp United) to purchase Avon, FirstEnergy's wholly owned holding company for Midlands Electricity plc, for $2.1 billion (including the assumption of $1.7 billion of debt). The transaction closed on May 8, 2002 and reflected the March 2002 modification of Aquila's initial offer such that Aquila acquired a 79.9 percent equity interest in Avon for approximately $1.9 billion (including the assumption of $1.7 billion of debt). Proceeds to FirstEnergy included $155 million in cash and a note receivable for approximately $87 million (representing the present value of $19 million per year to be received over six years beginning in 2003) from Aquila for its 79.9 percent interest. FirstEnergy and Aquila together

own all of the outstanding shares of Avon through a jointly owned subsidiary, with each company having an ownership voting interest. Originally, in accordance with applicable accounting guidance, the earnings of those foreign operations were not recognized in current earnings from the date of the GPU acquisition. However, as a result of the decision to retain an ownership interest in Avon in the quarter ended March 31, 2002, EITF Issue No. 90-6, "Accounting for Certain Events Not Addressed in Issue No. 87-11 relating to an Acquired Operating Unit to be Sold" required FirstEnergy to reallocate the purchase price of GPU based on amounts as of the purchase date as if Avon had never been held for sale, including reversal of the effects of having applied EITF Issue No. 87-11, to the transaction. The effect of reallocating the purchase price and reversal of the effects of EITF Issue No. 87-11, including the allocation of capitalized interest, has been reflected in the Consolidated Statement of Income for the six months ended June 30, 2002 by reclassifying certain revenue and expense amounts related to activity during the quarter ended March 31, 2002 to their respective income statement classifications for the six-month 2002 period. See Note 1 for the effects of the change in classification. In the fourth quarter of 2002, FirstEnergy recorded a $50 million charge ($32.5 million net of tax) to reduce the carrying value of its remaining 20.1 percent interest.

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

GPU's former Argentina operations were also identified by FirstEnergy for divestiture within one year of the merger. FirstEnergy determined the fair value of Emdersa, based on the best available information as of the date of the merger. Subsequent to that date, a number of economic events occurred in Argentina which affected FirstEnergy's ability to realize Emdersa's estimated fair value. These events included currency devaluation, restrictions on repatriation of cash, and the anticipation of future asset sales in that region by competitors. FirstEnergy did not reach a definitive agreement to sell Emdersa as of December 31, 2002. Therefore, these assets were no longer classified as "Assets Pending Sale" on the Consolidated Balance Sheet as of December 31, 2002. Additionally, under EITF Issue No. 90-6, FirstEnergy recorded in the fourth quarter of 2002 a one-time, non-cash charge included as a "Cumulative Adjustment for Retained Businesses Previously Held for Sale" on its 2002 Consolidated Statement of Income related to Emdersa's cumulative results of operations from November 7, 2001 through September 30, 2002. The amount of this one-time, after-tax charge was $93.7 million, or $0.32 per share of common stock (comprised of $108.9 million in currency transaction losses arising principally from U.S. dollar denominated debt, offset by $15.2 million of operating income).

In October 2002, FirstEnergy began consolidating the results of Emdersa's operations in its financial statements. In addition to the currency transaction losses of $108.9 million, FirstEnergy also recognized a currency translation adjustment (CTA) in other comprehensive income (OCI) of $91.5 million as of December 31, 2002, which reduced FirstEnergy's common stockholders' equity. This adjustment represented the impact of translating Emdersa's financial statements from its functional currency to the U.S. dollar for GAAP financial reporting.

On April 18, 2003, FirstEnergy divested its ownership in Emdersa through the abandonment of its shares in Emdersa's parent company, GPU Argentina Holdings, Inc. The abandonment was accomplished by relinquishing FirstEnergy's shares to the independent Board of Directors of GPU Argentina Holdings, relieving FirstEnergy of all rights and obligations relative to this business. As a result of the abandonment, FirstEnergy recognized a one-time, non-cash charge of $67.4 million, or $0.23 per share of common stock in the second quarter of 2003. This charge is the result of realizing the CTA losses through current period earnings ($89.8 million, or $0.30 per share), partially offset by the gain recognized from abandoning FirstEnergy's investment in Emdersa ($22.4 million, or $0.07 per share). Since FirstEnergy had previously recorded $89.8 million of CTA adjustments in OCI, the net effect of the $67.4 million charge was an increase in common stockholders' equity of $22.4 million.

The $67.4 million charge does not include the anticipated income tax benefits related to the abandonment, which were fully reserved during the second quarter. FirstEnergy anticipates tax benefits of approximately $129 million, of which $50 million would increase net income in the period that it becomes probable those benefits will be realized. The remaining $79 million of tax benefits would reduce goodwill recognized in connection with the acquisition of GPU.

SALE OF GENERATING ASSETS-

In November 2001, FirstEnergy reached an agreement to sell four coal-fired power plants totaling 2,535 megawatts (MW) to NRG Energy Inc. On August 8, 2002, FirstEnergy notified NRG that it was canceling the agreement because NRG stated that it could not complete the transaction under the original terms of the agreement. FirstEnergy also notified NRG that FirstEnergy reserves the right to pursue legal action against NRG, its affiliate and its parent, Xcel

Energy for damages, based on the anticipatory breach of the agreement. On February 25, 2003, the U.S. Bankruptcy Court in Minnesota approved FirstEnergy's request for arbitration against NRG. The arbitration hearing is scheduled for the week of February 23, 2004.

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

4 - REGULATORY MATTERS:

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

- allowing the Companies' electric customers to select their generation suppliers;

- establishing provider of last resort (PLR) obligations to customers in the Companies' service areas;

- allowing recovery of potentially stranded investment (sometimes referred to as transition costs);

- itemizing (unbundling) the current price of electricity into its component elements - including generation, transmission, distribution and stranded costs recovery charges;

- deregulating the Companies' electric generation businesses; and

- continuing regulation of the Companies' transmission and distribution systems.

Ohio

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

In July 2000, the PUCO approved FirstEnergy's transition plan for OE, CEI and TE (Ohio Companies) as modified by a settlement agreement with major parties to the transition plan. The application of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" to OE's generation business and the nonnuclear generation businesses of CEI and TE was discontinued with the issuance of the PUCO transition plan order, as described further below. Major provisions of the settlement agreement consisted of approval of recovery of generation-related transition costs as filed of $4.0 billion net of deferred income taxes (OE-$1.6 billion, CEI-$1.6 billion and TE-$0.8 billion) and transition costs related to regulatory assets as filed of $2.9 billion net of deferred income taxes (OE-$1.0 billion, CEI-$1.4 billion and TE-$0.5 billion), with recovery through no later than 2006 for OE, mid-2007 for TE and 2008 for CEI, except where a longer period of recovery is provided for in the settlement agreement. The generation-related transition costs include $1.4 billion, net of deferred income taxes, (OE-$1.0 billion, CEI-$0.2 billion and TE-$0.2 billion) of impaired generating assets recognized as regulatory assets as described further below, $2.4 billion, net of deferred income taxes, (OE-$1.2 billion, CEI-$0.4 billion and TE-$0.8 billion) of above market operating lease costs and $0.8 billion, net of deferred income taxes, (CEI-$0.5 billion and TE-$0.3 billion) of additional plant costs that were reflected on CEI's and TE's regulatory financial statements.

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

FirstEnergy's Ohio customers choosing alternative suppliers receive an additional incentive applied to the shopping credit (generation component) of 45% for residential customers, 30% for commercial customers and 15% for

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

New Jersey

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

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

JCP&L's PLR obligation to provide basic generation service (BGS) to non-shopping customers is supplied almost entirely from contracted and open market purchases. JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers and costs incurred under nonutility generation (NUG) agreements exceed amounts collected through BGS and MTC rates. As of June 30, 2003, the accumulated deferred cost balance totaled approximately $450 million, after the charge discussed below. The NJBPU also allowed securitization of JCP&L's deferred balance to the extent permitted by law upon application by JCP&L and a determination by the NJBPU that the conditions of the New Jersey restructuring legislation are met. There can be no assurance as to the extent, if any, that the NJBPU will permit such securitization.

Under New Jersey transition legislation, all electric distribution companies were required to file rate cases to determine the level of unbundled rate components to become effective August 1, 2003. JCP&L submitted two rate filings with the NJBPU in August 2002. The first filing requested increases in base electric rates of approximately $98 million annually. The second filing was a request to recover deferred costs that exceeded amounts being recovered under the current MTC and SBC rates; one proposed method of recovery of these costs is the securitization of the deferred balance. This securitization methodology is similar to the Oyster Creek securitization discussed above. On July 25, 2003, the NJBPU announced its JCP&L base electric rate proceeding decision which would reduce JCP&L's annual revenues by approximately $62 million effective August 1, 2003. The NJBPU decision also provided for an interim return on equity of 9.5 percent on JCP&L's rate base for the next 6 to 12 months. During that period, JCP&L will initiate another proceeding to request recovery of additional costs incurred to enhance system reliability. In that proceeding, the NJBPU could increase the return on equity to 9.75 percent or decrease it to 9.25 percent, depending on its assessment of the reliability of JCP&L's service. Any reduction would be retroactive to August 1, 2003. The revenue decrease in the decision consists of a $223 million decrease in the electricity delivery charge, a $111 million increase due to the August 1, 2003 expiration of annual customer credits previously mandated by the New Jersey transition legislation, a $49 million increase in the MTC tariff component, and a net $1 million increase in the SBC charge. The MTC would allow for the recovery of $465 million in deferred energy costs over the next ten years on an interim basis, thus disallowing $153 million of the $618 million provided for in a preliminary settlement agreement between certain parties. In the second quarter of 2003, JCP&L recorded charges to net income aggregating $158 million ($94 million net of tax) consisting of the $153 million deferred energy costs and other regulatory assets.

In 1997, the NJBPU authorized JCP&L to recover from customers, subject to possible refund, $135 million of costs incurred in connection with a

1996 buyout of a power purchase agreement. JCP&L has recovered the full $135 million; the NJBPU has established a procedural schedule to take further evidence with respect to the buyout to enable it to make a final prudence determination contemporaneously with the resolution of the pending rate case. On July 25, 2003, the NJBPU approved a Stipulation Settlement between the parties and authorized the recovery of the total $135 million of buyout costs.

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

Pennsylvania

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

In June 2001, the PPUC approved the Settlement Stipulation with all of the major parties in the combined merger and rate relief proceedings which approved the merger and provided PLR deferred accounting treatment for energy costs, permitting Met-Ed and Penelec to defer, for future recovery, energy costs in excess of amounts reflected in their capped generation rates retroactive to January 1, 2001. This PLR deferral accounting procedure was later denied in a February 2002 Commonwealth Court of Pennsylvania decision. The court decision also affirmed the PPUC decision regarding the merger, remanding the decision to the PPUC only with respect to the issue of merger savings. In September 2002, FirstEnergy established reserves for Met-Ed's and Penelec's PLR deferred energy costs which aggregated $287.1 million, reflecting the potential adverse impact of the then pending Pennsylvania Supreme Court decision whether to review the Commonwealth Court decision.

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

On April 2, 2003, the PPUC remanded the merger savings issue to the Office of Administrative Law for hearings and directed Met-Ed and Penelec to file a position paper on the effect of the Commonwealth Court's order on the

Settlement Stipulation by May 2, 2003 and for the other parties to file their responses to the Met-Ed and Penelec position paper by June 2, 2003. In summary, the Met-Ed and Penelec position paper essentially stated the following:

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

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

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

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

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

remaining issues before the Administrative Law Judge are the appropriate treatment of merger savings issues and whether their accounting and related tariff modifications are consistent with the Court Order.

Effective September 1, 2002, Met-Ed and Penelec assigned their PLR responsibility to their FES affiliate through a wholesale power sale agreement. The PLR sale currently runs through December 2003 and will be automatically extended for each successive calendar year unless any party elects to cancel the agreement by November 1 of the preceding year. Under the terms of the wholesale agreement, FES assumed the supply obligation and the supply profit and loss risk, for the portion of power supply requirements not self-supplied by Met-Ed and Penelec under their NUG contracts and other existing power contracts with nonaffiliated third party suppliers. This arrangement reduces Met-Ed's and Penelec's exposure to high wholesale power prices by providing power at or below the shopping credit for their uncommitted PLR energy costs during the term of the agreement with FES. FES has hedged most of Met-Ed's and Penelec's unfilled PLR on-peak obligation through 2004 and a portion of 2005, the period during which deferred accounting was previously allowed under the PPUC's order. Met-Ed and Penelec are authorized to continue deferring differences between NUG contract costs and amounts recovered through their capped generation rates.

5 - NEW ACCOUNTING STANDARDS:

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS 143, "Accounting for Asset Retirement Obligations." That 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 (ARO) 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 instead if the criteria for such treatment are met. Upon retirement, a gain or loss would be recorded if the cost to settle the retirement obligation differs from the carrying amount.

FirstEnergy identified applicable legal obligations as defined under the new standard for nuclear power plant decommissioning, reclamation of a sludge disposal pond related to the Bruce Mansfield plant, and closure of two coal ash disposal sites. As a result of adopting SFAS 143 in January 2003 asset retirement costs were recorded in the amount of $602 million as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $415 million. The ARO liability at the date of adoption was $1.109 billion, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. As of December 31, 2002, FirstEnergy had recorded decommissioning liabilities of $1.243 billion. FirstEnergy expects substantially all nuclear decommissioning costs for Met-Ed, Penelec, JCP&L and Penn would be recoverable in rates over time. Therefore, FirstEnergy recognized a regulatory liability of $185 million upon adoption of SFAS 143 for the transition amounts related to establishing the ARO for nuclear decommissioning for these operating companies. The remaining cumulative effect adjustment for unrecognized depreciation and accretion offset by the reduction in the existing decommissioning liabilities and ceasing the accounting practice of depreciating non-regulated generation assets using a cost of removal component was a $174.7 million increase to income, $102.1 million net of tax, or $0.35 per share of common stock (basic and diluted).

FirstEnergy recorded an ARO for nuclear decommissioning ($1.096 billion) of the Beaver Valley 1, Beaver Valley 2, Davis-Besse, Perry, and TMI-2 nuclear generation facilities with the remaining ARO related to Bruce Mansfield's sludge impoundment facilities and two coal ash disposal sites. The Company maintains nuclear decommissioning trust funds, which had balances as of June 30, 2003 of $1.161 billion. This amount represents the fair value of the assets that are legally restricted for purposes of settling the nuclear decommissioning ARO. The following table provides the beginning and ending aggregate carrying amount of the total ARO and the changes to the balance during the second quarter and the first six months of 2003.

	PERIODS ENDED JUNE 30, 2003	
ARO RECONCILIATION	THREE MONTHS	SIX MONTHS
	(IN MILLIONS)	
Balance at beginning of period	$1,127	$1,109
Liabilities incurred in the current period.......	--	--
Liabilities settled in the current period........	--	--

Accretion expense..............................	18	36
Revisions in estimated cash flows...............	--	--
ENDING BALANCE AS OF JUNE 30, 2003..............	$1,145	$1,145

The following table provides on an adjusted basis the year-end balance of the ARO related to nuclear decommissioning and sludge impoundment for 2002, as if SFAS 143 had been adopted on January 1, 2002.

ADJUSTED ARO RECONCILIATION	
(IN MILLIONS)	
Beginning balance as of January 1, 2002........................	$1,042
Accretion 2002..	67
ENDING BALANCE AS OF DECEMBER 31, 2002.........................	$1,109

In accordance with SFAS 143 FirstEnergy ceased the accounting practice of depreciating non-regulated generation assets using a cost of removal component in the depreciation rates that are applied to the generation assets. This practice recognizes accumulated depreciation in excess of the historical cost of an asset, because the removal cost exceeds the estimated salvage value. The change in accounting resulted in a $60 million credit to income as part of the SFAS 143 cumulative effect adjustment. Beginning in 2003 depreciation rates applied to non-regulated generation assets exclude the cost of removal component and cost of removal is charged to expense rather than charged to the accumulated provision for depreciation. In accordance with SFAS 71, the regulated plant assets will continue the accounting practice of depreciating assets using a cost of removal component in the depreciation rates. The net removal cost credit balance included in the accumulated provision for regulated assets as of June 30, 2003 was approximately $312.5 million.

The following table provides, on an adjusted basis, the effect on income as if the accounting for SFAS 143 had been applied during the second quarter and first six months of 2002.

	PERIOD ENDED JUNE 30, 2002	
EFFECT OF THE CHANGE IN ACCOUNTING PRINCIPLE APPLIED RETROACTIVELY TO 2002 INCREASE(DECREASE)	THREE MONTHS	SIX MONTHS
	(RESTATED - SEE NOTE 1) (IN MILLIONS)	
Reported net income..........................	$ 208	$ 326
Elimination of decommissioning expense........	26	52
Depreciation of asset retirement cost.........	(1)	(2)
Accretion of ARO liability....................	(9)	(18)

Income tax effect...........................	(7)	(13)
Net earnings effect..........................	9	19
Net income adjusted..........................	$ 217	$ 345
Basic earnings per share of common stock:		
Net income as previously reported............	$0.71	$1.11
Adjustment for effect of change in accounting principle applied retroactively..	.03	0.06
Net income adjusted..........................	$0.74	$1.17
Diluted earnings per share of common stock:		
Net income as previously reported............	$0.70	$1.10
Adjustment for effect of change in accounting principle applied retroactively..	0.03	0.06
Net income adjusted..........................	$0.73	$1.16

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

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

In addition to the entities FirstEnergy is currently consolidating, FirstEnergy believes that the PNBV Capital Trust, which reacquired a portion of the off-balance sheet debt issued in connection with the sale and leaseback of OE's interest in the Perry Plant and Beaver Valley Unit 2, would require consolidation. Ownership of the trust includes a three-percent equity interest by a nonaffiliated party and a three-percent equity interest by OES Ventures, a wholly owned

subsidiary of OE. Full consolidation of the trust under FIN 46 would change the characterization of the PNBV trust investment to a lease obligation bond investment. Also, consolidation of the outside minority interest would be required, increasing assets and liabilities by $11.6 million.

Issued by the FASB in April 2003, SFAS 149 further clarifies and amends accounting and reporting for derivative instruments. The statement amends SFAS 133 for decisions made by the Derivative Implementation Group (DIG), as well as issues raised in connection with other FASB projects and implementation issues. The statement is effective for contracts entered into or modified after June 30, 2003 except for implementation issues that have been effective for reporting periods beginning before June 15, 2003, which continue to be applied based on their original effective dates. FirstEnergy is currently assessing the new standard and has not yet determined the impact on its financial statements.

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

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

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.

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.

In June 2002, the EITF reached a partial consensus on Issue

No. 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." Based on the EITF's partial consensus position, for periods after July 15, 2002, mark-to-market revenues and expenses and their related kilowatt-hour (KWH) sales and purchases on energy trading contracts must be shown on a net basis in the Consolidated Statements of Income. Prior to its adoption for 2002 year end reporting, FirstEnergy had previously reported such contracts as gross revenues and purchased power costs. Comparative quarterly disclosures and the Consolidated Statements of Income for revenues and expenses have been reclassified for 2002 to conform with the revised presentation. In addition, the related KWH sales and purchases statistics described under Management's Discussion and Analysis of Results of Operations and Financial Condition were reclassified. The following table displays the impact of changing to a net presentation for FirstEnergy's energy trading operations.

	THREE MONTHS ENDED JUNE 30, 2002		SIX MONTHS ENDED JUNE 30, 2002	
2002 IMPACT OF RECORDING ENERGY TRADING NET	REVENUES	EXPENSES	REVENUES	EXPENSES
		RESTATED (SEE NOTE 1)		RESTATED (SEE NOTE 1)
	(IN MILLIONS)		(IN MILLIONS)	
Total as originally reported............	$2,949	$2,323	$5,842	$4,725
Adjustment.............................	(50)	(50)	(90)	(90)
Total as currently reported............	$2,899	$2,273	$5,752	$4,635

6 - SEGMENT INFORMATION:

FirstEnergy operates under two reportable segments: regulated services and competitive services. The aggregate "Other" segments do not individually meet the criteria to be considered a reportable segment. "Other" consists of interest expense related to the 2001 merger acquisition debt; corporate support services and the international businesses acquired in the 2001 merger. FirstEnergy's primary segment is its regulated services segment, which includes eight electric utility operating companies in Ohio, Pennsylvania and New Jersey that provide electric transmission and distribution services. Its other material business segment consists of the subsidiaries that operate unregulated energy and energy-related businesses.

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

SEGMENT FINANCIAL INFORMATION

	REGULATED SERVICES	COMPETITIVE SERVICES	OTHER	RECONC ADJUST
			(IN MILLIONS)	
THREE MONTHS ENDED:				
JUNE 30, 2003				
External revenues	$ 2,083	$ 740	$ 22	$
Internal revenues	233	512	147	(
Total revenues	2,316	1,252	169	(
Depreciation and amortization	291	8	10	
Net interest charges	132	11	104	
Income taxes	89	(32)	(32)	
Income before discontinued operations and cumulative effect of accounting change ...	118	(45)	(54)	
Net income (loss)	118	(45)	(121)	
Total assets	30,123	2,499	1,403	
Property additions	92	79	29	
JUNE 30, 2002 (RESTATED - SEE NOTE 1)				
External revenues	$ 2,161	$ 696	$ 36	$
Internal revenues	177	417	125	(
Total revenues	2,338	1,113	161	(
Depreciation and amortization	282	6	12	
Net interest charges	156	7	102	
Income taxes	196	5	(33)	
Net income (loss)	248	7	(47)	
Total assets	30,261	2,010	2,009	
Property additions	120	72	32	
SIX MONTHS ENDED:				
JUNE 30, 2003 (RESTATED - SEE NOTE 1)				
External revenues	$ 4,398	$ 1,606	$ 62	$
Internal revenues	498	1,072	271	(1,
Total revenues	4,896	2,678	333	(1,
Depreciation and amortization	597	16	21	
Net interest charges	257	21	209	
Income taxes	248	(63)	(62)	
Income before discontinued operations and cumulative effect of accounting change ...	345	(89)	(105)	
Net income (loss)	446	(88)	(165)	
Total assets	30,123	2,499	1,403	
Property additions	210	158	56	
JUNE 30, 2002 (RESTATED - SEE NOTE 1)				
External revenues	$ 4,156	$ 1,283	$ 301	$
Internal revenues	532	827	242	(1,
Total revenues	4,688	2,110	543	(1,
Depreciation and amortization	573	13	24	
Net interest charges	317	17	224	
Income taxes	358	(37)	(59)	
Net income (loss)	447	(53)	(68)	
Total assets	30,261	2,010	2,009	
Property additions	264	110	46	

Reconciling adjustments to segment operating results from internal management reporting to consolidated external financial reporting:

(a) Principally fuel marketing revenues which are reflected as reductions to expenses for internal management reporting purposes.

(b) Elimination of intersegment transactions.

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FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	THREE MONTHS ENDED JUNE 30,	
	2003	2002
		RESTATED (SEE NOTE 1)
	(IN THOUSANDS, EXCEPT	
REVENUES:		
Electric utilities	$ 2,082,659	$ 2,210,316
Unregulated businesses	780,487	688,257
Total revenues	2,863,146	2,898,573
EXPENSES:		
Fuel and purchased power	1,121,553	766,288
Purchased gas	128,634	145,954
Other operating expenses	907,854	914,906
Provision for depreciation and amortization	309,022	300,405
General taxes	163,042	145,106
Total expenses	2,630,105	2,272,659
INCOME BEFORE INTEREST AND INCOME TAXES	233,041	625,914
NET INTEREST CHARGES:		
Interest expense	199,670	231,782
Capitalized interest	(7,622)	(6,605)
Subsidiaries' preferred stock dividends	13,860	25,105
Net interest charges	205,908	250,282
INCOME TAXES	17,649	167,734
INCOME BEFORE DISCONTINUED OPERATIONS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	9,484	207,898
Discontinued operations (net of income taxes of $3,700,000 in the six months period) (Note 3)	(67,372)	--
Cumulative effect of accounting change (net of income taxes		

of $72,516,000) (Note 5)	--	--
NET INCOME (LOSS)	$ (57,888)	$ 207,898
BASIC EARNINGS (LOSS) PER SHARE OF COMMON STOCK:		
Income before discontinued operations and cumulative effect of accounting change	$ .03	$ .71
Discontinued operations (net of income taxes) (Note 3)	(.23)	--
Cumulative effect of accounting change (net of income taxes) (Note 5)	--	--
Net income (loss)	$ (.20)	$ .71
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	294,166	293,080
DILUTED EARNINGS (LOSS) PER SHARE OF COMMON STOCK:		
Income before discontinued operations and cumulative effect of accounting change	$ .03	$ .71
Discontinued operations (net of income taxes) (Note 3)	(.23)	--
Cumulative effect of accounting change (net of income taxes) (Note 5)	--	--
Net income (loss)	$ (.20)	$ .71
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	295,888	294,589
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$ .375	$ .375

The preceding Notes to Financial Statements as they relate to FirstEnergy Corp. are an integral part of these statements.

FIRSTENERGY CORP.

CONSOLIDATED BALANCE SHEETS

	(UNAUDITED) JUNE 30, 2003	DE
		R (
	(IN THOU	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 64,204	$

Receivables-	
Customers (less accumulated provisions of $51,644,000 and $52,514,000 respectively, for uncollectible accounts)	1,133,619
Other (less accumulated provisions of $8,003,000 and $12,851,000, respectively, for uncollectible accounts)	507,635
Materials and supplies, at average cost-	
Owned	292,728
Under consignment	167,889
Other	327,847
	2,493,922
PROPERTY, PLANT AND EQUIPMENT:	
In service	21,460,203
Less--Accumulated provision for depreciation	9,152,201
	12,308,002
Construction work in progress	606,234
	12,914,236
INVESTMENTS:	
Capital trust investments	1,028,433
Nuclear plant decommissioning trusts	1,161,259
Letter of credit collateralization	277,763
Other	917,251
	3,384,706
DEFERRED CHARGES:	
Regulatory assets	8,088,548
Goodwill	6,249,363
Other	893,765
	15,231,676
	$34,024,540

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FIRSTENERGY CORP.

CONSOLIDATED BALANCE SHEETS

	(UNAUDITED) JUNE 30, 2003
	(IN THOUSA
CAPITALIZATION AND LIABILITIES	
CURRENT LIABILITIES:	
Currently payable long-term debt and preferred stock	$ 1,328,415
Short-term borrowings	1,045,067

Accounts payable	857,724
Accrued taxes	474,754
Other	982,520
	4,688,480
CAPITALIZATION:	
Common stockholders' equity-	
Common stock, $.10 par value, authorized 375,000,000 shares - 297,636,276 shares outstanding	29,764
Other paid-in capital	6,121,164
Accumulated other comprehensive loss	(534,084)
Retained earnings	1,575,153
Unallocated employee stock ownership plan common stock - 3,378,651 and 3,966,269 shares, respectively	(67,246)
Total common stockholders' equity	7,124,751
Preferred stock of consolidated subsidiaries-	
Not subject to mandatory redemption	335,123
Subject to mandatory redemption	18,517
Subsidiary-obligated mandatorily redeemable preferred securities	284,834
Long-term debt	11,239,278
	19,002,503
DEFERRED CREDITS:	
Accumulated deferred income taxes	2,066,541
Accumulated deferred investment tax credits	224,759
Asset retirement obligations	1,144,564
Nuclear plant decommissioning costs	--
Power purchase contract loss liability	3,022,798
Retirement benefits	1,723,069
Lease market valuation liability	1,063,600
Other	1,088,226
	10,333,557
COMMITMENTS, GUARANTEES AND CONTINGENCIES (NOTE 2)	
	$ 34,024,540

The preceding Notes to Financial Statements as they relate to FirstEnergy Corp. are an integral part of these balance sheets.

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	THREE MONTHS ENDED JUNE 30,	
	2003	200
		RESTA

		(SEE NO (I
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (57,888)	$ 207
Adjustments to reconcile net income (loss) to net cash from operating activities-		
Provision for depreciation and amortization	309,022	300
Nuclear fuel and lease amortization	15,578	19
Other amortization, net	(409)	(4
Deferred costs recoverable as regulatory assets	81,558	(55
Deferred income taxes, net	(52,906)	33
Investment tax credits, net	(6,247)	(6
Disallowed regulatory assets (Note 4)	158,500	
Discontinued operations (Note 3)	67,372	
Cumulative effect of accounting change (Note 5)	--	
Receivables	(58,659)	(150
Materials and supplies	(45,397)	(21
Accounts payable	(27,928)	47
Accrued taxes	(75,699)	4
Accrued interest	(105,277)	(106
Deferred lease costs	(62,370)	(142
Prepayments	(50,885)	(128
Other	(66,634)	264
Net cash provided from operating activities	21,731	262
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	722,041	261
Short-term borrowings, net	189,741	
Redemptions and Repayments-		
Preferred stock	(125,337)	(5
Long-term debt	(815,166)	(194
Short-term borrowings, net	--	(85
Common stock dividend payments	(110,284)	(109
Net cash used for financing activities	(139,005)	(132
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(199,742)	(224
Proceeds from sale of assets	5,877	155
Proceeds from note receivable	19,000	
Avon cash and cash equivalents (Note 3)	--	(380
Proceeds from nonutility generation trusts	--	
Cash investments	(9,650)	68
Other	75,957	(36
Net cash used for investing activities	(108,558)	(417
Net increase (decrease) in cash and cash equivalents	(225,832)	(288
Cash and cash equivalents at beginning of period	290,036	647
Cash and cash equivalents at end of period	$ 64,204	$ 359

The preceding Notes to Financial Statements as they relate to FirstEnergy Corp. are an integral part of these statements.

REPORT OF INDEPENDENT AUDITORS

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

We have reviewed the accompanying consolidated balance sheet of FirstEnergy Corp. and its subsidiaries as of June 30, 2003, and the related consolidated statements of income and cash flows for each of the three-month and six-month periods ended June 30, 2003 and 2002. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with generally accepted auditing standards, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated interim financial statements, the Company has restated its previously issued consolidated interim financial statements for the quarter ended June 30, 2002.

We previously audited in accordance with auditing standards generally accepted in the United States of America, the consolidated balance sheet and the consolidated statement of capitalization as of December 31, 2002, and the related consolidated statements of income, common stockholders' equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report (which contained references to the Company's change in its method of accounting for goodwill in 2002 as discussed in Note 2(E) to those consolidated financial statements and the Company's restatement of its previously issued consolidated financial statements for the year ended December 31, 2002 as discussed in Note 2(L) and Note 2(M) to those consolidated financial statements) dated February 28, 2003, except as to Note 2(L), which is as of May 9, 2003, and Notes 2(M) and 8, which are as of August 18, 2003, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2002, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio
August 18, 2003

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FIRSTENERGY CORP.

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

FirstEnergy Corp. is a registered public utility holding company that provides regulated and competitive energy services (see Results of

Operations - Business Segments). International assets were acquired as part of FirstEnergy's acquisition of GPU, Inc. in November 2001. GPU Capital, Inc. and its subsidiaries provided electric distribution services in foreign countries (see Results of Operations - Discontinued Operations). GPU Power, Inc. and its subsidiaries develop, own and operate generation facilities in foreign countries. Sales are planned but not pending for the remaining international assets (see Capital Resources and Liquidity). Regulated electric distribution services are provided in Ohio by wholly owned subsidiaries (Ohio electric utilities) - Ohio Edison Company (OE), The Cleveland Electric Illuminating Company (CEI), and The Toledo Edison Company (TE). Regulated services are provided in Pennsylvania through wholly owned subsidiaries (Pennsylvania electric utilities) - Metropolitan Edison Company (Met-Ed), Pennsylvania Electric Company (Penelec) and Pennsylvania Power Company (Penn) - a wholly owned subsidiary of OE. Jersey Central Power & Light Company (JCP&L) provides electric distribution services in New Jersey. Transmission services are provided in the franchise areas of the Ohio electric utilities and Penn by wholly owned subsidiary American Transmission Systems, Inc. Transmission services are provided by Met-Ed, Penelec and JCP&L in their respective franchise areas. The coordinated delivery of energy and energy-related products, including electricity, natural gas and energy management services, to customers in competitive markets is provided through a number of subsidiaries. Subsidiaries providing competitive services include FirstEnergy Solutions Corp. (FES), FirstEnergy Facilities Services Group, LLC (FSG), MARBEL Energy Corporation and MYR Group, Inc (MYR).

RESTATEMENTS

As further discussed in Note 1 to the Consolidated Financial Statements, FirstEnergy determined that it was appropriate to restate its consolidated financial statements for the year ended December 31, 2002 and the three months ended March 31, 2003. The revisions reflect a change in the method of amortizing the costs being recovered under the Ohio transition plan and recognition of above-market values of certain leased generation facilities.

Transition Cost Amortization

As discussed in Note 4 - Regulatory Matters, FirstEnergy's Ohio electric utilities recover transition costs, including regulatory assets, through an approved transition plan filed under Ohio's electric utility restructuring legislation. The plan, which was approved in July 2000, provides for the recovery of costs from January 1, 2001 through a fixed number of kilowatt-hour sales to all customers that continue to receive regulated transmission and distribution service, which is expected to end in 2006 for OE, 2007 for TE and in 2009 for CEI.

FirstEnergy and the Ohio utilities amortize transition costs using the effective interest method. The amortization schedules originally developed at the beginning of the transition plan in 2001 in applying this method were based on total transition revenues, including revenues designed to recover costs which have not yet been incurred or that were recognized on the regulatory financial statements (fair value purchase accounting adjustments) but not in the financial statements prepared under GAAP. The Ohio electric utilities have revised their amortization schedules under the effective interest method to consider only revenues relating to transition regulatory assets recognized on the GAAP balance sheet. The impact of this change will result in higher amortization of these regulatory assets in the first several years of the transition cost recovery period, versus the method previously applied. The change in method results in no change in total amortization of the regulatory assets recovered under the transition period through the end of 2009. The amortization expense under the revised method (see Note 1) increased by $49.7 million for the three months and $82.1 million for the six months ended June 30, 2002.

Above-Market Lease Costs

In 1997, FirstEnergy Corp. was formed through a merger between OE and Centerior Energy Corp. The merger was accounted for as an acquisition of Centerior, the parent company of CEI and TE, under the purchase accounting rules of Accounting Principles Board (APB) Opinion No. 16. In connection with the reassessment of the accounting for the transition plan, FirstEnergy reassessed its accounting for the Centerior purchase and determined that above market lease liabilities should have been recorded at the time of the merger. Accordingly, as of 2002, FirstEnergy recorded 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 CEI and TE had previously entered into sale-leaseback arrangements. CEI and TE 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 liability would have increased goodwill at the date of the merger. The corresponding impact of the above market lease liabilities for the Bruce Mansfield Plant were recorded as regulatory assets because regulatory accounting had not been discontinued at that time for the fossil generating assets and recovery of these liabilities was provided for under the transition plan.

The total above market lease obligation of $722 million (CEI - $611; TE - $111 million) associated with Beaver Valley Unit 2 will be amortized through the end of the lease term in 2017. The additional goodwill has been recorded on a net basis, reflecting amortization that would have been recorded through 2001 when goodwill amortization ceased with the adoption of SFAS 142. The total above market lease obligation of $755 million (CEI - $457 million; TE - $298 million) associated with the Bruce Mansfield Plant is being amortized through the end of 2016. Before the start of the transition plan in 2001, the regulatory asset would have been amortized at the same rate as the lease obligation. Beginning in 2001, the remaining unamortized regulatory asset would have been included in CEI's and TE's amortization schedules for regulatory assets and amortized through the end of the recovery period - approximately 2009 for CEI and 2007 for TE.

RESULTS OF OPERATIONS

FirstEnergy experienced a net loss in the second quarter of 2003 of $57.9 million, or loss of $(0.20) per share of common stock (basic and diluted), compared to net income of $207.9 million, or earnings of $0.71 per share of common stock (basic and diluted) in the second quarter of 2002. Results in the second quarter of 2003 included an after-tax charge of $67.4 million or $0.23 per share of common stock (basic and diluted) resulting from the abandonment of FirstEnergy's shares in Emdersa's parent company, GPU Argentina Holdings, Inc. on April 18, 2003. During the first six months of 2003, net income was $160.6 million, or basic earnings of $0.55 per share of common stock ($0.54 diluted), compared to $326.2 million, or earnings of $1.11 per share of common stock (basic and diluted) in the first half of 2002. Net income in the first half of 2003 included a $60.5 million after-tax charge for discontinued operations in Argentina and an after-tax credit of $102.1 million resulting from the cumulative effect of an accounting change due to the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations." Income before discontinued operations and the cumulative effect of an accounting change was $9.5 million, or $0.03 per share of common stock (basic and diluted) in the second quarter and $119.0 million, or basic earnings of $0.41 per share of common stock ($0.40 diluted) in the first six months of 2003.

Results in the second quarter of 2003 were adversely affected by mild weather which reduced revenues after benefiting from unusually cold weather earlier in the year. Expenses in both periods were higher due to a $158.5 million charge for costs disallowed in the JCP&L rate case decision (see State Regulatory Matters - New Jersey), replacement power and additional nuclear expenses related to the extended outage at the Davis-Besse Nuclear Power Station (see Davis-Besse Restoration) and additional unplanned work performed during two nuclear refueling outages in the second quarter of 2003. Incremental costs of the extended outage at Davis-Besse reduced basic and diluted earnings per share of common stock by $0.13 in the second quarter and $0.30 in the first six months of 2003, compared to $.09 for both corresponding periods of 2002. Higher employee benefit expenses also contributed to increased costs in the second quarter and first six months of 2003 compared to the corresponding periods last year. However, the absence in the first six months of 2003 of the unusual charges incurred in the corresponding period of 2002 partially offset the higher costs in 2003.

Reclassifications of Previously Reported Income Statement

FirstEnergy recorded an increase to income during the six months ended June 30, 2002 of $31.7 million (net of income taxes of $13.6 million) relative to its decision to retain an interest in the Avon Energy Partners Holdings (Avon) business previously classified as held for sale - see Note 3. This amount represents the aggregate results of operations of Avon for the period this business was held for sale. It was previously reported on the Consolidated Statement of Income as the cumulative effect of a change in accounting. In April 2003, it was determined that this amount should instead have been classified as part of normal operations. As further discussed in Note 3, the decision to retain Avon was made in the first quarter of 2002 and Avon's results of operations for that quarter have been classified in their respective revenue and expense captions on the Consolidated Statement of Income. This change in classification had no effect on

previously reported net income. The effects of this change to the Consolidated Statement of Income previously reported for the six months ended June 30, 2002 are reflected in the restatements shown in Note 1.

In June 2002, the Emerging Issues Task Force (EITF) reached a partial consensus on Issue No. 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." Based on the EITF's partial consensus position, for periods after July 15, 2002, mark-to-market revenues and expenses and their related kilowatt-hour sales and purchases on energy trading contracts must be shown on a net basis on the Consolidated Statements of Income. FirstEnergy had previously reported such contracts as gross revenues and purchased power costs. Therefore, revenues and expenses for the second quarter and first six months of 2002 have been reclassified (see Implementation of Accounting Standard).

In April 2003, FirstEnergy divested its ownership of Emdersa -- see Note 3. As part of the abandonment, FirstEnergy recognized a one-time, non-cash charge of $67.4 million. The charge does not include the anticipated tax benefits of approximately $129 million, of which $50 million would increase net income in the period that it becomes probable those benefits will be realized. The remaining $79 million of tax benefits would reduce goodwill recognized in connection with the acquisition of GPU. Discontinued operations for the six-month period of 2003 totaled $60.5 million and included $6.9 million of after-tax earnings from the Argentina operation from the first quarter of 2003 - previously reported as $10.7 million of revenue, $0.1 million of expenses and $3.7 million of income taxes.

Revenues

Total revenues decreased $35.4 million in the second quarter of 2003, compared to the same period last year, primarily due to lower retail regulated electric sales and reduced international sales reflecting the May 2002 sale of a 79.9% interest in Avon. Increased revenues from competitive services, primarily electric sales to wholesale customers, partially offset the decrease in regulated electric retail and international revenues in the second quarter of 2003. In the first six months of 2003, revenues increased $345.1 million compared to the same period of 2002 from increased regulated and competitive sales, offset in part by reduced international sales from the partial sale of Avon. Sources of changes in revenues during the second quarter and first six months of 2003 compared to the corresponding periods of 2002 are summarized in the following table:

SOURCES OF REVENUE CHANGES	THREE MONTHS	SIX MONTHS
INCREASE (DECREASE)	(IN MILLIONS)	
Electric Utilities (Regulated Services):		
Retail electric sales.................	$ (151.2)	$ (43.0)
Wholesale electric sales	39.2	178.8
All other revenues....................	(15.8)	(2.4)
Total Electric Utilities................	(127.8)	133.4
Unregulated Businesses (Competitive Services):		
Retail electric sales.................	48.3	115.0
Wholesale electric sales..............	195.8	429.5
Gas sales.............................	(32.1)	11.8
FSG...................................	(51.5)	(93.9)
MYR...................................	(25.7)	(53.2)
Other.................................	15.3	21.8
Total Unregulated Businesses............	150.1	431.0
International...........................	(70.3)	(243.3)
Other...................................	12.6	24.0
Net Change in Revenue...................	$ (35.4)	$ 345.1

Electric Sales

Retail sales by FirstEnergy's electric utility operating companies (EUOC) decreased by $151.2 million in the second quarter of 2003 and by $43.0 million in the first six months of 2003 from the corresponding periods of 2002.

Changes in electric generation kilowatt-hour sales and distribution deliveries in the second quarter and first six months of 2003 from the same periods of 2002 are summarized in the following table:

CHANGES IN KILOWATT-HOUR SALES	THREE MONTHS	SIX MONTHS
INCREASE (DECREASE)		
Electric Generation Sales:		
Retail -		
Regulated services......................	(10.8)%	(4.4)%
Competitive services....................	62.8%	90.2%
Wholesale................................	130.1%	135.8%
Total Electric Generation Sales.............	15.9%	23.2%
EUOC Distribution Deliveries:		
Residential..............................	(5.6)%	5.6%
Commercial...............................	(0.3)%	5.5%
Industrial...............................	(2.6)%	(0.8)%
Total Distribution Deliveries...............	(2.8)%	3.3%

Reduced air-conditioning load due to cooler-than-normal temperatures, continued sluggishness in the economy and increased sales by alternative suppliers all combined to decrease regulated retail generation sales revenue by $107.9 million in the second quarter of 2003 compared to the same quarter of 2002. These factors also accounted for most of the $112.6 million decrease in retail generation sales revenue in the first half of 2003 compared to the same period last year. Kilowatt-hour sales of electricity by alternative suppliers in FirstEnergy's franchise areas increased by 7.1 percentage points in the second quarter and 6.4 percentage points in the first half of 2003 from the corresponding periods last year.

Revenues from distribution deliveries decreased by $32.8 million or 2.7% in the second quarter of 2003 compared to the second quarter of 2002 due in part to cooler-than-normal temperatures which reduced the air-conditioning load of residential and commercial customers. Weather also contributed to the $99.4 million (5.6%) increase in distribution deliveries to residential and commercial customers in the first half of 2003 from the same period last year. Temperatures ranged from 20% to 30% colder in the first three months of 2003 than the same period last year adding to heating-related loads. Sluggish economic conditions in both the second quarter and first half of 2003 contributed to reduced distribution deliveries to industrial customers from the corresponding periods last year.

Further contributing to the decrease in retail electric revenues were Ohio transition plan incentives provided to customers to promote customer shopping for alternative suppliers - $10.4 million of additional credits in the second quarter and $24.8 million of credits in the first half of 2003 compared to the same periods in 2002. These reductions in revenue are deferred for future recovery under the Ohio transition plan and do not materially affect current period earnings.

EUOC sales to wholesale customers increased by $39.2 million in the second quarter and $178.8 million in the first six months of 2003, from the same periods last year. Substantially all of those increases resulted from the auction of JCP&L's basic generation service (BGS) responsibility to alternative suppliers. At the direction of the New Jersey Board of Public Utilities (NJBPU), JCP&L is selling its pre-existing sources of power supply, including energy provided by non-utility generation (NUG) contracts, into the wholesale market.

Electric generation sales by FirstEnergy's competitive segment increased $244.1 million in the second quarter and $544.5 million in the first six months of 2003 from the corresponding periods of 2002, primarily from additional sales to the wholesale market ($195.8 million in the second quarter and $429.5 million in the first half of 2003). The increases resulted principally from sales into the New Jersey market as FES began supplying a portion of that state's BGS in September 2002. Retail sales by FirstEnergy's competitive services segment increased by $48.3 million in the second quarter and $115.0 million in the first six months of 2003 from the same periods of 2002. The increases primarily resulted from retail customers within FirstEnergy's Ohio franchise areas switching to FES under Ohio's electricity choice program.

FirstEnergy's regulated and unregulated subsidiaries record purchase and sale transactions with PJM Interconnection ISO, an independent system operator, on a gross basis in accordance with EITF 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent." This gross basis classification of revenues and costs may not be comparable to other energy companies that operate in regions that have not established ISOs and do not meet EITF 99-19 criteria. The aggregate purchase and sales transactions for the three and six months ended June 30, 2003 and 2002 are summarized as follows:

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2003	2002	2003	2002
	(IN MILLIONS)			
Sales................	$ 206	$ 35	$544	$ 67
Purchases............	225	117	579	197

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

Nonelectric Sales

Nonelectric sales revenues of the competitive services segment declined by $94.0 million in the second quarter and $113.4 million in the first six months of 2003 from the corresponding periods of 2002. The reduced revenues from FSG reflected the divestiture in early 2003 of its Colonial Mechanical and Webb Technologies subsidiaries (accounting for the majority of the decreases), as well as declines associated with weak economic conditions. MYR also experienced revenue reductions resulting from the sluggish economic environment. Natural gas sales were $32.1 million lower in the second quarter of 2003, but increased $11.8 million in the year-to-date period from the corresponding periods last year. Trends from the first quarter of 2003 continued into the second quarter with higher unit prices and reduced volumes. However, the reduction in gas sales volumes accelerated in the second quarter of 2003 as FES focused its operations in a narrower geographic area and on higher margin gas customers which resulted in a decline in sales volume that more than offset the effect of higher gas costs.

International Revenues

International revenues declined $70.3 million in the second quarter and $243.3 million in the first six months of 2003 from the corresponding periods last year due to the sale of a 79.9% interest in Avon during the second quarter of 2002 and the subsequent application of equity accounting to FirstEnergy's remaining 20.1% interest. As a result, no revenues were recorded for FirstEnergy's equity interest in Avon in the second quarter and first six months of 2003.

Expenses

Total expenses increased $357.4 million in the second quarter and $819.6 million in the first six months of 2003 from the same periods of 2002. Sources of changes in expenses in the second quarter and first six months of 2003 compared to the corresponding periods of 2002 are summarized in the following table:

SOURCES OF EXPENSE CHANGES	THREE MONTHS	SIX MONTHS
INCREASE (DECREASE)	(IN MILLIONS)	
Fuel and purchased power..............	$ 355.3	$ 884.1
Purchased gas.........................	(17.3)	5.9
Other operating expenses..............	(7.1)	(118.7)
Depreciation and amortization.........	8.6	24.1
General taxes.........................	17.9	24.2
NET INCREASE IN EXPENSES...............	$ 357.4	$ 819.6

The increases in expenses in the second quarter and first six months of 2003 compared to the same periods of 2002 resulted from increased purchased power costs - $375.2 million higher in the second quarter and $910.4 million higher in the first six months of 2003. The higher costs resulted from $152.5 million of purchased power costs disallowed in the JCP&L rate case decision (see State Regulatory Matters - New Jersey), additional volumes to cover supply obligations assumed by FES for BGS sales to the New Jersey market, as well as other wholesale commitments, and additional supplies required to replace reduced nuclear generation. The combined effect of the extended Davis-Besse outage and additional unplanned work performed during the refueling outages at the Perry Plant and Beaver Valley Unit 1 reduced nuclear generation by 33.5% in the second quarter and 24.6% in the first six months of 2003 from the corresponding periods last year. Fuel expenses were $19.9 million and $26.4 million lower in the second quarter and first half of 2003, respectively, from the same periods of 2002, primarily reflecting reduced generation. Purchased gas costs decreased by $17.3 million in the second quarter of 2003 compared to the same period of 2002 due to lower volumes purchased to meet reduced sales levels, partially offset by higher unit costs.

Other operating expenses decreased $9.6 million in the second quarter of 2003 compared to the same period of 2002, primarily due to reduced business volume from domestic energy-related businesses ($75.7 million) and decreased international expenses as a result of the sale of Avon ($31.1 million). The reduced volume of energy-related business reflects the sale in early 2003 of Colonial Mechanical and Webb Technologies businesses ($30.3 million), as well as continued declines associated with weak economic conditions. Partially offsetting these lower expenses were increased costs resulting from the Davis-Besse extended outage, unplanned work performed during the refueling outages at the Perry Plant and Beaver Valley Unit 1 in the second quarter of 2003, higher administration and general costs of $43.8 million (principally employee benefit costs - see Employee Benefit Plan Costs) and a $12.6 million

impairment of a note receivable related to the sale of 79.9% of Avon. Nuclear nonfuel operating costs in the second quarter of 2003 were $61.7 million higher, including $10.3 million of additional incremental expense from the Davis-Besse extended outage.

In the first six months of 2003, other operating expenses decreased $118.7 million as a result of the same factors which influenced the second quarter comparison: reduced business volume from domestic energy-related businesses ($141.8 million) and decreased international expenses as a result of the sale of Avon ($103.8 million). The sale of Colonial and Webb reduced expenses by $57.8 million in the first six months of 2003 compared to the same period of 2002. The absence of unusual charges recorded in the first six months of 2002 resulted in a further net reduction of other operating expenses ($59.4 million) from the corresponding period last year. Offsetting a portion of these lower expenses in the first half of 2003 were increased nuclear costs resulting from the extended Davis-Besse outage, unplanned work performed during the refueling outages in the second quarter of 2003 and higher administrative and general costs of $133.4 million (principally employee benefit costs). Nuclear nonfuel operating costs increased $88.1 million in the first six months of 2003 from the same period of 2002, including $46.5 million of additional incremental expense related to the Davis-Besse extended outage.

Charges for depreciation and amortization increased by $8.6 million in the second quarter of 2003 compared to the corresponding three-month period of 2002. The higher charges primarily resulted from five factors - increased amortization of the Ohio transition regulatory assets ($17.9 million), recognition of depreciation on four power plants ($10.0 million) which had been held pending sale in the second quarter of 2002, but were subsequently retained by FirstEnergy in the fourth quarter of 2002, costs of $6.0 million disallowed in the JCP&L rate case decisions (see State Regulatory Matters - New Jersey) and reduced regulatory asset deferrals in 2003 ($7.1 million). Partially offsetting these increases in depreciation and amortization were higher shopping incentive deferrals in Ohio ($10.4 million), lower charges resulting from the implementation of SFAS 143 ($11.5 million) and revised service life assumptions for generating plants ($6.5 million).

In the first six months of 2003, depreciation and amortization increased $24.1 million as a result of the same factors which influenced the second quarter comparison - increased amortization of the Ohio transition regulatory assets ($42.1 million), recognition of depreciation on four power plants ($19.6 million) which had been held pending sale in the first half of 2002, costs of $6.0 million disallowed in the JCP&L rate case decision and reduced regulatory asset deferrals in 2003 ($15.0 million). Partially offsetting these increases in depreciation and amortization were higher shopping incentive deferrals in Ohio ($24.8 million), lower charges resulting from the implementation of SFAS 143 ($26.0 million) and revised service life assumptions for generating plants ($14.1 million).

General taxes increased $17.9 million in the second quarter and $24.2 million in the first six months of 2003 compared to the same periods last year. Higher payroll and kilowatt-hour taxes in 2003 and a $9 million energy assessment credit adjustment that reduced general taxes in the second quarter of 2002 were the principal factors contributing to the increases.

Net Interest Charges

Net interest charges decreased $44.4 million in the second quarter and $117.1 million in the first six months of 2003 compared to the same periods of 2002, due to previous debt and preferred stock redemptions and refinancing activities and the sale of a 79.9% interest in Avon in 2002. Redemption and refinancing activities during the first six months of 2003 totaled $415 million and $835 million (including $213 million of pollution control note repricings), respectively, and are expected to result in annualized savings of approximately $47 million. Partially offsetting these savings are interest charges on additional borrowings under revolving bank credit facilities.

FirstEnergy also exchanged existing fixed-rate payments on outstanding debt (principal amount of $550 million as of June 30, 2003) for short-term variable rate payments through interest rate swap transactions (see Market Risk Information - Interest Rate Swap Agreements below). Net interest charges were reduced by $7.8 million in the second quarter and $14.6 million in the first six months of 2003, compared to the corresponding periods of 2002 as a result of the lower variable rates paid under these agreements. FirstEnergy also closed out $168.5 million (notional amount) of interest rate swap transactions in the second quarter of 2003 and recognized gains of $5.7 million.

Discontinued Operations

On April 18, 2003, FirstEnergy divested its ownership in Emdersa. The abandonment was accomplished by relinquishing FirstEnergy's shares of Emdersa's parent company, GPU Argentina Holdings, to that company's independent Board of Directors, relieving FirstEnergy of all rights and obligations relative to this business. As a result of this action, FirstEnergy's gains and losses related to discontinuing these operations have been presented as a separate item on the Consolidated Statements of Income - "Discontinued operations" - in accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Due to the abandonment, FirstEnergy recognized a one-time, non-cash charge of $67.4 million in the second quarter of 2003. This charge resulted from realizing $89.8

million of currency translation losses through current period earnings, partially offset by a $22.4 million gain recognized from eliminating FirstEnergy's investment in Emdersa. Discontinued operations for the six-month period reflected a net after-tax charge of $60.5 million, which included $6.9 million of earnings from Emdersa in the first quarter of 2003. As a result of the abandonment, FirstEnergy has substantially divested all of GPU Capital's international operations.

Cumulative Effect of Accounting Change

Results for the first six months of 2003 include an after-tax credit to net income of $102.1 million recorded upon the adoption of SFAS 143 in January 2003 (see discussion below). FirstEnergy identified applicable legal obligations as defined under the new standard for nuclear power plant decommissioning, reclamation of a sludge disposal pond at the Bruce Mansfield

Plant and two coal ash disposal sites. As a result of adopting SFAS 143 in January 2003, asset retirement costs of $602 million were recorded as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $415 million. The asset retirement obligation (ARO) liability at the date of adoption was $1.109 billion, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. As of December 31, 2002, FirstEnergy had recorded decommissioning liabilities of $1.232 billion, including unrealized gains on decommissioning trust funds of $12 million. FirstEnergy expects substantially all of its nuclear decommissioning costs for Met-Ed, Penelec, JCP&L and Penn to be recoverable in rates over time. Therefore, FirstEnergy recognized a regulatory liability of $185 million upon adoption of SFAS 143 for the transition amounts related to establishing the ARO for nuclear decommissioning for those companies. The remaining cumulative effect adjustment for unrecognized depreciation and accretion offset by the reduction in the liabilities was a $174.6 million increase to income, or $102.1 million net of income taxes.

Earnings Effect of SFAS 143

In June 2001, the FASB issued SFAS 143. That 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 instead 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.

In the second quarter and first six months of 2003, application of SFAS 143 (excluding the cumulative adjustment recorded upon adoption - see Note 5) resulted in the following changes to income and expense categories:

	ENDED JUNE 30, 2003	
EFFECT OF SFAS 143	THREE MONTHS	SIX MONTHS
INCREASE (DECREASE)	(IN MILLIONS)	
Other operating expense		
Cost of removal (previously included in depreciation)	$ 0.1	$ 4.3
Depreciation		
Elimination of decommissioning expense..............	(22.3)	(44.7)
Depreciation of asset retirement cost...............	0.3	2.2
Accretion of asset retirement liability.............	10.5	20.4
Reclassification of cost of removal to expense	--	(3.9)
Net decrease to depreciation........................	(11.5)	(26.0)
Other Income		
Earnings on decommissioning trust balances..........	0.7	3.2
Income taxes..	4.9	10.2

Net income effect.................................	$ 7.2	$ 14.7

Employee Benefit Plan Costs

Sharp declines in equity markets since the second quarter of 2000 and a reduction in FirstEnergy's assumed discount rate for pensions and other post-employment benefit (OPEB) obligations have combined to produce a significant increase in those costs. Also, increases in health care payments and a related increase in projected trend rates have led to higher health care costs. Combined, these employee benefit expenses increased by $44.6 million in the second quarter and $93.8 million in the first six months of 2003 compared to the same periods in 2002. The following table summarizes the net pension and OPEB expense (excluding amounts capitalized) for the three months and six months ended June 30, 2003 and 2002.

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PENSION AND OPEB EXPENSE (INCOME)	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2003	2002	2003	2002
	(IN MILLIONS)			
Pension...........................	$ 27.4	$ (0.7)	$ 58.7	$ (4.5)
OPEB..............................	38.5	22.0	79.0	48.4
Total.......................	$ 65.9	$ 21.3	$137.7	$ 43.9

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

RESULTS OF OPERATIONS - BUSINESS SEGMENTS

FirstEnergy manages its business as two separate major business segments - regulated services and competitive services. The regulated services segment designs, constructs, operates and maintains FirstEnergy's regulated domestic transmission and distribution systems. It also provides generation services to franchise customers who have not chosen an alternative generation supplier. The Ohio electric utilities and Penn obtain generation through a power supply agreement with the competitive services segment (see Outlook - Business Organization). The competitive services segment also supplies a substantial portion of the "provider of last resort" (PLR) requirements for Met-Ed and Penelec through a wholesale contract. The competitive services segment includes all competitive energy and energy-related services including commodity sales (both electricity and natural gas) in the retail and wholesale markets, marketing, generation, trading and sourcing of commodity requirements, as well as other competitive energy services such as heating, ventilation and air-conditioning. Financial results discussed below include intersegment revenues. A reconciliation of segment financial results to consolidated financial results is provided in Note 6 to the consolidated financial statements.

Regulated Services

Net income decreased to $107.0 million in the second quarter of 2003, compared to $247.5 million in the second quarter of 2002. In the first six months of 2003, net income decreased to $424.1 from $447.2 million in the first six months of 2002. The factors contributing to the changes in net income are summarized in the following table:

REGULATED SERVICES	THREE MONTHS	SIX MONTHS
INCREASE (DECREASE)	(IN MILLIONS)	
Revenues	$ (130.5)	$ 101.0
Expenses	149.6	408.4
Income Before Interest and Income Taxes	(280.1)	(307.4)
Net interest charges	(23.6)	(59.5)
Income taxes	(116.0)	(123.8)
Decrease in Income Before Cumulative Effect of a Change in Accounting	(140.5)	(124.1)
Cumulative effect of a change in accounting	--	101.0
Net Income Decrease	$ (140.5)	$ (23.1)

Lower generation sales and distribution deliveries combined to decrease external electric revenues by $112.0 million in the second quarter of 2003 compared to the same quarter of 2002. Cooler than normal temperatures and a continued sluggish economy reduced sales in the second quarter. Retail generation sales were also adversely affected by additional kilowatt-hour sales by alternative suppliers in the FirstEnergy franchise area. The remaining change in sales primarily resulted from a decrease in energy-related revenues. Revenues in the first six months of 2003 increased $101.0 million from the same period last year due to a stronger first quarter performance in 2003 due in part to colder than normal weather compared to the same period in 2002.

Expenses increased in the second quarter and first six months of 2003 from the corresponding periods of 2002. The increase in expenses in the second quarter of 2003 resulted principally from a $117.8 million increase in purchased power costs resulting from a $152.5 million charge related to the JCP&L rate case. Additional factors included a $15.9 million increase in other operating expenses, $10.6 million increase in depreciation and amortization expense and $6.5 million increase in general taxes. In the first six months of 2003, expenses increased $408.4 million from the same period of 2002. The increase in expenses resulted principally from a $344.4 million increase in purchased power costs due to higher sales to wholesale generation customers and the charge resulting from the JCP&L rate case. The other expense factors in the first six months of 2003 compared to the first six months of 2002 include a $29.9 million increase in other operating expense, $27.2 million increase in depreciation and amortization expense and $9.4 million increase in general taxes. Other operating expenses in both the second quarter and first six months of 2003 increased in part due to additional employee benefit costs from the corresponding periods of 2002. Depreciation and amortization expenses increased in the second quarter and first six months of 2003 from the same periods last year due principally to four factors - increased amortization of the Ohio transition regulatory assets, recognition of depreciation on four power plants which had been pending sale in the second quarter of 2002, but were subsequently retained by FirstEnergy in the fourth quarter of 2002, the write-off of disallowed costs in the JCP&L rate case and the termination of regulatory asset deferrals in February 2003. Partially offsetting these increases in depreciation and amortization were higher shopping tax incentive deferrals in Ohio and lower charges resulting from the implementation of SFAS 143, including revised service life assumptions for generating plants.

Competitive Services

Net losses increased to $44.0 million in the second quarter and $98.7 million in the first six months of 2003, compared to net income of $6.4 million and a net loss of $53.3 million in the corresponding periods of 2002. The factors contributing to the increased losses are summarized in the following table:

COMPETITIVE SERVICES	THREE MONTHS	SIX MONTHS
INCREASE (DECREASE)	(IN MILLIONS)	
Revenues..................................	$ 304.8	$ 674.7
Expenses..................................	387.5	741.4
Income Before Interest and Income Taxes....	(82.7)	(66.7)
Net interest charges......................	3.1	4.1
Income taxes..............................	(35.4)	(24.2)
Decrease in Income Before Cumulative Effect of a Change in Accounting..................	(50.4)	(46.6)
Cumulative effect of a change in accounting	--	1.2
Net Income................................	$ (50.4)	$ (45.4)

The increase in revenues in the second quarter and first six months of 2003, compared to the corresponding periods of 2002, includes the net effect of several factors. Revenues from the electric wholesale market increased $195.8 million in the second quarter and $429.5 million in the first six months of 2003 from the same periods last year as kilowatt-hour sales more than doubled resulting principally from sales as an alternative supplier for a portion of New Jersey's BGS requirements. Retail kilowatt-hour sales revenues increased $48.3 million in the second quarter and $115.0 million in the first six months of 2003 from the same periods last year as a result of expanding the FES business in Ohio under Ohio's electricity choice program. Internal sales to the regulated services segment increased $154.6 million in the second quarter and $244.9

million in the first six months of 2003 compared to the same periods of 2002 primarily reflecting sales to Met-Ed and Penelec in supplying a substantial portion of their PLR requirements in Pennsylvania. Several factors partially offset the increase in revenues.

Energy-related services such as heating, ventilation and air-conditioning work reflected the divestiture in early 2003 of Colonial and Webb, as well as continued declines associated with weak economic conditions. Revenues from energy-related services decreased $77.2 million in the second quarter and $147.1 million in the first six months of 2003 from the corresponding periods of 2002.

Natural gas sales decreased $32.1 million in the second quarter, but increased $11.8 million in the first six months of 2003 from the corresponding periods last year. Gas revenue trends in the first quarter of 2003 continued into the second quarter with higher unit prices and reduced volumes. However, the reduction in gas sales volumes accelerated in the second quarter of 2003 as FES focused its operations to a narrower geographic area and on higher-margin gas customers with a resulting decline in volume that more than offset the effect of higher prices.

Expenses increased $387.5 million in the second quarter and $741.4 million in the first six months of 2003 from the same periods of 2002 due to purchased power costs, which increased $400.8 million in the second quarter and $810.9 million in the first six months of 2003. The increases reflected the higher sales combined with reduced internal generation. Expenses of energy-related businesses declined $75.7 million in the second quarter and $141.8 million in the first six months of 2003 from the corresponding periods last year as a result of the divestiture of Colonial and Webb, as well as continued declines associated with weak economic conditions. Other operating expenses increased $99.0 million in the second quarter and $73.4 million in the first six months of 2003 from the corresponding periods of 2002. Additional costs resulting from the Davis-Besse extended outage, unplanned work performed during two nuclear refueling outages

in the second quarter of 2003 and higher employee benefit costs all contributed to the increase in other operating expenses. The absence of unusual charges recorded in 2002 moderated the increase in operating expenses by $59.4 million in the year-to-date period of 2003 compared to the corresponding period of 2002. Purchased gas costs decreased $17.3 million in the second quarter of 2003 compared to the second quarter of last year as a result of reduced volumes required for gas sales.

CAPITAL RESOURCES AND LIQUIDITY

FirstEnergy's cash requirements in 2003 for operating expenses, construction expenditures, scheduled debt maturities and preferred stock redemptions are expected to be met without materially increasing FirstEnergy's 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, FirstEnergy expects to meet its contractual obligations with cash from operations. Thereafter, FirstEnergy expects to use a combination of cash from operations and funds from the capital markets.

Changes in Cash Position

The primary source of ongoing cash for FirstEnergy, as a holding company, is cash dividends from its subsidiaries. The holding company also has access to $1.5 billion of revolving credit facilities. In the first six months of 2003, FirstEnergy received $485.0 million of cash dividends from its subsidiaries and paid $220.4 million in cash common stock dividends to its shareholders. There are no material restrictions on the payment of cash dividends by FirstEnergy's subsidiaries.

As of June 30, 2003, FirstEnergy had $64.2 million of cash and cash equivalents, compared with $196.3 million as of December 31, 2002. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Cash provided from operating activities during the second quarter and first six months of 2003, compared with the corresponding periods of 2002 were as follows:

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
OPERATING CASH FLOWS	2003	2002	2003	2002
	(IN MILLIONS)			
Cash earnings (1)........	$ 509	$ 530	$ 867	$ 856
Working capital and other	(487)	(268)	(383)	(130)
Total...................	$ 22	$ 262	$ 484	$ 726

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

Net cash provided from operating activities decreased $240 million due to a $219 million change in funds used for working capital and a $21 million decrease in cash earnings. The change in funds used for working capital primarily represents offsetting changes for receivables, sale and leaseback rent payments, and prepayments.

Cash Flows From Financing Activities

The following table provides details regarding security issuances and redemptions during the second quarter and first six months of 2003:

SECURITIES ISSUED OR REDEEMED	THREE MONTHS	SIX MONTHS
	(IN MILLIONS)	
New Issues		
Senior Notes.......................	$ 159	$ 409
Long-Term Revolving Credit..........	230	280
Unsecured Notes....................	333	331
	$ 722	$1,020
Redemptions		
First Mortgage Bonds................	$ 593	$ 633
Pollution Control Notes............	--	50

Secured Notes......................	222	333
	$ 815	$1,016
Short-term Borrowings, Net...........	$ 190	$ (48)

Net cash used for financing activities increased by $6 million in the second quarter of 2003 from the second quarter of 2002. The increase in funds used for financing activities resulted from increased financing of $650 million that was exceeded by $656 million of additional redemptions and repayments during the second quarter of 2003 compared to the same period of 2002.

FirstEnergy had approximately $1.045 billion of short-term indebtedness as of June 30, 2003 compared to $1.093 billion at the end of 2002. Available borrowing capability included $151 million under $1.5 billion revolving lines of credit and $59 million under bilateral bank facilities. As of June 30, 2003, OE, CEI, TE and Penn had the aggregate capability to issue $2.2 billion of additional first mortgage bonds (FMB) on the basis of property additions and retired bonds. JCP&L, Met-Ed and Penelec no longer issue FMB other than as collateral for senior notes, since their senior note indentures prohibit them (subject to certain exceptions) from issuing any debt which is senior to the senior notes. As of June 30, 2003, JCP&L, Met-Ed and Penelec had the aggregate capability to issue $737 million of additional senior notes based upon FMB collateral. Based upon applicable earnings coverage tests and their respective charters, OE, Penn, TE and JCP&L could issue a total of $4.0 billion of preferred stock. CEI, Met-Ed and Penelec have no restrictions on the issuance of preferred stock.

On March 17, 2003, FirstEnergy filed a registration statement with the U.S. Securities and Exchange Commission covering securities in the aggregate of up to $2 billion. The shelf registration provides the flexibility to issue and sell various types of securities, including common stock, debt securities, or share purchase contracts and related share purchase units.

On April 21, 2003, OE completed a $325 million refinancing transaction that included two tranches - $175 million of 4.00% five-year notes and $150 million of 5.45% twelve-year notes. The net proceeds were used to redeem approximately $220 million of outstanding OE first mortgage bonds having a weighted average cost of 7.99%, with the remainder used to pay down short-term debt.

On May 22, 2003, JCP&L completed a $150 million refinancing transaction that included one tranche - 4.8% Senior Notes due 2018. The proceeds of this transaction were used in conjunction with short-term borrowing, to call and redeem $78 million of medium term notes with a weighted average interest cost of 8.35% and $125 million of JCP&L Capital's Monthly Income Preferred Securities (8.56%).

In May and June of 2003, OE executed four fixed-to-floating interest rate swap agreements with notional values of $50 million each on underlying senior notes with an average fixed rate of 5.09%. Counterparties closed $168.5 million of FirstEnergy fixed-to-floating interest rate swap agreements in the second quarter of 2003 on which $5.7 million of gains were recognized. In July 2003, FirstEnergy executed a fixed-to-floating rate swap agreement with a fixed rate of 4.80% on an underlying senior note.

Cash Flows From Investing Activities

Net cash used for investing activities totaled $109 million in the second quarter and $226 million in the first six months of 2003, compared to net cash of $418 million and $196 million, respectively, used for investing activities for the same periods of 2002. The $309 million change in the second quarter of 2003 resulted from the absence of the Avon cash amount recognized in the first quarter of 2002 resulting from the reclassification from the "Assets Pending Sale" presentation to normal operations presentation (see Note 3), and decreased capital expenditures.

In May 2003, FirstEnergy received $19 million from Aquila as its first annual installment payment on the note receivable FirstEnergy had as part of its 79.9 percent sale of Avon in May 2002. After receiving this payment, FirstEnergy sold the remaining balance of its note receivable in the secondary market and received $63.2 million in proceeds on July 28, 2003. On May 22, 2003, FirstEnergy reached an agreement to sell its remaining 20.1% interest in Avon to Scottish and Southern Energy. Under the terms of the agreement, FirstEnergy will receive approximately $14 million, subject to bondholder approval.

The following table summarizes investments made in the second quarter and first six months of 2003 by FirstEnergy's regulated services and competitive services segments:

SUMMARY OF CASH USED FOR INVESTING ACTIVITIES	PROPERTY ADDITIONS	INVESTMENTS	OTHER	TOTAL
SOURCES (USES)		(IN MILLIONS)		
THREE MONTHS ENDED JUNE 30, 2003				
Regulated Services	$ (37)(1)	$ (69)	$ 32	$ (74)
Competitive Services	(135)(2)	1	(22)	(156)
Other	(28)	47	102(5)	121
Eliminations	--	--	--	--
Total	$ (200)	$ (21)	$ 112	$ (109)
SIX MONTHS ENDED JUNE 30, 2003				
Regulated Services	$ (155)(1)	$ 67(3)	$ 24	$ (64)
Competitive Services	(214)(2)	64(4)	(93)	(243)
Other	(55)	(30)	106(5)	21
Eliminations	--	--	60	60
Total	$ (424)	$ 101	$ 97	$ (226)

(1) Property additions to distribution facilities.

(2) Property additions to generation facilities.

(3) Net of several items from cash investments and NUG trust offset in part by investments in nuclear decommissioning trusts.

(4) Sale of assets - includes Colonial and Webb sale.

(5) Primarily a change in OCI from Emdersa abandonment (see Note 3).

During the second half of 2003, capital requirements for property additions and capital leases are expected to be approximately $397 million, including $31 million for nuclear fuel. FirstEnergy has additional requirements of approximately $264 million to meet sinking fund requirements for preferred stock and maturing long-term debt during the remainder of 2003. These cash requirements are expected to be satisfied from internal cash and short-term credit arrangements.

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

On August 7, 2003, S&P affirmed its "BBB" corporate credit rating for FirstEnergy. However, S&P stated that although FirstEnergy generates substantial free cash, that its strategy for reducing debt had deviated substantially from the one presented to S&P around the time of the GPU merger when the current rating was assigned. S&P further noted that their affirmation of FirstEnergy's corporate credit rating was based on the assumption that FirstEnergy would take appropriate steps quickly to maintain its investment grade ratings including the issuance of equity or possible sale of assets. Key issues being monitored by S&P include the restart of Davis-Besse, FirstEnergy's liquidity position, its ability to forecast provider-of-last-resort load and the performance of its hedged portfolio, and continued capture of merger synergies. On August 11, 2003, S&P stated that a recent U.S. District Court ruling (see Environmental Matters below) with respect to the Sammis Plant is negative for FirstEnergy's credit quality.

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

OTHER OBLIGATIONS

Obligations not included on FirstEnergy's Consolidated Balance Sheet primarily consist of sale and leaseback arrangements involving Perry Unit 1, Beaver Valley Unit 2 and the Bruce Mansfield Plant. As of June 30, 2003, the

present value of these sale and leaseback operating lease commitments, net of trust investments, total $1.5 billion. Also, CEI and TE continue to sell substantially all of their retail customer receivables, which provided $145 million of financing not included on the Consolidated Balance Sheet as of June

30, 2003.

GUARANTEES AND OTHER ASSURANCES

As part of normal business activities, FirstEnergy enters into various agreements on behalf of its subsidiaries to provide financial or performance assurances to third parties. Such agreements include contract guarantees, surety bonds, and ratings contingent collateralization provisions.

As of June 30, 2003, the maximum potential future payments under outstanding guarantees and other assurances totaled approximately $1.0 billion as summarized below:

GUARANTEES AND OTHER ASSURANCES	MAXIMUM EXPOSURE
	(IN MILLIONS)
FirstEnergy Guarantees of Subsidiaries:	
Energy and Energy-Related Contracts(1)......	$ 855.0
Financings (2)(3).........................	63.2
	918.2
Surety Bonds................................	24.5
Rating-Contingent Collateralization (4).......	106.8
Total Guarantees and Other Assurances.......	$ 1,049.5

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

(2) Includes parental guarantees of subsidiary debt and lease financing including FirstEnergy's letters of credit supporting subsidiary debt.

(3) Issued for various terms.

(4) Estimated net liability under contracts subject to rating-contingent collateralization provisions.

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

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

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

MARKET RISK INFORMATION

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

Commodity Price Risk

FirstEnergy is exposed to market risk primarily due to fluctuations in electricity, natural gas and coal prices. To manage the volatility relating to these exposures, it uses a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging

purposes and, to a much lesser extent, for trading purposes. Most of FirstEnergy's non-hedge derivative contracts represent non-trading positions that do not qualify for hedge treatment under SFAS 133.

The change in the fair value of commodity derivative contracts related to energy production during the second quarter and first six months of 2003 is summarized in the following table:

INCREASE (DECREASE) IN THE FAIR VALUE
OF COMMODITY DERIVATIVE CONTRACTS

	THREE MONTHS ENDED JUNE 30, 2003		
	NON-HEDGE	HEDGE	TOTAL
			(IN MIL
CHANGE IN THE FAIR VALUE OF COMMODITY DERIVATIVE CONTRACTS			
Net asset at beginning of period	$ 66.4	$ 42.9	$109.3
New contract value when entered	--	--	--
Change in value of existing contracts	(1.4)	9.2	7.8
Change in techniques/assumptions	--	--	--
Settled contracts	1.0	(16.6)	(15.6)
Net asset at end of period (1)	66.0	35.5	101.5
NON-COMMODITY NET ASSETS AT END OF PERIOD:			
Interest Rate Swaps (2)	--	13.2	13.2

NET ASSETS - DERIVATIVE CONTRACTS AT END OF PERIOD (3) ...	$ 66.0	$ 48.7	$114.7
IMPACT OF CHANGES IN COMMODITY DERIVATIVE CONTRACTS (4)			
Income Statement Effects (Pre-Tax)	$ (0.9)	$ --	$ (0.9)
Balance Sheet Effects:			
Other Comprehensive Income (Pre-Tax)	$ --	$ (7.4)	$ (7.4)
Regulatory Liability	$ 0.5	$ --	$ 0.5

(1) Includes $50.8 million in non-hedge commodity derivative contracts which are offset by a regulatory liability.

(2) Interest rate swaps are treated as fair value hedges. Changes in derivative values are offset by changes in the hedged debts' premium or discount.

(3) Excludes $28.7 million of derivative contract fair value decrease, as of June 30, 2003, representing FirstEnergy's 50% share of Great Lakes Energy Partners, LLC.

(4) Represents the increase in value of existing contracts, settled contracts and changes in techniques/assumptions.

Derivatives are included on the Consolidated Balance Sheet as of June 30, 2003 as follows:

	NON-HEDGE	HEDGE	TOTAL
		(IN MILLIONS)	
CURRENT-			
Other Assets.....................	$ 19.6	$ 18.5	$ 38.1
Other Liabilities................	(28.2)	(1.6)	(29.8)
NON-CURRENT-			
Other Deferred Charges...........	75.8	32.4	108.2
Other Deferred Credits...........	(1.2)	(0.6)	(1.8)
Net assets......................	$ 66.0	$ 48.7	$ 114.7

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

SOURCE OF INFORMATION - FAIR VALUE BY CONTRACT YEAR	2003(1)	2004	2005	2006	THEREAFTER
			(IN MILLIONS)		

Prices actively quoted(2)	$ 7.3	$ 7.9	$ (0.1)	$ --	$ --
Other external sources(3)	12.2	18.4	11.1	--	--
Prices based on models	--	--	--	6.9	37.8
TOTAL(4)	$ 19.5	$ 26.3	$ 11.0	$ 6.9	$ 37.8

(1) For the last two quarters of 2003.

(2) Exchange traded.

(3) Broker quote sheets.

(4) Includes $50.8 million from an embedded option that is offset by a regulatory liability and does not affect earnings.

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FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% adverse shift (an increase or decrease depending on the derivative position) in quoted market prices in the near term on both FirstEnergy's trading and nontrading derivative instruments would not have had a material effect on its consolidated financial position (assets, liabilities and equity) or cash flows as of June 30, 2003. Based on derivative contracts held as of June 30, 2003, an adverse 10% change in commodity prices would decrease net income by approximately $6.7 million during the next twelve months.

Interest Rate Swap Agreements

During the second quarter of 2003, FirstEnergy entered into fixed-to-floating interest rate swap agreements, as part of its ongoing effort to manage the interest rate risk of its debt portfolio. These derivatives are treated as fair value hedges of fixed-rate, long-term debt issues - protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. Swap maturities, fixed interest rates and interest payment dates match those of the underlying obligations. The swap agreements consummated in the second quarter of 2003 are based on a notional principal amount of $200 million.

As of June 30, 2003, the debt underlying FirstEnergy's $550 million notional amount of outstanding fixed-for-floating interest rate swaps had a weighted average fixed interest rate of 5.69%, which the swaps have effectively converted to a current weighted average variable interest rate of 2.32%. GPU Power (through a subsidiary) used existing dollar-denominated interest rate swap agreements in the first six months of 2003. The GPU Power agreements convert variable-rate debt to fixed-rate debt to manage the risk of increases in variable interest rates. GPU Power's swaps had a weighted average fixed interest rate of 6.68% as of June 30, 2003 and December 31, 2002. The following summarizes the principal characteristics of the swap agreements:

	JUNE 30, 2003			DECEMBER 31, 2002		
INTEREST RATE SWAPS	NOTIONAL AMOUNT	MATURITY DATE	FAIR VALUE	NOTIONAL AMOUNT	MATURITY DATE	FAIR VALUE

(DOLLARS IN MILLIONS)

Fixed to Floating Rate						
(Fair value hedges)	$ 200	2006	$ 6.5			
	50	2008	1.3			
	150	2015	(0.6)	$ 444	2023	$ 15.5
	150	2025	6.6	150	2025	5.9
Floating to Fixed Rate						
(Cash flow hedges)	$ 10	2005	$ (0.6)	$ 16	2005	$ (0.9)

Equity Price Risk

Included in FirstEnergy's nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $623 million and $532 million as of June 30, 2003 and December 31, 2002, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $62 million reduction in fair value as of June 30, 2003.

OUTLOOK

FirstEnergy continues to pursue its goal of being the leading regional supplier of energy and related services in the northeastern quadrant of the United States, where it sees the best opportunities for growth. Its fundamental business strategy remains stable and unchanged. While FirstEnergy continues to build toward a strong regional presence, key elements for its strategy are in place and management's focus continues to be on execution. FirstEnergy intends to provide competitively priced, high-quality products and value-added services - energy sales and services, energy delivery, power supply and supplemental services related to its core business. As FirstEnergy's industry changes to a more competitive environment, FirstEnergy has taken and expects to take actions designed to create a larger, stronger regional enterprise that will be positioned to compete in the changing energy marketplace.

FirstEnergy's current focus includes: 1) returning Davis-Besse to safe and reliable operation; 2) optimizing FirstEnergy's generation portfolio; 3) effectively managing commodity supplies and risks; 4) reducing FirstEnergy's cost structure; and 5) enhancing its credit profile and financial flexibility.

Business Organization

FirstEnergy's business is managed as two distinct operating segments - a competitive services segment and a regulated services segment. FES provides competitive retail energy services while the EUOC provide regulated transmission and distribution services. FirstEnergy Generation Corp. (FGCO), a wholly owned subsidiary of FES, leases fossil and hydroelectric plants from the EUOC and operates those plants. FirstEnergy expects the transfer of ownership

of EUOC non-nuclear generating assets to FGCO will be substantially completed by the end of the Ohio market development period in 2005. All of the EUOC power supply requirements for the Ohio Companies and Penn are provided by FES to satisfy their PLR obligations, as well as grandfathered wholesale contracts.

State Regulatory Matters

In Ohio, New Jersey and Pennsylvania, laws applicable to electric industry deregulation included similar provisions which are reflected in the

EUOCs' respective state regulatory plans. However, despite these similarities, the specific approach taken by each state and for each of the EUOCs varies. Those provisions include:

- allowing the EUOC's electric customers to select their generation suppliers;

- establishing PLR obligations to non-shopping customers in the EUOC's service areas;

- allowing recovery of potentially stranded investment (or transition costs) not otherwise recoverable in a competitive generation market;

- itemizing (unbundling) the price of electricity into its component elements - including generation, transmission, distribution and stranded costs recovery charges;

- deregulating the EUOC's electric generation businesses; and

- continuing regulation of the EUOC's transmission and distribution systems.

Regulatory assets are costs that the respective regulatory agencies have authorized for recovery from customers in future periods and, without such authorization, would have been charged to income when incurred. All of the regulatory assets are expected to continue to be recovered under the provisions of the respective transition and regulatory plans as discussed below. Regulatory assets declined by $664.9 million to $8.1 billion as of June 30, 2003 from the balance as of December 31, 2002. Over one-half of the reduction in regulatory assets resulted from the costs disallowed in the JCP&L rate case decision and adoption of SFAS 143 by JCP&L, Met-Ed, Penelec and Penn. The regulatory assets of the individual companies are as follows:

REGULATORY ASSETS AS OF

COMPANY	JUNE 30, 2003	DECEMBER 31, 2002
	(IN MILLIONS)	
OE...............	$ 1,689.9	$ 1,848.7
CEI..............	1,148.3	1,191.8
TE...............	537.2	578.2
Penn.............	60.3	156.9
JCP&L............	3,004.4	3,199.0
Met-Ed...........	1,091.0	1,179.1
Penelec..........	557.4	599.7
Total............	$ 8,088.5	$ 8,753.4

Ohio

FirstEnergy's transition plan (which FirstEnergy filed on behalf of its Ohio electric utilities) included approval for recovery of transition costs, including regulatory assets, as filed in the transition plan through no later than 2006 for OE, mid-2007 for TE and 2008 for CEI, except where a longer period of recovery is provided for in the settlement agreement. The approved plan also granted preferred access over FirstEnergy's subsidiaries to nonaffiliated marketers, brokers and aggregators to 1,120 megawatts of generation capacity through 2005 at established prices for sales to the Ohio Companies' retail customers. Customer prices are frozen through a five-year market development period (2001-2005), except for certain limited statutory exceptions including a 5% reduction in the price of generation for residential customers. In February 2003, the Ohio electric utilities were authorized increases in revenues aggregating approximately $50 million (OE - $41 million, CEI - $4 million and TE - $5 million) to recover their higher tax costs resulting from the Ohio deregulation legislation. FirstEnergy's Ohio customers choosing alternative suppliers receive an additional incentive applied to the shopping credit (generation component) of 45% for residential customers, 30% for commercial customers and 15% for industrial customers. The amount of the incentive is deferred for future recovery from customers - recovery will be accomplished by extending the respective transition cost recovery periods.

New Jersey

Under New Jersey transition legislation, all electric distribution companies were required to file rate cases to determine the level of unbundled rate components to become effective August 1, 2003. JCP&L submitted two rate filings with the NJBPU in August 2002. The first filing requested increases in base electric rates of approximately $98 million annually. The second filing was a request to recover deferred costs that exceeded amounts being recovered under the current MTC and SBC rates; one proposed method of recovery of these costs is the securitization of the deferred balance. This securitization methodology is similar to the Oyster Creek securitization. On July 25, 2003, the NJBPU announced its JCP&L base electric rate proceeding decision which reduces JCP&L's annual revenues by approximately $62 million effective August 1, 2003. The NJBPU decision also provided for an interim return on equity of 9.5 percent on JCP&L's rate base for the next 6 to 12 months. During that period, JCP&L will initiate another proceeding to request recovery of additional costs incurred to enhance system reliability. In that proceeding, the NJBPU could increase the return on equity to 9.75 percent or decrease it to 9.25 percent, depending on its assessment of the reliability of JCP&L's service. Any reduction would be retroactive to August 1, 2003. The revenue decrease in the decision consists of a $223 million decrease in the electricity delivery charge, a $111 million increase due to the August 1, 2003 expiration of annual customer credits previously mandated by the New Jersey transition legislation, a $49 million increase in the MTC tariff component, and a net $1 million increase in the SBC charge. The MTC would allow for the recovery of $465 million in deferred energy costs over the next ten years on an interim basis, thus disallowing $152.5 million. JCP&L also announced on July 25, 2003 that it is reviewing the NJBPU decision and will decide on its appropriate course of action, which could include filing an appeal for reconsideration with the NJBPU and possibly an appeal to the Appellate Division of the Superior Court of New Jersey.

Pennsylvania

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

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

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

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

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

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

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

The other parties' responses included significant disagreement with the position paper and disagreement among the other parties themselves, including the Stipulation's original signatory parties. Some parties believe that no portion of the Stipulation has survived the Commonwealth Court's Order. Because of these disagreements, Met-Ed and Penelec filed a letter on June 11, 2003 with the Administrative Law Judge assigned to the remanded case voiding the Stipulation in its entirety pursuant to the termination provisions. They believe this will significantly simplify the issues in the pending action by

reinstating Met-Ed's and Penelec's Restructuring Settlement previously approved by the PPUC. In addition, they have agreed to voluntarily continue certain Stipulation provisions including funding for energy and demand side response programs and to cap distribution rates at current levels through 2007. This voluntary distribution rate cap is contingent upon a finding that Met-Ed and Penelec have satisfied the "public interest" test applicable to mergers and that any rate impacts of merger savings will be dealt with in a subsequent rate case. Based upon this letter, Met-Ed and Penelec believe that the remaining issues before the Administrative Law Judge are the appropriate treatment of merger savings issues and whether their accounting and related tariff modifications are consistent with the Court Order.

Davis-Besse Restoration

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

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

Incremental costs associated with the extended Davis-Besse outage for the second quarter and first six months of 2003 and 2002 were as follows:

COSTS OF DAVIS-BESSE EXTENDED OUTAGE	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30	
	2003	2002	2003	2002
	(IN MILLIONS)			
INCREMENTAL PRE-TAX EXPENSE				
Replacement power	$ 41.1	$ 33.6	$ 93.4	$ 33.6
Maintenance	22.4	12.1	58.6	12.1
Total	$ 63.5	$ 45.7	$152.0	$ 45.7
CAPITAL EXPENDITURES	$ 2.4	$ 12.0	$ 2.4	$ 12.0

It is anticipated that an additional $22 million in maintenance costs will be expended over the remainder of the Davis-Besse outage. Replacement power costs are expected to be $15 million per month in the non-summer months and $20-25 million per month during the summer months of July and August.

FirstEnergy has hedged the on-peak replacement energy supply for Davis-Besse for the expected length of the outage.

Environmental Matters

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

The Companies are required to meet federally approved sulfur dioxide (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 SO2 regulations in Ohio that allows for compliance based on a 30-day averaging period. The Companies cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The Companies believe they are in compliance with the current 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 Companies' 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 New Jersey, 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 required compliance with the NO_x budgets at the Companies' Pennsylvania facilities by May 1, 2003 and Ohio submitted a SIP that requires compliance with the NO_x budgets at the Companies' Ohio facilities by May 31, 2004.

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

In 1999 and 2000, the EPA issued Notices of Violation (NOV) or a Compliance Order to nine utilities covering 44 power plants, including the W. H. Sammis Plant. In addition, the U.S. Department of Justice filed eight civil complaints against various investor-owned utilities, which included a complaint against OE and Penn in the U.S. District Court for the Southern District of Ohio. The NOV and complaint allege violations of the Clean Air Act based on operation and maintenance of the Sammis Plant dating back to 1984. The civil complaint requests permanent injunctive relief to require the installation of "best available control technology" and civil penalties of up to $27,500 per day of violation. On August 7, 2003, the United States District Court for the Southern District of Ohio ruled that 11 projects undertaken at the Sammis Plant between 1984 and 1998 required pre-construction permits under the Clean Air Act. The ruling concludes the liability phase of the case, which deals with applicability of Prevention of Significant Deterioration provisions of the Clean Air Act. The remedy phase, which is currently scheduled to be ready for trial beginning March 15, 2004, will address civil penalties and what, if any, actions should be taken to further reduce emissions at the plant. In the ruling, the Court indicated that the remedies it "may consider and impose involved a much broader, equitable analysis, requiring the Court to consider air quality, public health, economic impact, and employment consequences. The Court may also consider the less than consistent efforts of the EPA to apply and further enforce the Clean Air Act." The potential penalties that may be imposed, as well as the capital expenditures necessary to comply with substantive remedial measures they may be required, may have a material adverse impact on the Company's financial condition and results of operations. Management is unable to predict the ultimate outcome of this matter.

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.

Several EUOCs have been named as "potentially responsible parties" (PRPs) at waste disposal sites which may require cleanup under the Comprehensive Environmental Response, Compensation and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site be held liable on a joint and several basis. Therefore, potential environmental liabilities have been recognized on the Consolidated Balance Sheet as of June 30, 2003, based on estimates of the total costs of cleanup, the Companies' proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay. In addition, JCP&L has accrued liabilities for environmental remediation of former manufactured gas plants in New Jersey; those costs are being recovered by JCP&L through the SBC. The Companies have total accrued liabilities aggregating approximately $53.8 million as of June 30, 2003.

The effects of compliance on the EUOCs with regard to environmental matters could have a material adverse effect on FirstEnergy's earnings and competitive position. These environmental regulations affect FirstEnergy's earnings

and competitive position to the extent it competes with companies that are not subject to such regulations and therefore do not bear the risk of costs associated with compliance, or failure to comply, with such regulations. FirstEnergy believes it is in material compliance with existing regulations, but is unable to predict how and when applicable environmental regulations may change and what, if any, the effects of any such change would be.

Power Outage

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

As of August 18, 2003, the following facts about FirstEnergy's system were known. Early in the afternoon of August 14, hours before the event, Unit 5 of the Eastlake Plant in Eastlake, Ohio tripped off. Later in the afternoon, three FirstEnergy transmission lines and one owned by American Electric Power and FirstEnergy tripped out of service. The Midwest Independent System Operator (MISO), which oversees the regional transmission grid, indicated that there were a number of other transmission line trips in the region outside of FirstEnergy's system. FirstEnergy customers experienced no service interruptions resulting from these conditions. Indications to FirstEnergy were that the Company's system was stable. Therefore, no isolation of FirstEnergy's system was called for. In addition, FirstEnergy determined that its computerized system for monitoring and controlling its transmission and generation system was operating, but the alarm screen function was not. However, MISO's monitoring system was operating properly. FirstEnergy believes that extensive data needs to be gathered and analyzed in order to determine with any degree of certainty the circumstances that led to the outage. This is a very complex situation, far broader than the power line outages FirstEnergy experienced on its system. From the preliminary data that has been gathered, FirstEnergy believes that the transmission grid in the Eastern Interconnection, not just within FirstEnergy's system, was experiencing unusual electrical conditions at various times prior to the event. These included unusual voltage and frequency fluctuations and load swings on the grid. FirstEnergy is committed to working with the North American Electric Reliability Council and others involved to determine exactly what events in the entire affected region led to the outage. There is no timetable as to when this entire process will be completed. It is, however, expected to last several weeks, at a minimum.

Legal Matters

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

Various lawsuits, claims and proceedings related to FirstEnergy's normal business operations are pending against it, the most significant of which are described above.

IMPLEMENTATION OF ACCOUNTING STANDARD

In June 2002, the EITF reached a partial consensus on Issue No. 02-03. Based on the EITF's partial consensus position, for periods after July 15, 2002, mark-to-market revenues and expenses and their related kilowatt-hour sales and purchases on energy trading contracts must be shown on a net basis on the Consolidated Statements of Income. FirstEnergy had previously reported such contracts as gross revenues and purchased power costs. Comparative quarterly disclosures and the Consolidated Statements of Income for revenues and expenses have been reclassified for 2002 to conform with the revised presentation (see Note 5). In addition, the related kilowatt-hour sales and purchases statistics described above under Results of Operations were reclassified (1.4 billion kilowatt-hours in the second quarter and 2.7 billion kilowatt-hours in the first six months of 2002). The following table displays the impact of changing to a net presentation for FirstEnergy's energy trading operations.

	THREE MONTHS ENDED JUNE 30, 2002		SIX MONTHS ENDED JUNE 30, 2002	
IMPACT OF RECORDING ENERGY TRADING NET	REVENUES	EXPENSES	REVENUES	EXPEN
		(IN MILLIONS)		
Total as originally reported......................	$ 2,949	$ 2,309	$ 5,842	$ 4,
Adjustment..	(50)	(50)	(90)	
Total as currently reported.......................	$ 2,899	$ 2,259	$ 5,752	$ 4,

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SIGNIFICANT ACCOUNTING POLICIES

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

Purchase Accounting - Acquisition of GPU

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

Regulatory Accounting

FirstEnergy's regulated services segment is subject to regulation that sets the prices (rates) it is permitted to charge its customers based on costs that the regulatory agencies determine FirstEnergy is permitted to recover. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by an unregulated company. This rate-making process results in the recording of regulatory assets based on anticipated future cash inflows. As a result of the changing regulatory framework in each state in which FirstEnergy operates, a significant amount of regulatory assets have been recorded - $8.1 billion as of June 30, 2003. FirstEnergy regularly reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future.

Derivative Accounting

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

Revenue Recognition

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

- Net energy generated or purchased for retail load

- Losses of energy over transmission and distribution lines

- Mix of 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

FirstEnergy's reported costs of providing non-contributory defined pension and OPEB benefits 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 FirstEnergy makes to the plans, and earnings on plan assets. Such factors may be further affected by business combinations (such as FirstEnergy's merger with

GPU, Inc. in November 2001), which impacts employee demographics, plan experience and other factors. Pension and OPEB costs may also be affected by changes to key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for 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, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. Due to the significant decline in corporate bond yields and interest rates in general during 2002, FirstEnergy reduced the assumed discount rate as of December 31, 2002 to 6.75% from 7.25% used at the end of 2001.

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by its pension trusts. The market values of FirstEnergy's pension assets have been affected by sharp declines in the equity markets since mid-2000. In 2002 and 2001 plan assets earned (11.3)% and (5.5)%, respectively. FirstEnergy's pension costs in 2002 were computed assuming a 10.25% rate of return on plan assets. Beginning in 2003, the assumed return on plan assets was reduced to 9.00% based upon FirstEnergy's 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, FirstEnergy will not be required to fund its 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 the 2002 assumption of approximately 10% in 2002, gradually decreasing to 4%-6% in later years. In determining its trend rate assumptions, FirstEnergy included the specific provisions of its health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in its health care plans, and projections of future medical trend rates.

Ohio Transition Cost Amortization

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

Long-Lived Assets

In accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," FirstEnergy periodically evaluates its 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, FirstEnergy recognizes a loss - calculated as the difference between the carrying value and the estimated fair value of the asset (discounted future net cash flows).

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by SFAS 142, FirstEnergy evaluates its 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 FirstEnergy 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. FirstEnergy's annual review was completed in the third quarter of 2002. The results of that review indicated no impairment of goodwill - fair value was higher than carrying value for each of its reporting units. The forecasts used in FirstEnergy's evaluations of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on FirstEnergy's future evaluations of goodwill. As of June 30, 2003, FirstEnergy had $6.3 billion of goodwill that primarily relates to its regulated services segment.

RECENTLY ISSUED ACCOUNTING STANDARDS NOT YET IMPLEMENTED

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

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

2003). The FASB also identified transitional disclosure provisions for all financial statements issued after January 31, 2003.

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

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

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

Issued by the FASB in April 2003, SFAS 149 further clarifies and amends accounting and reporting for derivative instruments. The statement amends SFAS133 for decisions made by the Derivative Implementation Group (DIG), as well as issues raised in connection with other FASB projects and implementation issues. The statement is effective for contracts entered into or modified after June 30, 2003 except for implementation issues that have been effective for reporting periods beginning before June 15, 2003, which continue to be applied based on their original effective dates. FirstEnergy is currently assessing the new standard and has not yet determined the impact on its financial statements.

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

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

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

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

In June 2003, the FASB cleared DIG Issue C20 for implementation in fiscal quarters beginning after July 10, 2003 which would correspond to FirstEnergy's fourth quarter of 2003. The issue supersedes earlier DIG Issue C11, "Interpretation of Clearly and Closely Related in Contracts That Qualify for the Normal Purchases and Normal Sales Exception." DIG Issue C20 provides guidance regarding when the presence in a contract of a general index, such as the Consumer Price Index, would prevent that contract from qualifying for the normal purchases and normal sales (NPNS) exception under SFAS 133, as amended, and therefore exempt from the mark-to-market treatment of certain contracts. DIG Issue C20 is to be applied prospectively to all existing contracts as of its effective date and for all future transactions. If it is determined under DIG Issue C20 guidance that the NPNS exception was claimed for an existing contract that was not eligible for this exception, the contract will be recorded at fair value, with a corresponding adjustment of net income as the cumulative effect of a change in accounting principle in the fourth quarter of 2003. FirstEnergy is currently assessing the new guidance and has not yet determined the impact on its financial statements.

EITF Issue No. 01-08, "Determining whether an Arrangement Contains a Lease"

In May 2003, the EITF reached a consensus regarding when arrangements contain a lease. Based on the EITF consensus, an arrangement contains a lease if (1) it identifies specific property, plant or equipment (explicitly or implicitly), and (2) the arrangement transfers the right to the purchaser to control the use of the property, plant or equipment. The consensus will be applied prospectively to arrangements committed to, modified or acquired through a business combination, beginning in the third quarter of 2003. FirstEnergy is currently assessing the new EITF consensus and has not yet determined the impact on its financial position or results of operations following adoption.

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OHIO EDISON COMPANY

CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	THREE MONTHS ENDED JUNE 30, 2003	THREE MONTHS ENDED JUNE 30, 2002
		RESTATED (SEE NOTE 1)
		(IN THOUS
OPERATING REVENUES	$ 673,708	$ 744,550
OPERATING EXPENSES AND TAXES:		
Fuel	10,290	15,129
Purchased power	216,355	213,172
Nuclear operating costs	118,209	80,700
Other operating costs	80,327	78,497
Total operation and maintenance expenses	425,181	387,498
Provision for depreciation and amortization	105,753	98,821

General taxes	44,406	42,524
Income taxes	34,379	82,226
Total operating expenses and taxes	609,719	611,069
OPERATING INCOME	63,989	133,481
OTHER INCOME	15,411	15,087
INCOME BEFORE NET INTEREST CHARGES	79,400	148,568
NET INTEREST CHARGES:		
Interest on long-term debt	24,957	30,312
Allowance for borrowed funds used during construction and capitalized interest	(1,124)	(883)
Other interest expense	9,325	2,801
Subsidiaries' preferred stock dividend requirements	912	3,626
Net interest charges	34,070	35,856
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	45,330	112,712
Cumulative effect of accounting change (net of income taxes of $22,389,000) (Note 5)	--	--
NET INCOME	45,330	112,712
PREFERRED STOCK DIVIDEND REQUIREMENTS	659	2,597
EARNINGS ON COMMON STOCK	$ 44,671	$ 110,115

The preceding Notes to Financial Statements as they relate to Ohio Edison Company are an integral part of these statements.

OHIO EDISON COMPANY

CONSOLIDATED BALANCE SHEETS

	(UNAUDITED) JUNE 30, 2003	DECEMBE 2002 RESTA (SEE NO
	(IN THOUSANDS)	

ASSETS

UTILITY PLANT:		
In service	$5,212,254	$ 4,98
Less-Accumulated provision for depreciation	2,585,546	2,55
	2,626,708	2,43
Construction work in progress-		
Electric plant	118,927	12
Nuclear fuel	5,674	2
	124,601	14
	2,751,309	2,58
OTHER PROPERTY AND INVESTMENTS:		
PNBV Capital Trust	388,225	40
Letter of credit collateralization	277,763	27
Nuclear plant decommissioning trusts	325,073	29
Long-term notes receivable from associated companies	503,192	50
Other	67,824	7
	1,562,077	1,55
CURRENT ASSETS:		
Cash and cash equivalents	2,364	2
Receivables-		
Customers (less accumulated provisions of $5,708,000 and $5,240,000, respectively for uncollectible accounts)	291,501	29
Associated companies	989,299	59
Other (less accumulated provisions of $1,000,000 for uncollectible accounts at both dates)	28,295	3
Notes receivable from associated companies	387,025	43
Materials and supplies, at average cost-		
Owned	58,989	5
Under consignment	13,115	1
Prepayments and other	21,603	1
	1,792,191	1,46
DEFERRED CHARGES:		
Regulatory assets	1,750,174	2,00
Property taxes	59,035	5
Unamortized sale and leaseback costs	68,325	7
Other	55,802	5
	1,933,336	2,18
	$8,038,913	$ 7,79

OHIO EDISON COMPANY

CONSOLIDATED BALANCE SHEETS

	(UNAUDITED) JUNE 30, 2003	DECEMBE 2002 RESTA (SEE NO
	(IN THOUSANDS)	
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common stockholder's equity		
Common stock, without par value, authorized 175,000,000 shares- 100 shares outstanding	$ 2,098,729	$ 2,09
Accumulated other comprehensive loss	(101,077)	(5
Retained earnings	647,838	80
Total common stockholder's equity	2,645,490	2,83
Preferred stock not subject to mandatory redemption	60,965	6
Preferred stock of consolidated subsidiary-		
Not subject to mandatory redemption	39,105	3
Subject to mandatory redemption	13,500	1
Long-term debt	1,521,866	1,21
	4,280,926	4,17
CURRENT LIABILITIES:		
Currently payable long-term debt and preferred stock	585,553	56
Short-term borrowings-		
Associated companies	1,170	22
Other	187,902	18
Accounts payable-		
Associated companies	410,027	14
Other	3,634	1
Accrued taxes	515,198	46
Accrued interest	23,103	2
Other	72,562	7
	1,799,149	1,70
DEFERRED CREDITS:		
Accumulated deferred income taxes	909,937	1,01
Accumulated deferred investment tax credits	82,135	8
Asset retirement obligation	307,501	
Nuclear plant decommissioning costs	--	28
Retirement benefits	384,618	24
Other	274,647	27
	1,958,838	1,91
COMMITMENTS, GUARANTEES AND CONTINGENCIES (NOTE 2)		
	$ 8,038,913	$ 7,79

The preceding Notes to Financial Statements as they relate to Ohio Edison Company are an integral part of these balance sheets.

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OHIO EDISON COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	THREE MONTHS ENDED JUNE 30,	
	2003	2002
		RESTATED (SEE NOTE 1)
	(IN THOUSA	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 45,330	$ 112,712
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation and amortization	105,753	98,821
Nuclear fuel and lease amortization	10,763	12,133
Deferred income taxes, net	(28,387)	(11,386)
Investment tax credits, net	(3,692)	(3,439)
Cumulative effect of accounting change (Note 5)	--	--
Receivables	(350,873)	(31,345)
Materials and supplies	6,969	(3,158)
Accounts payable	240,948	(1,166)
Accrued taxes	43,083	149,376
Accrued interest	(7,543)	(8,200)
Deferred lease costs	(34,360)	(31,865)
Prepayments and other	5,094	15,178
Other	41,445	(4,232)
Net cash provided from operating activities	74,530	293,429
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	575,000	--
Short-term borrowings, net	13,688	--
Redemptions and Repayments-		
Long-term debt	(238,963)	(244,179)
Short-term borrowings, net	--	(66,464)
Dividend Payments-		
Common stock	(272,000)	--
Preferred stock	(659)	(2,596)
Net cash provided from (used for) financing activities	77,066	(313,239)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(33,327)	(25,377)
Notes receivable from associated companies, net	(121,971)	3,402
Other	(8,254)	8,431

Net cash used for investing activities	(163,552)	(13,544)
Net increase (decrease) in cash and cash equivalents	(11,956)	(33,354)
Cash and cash equivalents at beginning of period	14,320	57,493
Cash and cash equivalents at end of period	$ 2,364	$ 24,139

The preceding Notes to Financial Statements as they relate to Ohio Edison Company are an integral part of these statements.

REPORT OF INDEPENDENT AUDITORS

To the Stockholders and Board of
Directors of Ohio Edison Company:

We have reviewed the accompanying consolidated balance sheet of Ohio Edison Company and its subsidiaries as of June 30, 2003, and the related consolidated statements of income and cash flows for each of the three-month and six-month periods ended June 30, 2003 and 2002. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with generally accepted auditing standards, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated interim financial statements, the Company has restated its previously issued consolidated interim financial statements for the quarter ended June 30, 2002.

We previously audited in accordance with auditing standards generally accepted in the United States of America, the consolidated balance sheet and the consolidated statement of capitalization as of December 31, 2002, and the related consolidated statements of income, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report (which contained a reference to the Company's restatement of its previously issued consolidated financial statements for the year ended December 31, 2002 as discussed in Note 1(M) to those consolidated financial statements) dated February 28, 2003, except as to Note 1(M), which is as of August 18, 2003, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2002, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP

Cleveland, Ohio
August 18, 2003

OHIO EDISON COMPANY

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

OE is a wholly owned, electric utility subsidiary of FirstEnergy. OE and its wholly owned subsidiary, Penn, conduct business in portions of Ohio and Pennsylvania, providing regulated electric distribution services. OE and Penn (OE Companies) also provide generation services to those customers electing to retain them as their power supplier. The OE Companies provide power directly to wholesale customers under previously negotiated contracts, as well as to alternative energy suppliers under OE's transition plan. The OE Companies have unbundled the price of electricity into its component elements - including generation, transmission, distribution and transition charges. Power supply requirements of the OE Companies are provided by FES - an affiliated company.

RESTATEMENTS

As further discussed in Note 1 to the Consolidated Financial Statements, OE identified certain accounting matters that require restatement of the consolidated financial statements for the year ended December 31, 2002 and the three months ended March 31, 2003. The revisions reflect a change in the method of amortizing the costs associated with the Ohio transition plan.

Transition Cost Amortization

As discussed in Note 4 - Regulatory Matters, OE 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 2006 for OE.

OE amortizes transition costs using the effective interest method. The amortization schedules developed in applying this method were previously based on total transition revenues, including revenues designed to recover costs which have not yet been incurred. OE has subsequently revised the amortization schedules under the effective interest method to consider only revenues relating to transition regulatory assets recognized on the balance sheet. The amortization expense under the revised method (see Note 1) increased by $7.3 million for the three months and decreased by $0.7 million for the six months ended June 30, 2002.

RESULTS OF OPERATIONS

Earnings on common stock in the second quarter of 2003 decreased to $44.7 million from $110.1 million in the second quarter of 2002. During the first six months of 2003, earnings on common decreased to $132.8 million from $174.2 million in the same period of 2002. In the first six months of 2003 earnings on common stock included an after tax credit of $31.7 million from the cumulative effect of an accounting change due to the adoption of SFAS 143, "Accounting for Asset Retirement Obligations." Income before the cumulative effect was $102.4 million in the first six months of 2003, compared to $179.3 million for the same period of 2002.

Results in the second quarter of 2003 were adversely affected by lower revenues due to mild weather and higher operating expenses principally from additional outage-related work at the nuclear generating plants and increased amortization of the Ohio transition regulatory assets compared to the same quarter of last year. The lower results in the second quarter of 2003 were partially offset by reduced nuclear fuel expenses as a result of the additional nuclear outages and reduced financing costs compared to the second quarter of 2002.

In the first six months of 2003, results were negatively affected by lower revenues reflecting mild weather in the second quarter of 2003, which moderated the affect of unusually cold weather earlier in the year. Additional outage-related work and increased amortization of the Ohio transition regulatory asset were also primary factors contributing to an increase in operating expenses in the first half of 2003 from the same period in 2002. Partially offsetting these factors were reduced fuel expense resulting from lower nuclear production and the absence in 2003 of an adjustment recorded in the first quarter of 2002 for low income housing investments.

Operating revenues decreased by $70.8 million or 9.5% in the second quarter and $35.9 million or 2.5% in the first six months of 2003 compared with the same periods in 2002 due to cooler-than-normal temperatures in the second quarter, continued sluggishness in the economy and increased sales by alternative suppliers. The lower revenues primarily resulted from reduced generation sales revenues, which included all retail customer categories - residential, commercial and industrial. Kilowatt-hour sales to retail customers declined by 17.3% in the second quarter

and 9.2% in the first six months of 2003 from the same periods of 2002, which reduced generation sales revenue by $47.0 million and $60.6 million, respectively. Electric generation services provided to retail customers by alternative suppliers as a percent of total sales delivered in OE's franchise area increased 10.3 percentage points in the second quarter and 8.4 percentage points in the first six months of 2003 from the corresponding periods last year.

Distribution deliveries decreased 5.3% in the second quarter of 2003 but increased 1.2% in the first six months of 2003 compared with the corresponding periods of 2002. The decreased distribution deliveries in the second quarter of 2003 reflected the mild weather in that period compared to the same period last year which reduced residential and commercial usage - the customer groups accounting for most of the $13.5 million reduction in revenues from electricity throughput. In the first half of 2003, unusually cold weather in the first few months of 2003 benefited distribution deliveries to residential and commercial customers which provided most of the increase in revenues from distribution throughput compared to the same period in 2002. The second quarter and first six months of 2003 were both adversely impacted by the continued effects of a sluggish economy and the demand by industrial customers in OE's franchise area.

Operating revenues also decreased in 2003 as a result of the Ohio transition plan incentives provided to customers to promote customer shopping for alternative suppliers - $4.6 million of additional credits in the second quarter and $11.0 million of additional credits in the first six months of 2003 from the corresponding periods of 2002. These reductions in revenues are deferred for future recovery under OE's transition plan and do not materially affect current period earnings.

Sales revenues from wholesale customers decreased by $4.9 million in the second quarter but increased by $10.1 million in the first six months of 2003 compared to the same periods of 2002. The changes in kilowatt-hour sales to the wholesale market reflected reduced nuclear generation available for sale to FES and offsetting increases in unit prices.

Changes in electric generation sales and distribution deliveries in the second quarter and first six months of 2003 from the corresponding periods of 2002 are summarized in the following table:

CHANGES IN KILOWATT-HOUR SALES	THREE MONTHS	SIX MONTHS
INCREASE (DECREASE)		
Electric Generation:		
Retail	(17.3)%	(9.2)%
Wholesale	(27.6)%	(17.4)%
Total Electric Generation Sales	(22.1)%	(13.0)%
Distribution Deliveries:		
Residential	(10.8)%	1.7%
Commercial	(4.4)%	2.0%
Industrial	(1.7)%	0.1%
Total Distribution Deliveries	(5.3)%	1.2%

Operating Expenses and Taxes

Total operating expenses and taxes decreased $1.3 million in the second quarter and increased $70.9 million in the first six months of 2003 from the same periods last year. The following table presents changes from the prior year by expense category.

OPERATING EXPENSES AND TAXES - CHANGES	THREE MONTHS	SIX MONTHS
INCREASE (DECREASE)	(IN MILLIONS)	
Fuel..	$ (4.8)	$ (6.2)
Purchased power costs.......................	3.2	5.5
Nuclear operating costs.....................	37.5	67.6
Other operating costs.......................	1.8	12.5
TOTAL OPERATION AND MAINTENANCE EXPENSES....	37.7	79.4
Provision for depreciation and amortization...	6.9	31.2
General taxes................................	1.9	4.8
Income taxes.................................	(47.8)	(44.5)
NET CHANGE IN OPERATING EXPENSES AND TAXES..	$ (1.3)	$ 70.9

Lower fuel costs in the second quarter and first six months of 2003, compared with the same periods of 2002, resulted from reduced nuclear generation - down 30.7% and 20.5%, respectively. Although the required kilowatt-hour purchases were lower because of reduced electric generation sales, in the second quarter and first six months of 2003, compared to the corresponding periods of 2002, higher unit costs more than offset the lower volume and resulted in

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higher purchased power costs. Nuclear operating costs increased in the second quarter and first six months of 2003, compared to the same periods of 2002 driven by two refueling outages in 2003 - Beaver Valley Unit 1 (100% ownership) and the Perry nuclear plant (35.24% ownership) in 2003 compared with one refueling outage at Beaver Valley Unit 2 (55.62% ownership) in 2002. The two refueling outages in 2003 included additional unplanned work which extended the length of the outages and increased their cost. The increase in other operating costs in the second quarter and first six months of 2003, compared to the same periods of 2002, primarily reflects higher employee benefit costs.

Charges for depreciation and amortization increased by $6.9 million in the second quarter of 2003 compared to the second quarter of 2002 primarily from three factors - increased amortization of the Ohio transition regulatory assets ($10.8 million) and reduced regulatory asset deferrals in 2003 ($5.9 million). Partially offsetting these increases were higher shopping incentive deferrals ($4.6 million) and lower charges resulting from the implementation of SFAS 143 ($4.6 million).

In the first six months of 2003, depreciation and amortization increased by $31.2 million compared to the corresponding period of 2002 as a result of the same factors which impacted the second quarter comparison - increased amortization of the Ohio transition regulatory asset ($41.7 million which reflects a cumulative adjustment credit in the first quarter of 2002 - see Restatements section) and reduced transition plan regulatory asset deferrals ($12.2 million) in 2003. Partially offsetting these increases in depreciation and amortization were higher shopping incentive deferrals ($11.0 million) and lower charges resulting from the implementation of SFAS 143 ($10.9 million).

General taxes increased in the second quarter and first six months of 2003 from the same periods of 2002 principally due to higher kilowatt-hour taxes in Ohio.

Other Income

Other income increased by $13.3 million in the first six months of 2003 from the same period last year, primarily due to the absence in 2003 of adjustments recorded in the first half of 2002 related to OE's low income housing investments.

Net Interest Charges

Net interest charges continued to trend lower, decreasing by $1.8 million in the second quarter and $16.5 million in the first six months of 2003 from the same periods last year, reflecting redemptions and refinancings since the second quarter of last year. OE's net debt redemptions totaled $21.2 million during the first six months of 2003, which will result in annualized savings of $6.3 million.

Cumulative Effect of Accounting Change

Results for the first six months of 2003 include an after-tax credit to net income of $31.7 million recorded upon the adoption of SFAS 143 in January 2003. OE identified applicable legal obligations as defined under the new standard for nuclear power plant decommissioning and reclamation of a sludge disposal pond at the Bruce Mansfield Plant. As a result of adopting SFAS 143 in January 2003, asset retirement costs of $133.7 million were recorded as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $25.2 million. The asset retirement obligation (ARO) liability at the date of adoption was $297.6 million, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. As of December 31, 2002, OE had recorded decommissioning liabilities of $292.4 million, including unrealized gains on the decommissioning trust funds of $10.6 million. Penn expects substantially all of its nuclear decommissioning costs to be recoverable in rates over time. Therefore, OE recognized a regulatory liability of $10.6 million upon adoption of SFAS 143 for the transition amounts related to establishing the ARO for nuclear decommissioning for Penn. The remaining cumulative effect adjustment for unrecognized depreciation, accretion offset by the reduction in the existing decommissioning liabilities and ceasing the accounting practice of depreciating non-regulated generation assets using a cost of removal component was a $54.1 million increase to income, or $31.7 million net of income taxes.

CAPITAL RESOURCES AND LIQUIDITY

OE's cash requirements in 2003 for operating expenses, construction expenditures, scheduled debt maturities and preferred stock redemptions are expected to be met without significantly increasing its 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, OE expects to meet its contractual obligations with cash from operations. Thereafter, OE expects to use a combination of cash from operations and funds from the capital markets.

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Changes in Cash Position

As of June 30, 2003, OE had $2.4 million of cash and cash equivalents, compared with $20.5 million as of December 31, 2002. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Cash provided by operating activities during the second quarter and first six months of 2003, compared with the corresponding periods in 2002 were as follows:

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
OPERATING CASH FLOWS	2003	2002	2003	2002
	(IN MILLIONS)			
Cash earnings (1)............	$130	$209	$284	$352
Working capital and other....	(55)	84	(56)	209
Total........................	$ 75	$293	$228	$561

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

Net cash from operating activities decreased $218 million in the second quarter of 2003 due to a $139 million decrease in funds from working capital and a $79 million decrease in cash earnings. The change in working capital and other primarily reflects higher accounts receivable in the second quarter of 2003 compared with corresponding amounts in the second quarter of 2002 ($320 million). A change in accrued tax liabilities also contributed $106 million to the decrease in working capital primarily due to an increase in tax payments in the second quarter of 2003 compared with the second quarter of 2002.

Cash Flows From Financing Activities

In the second quarter of 2003, net cash provided from financing activities increased to $77 million from $313 million used in the same period last year. The increase resulted from new financing partially offset by dividends to FirstEnergy.

OE had approximately $389.4 million of cash and temporary investments and approximately $189.1 million of short-term indebtedness as of June 30, 2003. Available borrowing capability under bilateral bank facilities totaled $20.0 million as of June 30, 2003. OE had the capability to issue $1.6 billion of additional first mortgage bonds on the basis of property additions and retired bonds. Based upon applicable earnings coverage tests OE could issue up to $2.2 billion of preferred stock (assuming no additional debt was issued) as of June 30, 2003.

On April 21, 2003, OE completed a $325 million debt refinancing transaction that included two tranches - $175 million of 4.00% five-year notes and $150 million of 5.45% twelve year notes. The net proceeds will be used to redeem approximately $220 million of outstanding OE first mortgage bonds having a weighted average cost of 7.99%, with the remainder to be used to pay down short-term debt. On May 12, 2003, OE completed a new two-year $250 million revolving credit facility.

In May and June of 2003, OE executed four fixed-to-floating interest rate swap agreements with notional values of $50 million each on underlying senior notes with an average fixed rate of 5.09%.

Cash Flows From Investing Activities

Net cash used for investing activities totaled $164 million in the second quarter of 2003, compared to $14 million for the same period of 2002. The $150 million increase in funds used for investing activities resulted from payments on notes to associated companies.

During the second half of 2003, capital requirements for property additions and capital leases are expected to be about $92 million, including $17 million for nuclear fuel. OE has additional requirements of approximately $220 million to meet sinking fund requirements for preferred stock and maturing long-term debt during the remainder of 2003. These cash requirements are expected to be satisfied from internal cash and short-term credit arrangements.

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

On August 7, 2003, S&P affirmed its "BBB" corporate credit rating for FirstEnergy. However, S&P stated that although FirstEnergy generates substantial free cash, that its strategy for reducing debt had deviated substantially from the one presented to S&P around the time of the GPU merger when the current rating was assigned. S&P further noted that their affirmation of FirstEnergy's corporate credit rating was based on the assumption that FirstEnergy would take appropriate steps quickly to maintain its investment grade ratings including the issuance of equity or possible sale of assets. Key issues being monitored by S&P include the restart of Davis-Besse, FirstEnergy's liquidity position, its ability to forecast provider-of-last-resort load and the performance of its hedged portfolio and continued capture of merger synergies. On August 11, 2003, S&P stated that a recent U.S. District Court ruling (see Environmental Matters below) with respect to the Sammis Plant is negative for FirstEnergy's credit quality.

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

Pension and Other Postretirement Benefits

As a result of GPU Service Inc. merging with FirstEnergy Service Company in the second quarter of 2003, operating company employees of GPU Service were transferred to JCP&L, Met-Ed and Penelec. Accordingly, FirstEnergy requested an actuarial study to update the pension and other post-employment benefit (OPEB) assets and liabilities for each of its subsidiaries. Based on the actuary's report, OE's accrued pension and OPEB costs as of June 30, 2003 increased by $66.8 million and $58.5 million, respectively.

Other Obligations

Obligations not included on OE's Consolidated Balance Sheet primarily consist of sale and leaseback arrangements involving Perry Unit 1 and Beaver Valley Unit 2. As of June 30, 2003, the present value of these sale and leaseback operating lease commitments, net of trust investments, total $693 million.

EQUITY PRICE RISK

Included in OE's nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $177 million and $148 million as of June 30, 2003 and December 31, 2002, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $18 million reduction in fair value as of June 30, 2003.

OUTLOOK

Beginning in 2001, OE's customers were able to select alternative energy suppliers. OE continues to deliver power to residential homes and businesses through its existing distribution system, which remains regulated. Customer rates have been restructured into separate components to support customer choice. In Ohio and Pennsylvania, the OE Companies have a continuing responsibility to provide power to those 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

In 2001, Ohio customer rates were restructured to establish separate charges for transmission, distribution, transition cost recovery and a generation-related component. When one of OE's Ohio customers elects to obtain power from an alternative supplier, OE reduces 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. OE has continuing PLR responsibility to its franchise customers through December 31, 2005.

Regulatory assets are costs which have been authorized by the Public Utilities Commission of Ohio (PUCO), Pennsylvania Public Utility Commission and the Federal Energy Regulatory Commission, for recovery from customers in future periods and, without such authorization, would have been charged to income when incurred. Regulatory assets declined $255.4 million to $1.8 billion on June 30, 2003 from the balance as of December 31, 2002, with $10.6 million of the decrease related to the cumulative entry adopting SFAS 143 at Penn and the balance of the reduction resulting from recovery of transition plan regulatory assets. All of the OE Companies' regulatory assets are expected to continue to be recovered under the provisions of their respective transition plan and rate restructuring plan. The OE Companies' regulatory assets are as follows:

REGULATORY ASSETS	JUNE 30, 2003	DECEMBER 31, 2002
	(IN MILLIONS)	
OE........................	$1,689.9	$1,848.7
Penn......................	60.3	156.9
Consolidated Total......	$1,750.2	$2,005.6

As part of OE's Ohio transition plan it is obligated to supply electricity to customers who do not choose an alternative supplier. OE is also required to provide 560 megawatts (MW) of low cost supply to unaffiliated alternative suppliers that serve customers within its service area. OE's competitive retail sales affiliate, FES, acts as an alternate supplier for a portion of the load in its franchise area. In 2003, the total peak load forecasted for customers electing to stay with OE, including the 560 MW of low cost supply and the load served by OE's affiliate is 5,820 MW.

Environmental Matters

OE believes it is 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 OE's Ohio and Pennsylvania facilities. Various regulatory and judicial actions have since sought to further define $NO_{(x)}$ reduction requirements (see Note 2 - Environmental Matters). OE continues to evaluate its 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. OE cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

In 1999 and 2000, the EPA issued Notices of Violation (NOV) or a Compliance Order to nine utilities covering 44 power plants, including the W. H. Sammis Plant. In addition, the U. S. Department of Justice filed eight civil complaints against various investor-owned utilities, which included a complaint against OE and Penn in the U.S. District Court for the Southern District of Ohio. The NOV and complaint allege violations of the Clean Air Act (CAA). The civil complaint against OE and Penn requests installation of "best available control technology" as well as civil penalties of up to $27,500 per day of violation. On August 7, the United States District Court for the Southern District of Ohio ruled that 11 projects undertaken at the W. H. Sammis Plant between 1984 and 1998 required pre-construction permits under the Clean Air Act. The ruling concludes the liability phase of the case, which deals with applicability of Prevention of Significant Deterioration provisions of the Clean Air Act. The remedy phase, which is currently scheduled to be ready for trial beginning March 15, 2004, will address civil penalties and what, if any, actions should be taken to further reduce emissions at the plant. In the ruling, the Court indicated that the remedies it "may consider and impose involved a much broader, equitable analysis, requiring the Court to consider air quality, public health, economic impact and employment consequences. The Court may also consider the less than consistent efforts of the EPA to apply and further enforce the Clean Air Act." The potential penalties that may be imposed, as well as the capital expenditures necessary to comply with substantive remedial measures they may be required, may have a material adverse impact on the Company's financial condition and results of operations. Management is unable to predict the ultimate outcome of this matter.

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.

OE believes it is in compliance with the current SO_2 and 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 Companies' 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 New Jersey, 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 NOx budgets at the Companies' Pennsylvania facilities by May 1, 2003 and Ohio submitted a SIP that requires compliance with the NO_x budgets at the Companies' Ohio facilities by May 31, 2004.

The effects of compliance on OE with regard to environmental matters could have a material adverse effect on its earnings and competitive position. These environmental regulations affect our earnings and competitive position to the extent OE 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. OE believes it is in material compliance with existing regulations, but is unable to predict how and when applicable environmental regulations may change and what, if any, the effects of any such change would be.

Legal Matters

Various lawsuits, claims and proceedings related to OE's normal business operations are pending against it, the most significant of which are described above.

SIGNIFICANT ACCOUNTING POLICIES

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

Regulatory Accounting

The OE Companies are subject to regulation that sets the prices (rates) they are permitted to charge their customers based on the costs that the regulatory agencies determine the OE Companies 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 and Pennsylvania, a significant amount of regulatory assets have been recorded. As of June 30, 2003, the OE Companies' regulatory assets totaled approximately $1.8 billion. OE regularly reviews 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

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

- Net energy generated or purchased for retail load
- Losses of energy over 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

FirstEnergy's reported costs of providing non-contributory defined pension benefits and 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 FirstEnergy makes 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 for 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, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. Due to the significant decline in corporate bond yields and interest rates in general during 2002, FirstEnergy reduced the assumed discount rate as of December 31, 2002 to 6.75% from 7.25% used in 2001.

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by its pension trusts. The market values of FirstEnergy's pension assets have been affected by sharp declines in the equity markets since mid-2000. In 2002 and 2001 plan assets earned (11.3)% and (5.5)%, respectively. FirstEnergy's 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 FirstEnergy's 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, FirstEnergy will not be required to fund its 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 the 2002 assumption of approximately 10% in 2002, gradually decreasing to 4%-6% in later years. In determining its trend rate assumptions, FirstEnergy included the specific provisions of its health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in its health care plans, and projections of future medical trend rates.

Ohio Transition Cost Amortization

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

Long-Lived Assets

In accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the OE Companies periodically evaluate their 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, the OE Companies recognize a loss - calculated as the difference between the carrying value and the estimated fair value of the asset (discounted future net cash flows).

RECENTLY ISSUED ACCOUNTING STANDARDS NOT YET IMPLEMENTED

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

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

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

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

In May 2003, the FASB issued SFAS 150, which establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. In accordance with the standard, certain financial instruments that embody obligations for the issuer are required to be classified as liabilities. SFAS 150 is effective immediately 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 (OE's third quarter of 2003) for all other financial instruments.

OE 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, OE expects to classify as debt the preferred stock of consolidated subsidiaries subject to mandatory redemptions with a carrying value of approximately $13.5 million as of June 30, 2003. Subsidiary preferred dividends on OE'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.

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

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THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	THREE MONTHS ENDED JUNE 30,	
	2003	2002 RESTATED (SEE NOTE 1)
	(IN THOUSANDS	
OPERATING REVENUES	$412,133	$462,874
OPERATING EXPENSES AND TAXES:		
Fuel	13,385	15,088
Purchased power	131,255	118,458
Nuclear operating costs	67,218	30,985
Other operating costs	63,286	61,053
Total operation and maintenance expenses	275,144	225,584
Provision for depreciation and amortization	53,311	53,133
General taxes	37,339	36,493
Income taxes	1,792	40,589
Total operating expenses and taxes	367,586	355,799
OPERATING INCOME	44,547	107,075
OTHER INCOME	4,684	3,356
INCOME BEFORE NET INTEREST CHARGES	49,231	110,431
NET INTEREST CHARGES:		
Interest on long-term debt	39,299	45,372
Allowance for borrowed funds used during construction	(1,637)	(747)
Other interest expense (credit)	5	(125)
Subsidiaries' preferred stock dividend requirements	2,250	2,250
Net interest charges	39,917	46,750
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	9,314	63,681

Cumulative effect of accounting change (net of income taxes of $30,168,000) (Note 5)	--	--	
NET INCOME	9,314	63,681	
PREFERRED STOCK DIVIDEND REQUIREMENTS	1,864	3,054	
EARNINGS ON COMMON STOCK	$ 7,450	$ 60,627	$

The preceding Notes to Financial Statements as they relate to The Cleveland Electric Illuminating Company are an integral part of these statements.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

CONSOLIDATED BALANCE SHEETS

	(UNAUDITED) JUNE 30, 2003
	(IN THOU
ASSETS	
UTILITY PLANT:	
In service	$ 4,194,157
Less - Accumulated provision for depreciation	1,860,624
	2,333,533
Construction work in progress-	
Electric plant	127,827
Nuclear fuel	24,309
	152,136
	2,485,669
OTHER PROPERTY AND INVESTMENTS:	
Shippingport Capital Trust	416,836
Nuclear plant decommissioning trusts	257,635
Long-term notes receivable from associated companies	102,741
Other	20,822
	798,034
CURRENT ASSETS:	
Cash and cash equivalents	159

Receivables -	
Customers	--
Associated companies	158,545
Other (less accumulated provisions of $1,000,000 and $1,015,000, respectively, for uncollectible accounts)	209,361
Notes receivable from associated companies	464
Materials and supplies, at average cost -	
Owned	16,913
Under consignment	28,663
Prepayments and other	3,024
	417,129
DEFERRED CHARGES:	
Regulatory assets	1,148,324
Goodwill	1,693,629
Property taxes	79,430
Other	24,044
	2,945,427
	$ 6,646,259

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

CONSOLIDATED BALANCE SHEETS

	(UNAUDITED) JUNE 30, 2003
	(IN THOU
CAPITALIZATION AND LIABILITIES	
CAPITALIZATION:	
Common stockholder's equity-	
Common stock, without par value, authorized 105,000,000 shares - 79,590,689 shares outstanding	$ 981,962
Accumulated other comprehensive loss	(19,323)
Retained earnings	328,208
Total common stockholder's equity	1,290,847
Preferred stock -	
Not subject to mandatory redemption	96,404
Subject to mandatory redemption	5,017
Company obligated mandatorily redeemable preferred securities of subsidiary trust holding solely Company subordinated debentures	100,000
Long-term debt	2,055,568
	3,547,836

CURRENT LIABILITIES:	
Currently payable long-term debt and preferred stock	158,279
Accounts payable-	
Associated companies	455,589
Other	5,904
Notes payable to associated companies	338,804
Accrued taxes	113,699
Accrued interest	48,199
Other	138,351
	1,258,825
DEFERRED CREDITS:	
Accumulated deferred income taxes	478,669
Accumulated deferred investment tax credits	68,400
Nuclear plant decommissioning costs	--
Asset retirement obligation	246,610
Retirement benefits	111,604
Lease market valuation liability	758,700
Other	175,615
	1,839,598
COMMITMENTS, GUARANTEES AND CONTINGENCIES (NOTE 2)	
	$ 6,646,259

The preceding Notes to Financial Statements as they relate to The Cleveland Electric Illuminating Company are an integral part of these balance sheets.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	THREE MONTHS ENDED JUNE 30,		
	2003	2002	
		RESTATED (SEE NOTE 1)	
			(IN THOUSANDS
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 9,314	$ 63,681	$
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation and amortization	53,311	53,133	
Nuclear fuel and lease amortization	2,995	4,794	

Other amortization................................	(409)	(4,275)	
Deferred income taxes, net........................	133	2,084	
Investment tax credits, net.......................	(1,201)	(1,270)	
Receivables.......................................	(163,454)	(38,473)	(
Materials and supplies............................	10,939	(1,840)	
Accounts payable..................................	223,375	8,057	
Cumulative effect of accounting charge (Note 5)....	-	-	
Accrued taxes.....................................	(15,458)	12,591	
Accrued interest..................................	(12,412)	(5,907)	
Prepayments and other.............................	(579)	7,103	
Deferred lease costs..............................	(222)	(51,545)	
Other...	18,122	(5,181)	
Net cash provided from operating activities......	124,454	42,952	
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing -			
Short-term borrowings, net..........................	16,976	-	
Redemptions and Repayments-			
Preferred stock....................................	(93)	-	
Long-term debt.....................................	(100,962)	(96)	(
Short-term borrowings, net..........................	-	(48,821)	
Dividend Payments-			
Preferred stock....................................	(1,865)	(3,133)	
Net cash used for financing activities...........	(85,944)	(52,050)	(
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions..................................	(30,805)	(25,452)	
Notes receivable from associated companies............	220	205	
Capital trust investments............................	-	27,394	
Other...	(8,592)	(8,021)	
Net cash used for investing activities...........	(39,177)	(5,874)	
Net decrease in cash and cash equivalents................	(667)	(14,972)	
Cash and cash equivalents at beginning of period..........	826	15,262	
Cash and cash equivalents at end of period...............	$ 159	$ 290	$

The preceding Notes to Financial Statements as they relate to The Cleveland Electric Illuminating Company are an integral part of these statements.

REPORT OF INDEPENDENT AUDITORS

To the Stockholders and Board of
Directors of The Cleveland
Electric Illuminating Company

We have reviewed the accompanying consolidated balance sheet of The Cleveland Electric Illuminating Company and its subsidiaries as of June 30, 2003, and the related consolidated statements of income and cash flows for each of the three-month and six-month periods ended June 30, 2003 and 2002. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with generally accepted auditing standards, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated interim financial statements, the Company has restated its previously issued consolidated interim financial statements for the quarter ended June 30, 2002.

We previously audited in accordance with auditing standards generally accepted in the United States of America, the consolidated balance sheet and the consolidated statement of capitalization as of December 31, 2002, and the related consolidated statements of income, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report (which contained references to the Company's change in its method of accounting for goodwill in 2002 as discussed in Note 1(D) to those consolidated financial statements and the Company's restatement of its previously issued consolidated financial statements as of December 31, 2002 and 2001 and for each of the three years in the period ended December 31, 2002 as discussed in Note 1(M) to those consolidated financial statements) dated August 18, 2003 we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2002, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio
August 18, 2003

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THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

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

CEI is a wholly owned, electric utility subsidiary of FirstEnergy. CEI conducts business in portions of Ohio, providing regulated electric distribution services. CEI also provides generation services to those customers electing to retain them as their power supplier. CEI provides power directly to alternative energy suppliers under CEI's transition plan. CEI has unbundled the price of electricity into its component elements - including generation, transmission, distribution and transition charges. Power supply requirements of CEI are provided by FES - an affiliated company.

RESTATEMENTS

As further discussed in Note 1 to the Consolidated Financial

Statements, CEI identified certain accounting matters that require restatement of the consolidated financial statements for the year ended December 31, 2002 and the three months ended March 31, 2003. The revisions reflect a change in the method of amortizing the costs associated with the Ohio transition plan and recognition of above-market values of certain leased generation facilities.

Transition Cost Amortization

As discussed in Note 4 - Regulatory Matters, CEI 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 2009 for CEI.

CEI amortizes transition costs using the effective interest method. The amortization schedules developed in applying this method were previously based on total transition revenues, including revenues designed to recover costs which have not yet been incurred or that were recognized on the regulatory financial statements (fair value purchase accounting adjustments). CEI has subsequently revised the amortization schedules under the effective interest method to consider only revenues relating to transition regulatory assets recognized on the balance sheet. The amortization expense under the revised method (see Note 1) increased by $24.8 million for the three months and $48.8 million for the six months ended June 30, 2002.

Above-Market Lease Costs

In 1997, FirstEnergy Corp. was formed through a merger between OE and Centerior Energy Corp. The merger was accounted for as an acquisition of Centerior, the parent company of CEI, under the purchase accounting rules of Accounting Principles Board (APB) Opinion No. 16. In connection with the reassessment of the accounting for the transition plan, FirstEnergy reassessed its accounting for the Centerior purchase and determined that above market lease liabilities should have been recorded at the time of the merger. Accordingly, as of 2002, FirstEnergy recorded 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 CEI had previously entered into sale-leaseback arrangements. CEI 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 liability would have increased goodwill at the date of the merger. The corresponding impact of the above market lease liabilities for the Bruce Mansfield Plant were recorded as regulatory assets because regulatory accounting had not been discontinued at that time for the fossil generating assets and recovery of these liabilities was provided for under the transition plan.

The total above market lease obligation of $611 million associated with Beaver Valley Unit 2 will be amortized through the end of the lease term in 2017. The additional goodwill has been recorded on a net basis, reflecting amortization that would have been recorded through 2001 when goodwill amortization ceased with the adoption of SFAS No. 142. The total above market lease obligation of $457 million associated with the Bruce Mansfield Plant is being amortized through the end of 2016. 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. Beginning in 2001, the remaining unamortized regulatory asset would have been included in CEI's amortization schedule for regulatory assets and amortized through the end of the recovery period - approximately 2009 for CEI.

RESULTS OF OPERATIONS

Earnings on common stock in the second quarter of 2003 decreased to $7.5 million from $60.6 million in the second quarter of 2002. Earnings on common stock in the first six months of 2003 included an after-tax credit of $42.4 million from the cumulative effect of an accounting change due to the adoption of SFAS 143, "Accounting for Asset Retirement Obligations." Income before the cumulative effect was $24.6 million in the first six months of 2003, compared to $78.6 million for the same period of 2002. Lower earnings in both periods resulted principally from lower revenues and higher operation and maintenance expenses in 2003 compared to 2002. Revenues were affected by mild weather in the second quarter after benefiting from unusually cold weather earlier in 2003. Higher nuclear costs as a result of the extended outage at Davis-Besse and additional unplanned work performed during the Perry Plant's nuclear refueling outage in the second quarter of 2003 was the largest factor contributing to the increased operation and maintenance expenses. Higher employee benefit costs and purchased power costs also contributed to the increased expenses.

Operating revenues decreased by $50.7 million or 11.0% in the second quarter and $64.2 million or 7.2% in the first six months of 2003 from the same periods of 2002 due to cooler-than-normal temperatures and increased sales by alternative suppliers. Kilowatt-hour sales to retail customers declined 16.5% in the second quarter and 10.5% in the first six months of 2003 from the corresponding periods of 2002, which reduced generation sales revenue by $22.0 million and $28.6 million, respectively. Mild temperatures in the second quarter of 2003 reduced sales to residential and commercial customers. Kilowatt-hour sales of electricity by alternative suppliers in CEI's franchise area increased by 12.2 percentage points in the second quarter and 10.8 percentage points in the first six months of 2003 from the corresponding periods last year.

Distribution deliveries were nearly unchanged in the second quarter and increased 5.4% in the first six months of 2003 compared to the corresponding periods of 2002. Lower unit prices and the change in distribution deliveries in the second quarter and first six months of 2003 contributed to an $11.3 million reduction in revenues in the second quarter and $4.2 million increase in revenues from electricity throughput in the first six months of 2003 compared to the same periods last year. Cooler-than-normal temperatures in the second quarter of 2003 reduced air-conditioning loads of residential and commercial customers while residential and commercial loads benefited from colder temperatures earlier in the year which increased demand in the first six months of 2003 compared to the corresponding periods from last year. As a result, deliveries to residential and commercial customers decreased by a combined 2.6% in the second quarter and increased 4.0% in the first six months of 2003 compared to the same periods of 2002. Distribution deliveries to industrial customers increased in the second quarter and first six months of 2003 despite the continued effect of a sluggish economy due in part to the expansion of steel production in the franchise area.

Further decreasing operating revenues were Ohio transition plan incentives, provided to customers to encourage switching to alternative energy providers - $4.7 million of additional credits in the second quarter and $10.5 million of additional credits in the first six months of 2003 compared with the corresponding periods of 2002. These revenue reductions are deferred for future recovery under CEI's transition plan and do not materially affect current period earnings.

Sales revenues from wholesale customers (primarily FES) decreased by $10.8 million in the second quarter and $21.5 million in the first six months of 2003 compared with the same periods of 2002. The lower sales resulted from reductions in available nuclear generation of 41.1% in the second quarter and 29.3% in the first half of 2003 compared to the corresponding periods of 2002. Available generation decreased due to the extended outage at Davis-Besse and generating capacity removed from service due to refueling activities in 2003 compared to 2002.

Changes in electric generation sales and distribution deliveries in the second quarter and first six months of 2003 from the corresponding periods of 2002 are summarized in the following table:

CHANGES IN KILOWATT-HOUR SALES	THREE MONTHS	SIX MONTHS
INCREASE (DECREASE)		
Electric Generation:		
Retail	(16.5)%	(10.5)%
Wholesale	(18.7)%	(18.2)%
TOTAL ELECTRIC GENERATION SALES	(17.5)%	(14.3)%
Distribution Deliveries:		
Residential	(3.7)%	5.1%
Commercial	(1.5)%	2.7%
Industrial	3.6%	7.0%
TOTAL DISTRIBUTION DELIVERIES	0.4%	5.4%

Operating Expenses and Taxes

Total operating expenses and taxes increased by $11.8 million in the second quarter and $4.2 million in the first six months of 2003 from the same periods of 2002. The following table presents changes from the prior year by expense category.

OPERATING EXPENSES AND TAXES - CHANGES	THREE MONTHS	SIX MONTHS
INCREASE (DECREASE)	(IN MILLIONS)	
Fuel	$ (1.7)	$ (6.3)
Purchased power costs	12.8	9.7
Nuclear operating costs	36.2	28.0
Other operating costs	2.2	7.2
TOTAL OPERATION AND MAINTENANCE EXPENSES	49.5	38.6
Provision for depreciation and amortization	0.2	(0.9)
General taxes	0.9	1.8
Income taxes	(38.8)	(37.7)
NET INCREASE IN OPERATING EXPENSES AND TAXES	$ 11.8	$ 1.8

Lower fuel costs in the second quarter and first six months of 2003, compared with the same periods of 2002 resulted from reduced nuclear generation. Higher purchased power costs primarily reflect increased unit costs in the second quarter and first six months of 2003 compared to the corresponding periods of 2002. Increased nuclear costs resulted from additional incremental costs associated with the extended Davis-Besse outage and unplanned work performed during the Perry nuclear plant's 56-day refueling outage (44.85% ownership) in the second quarter of 2003, compared with the 24-day refueling outage at Beaver Valley Unit 2 (24.47% ownership) in the first quarter of 2002. The increase in other operating costs in the second quarter and first six months of 2003, compared to the same periods of 2002 primarily resulted from higher employee benefit costs.

The small increase in depreciation and amortization charges in the second quarter of 2003, compared with the second quarter of 2002 was primarily attributable to three factors - increased amortization of regulatory assets being recovered under CEI's transition plan ($3.6 million) and recognition of depreciation on three fossil plants ($5.8 million) which had been held pending sale in the second quarter of 2002 but were subsequently retained by FirstEnergy in the fourth quarter of 2002. Substantially offsetting these three factors were higher shopping incentive deferrals ($4.7 million) and lower charges resulting from the implementation of SFAS 143 ($3.6 million). During the first six months of 2003 depreciation and amortization charges decreased slightly from the same period of 2002 primarily as the result of the same offsetting factors affecting the second quarter of 2003.

Net Interest Charges

Net interest charges continued to trend lower, decreasing by $6.8 million in the second quarter and $11.2 million in the first six months of 2003 from the same periods last year, reflecting redemption and refinancing activities. CEI's redemption and repricing activities during the first six months of 2003 totaled $115 million and $113 million, respectively, and are expected to result in annualized savings of approximately $9 million.

Cumulative Effect of Accounting Changes

Results for the first six months of 2003 include an after-tax credit to net income of $42.4 million recorded by CEI upon adoption of SFAS 143 in January of 2003. CEI identified applicable legal obligations as defined under the new accounting standard for nuclear power plant decommissioning, reclamation of a sludge disposal pond at the Bruce Mansfield Plant, and closure of two coal ash disposal sites. As a result of adopting SFAS 143 in January 2003, asset retirement costs of $49.9 million were recorded as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $6.8 million. The asset retirement obligation liability at the date of adoption was $238.3 million, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. As of December 31, 2002, CEI had recorded decommissioning liabilities of $239.7 million, including unrealized gains on the decommissioning trust funds of $0.4 million. The cumulative effect adjustment for unrecognized depreciation, accretion offset by the reduction in the existing decommissioning liabilities and ceasing the accounting practice of depreciating non-regulated generation assets using a cost of removal component was a $72.5 million increase to income, or $42.4 million net of income taxes.

Preferred Stock Dividend Requirements

Preferred stock dividend requirements decreased $8.5 million in the first six months of 2003, compared to the same period last year, principally due to optional redemptions of preferred stock in 2002.

CAPITAL RESOURCES AND LIQUIDITY

CEI's cash requirements in 2003 for operating expenses, construction expenditures, scheduled debt maturities and preferred stock redemptions are expected to be met without significantly increasing its 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, CEI expects to meet its contractual obligations with cash from operations. Thereafter, CEI expects to use a combination of cash from operations and funds from the capital markets.

Changes in Cash Position

As of June 30, 2003, CEI had $0.2 million of cash and cash equivalents, compared with $30.4 million as of December 31, 2002. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Cash provided by operating activities during the second quarter and first six months of 2003, compared with the corresponding periods in 2002 were as follows:

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
OPERATING CASH FLOWS	2003	2002	2003	2002
	(IN MILLIONS)			
Cash earnings (1)...........	$ 64	$118	$133	$187
Working capital and other...	60	(75)	(4)	(57)
Total......................	$ 124	$ 43	$129	$130

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

Net cash provided from operating activities increased $81 million in the second quarter of 2003 compared to the same period in 2002 due to a $135 million increase in working capital partially offset by a $54 million decrease in cash earnings. The largest factor contributing to the increase in working capital and other was primarily higher accounts payable.

Cash Flows From Financing Activities

In the second quarter and first six months of 2003, net cash used for financing activities increased $34 million and $18 million, respectively from the corresponding periods of 2002. The increase in funds used for financing activities primarily reflected higher security redemptions and repayments, which were partially offset by changes in short-term borrowings.

CEI had about $0.6 million of cash and temporary investments and approximately $338.8 million of short-term indebtedness as of June 30, 2003. CEI had the capability to issue $573.3 million of additional first mortgage bonds on the basis of property additions and retired bonds. CEI has no restrictions on the issuance of preferred stock.

Cash Flows From Investing Activities

Net cash used for investing activities increased $33 million in the second quarter of 2003 from the same quarter of 2002 due to a reduction in 2002 in the Shippingport Capital Trust investment and higher capital expenditures in 2003.

During the second half of 2003, capital requirements for property additions and capital leases are expected to be about $54 million, including $8 million for nuclear fuel. CEI has additional requirements of approximately $1 million to meet sinking fund requirements for preferred stock and maturing long-term debt during the remainder of 2003. These cash requirements are expected to be satisfied from internal cash and short-term credit arrangements.

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

On August 7, 2003, S&P affirmed its "BBB" corporate credit rating for FirstEnergy. However, S&P stated that although FirstEnergy generates substantial free cash, that its strategy for reducing debt had deviated substantially from the one presented to S&P around the time of the GPU merger when the current rating was assigned. S&P further noted that their affirmation of FirstEnergy's corporate credit rating was based on the assumption that FirstEnergy would take appropriate steps quickly to maintain its investment grade ratings including the issuance of equity or possible sale of assets. Key issues being monitored by S&P include the restart of Davis-Besse, FirstEnergy's liquidity position, its ability to forecast provider-of-last-resort load and the performance of its hedged portfolio and continued capture of merger synergies. On August 11, 2003, S&P stated that a recent U.S. District Court ruling (see Environmental Matters below) with respect to the Sammis Plant is negative for FirstEnergy's credit quality.

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

Pension and Other Postretirement Benefits

As a result of GPU Service Inc. merging with FirstEnergy Service Company in the second quarter of 2003, operating company employees of GPU Service were transferred to JCP&L, Met-Ed and Penelec. Accordingly, FirstEnergy requested an actuarial study to update the pension and other post-employment benefit (OPEB) assets and liabilities for each of its subsidiaries. Based on the actuary's report, CEI's accrued pension and OPEB costs as of June 30, 2003 decreased by $16.7 million and $49.5 million, respectively.

Other Obligations

Obligations not included on CEI's Consolidated Balance Sheet primarily consist of sale and leaseback arrangements involving the Bruce Mansfield Plant. As of June 30, 2003, the present value of these sale and leaseback operating lease commitments, net of trust investments, total $160 million. CEI sells substantially all of its retail customer receivables, which provided $96 million of off-balance sheet financing as of June 30, 2003.

EQUITY PRICE RISK

Included in CEI's nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $141 million and $119 million as of June 30, 2003 and December 31, 2002, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $14 million reduction in fair value as of June 30, 2003.

OUTLOOK

Beginning in 2001, CEI's customers were able to select alternative energy suppliers. CEI continues to deliver power to residential homes and businesses through its existing distribution systems, which remain regulated. Customer rates have been restructured into separate components to support customer choice. In Ohio CEI has a continuing responsibility to provide power to those 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

In 2001, Ohio customer rates were restructured to establish separate charges for transmission, distribution, transition cost recovery and a generation-related component. When one of CEI's customers elects to obtain power from an alternative supplier, CEI reduces 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. CEI has continuing PLR responsibility to its franchise customers through December 31, 2005.

Regulatory assets are costs which have been authorized by the PUCO and the Federal Energy Regulatory Commission for recovery from customers in future periods and, without such authorization, would have been charged to income when incurred. Regulatory assets decreased $43.5 million to $1,148.3 million as of June 30, 2003 from the balance as of December 31, 2002. All of CEI's regulatory assets are expected to continue to be recovered under the provisions of its transition plan.

As part of CEI's Ohio transition plan it is obligated to supply electricity to customers who do not choose an alternative supplier. CEI is also required to provide 400 megawatts (MW) of low cost supply to unaffiliated alternative suppliers that serve customers within its service area. CEI's competitive retail sales affiliate, FES, acts as an alternate supplier for a portion of the load in its franchise area.

Davis-Besse Restoration

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

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

Incremental costs associated with the extended Davis-Besse outage (CEI's share - 51.38%) for the second quarter and first six months of 2003 and 2002 were as follows:

COSTS OF DAVIS-BESSE EXTENDED OUTAGE	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30	
	2003	2002	2003	2002
	(IN MILLIONS)			
INCREMENTAL PRE-TAX EXPENSE				
Replacement power	$41.1	$33.6	$ 93.4	$33.6
Maintenance	22.4	12.1	58.6	12.1
TOTAL	$63.5	$45.7	$152.0	$45.7
CAPITAL EXPENDITURES	$ 2.4	$12.0	$ 2.4	$12.0

It is anticipated that an additional $22 million in maintenance costs will be expended over the remainder of the Davis-Besse outage. Replacement power costs are expected to be $15 million per month in the non-summer months and $20-25 million per month during the summer months of July and August.

FirstEnergy has hedged the on-peak replacement energy supply for Davis-Besse for the expected length of the outage.

Environmental Matters

CEI believes it is 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 its generating facilities. Various regulatory and judicial actions have since sought to further define NO(x) reduction requirements (see Note 2 - Environmental Matters). CEI continues to evaluate its 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. CEI 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.

CEI believes it is in compliance with the current SO(2) and 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 Companies' 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 New Jersey, 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 Companies' Pennsylvania facilities by May 1, 2003 and Ohio submitted a SIP that requires compliance with the NO(x) budgets at the Companies' Ohio facilities by May 31, 2004.

CEI 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 June 30, 2003, based on estimates of the total costs of cleanup, CEI's proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay. CEI's total accrued liabilities were approximately $2.5 million as of June 30, 2003.

The effects of compliance on CEI with regard to environmental matters could have a material adverse effect on its earnings and competitive position. These environmental regulations affect its earnings and competitive position to the extent CEI 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. CEI believes it is in material compliance with existing regulations, but is unable to predict how and when applicable environmental regulations may change and what, if any, the effects of any such change would be.

Legal Matters

Various lawsuits, claims and proceedings related to CEI's normal business operations are pending against CEI, the most significant of which are described above.

SIGNIFICANT ACCOUNTING POLICIES

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

Regulatory Accounting

CEI is subject to regulation that sets the prices (rates) it is permitted to charge its customers based on the costs that the regulatory agencies determine CEI is 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 a significant amount of regulatory assets have been recorded. As of June 30, 2003, CEI's regulatory assets totaled $1,148.3 million. CEI regularly reviews 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

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

- Net energy generated or purchased for retail load
- Losses of energy over 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

FirstEnergy's reported costs of providing non-contributory defined pension and OPEB benefits 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 FirstEnergy makes 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 for 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, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. Due to the significant decline in corporate bond yields and interest rates in general during 2002, FirstEnergy reduced the assumed discount rate as of December 31, 2002 to 6.75% from 7.25% used in 2001. FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by its pension trusts. The market values of FirstEnergy's pension assets have been affected by sharp declines in the equity markets since mid-2000. In 2002 and 2001, plan assets earned (11.3)% and (5.5)%, respectively. FirstEnergy's 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 FirstEnergy's 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, FirstEnergy will not be required to fund its 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 FirstEnergy's 2002 assumption of approximately 10% in 2002, gradually decreasing to 4%-6% in later years. In determining its trend rate assumptions, FirstEnergy included the specific provisions of its health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in its health care plans, and projections of future medical trend rates.

Ohio Transition Cost Amortization

In developing FirstEnergy'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 FirstEnergy's balance sheet prepared under GAAP since they included certain costs which have not yet been incurred or that were recognized on the regulatory financial statements (fair value purchase accounting adjustments). FirstEnergy uses an effective interest method for amortizing its transition costs, often referred to as a "mortgage-style" amortization.

The interest rate under this method is equal to the rate of return authorized by the PUCO in the transition plan for each respective company. In computing the transition cost amortization, FirstEnergy includes only the portion of the transition revenues associated with transition costs included on the balance sheet prepared under GAAP. Revenues collected for the off balance sheet costs and the return associated with these costs are recognized as income when received.

Long-Lived Assets

In accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," CEI periodically evaluates its 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, CEI recognizes a loss - calculated as the difference between the carrying value and the estimated fair value of the asset (discounted future net cash flows).

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by SFAS 142, CEI evaluates its 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, CEI 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. CEI's annual review was completed in the third quarter of 2002. The results of that review indicated no impairment of goodwill. The forecasts used in CEI's evaluations of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on its future evaluations of goodwill. As of June 30, 2003, CEI had approximately $1.7 billion of goodwill.

RECENTLY ISSUED ACCOUNTING STANDARDS NOT YET IMPLEMENTED

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 (CEI's third quarter of 2003). The FASB also identified transitional disclosure provisions for all financial statements issued after January 31, 2003.

CEI 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. One of these entities CEI 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., an affiliated company.

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

CEI 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, CEI classified as debt the preferred stock subject to mandatory redemptions with a carrying value of approximately $5.0 million as of June 30, 2003. Dividends on preferred stock subject to mandatory redemption in CEI's Consolidated Statements of Income are currently not included in net interest

charges. Therefore, the application of SFAS 150 will require the reclassification of such preferred dividends to net interest charges.

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. CEI 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 TOLEDO EDISON COMPANY

CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	THREE MONTHS ENDED JUNE 30,		
	2003	2002	
		RESTATED (SEE NOTE 1)	
		(IN THOUSANDS	
OPERATING REVENUES	$ 215,988	$ 250,307	$
OPERATING EXPENSES AND TAXES:			
Fuel	7,743	9,427	
Purchased power	74,225	79,352	
Nuclear operating costs	66,641	44,117	
Other operating costs	32,297	31,195	
Total operation and maintenance expenses	180,906	164,091	
Provision for depreciation and amortization	34,678	37,348	
General taxes	13,966	13,449	
Income taxes (benefit)	(11,482)	7,770	
Total operating expenses and taxes	218,068	222,658	
OPERATING INCOME (LOSS)	(2,080)	27,649	
OTHER INCOME	3,776	3,743	

INCOME BEFORE NET INTEREST CHARGES	1,696	31,392	
NET INTEREST CHARGES:			
Interest on long-term debt	11,631	15,601	
Allowance for borrowed funds used during construction	(1,184)	(382)	
Other interest expense (credit)	961	(360)	
Net interest charges	11,408	14,859	
INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	(9,712)	16,533	
Cumulative effect of accounting change (net of income taxes of $18,201,000) (Note 5)	--	--	
NET INCOME (LOSS)	(9,712)	16,533	
PREFERRED STOCK DIVIDEND REQUIREMENTS	2,211	2,210	
EARNINGS (LOSS) ON COMMON STOCK	$ (11,923)	$ 14,323	$

The preceding Notes to Financial Statements as they relate to The Toledo Edison Company are an integral part of these statements.

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THE TOLEDO EDISON COMPANY

CONSOLIDATED BALANCE SHEETS

	(UNAUDITED) JUNE 30, 2003
	(IN THOU
ASSETS	
UTILITY PLANT:	
In service	$ 1,696,989
Less--Accumulated provision for depreciation	734,675
	962,314
Construction work in progress-	
Electric plant	91,258
Nuclear fuel	22,414
	113,672

	1,075,986
OTHER PROPERTY AND INVESTMENTS:	
Shippingport Capital Trust	223,373
Nuclear plant decommissioning trusts	195,470
Long-term notes receivable from associated companies	162,059
Other	2,102
	583,004
CURRENT ASSETS:	
Cash and cash equivalents	10,309
Receivables-	
Customers	10,445
Associated companies	110,518
Other	8,233
Notes receivable from associated companies	10,796
Materials and supplies, at average cost-	
Owned	12,740
Under consignment	18,738
Prepayments and other	12,435
	194,214
DEFERRED CHARGES:	
Regulatory assets	537,251
Goodwill	504,522
Property taxes	23,429
Other	14,916
	1,081,118
	$ 2,933,322

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THE TOLEDO EDISON COMPANY

CONSOLIDATED BALANCE SHEETS

	(UNAUDITED) JUNE 30, 2003
	(IN THOU
CAPITALIZATION AND LIABILITIES	
CAPITALIZATION:	
Common stockholder's equity-	
Common stock, $5 par value, authorized 60,000,000 shares -	

39,133,887 shares outstanding	$ 195,669
Other paid-in capital	428,559
Accumulated other comprehensive loss	(5,564)
Retained earnings	88,801
Total common stockholder's equity	707,465
Preferred stock not subject to mandatory redemption	126,000
Long-term debt	501,938
	1,335,403
CURRENT LIABILITIES:	
Currently payable long-term debt	160,405
Accounts payable-	
Associated companies	173,255
Other	3,653
Notes payable to associated companies	281,245
Accrued taxes	35,448
Accrued interest	17,526
Other	103,998
	775,530
DEFERRED CREDITS:	
Accumulated deferred income taxes	198,151
Accumulated deferred investment tax credits	26,428
Nuclear plant decommissioning costs	--
Asset retirement obligation	163,603
Retirement benefits	57,849
Lease market valuation liability	304,900
Other	71,458
	822,389
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 2)	$ 2,933,322

The preceding Notes to Financial Statements as they relate to The Toledo Edison Company are an integral part of these balance sheets.

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THE TOLEDO EDISON COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	THREE MONTHS ENDED JUNE 30,	
	2003	2002
		RESTATED

	(SEE NOTE 1) (IN TH	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (9,712)	$ 16,533
Adjustments to reconcile net income (loss) to net cash from operating activities-		
Provision for depreciation and amortization	34,678	37,348
Nuclear fuel and lease amortization	1,820	2,671
Deferred income taxes, net	(2,138)	(4,322)
Investment tax credits, net	(514)	(527)
Receivables	(74,711)	(18,762)
Materials and supplies	5,877	(1,169)
Accounts payable	42,068	(9,210)
Cumulative effect of accounting change (Note 5)	--	--
Accrued taxes	(5,263)	15,091
Accrued interest	2,548	1,972
Prepayments and other	(3,858)	944
Deferred lease costs	(27,788)	(59,482)
Other	51,923	(5,560)
Net cash provided from (used for) operating activities	14,930	(24,473)
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Short-term borrowings, net	33,199	47,957
Redemptions and Repayments-		
Preferred stock	--	--
Long-term debt	(9,162)	(12,169)
Dividend Payments-		
Common stock	--	--
Preferred stock	(2,211)	(2,210)
Net cash provided from financing activities	21,826	33,578
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(17,540)	(14,702)
Loans to associated companies	(4,294)	(1,906)
Capital trust investments	(38)	16,883
Other	(6,020)	(11,536)
Net cash used for investing activities	(27,892)	(11,261)
Net increase (decrease) in cash and cash equivalents	8,864	(2,156)
Cash and cash equivalents at beginning of period	1,445	2,609
Cash and cash equivalents at end of period	$ 10,309	$ 453

The preceding Notes to Financial Statements as they relate to The Toledo Edison Company are an integral part of these statements.

REPORT OF INDEPENDENT AUDITORS

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

We have reviewed the accompanying consolidated balance sheet of The Toledo Edison Company and its subsidiary as of June 30, 2003, and the related consolidated statements of income and cash flows for each of the three-month and six-month periods ended June 30, 2003 and 2002. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with generally accepted auditing standards, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated interim financial statements, the Company has restated its previously issued consolidated interim financial statements for the quarter ended June 30, 2002.

We previously audited in accordance with auditing standards generally accepted in the United States of America, the consolidated balance sheet and the consolidated statement of capitalization as of December 31, 2002, and the related consolidated statements of income, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report (which contained references to the Company's change in its method of accounting for goodwill in 2002 as discussed in Note 1(D) to those consolidated financial statements and the Company's restatement of its previously issued consolidated financial statements as of December 31, 2002 and 2001 and for each of the three years in the period ended December 31, 2002 as discussed in Note 1(M) to those consolidated financial statements) dated August 18, 2003 we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2002, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio
August 18, 2003

THE TOLEDO EDISON COMPANY

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

TE is a wholly owned, electric utility subsidiary of FirstEnergy. TE conducts business in portions of Ohio, providing regulated electric distribution services. TE also provides generation services to those customers electing to retain them as their power supplier. TE provides power directly to wholesale customers under previously negotiated contracts, as well as to alternative energy suppliers under TE's transition plan. TE has unbundled the price of electricity into its component elements - including generation, transmission, distribution and transition charges. Power supply requirements of TE are provided by FES - an affiliated company.

RESTATEMENTS

As further discussed in Note 1 to the Consolidated Financial Statements, TE identified certain accounting matters that require restatement of the consolidated financial statements for the year ended December 31, 2002 and the three months ended March 31, 2003. The revisions reflect a change in the method of amortizing the costs associated with the Ohio transition plan and recognition of above-market values of certain leased generation facilities.

Transition Cost Amortization

As discussed in Note 4 - Regulatory Matters, 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 for TE.

TE amortizes transition costs using the effective interest method. The amortization schedules developed in applying this method were previously based on total transition revenues, including revenues designed to recover costs which have not yet been incurred or that were recognized on the regulatory financial statements (fair value purchase accounting adjustments). TE has subsequently revised the amortization schedules under the effective interest method to consider only revenues relating to transition regulatory assets recognized on the balance sheet. The amortization expense under the revised method (see Note 1) increased by $17.6 million for the three months and $34 million for the six months ended June 30, 2002.

Above-Market Lease Costs

In 1997, FirstEnergy Corp. was formed through a merger between OE and Centerior Energy Corp. 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, 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, as of 2002, FirstEnergy recorded 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. TE 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 liability would have increased goodwill at the date of the merger. The corresponding impact of the above market lease liabilities for the Bruce Mansfield Plant were recorded as regulatory assets because regulatory accounting had not been discontinued at that time for the fossil generating assets and recovery of these liabilities was provided for 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. The additional goodwill has been recorded on a net basis, reflecting amortization that would have been recorded through 2001 when goodwill amortization ceased with the adoption of 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. 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. Beginning in 2001, the remaining unamortized regulatory asset would have been included in TE's amortization schedule for regulatory assets and amortized through the end of the recovery period - approximately 2007 for TE.

RESULTS OF OPERATIONS

TE experienced a loss of $11.9 million on common stock in the second quarter of 2003 or a decrease of $26.2 million from earnings of $14.3 million in the second quarter of 2002. Earnings on common stock in the first six months of 2003 increased to $10.0 million from $9.9 million in the first half of 2002. Results in the first six months of 2003 included an after-tax credit of $25.60 million from the cumulative effect of an accounting change due to the adoption of SFAS 143, "Accounting for Asset Retirement Obligations." The loss before the cumulative effect was $11.1 million in the first half of 2003, compared to income of $16.9 million for the same period of 2002. The lower results in the second quarter and the first six months of 2003 before the cumulative effect reflected higher nuclear operating costs and lower operating revenues which were partially offset by lower fuel, purchased power, depreciation and amortization, and financing costs.

Operating revenues decreased by $34.3 million or 13.7% in the second quarter and $55.1 million or 10.9% in the first six months of 2003 from the same periods in 2002. The lower revenues resulted from reduced kilowatt-hour sales due, in large part, to the cooler-than-normal temperatures in the second quarter of 2003. These results were moderated in the first half of 2003 as compared to the corresponding period of 2002 by the effects of colder weather in the first quarter of 2003 which increased heating demands. Kilowatt-hour sales to retail customers declined by 16.4% in the second quarter of 2003 and 10.2% in the first half of 2003 from the same periods of 2002, which reduced generation sales revenue by $15.5 million and $27.1 million, respectively. Electric generation services provided to retail customers by alternative suppliers as a percent of total sales delivered in TE's franchise area increased 7.5 percentage points in the second quarter and first six months of 2003 from the corresponding periods last year.

Distribution deliveries decreased 8.3% in the second quarter and 1.5% in the first six months of 2003 compared to the corresponding periods of 2002. Decreases occurred in all customer sectors (residential, commercial and industrial) in the second quarter of 2003 and only residential sales increased in the first half of 2003. As a result, revenues from electricity throughput decreased by $10.8 million in the second quarter of 2003 from the second quarter of 2002. Revenues from electricity throughput increased by $9.8 million in the first six months of 2003 due to an increase in industrial sales revenues of $10.6 million which reflected the effect of higher unit prices partially offset by a 3.1% kilowatt-hour sales decrease as compared to the same period of 2002.

Transition plan incentives, provided to customers to encourage switching to alternative energy providers, reduced operating revenues by $1.2 million in the second quarter and $3.4 million in the first six months of 2003 compared with the same periods last year. These revenue reductions are deferred for future recovery under TE's transition plan and do not materially affect current period earnings.

Sales revenues from wholesale customers decreased by $6.3

million and $27.4 million (primarily to FES) in the second quarter and the first six months of 2003 compared with the same periods in 2002, due to reduced nuclear generation from the extended outage of the Davis-Besse Plant and a longer than planned refueling outage at Perry Plant. Available nuclear generation declined 32.4% in the second quarter and 30.8% in the first half of 2003 compared to the corresponding periods of 2002.

Changes in electric generation sales and distribution deliveries in the second quarter and the first half of 2003 from the second quarter and first half of 2002 are summarized in the following table:

CHANGES IN KILOWATT-HOUR SALES	THREE MONTHS	SIX MONTHS
INCREASE (DECREASE)		
Electric Generation:		
Retail	(16.4)%	(10.2)%
Wholesale	(17.1)%	(23.2)%
TOTAL ELECTRIC GENERATION SALES	(16.7)%	(15.9)%
Distribution Deliveries:		
Residential	(10.2)%	1.3%
Commercial	(12.4)%	(1.0)%
Industrial	(6.0)%	(3.1)%
TOTAL DISTRIBUTION DELIVERIES	(8.3)%	(1.5)%

Operating Expenses and Taxes

Total operating expenses and taxes decreased by $4.6 million in the second quarter and $20.1 million in the first six months of 2003 from the same periods in 2002. The following table presents changes from the prior year by expense category.

OPERATING EXPENSES AND TAXES - CHANGES	THREE MONTHS	SIX MONTHS
	(IN MILLIONS)	
INCREASE (DECREASE)		
Fuel	$ (1.7)	$ (5.4)
Purchased power costs	(5.1)	(13.3)
Nuclear operating costs	22.5	13.4
Other operating costs	1.1	8.0
TOTAL OPERATION AND MAINTENANCE EXPENSES	16.8	2.7
Provision for depreciation and amortization	(2.7)	(4.8)
General taxes	0.5	1.8
Income taxes	(19.2)	(19.8)
NET DECREASE IN OPERATING EXPENSES AND TAXES	$ (4.6)	$ (20.1)

Lower fuel costs in the second quarter and first half of 2003, compared with the same quarter and six months of 2002, resulted from reduced nuclear generation (down 32.4% and 30.8%, respectively). The lower purchased power costs reflected fewer kilowatt-hours required for customer needs which more than offset an increase in unit costs. Increased nuclear costs resulted from additional incremental costs associated with the extended Davis-Besse outage and unplanned work performed during the Perry nuclear plant's 56-day refueling outage (19.91% ownership) in the second quarter of 2003, compared with the 24-day refueling outage at Beaver Valley Unit 2 (19.91% ownership) in the first quarter of 2002. The increase in other operating costs resulted in part from higher employee benefit costs.

Charges for depreciation and amortization decreased by $2.7 million in the second quarter of 2003, compared with the second quarter of 2002 primarily from three factors - higher shopping incentive deferrals ($1.2 million), lower charges resulting from the implementation of SFAS 143 ($4.5 million) and revised service life assumptions for generating plants ($2.6 million). Partially offsetting these decreases were increased amortization of regulatory assets being recovered under TE's transition plan ($3.4 million), recognition of depreciation on the Bay Shore generating plant ($1.2 million) which had been held pending sale in the second quarter of 2002 but was subsequently retained by FirstEnergy in the fourth quarter of 2002 and reduced regulatory asset deferrals ($0.7 million).

In the first six months of 2003, depreciation and amortization decreased by $4.8 million compared to the corresponding period of 2002 as a result of the same factors which impacted the second quarter comparison - higher shopping incentive deferrals ($3.4 million), lower charges resulting from implementation of SFAS 143 ($8.2 million) and revised service life assumptions ($5.0 million). Partially offsetting these decreases were increased amortization of regulatory assets being recovered under TE's transition plan ($7.7 million), recognition of depreciation on the Bay Shore generating plant ($2.4 million) and reduced regulatory asset deferrals ($1.6 million).

Net Interest Charges

Net interest charges continued to trend lower, decreasing by $3.5 million in the second quarter and $7.5 million in the first half of 2003 from the same periods last year, reflecting security redemptions and refinancings since the beginning of the second quarter of 2002.

Cumulative Effect of Accounting Change

Upon adoption of SFAS 143 in the first quarter of 2003, TE recorded an after-tax credit to net income of $25.5 million. TE identified applicable legal obligations as defined under the new accounting standard for nuclear power plant decommissioning and reclamation of a sludge disposal pond at the Bruce Mansfield Plant. As a result of adopting SFAS 143 in January 2003, asset retirement costs of $41.1 million were recorded as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $5.5 million. The asset retirement obligation liability at the date of adoption was $172 million, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. As of December 31, 2002, TE had recorded decommissioning liabilities of $180.8 million, including unrealized gains on the decommissioning trust funds of $1.9 million. The cumulative effect adjustment for unrecognized depreciation, accretion offset by the reduction in the existing decommissioning liabilities and ceasing the accounting practice of depreciating non-regulated generation assets using a cost of removal component was a $43.8 million increase to income, or $25.6 million net of income taxes.

CAPITAL RESOURCES AND LIQUIDITY

TE's cash requirements in 2003 for operating expenses, construction expenditures, scheduled debt maturities and preferred stock redemptions are expected to be met without significantly increasing its 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, TE expects to meet its contractual obligations with cash from operations. Thereafter, TE expects to use a combination of cash from operations and funds from the capital markets.

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Changes in Cash Position

As of June 30, 2003, TE had $10.3 million of cash and cash equivalents, compared with $20.7 million as of December 31, 2002. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Cash provided by (used for) operating activities during the second quarter and first six months of 2003, compared with the corresponding periods in 2002 were as follows:

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
OPERATING CASH FLOWS	2003	2002	2003	2002
	(IN MILLIONS)			
Cash earnings (1)........	$24	$ 52	$ 62	$ 87
Working capital and other	(9)	(76)	(77)	(46)
TOTAL...................	$15	$(24)	$(15)	$ 41

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

Net cash provided from operating activities was $15 million in the second quarter and $15 million of net cash used in the first half of 2003 compared with $24 million and $41 million, respectively, in the corresponding periods of 2002. The second quarter increase in funds from operating activities resulted from a $67 million decrease in cash used for working capital.

Cash Flows From Financing Activities

In the second quarter of 2003, net cash provided from financing activities decreased to $22 million from $34 million in the second quarter of 2002. This decrease in cash provided from financing activities primarily resulted from lower short-term borrowings from associated companies and a slight reduction in security redemptions and repayments.

TE had approximately $21.1 million of cash and temporary investments and approximately $281.2 million of short-term indebtedness as of June 30, 2003. TE is currently precluded from issuing first mortgage bonds or preferred stock based upon applicable earnings coverage tests as of June 30, 2003.

Cash Flows From Investing Activities

Net cash used for investing activities increased $17 million between the second quarter of 2003 and the same quarter of 2002 due to a reduction in 2002 in the Shippingport Capital Trust investment.

During the second half of 2003, capital requirements for property additions and capital leases are expected to be about $34 million, including $6 million for nuclear fuel. TE has additional requirements of approximately $34 million to meet sinking fund requirements for preferred stock and maturing long-term debt during the remainder of 2003. These cash requirements are expected to be satisfied from internal cash and short-term credit arrangements.

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

On August 7, 2003, S&P affirmed its "BBB" corporate credit rating for FirstEnergy. However, S&P stated that although FirstEnergy generates substantial free cash, that its strategy for reducing debt had deviated substantially from the one presented to S&P around the time of the GPU merger when the current rating was assigned. S&P further noted that their affirmation of FirstEnergy's corporate credit rating was based on the assumption that FirstEnergy would take appropriate steps quickly to maintain its investment grade ratings including the issuance of equity or possible sale of assets. Key issues being monitored by S&P include the restart of Davis-Besse, FirstEnergy's liquidity position, its ability to forecast provider-of-last-resort load and the performance of its hedged portfolio and continued capture of merger synergies. On August 11, 2003, S&P stated that a recent U.S. District Court ruling (see Environmental Matters below) with respect to the Sammis Plant is negative for FirstEnergy's credit quality.

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

Pension and Other Postretirement Benefits

As a result of GPU Service Inc. merging with FirstEnergy Service Company in the second quarter of 2003, operating company employees of GPU Service were transferred to JCP&L, Met-Ed and Penelec. Accordingly, FirstEnergy requested an actuarial study to update the pension and other post-employment benefit (OPEB) assets and liabilities for each of its subsidiaries. Based on the actuary's report, TE's accrued pension and OPEB costs as of June 30, 2003 decreased by $3.4 million and $24.5 million, respectively.

Other Obligations

Obligations not included on TE's Consolidated Balance Sheet primarily consist of sale and leaseback arrangements involving the Bruce Mansfield Plant and Beaver Valley Unit 2. As of June 30, 2003, the present value of these sale and leaseback operating lease commitments, net of trust investments, totaled $474 million. TE sells substantially all of its retail customer receivables, which provided $49 million of off-balance sheet financing as of June 30, 2003.

EQUITY PRICE RISK

Included in TE's nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $107 million and $90 million as of June 30, 2003 and December 31, 2002, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $11 million reduction in fair value as of June 30, 2003.

OUTLOOK

Beginning in 2001, TE's customers were able to select alternative energy suppliers. TE continues to deliver power to residential homes and businesses through its existing distribution system, which remains regulated. Customer rates have been restructured into separate components to support customer choice. TE has a continuing responsibility to provide power to those 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

In 2001, Ohio customer rates were restructured to establish separate charges for transmission, distribution, transition cost recovery and a generation-related component. When one of TE's Ohio customers elects to obtain power from an alternative supplier, TE reduces 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. TE has continuing PLR responsibility to its franchise customers through December 31, 2005.

Regulatory assets are costs which have been authorized by The Public Utilities Commission of Ohio (PUCO) and the Federal Energy Regulatory Commission for recovery from customers in future periods and, without such authorization, would have been charged to income when incurred. Regulatory assets declined $41.0 million to $537.3 million as of June 30, 2003 from the balance as of December 31, 2002, resulting from recovery of transition plan regulatory assets.

As part of TE's transition plan it is obligated to supply electricity to customers who do not choose an alternative supplier. TE is also required to provide 160 megawatts (MW) of low cost supply to unaffiliated alternative suppliers that serve customers within its service area. TE's competitive retail sales affiliate, FES, acts as an alternate supplier for a portion of the load in its franchise area.

Davis-Besse Restoration

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

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

Incremental costs associated with the extended Davis-Besse outage (TE's share - 48.62%) for the second quarter and first six months of 2003 and 2002 were as follows:

COSTS OF DAVIS-BESSE EXTENDED OUTAGE	THREE MONTHS ENDED JUNE 30		SIX MONTHS ENDED JUNE 30	
	2003	2002	2003	2002
	(IN MILLIONS)			
INCREMENTAL PRE-TAX EXPENSE				
Replacement power	$ 41.1	$ 33.6	$ 93.4	$ 33.6
Maintenance	22.4	12.1	58.6	12.1
Total	$ 63.5	$ 45.7	$ 152.0	$ 45.7
CAPITAL EXPENDITURES	$ 2.4	$ 12.0	$ 2.4	$ 12.0

It is anticipated that an additional $22 million in maintenance costs will be expended over the remainder of the Davis-Besse outage. Replacement power costs are expected to be $15 million per month in the non-summer months and $20-25 million per month during the summer months of July and August.

FirstEnergy has hedged the on-peak replacement energy supply for Davis-Besse for the expected length of the outage.

Environmental Matters

TE believes it is 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 2C - Environmental Matters). TE continues to evaluate its 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.

TE believes it is in compliance with the current SO(2) and 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 Companies' 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 New Jersey, 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 Companies' Pennsylvania facilities by May 1, 2003 and Ohio submitted a SIP that requires compliance with the NO(x) budgets at the Companies' Ohio facilities by May 31, 2004.

TE 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 June 30, 2003, based on estimates of the total costs of cleanup, TE's proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay. TE has total accrued liabilities of approximately $0.2 million as of June 30, 2003.

The effects of compliance on TE with regard to environmental matters could have a material adverse effect on its earnings and competitive position. These environmental regulations affect its earnings and competitive position to the extent TE 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. TE believes it is in material compliance with existing regulations, but is unable to predict how and when applicable environmental regulations may change and what, if any, the effects of any such change would be.

Legal Matters

Various lawsuits, claims and proceedings relayed to TE's normal business operations are pending against TE, the most significant of which are described above.

SIGNIFICANT ACCOUNTING POLICIES

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

Regulatory Accounting

TE is subject to regulation that sets the prices (rates) it is permitted to charge its customers based on the costs that the regulatory agencies determine TE is 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, a significant amount of regulatory assets have been recorded. As of June 30, 2003, TE's regulatory assets totaled $548.5 million. TE regularly reviews 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

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

- Net energy generated or purchased for retail load
- Losses of energy over 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

FirstEnergy's reported costs of providing non-contributory defined pension and OPEB benefits 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 FirstEnergy makes 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 for 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, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. Due to the significant decline in corporate bond yields and interest rates in general during 2002, FirstEnergy reduced the assumed discount rate as of December 31, 2002 to 6.75% from 7.25% used in 2001.

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by its pension trusts. The market values of FirstEnergy's pension assets have been affected by sharp declines in the equity markets since mid-2000. In 2002 and 2001, plan assets earned (11.3)% and (5.5)%, respectively. FirstEnergy's 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 FirstEnergy's 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, FirstEnergy will not be required to fund its 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 the 2002 assumption of approximately 10% in 2002, gradually decreasing to 4%-6% in later years. In determining its trend rate assumptions, FirstEnergy included the specific provisions of its health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in its health care plans, and projections of future medical trend rates.

Ohio Transition Cost Amortization

In developing FirstEnergy'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 FirstEnergy's balance sheet prepared under GAAP since they included certain costs which have not yet been incurred or that were recognized on the regulatory financial statements (fair value purchase accounting adjustments). FirstEnergy uses an effective interest method for amortizing its transition costs, often referred to as a "mortgage-style" amortization. The interest rate under this method is equal to the rate of return authorized by the PUCO in the transition plan for each

respective company. In computing the transition cost amortization, FirstEnergy includes only the portion of the transition revenues associated with transition costs included on the balance sheet prepared under GAAP. Revenues collected for the off balance sheet costs and the return associated with these costs are recognized as income when received.

Long-Lived Assets

In accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," TE periodically evaluates its 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, TE recognizes a loss - calculated as the difference between the carrying value and the estimated fair value of the asset (discounted future net cash flows).

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by SFAS 142, TE evaluates its 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, TE 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. TE's annual review was completed in the third quarter of 2002. The results of that review indicated no impairment of goodwill. The forecasts used in TE's evaluations of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on its future evaluations of goodwill. As of June 30, 2003, TE had approximately $505 million of goodwill.

RECENTLY ISSUED ACCOUNTING STANDARD NOT YET IMPLEMENTED

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.

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.

PENNSYLVANIA POWER COMPANY

STATEMENTS OF INCOME
(UNAUDITED)

	THREE MONTHS ENDED JUNE 30, 2003	THREE MONTHS ENDED JUNE 30, 2002
	(IN THOUSANDS	
OPERATING REVENUES	$116,559	$127,737
OPERATING EXPENSES AND TAXES:		
Fuel	4,218	6,379
Purchased power	36,954	35,663
Nuclear operating costs	35,428	19,473
Other operating costs	10,060	9,717
Total operation and maintenance expenses	86,660	71,232
Provision for depreciation and amortization	13,480	14,208
General taxes	5,879	6,006
Income taxes	4,268	14,835
Total operating expenses and taxes	110,287	106,281
OPERATING INCOME	6,272	21,456
OTHER INCOME	563	476
INCOME BEFORE NET INTEREST CHARGES	6,835	21,932
NET INTEREST CHARGES:		
Interest expense	4,112	4,268
Allowance for borrowed funds used during construction	(699)	(345)
Net interest charges	3,413	3,923
INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	3,422	18,009
Cumulative effect of accounting change (net of income taxes of $7,532,000) (Note 5)	--	--
NET INCOME	3,422	18,009
PREFERRED STOCK DIVIDEND REQUIREMENTS	911	926
EARNINGS ON COMMON STOCK	$ 2,511	$ 17,083

The preceding Notes to Financial Statements as they relate to Pennsylvania Power Company are an integral part of these statements.

PENNSYLVANIA POWER COMPANY

BALANCE SHEETS

	(UNAUDITED) JUNE 30, 2003
	(IN THOU
ASSETS	
UTILITY PLANT:	
In service	$791,429
Less-Accumulated provision for depreciation	315,835
	475,594
Construction work in progress-	
Electric plant	55,785
Nuclear fuel	1,402
	57,187
	532,781
OTHER PROPERTY AND INVESTMENTS:	
Nuclear plant decommissioning trusts	126,425
Long-term notes receivable from associated companies	38,724
Other	2,459
	167,608
CURRENT ASSETS:	
Cash and cash equivalents	41
Receivables-	
Customers (less accumulated provisions of $775,000 and $702,000, respectively, for uncollectible accounts)	42,672
Associated companies	22,233
Other	706
Notes receivable from associated companies	10,901
Materials and supplies, at average cost	30,829
Prepayments	17,824
	125,206
DEFERRED CHARGES:	
Regulatory assets	60,306
Other	7,502
	67,808
	$893,403

PENNSYLVANIA POWER COMPANY

BALANCE SHEETS

	(UNAUDITED) JUNE 30, 2003
	(IN THOU
CAPITALIZATION AND LIABILITIES	
CAPITALIZATION:	
Common stockholder's equity-	
Common stock, $30 par value, authorized 6,500,000 shares - 6,290,000 shares outstanding	$188,700
Other paid-in capital	(310)
Accumulated other comprehensive loss	(22,259)
Retained earnings	32,379
Total common stockholder's equity	198,510
Preferred stock-	
Not subject to mandatory redemption	39,105
Subject to mandatory redemption	13,500
Long-term debt	171,030
	422,145
CURRENT LIABILITIES:	
Currently payable long-term debt and preferred stock	80,524
Accounts payable-	
Associated companies	50,111
Other	357
Accrued taxes	21,308
Accrued interest	5,582
Other	8,607
	166,489
DEFERRED CREDITS:	
Accumulated deferred income taxes	102,722
Accumulated deferred investment tax credits	3,663
Asset retirement obligation	125,387
Nuclear plant decommissioning costs	--
Other	72,997
	304,769
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 2)	
	$893,403

The preceding Notes to Financial Statements as they relate to Pennsylvania Power Company are an integral part of these balance sheets.

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PENNSYLVANIA POWER COMPANY

STATEMENTS OF CASH FLOWS
(UNAUDITED)

	THREE MONTHS ENDED JUNE 30,	
	2003	2002
	(IN THOUSA	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 3,422	$ 18,009
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation and amortization	13,480	14,208
Nuclear fuel and lease amortization	3,206	4,852
Deferred income taxes, net	(2,368)	(1,950)
Investment tax credits, net	(608)	(655)
Cumulative effect of accounting change (Note 5)	--	--
Receivables	4,278	(3,338)
Materials and supplies	(89)	(1,711)
Accounts payable	(30,005)	(3,147)
Accrued taxes	4,530	12,439
Accrued interest	2,033	1,707
Prepayments and other	3,810	4,687
Other	7,576	826
Net cash provided from operating activities	9,265	45,927
CASH FLOWS FROM FINANCING ACTIVITIES:		
Redemptions and Repayments-		
Long-term debt	(601)	(623)
Dividend Payments-		
Common stock	(13,000)	--
Preferred stock	(911)	(926)
Net cash used for financing activities	(14,512)	(1,549)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(9,680)	(8,343)
Capital trust investments	(7,155)	(5,274)
Notes receivable from associated companies, net	19,692	(36,357)
Other	604	5,185
Net cash provided from (used for) investing activities	3,461	(44,789)
Net increase (decrease) in cash and cash equivalents	(1,786)	(411)
Cash and cash equivalents at beginning of period	1,827	1,001
Cash and cash equivalents at end of period	$ 41	$ 590

The preceding Notes to Financial Statements as they relate to Pennsylvania Power Company are an integral part of these statements.

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REPORT OF INDEPENDENT AUDITORS

To the Stockholders and Board
of Directors of Pennsylvania
Power Company:

We have reviewed the accompanying balance sheet of Pennsylvania Power Company as of June 30, 2003, and the related statements of income and cash flows for each of the three-month and six-month periods ended June 30, 2003 and 2002. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with generally accepted auditing standards, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited in accordance with auditing standards generally accepted in the United States of America, the balance sheet and the statement of capitalization as of December 31, 2002, and the related statements of income, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report dated February 28, 2003 we expressed an unqualified opinion on those financial statements. In our opinion, the information set forth in the accompanying balance sheet as of December 31, 2002, is fairly stated in all material respects in relation to the balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio
August 18, 2003

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PENNSYLVANIA POWER COMPANY

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

Penn is a wholly owned, electric utility subsidiary of OE. Penn conducts business in western Pennsylvania, providing regulated electric distribution services. Penn also provides generation services to those customers electing to retain it as their power supplier. Penn provides power directly to wholesale customers under previously negotiated contracts. Penn has unbundled the price of electricity into its component elements - including generation, transmission, distribution and transition charges. Its power supply requirements are provided by FES - an affiliated company.

RESULTS OF OPERATIONS

Earnings on common stock in the second quarter of 2003 decreased to $2.5 million from $17.1 million in the second quarter of 2002. In the first six months of 2003, earnings on common stock decreased to $7.5 million from $28.1 million in the first six months of 2002. Earnings in the first half of 2003 included an after-tax credit of $10.6 million from the cumulative effect of an accounting change due to the adoption of SFAS 143, "Accounting for Asset Retirement Obligations." The loss before the cumulative effect was $1.3 million in the first half of 2003 compared to income of $30.0 million for the same period of 2002. The lower results in both periods of 2003 reflected lower operating revenues and higher operating expenses - primarily nuclear operating costs, purchased power costs and employee benefit costs. These increases were partially offset by lower fuel costs and reduced financing costs, compared with the second quarter and first six months of 2002.

Operating revenues decreased by $11.2 million, or 8.8% in the second quarter and $7.2 million, or 2.8% in the first six months of 2003 compared with the same periods in 2002. The lower revenues resulted from decreased retail sales revenues and lower sales to FES. Kilowatt-hour sales to retail customers were lower by 13.8% in the second quarter and 2.8% in the first half of 2003 from the same periods of 2002, which decreased generation sales revenue by $4.5 million and $2.6 million, respectively. The second quarter 2003 decreases were caused by cooler-than-normal temperatures which reduced air conditioning demands in all retail sectors. These decreases were moderated in the first six months by colder temperatures in the first quarter of 2003 that increased heating demands.

Distribution deliveries decreased 13.8% in the second quarter of 2003 and 3.2% in the first half of 2003 compared with the corresponding periods of 2002, with decreases in all customer sectors (residential, commercial and industrial). The weather related effects discussed above resulted in the lower distribution deliveries and decreased revenues from electricity throughput by approximately $5.2 million in the second quarter and $4.3 million in the first six months of 2003 from the respective quarter and first six months of the prior year.

Wholesale revenues decreased by $1.5 million in the second quarter and increased $0.5 million in the first half of 2003 compared to the corresponding periods of 2002 due to lower sales to FES. The lower sales resulted from reductions in available nuclear generation. Lower revenues resulted from reductions in nuclear generation (down 31.8% for the second quarter and 27.0% in the first half of 2003) which decreased sales to FES in both periods of 2003, but was more than offset in the six-month period by increased sales to non-associated companies.

Changes in electric generation sales and distribution deliveries in the second quarter and first six months of 2003 from the same periods of 2002 are summarized in the following table:

CHANGES IN KILOWATT-HOUR SALES	THREE MONTHS	SIX MONTHS
INCREASE (DECREASE)		
Electric Generation:		
Retail............................	(13.6)%	(2.8)%
Wholesale.........................	(29.2)%	(25.1)%
TOTAL ELECTRIC GENERATION SALES.......	(23.1)%	(16.3)%
Distribution Deliveries:		
Residential.......................	(14.3)%	(1.1)%
Commercial........................	(8.2)%	(0.6)%
Industrial........................	(17.5)%	(7.3)%
TOTAL DISTRIBUTION DELIVERIES.........	(13.8)%	(3.2)%

Operating Expenses and Taxes

Total operating expenses and taxes increased by $4.0 million in the second quarter and $25.0 million in the first half of 2003 from the second quarter and first half of 2002. The following table presents changes from the prior year by expense category.

OPERATING EXPENSES AND TAXES - CHANGES	THREE MONTHS	SIX MONTHS
	(IN MILLIONS)	
INCREASE (DECREASE)		
Fuel...	$ (2.2)	$ (3.8)
Purchased power costs..........................	1.3	5.4
Nuclear operating costs........................	16.0	40.6
Other operating costs..........................	0.3	6.9
TOTAL OPERATION AND MAINTENANCE EXPENSES......	15.4	49.1
Provision for depreciation and amortization......	(0.7)	(1.7)
General taxes..................................	(0.1)	0.1
Income taxes...................................	(10.6)	(22.5)
TOTAL INCREASE IN OPERATING EXPENSES AND TAXES	$ 4.0	$ 25.0

Lower fuel costs in the second quarter and first half of 2003, compared with the same periods of 2002, resulted from reduced nuclear generation. The increased purchased power costs in both periods of 2003 reflected higher units costs partially offset by decreased kilowatt-hour purchases due to lower demand by generation customers. Higher nuclear operating costs occurred in large part due to the refueling outages at Beaver Valley Unit 1 (65.00% ownership) in the first quarter of 2003 and at Perry (5.24% ownership) in the second quarter of 2003 compared with refueling outage costs at Beaver Valley Unit 2 (13.74% ownership) in the first quarter of 2002. The increase in other operating costs reflects higher employee benefit costs and increased uncollectible customer accounts.

Charges for depreciation and amortization decreased by $0.7 million in the second quarter and $1.7 million in the first half of 2003 compared to the second quarter and first half of 2002 primarily from lower charges resulting from the implementation of SFAS 143 ($0.3 million for the second quarter and $0.9 million for the first half of 2003) and revised service life assumptions for generating plants ($0.3 million for the second quarter and $0.6 million for the first half of 2003).

Net Interest Charges

Net interest charges continued to trend lower, decreasing by approximately $0.5 million in the second quarter and $0.9 million in the first six months of 2003 from the same periods last year, reflecting redemptions and refinancings since the beginning of the second quarter of 2002.

Cumulative Effect of Accounting Change

Upon adoption of SFAS 143 in the first quarter of 2003, Penn recorded an after-tax credit to net income of $10.6 million. Penn identified applicable legal obligations as defined under the new standard for nuclear power plant decommissioning and reclamation of a sludge disposal pond at the Bruce Mansfield Plant. As a result of adopting SFAS 143 in January 2003, asset retirement costs of $78 million were recorded as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $9 million. The asset retirement obligation (ARO) liability at the date of adoption was $121 million, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. As of December 31, 2002, Penn had recorded decommissioning liabilities of $120 million. Penn expects substantially all of its nuclear decommissioning costs to be recoverable in rates over time. Therefore, it recognized a regulatory liability of $69 million upon adoption of SFAS 143 for the transition amounts related to establishing the ARO for nuclear decommissioning. The remaining cumulative effect adjustment for unrecognized depreciation, offset by the reduction in the liabilities and ceasing the accounting practice of depreciating non-regulated generation assets using a cost of removal component, was an $18.2 million increase to income, or $10.6 million net of income taxes (see Note 5).

CAPITAL RESOURCES AND LIQUIDITY

Penn's cash requirements in 2003 for operating expenses, construction expenditures, scheduled debt maturities and preferred stock redemptions are expected to be met without materially increasing its 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, Penn expects to meet its contractual obligations with cash from operations. Thereafter, Penn expects to use a combination of cash from operations and funds from the capital markets.

Changes in Cash Position

As of June 30, 2003, Penn had $41,000 of cash and cash equivalents, compared with $1.2 million as of December 31, 2002. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Cash flows provided from operating activities during the second quarter and first six months of 2003, compared with the corresponding periods in 2002 were as follows:

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
OPERATING CASH FLOWS	2003	2002	2003	2002
	(IN MILLIONS)			
Cash earnings (1)...........	$ 17	$ 34	$ 27	$ 62
Working capital and other...	(8)	12	23	(10)
Total......................	$ 9	$ 46	$ 50	$ 52

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

Net cash from operating activities decreased to $9 million in the second quarter and $50 million in the first half of 2003 compared with $46 million and $52 million, respectively, in the same period of 2002. The decrease in working capital and other primarily was due to a decrease of $27 million in accounts payable from associated companies in the second quarter of 2003 compared with corresponding amounts in the second quarter of 2002. A decrease in accounts receivable also contributed $8 million to the increase in cash provided from working capital. The decrease in cash earnings in the second quarter of 2003 compared with the second quarter of 2002 primarily resulted from higher nuclear operating costs.

Cash Flows From Financing Activities

In the second quarter of 2003, net cash used for financing activities increased to $15 million from $2 million in the same period last year. The increase resulted from dividends to OE.

Penn had approximately $10.9 million of cash and temporary investments, primarily composed of notes receivable from associated companies and no short-term indebtedness as of June 30, 2003. Penn may borrow from its affiliates on a short-term basis. Penn had the capability to issue $193 million of additional first mortgage bonds on the basis of property additions and retired bonds. Based upon applicable earnings coverage tests, Penn could not issue preferred stock as of June 30, 2003.

Cash Flows From Investing Activities

Net cash provided from investing activities totaled $3 million in the second quarter and net cash used of $22 million in the first six months of 2003, compared to a net cash flows used for investing activities of $45 million and $1 million for the same periods of 2002, respectively. The $48 million change in funds for the second quarter resulted from higher payments received on notes from associated companies.

During the remaining half of 2003, capital requirements for property additions and capital leases are expected to be about $36 million, including $4 million for nuclear fuel. Penn has additional requirements of approximately $41 million to meet sinking fund requirements for preferred stock and maturing long-term debt during the remainder of 2003. These cash requirements are expected to be satisfied from internal cash and short-term credit arrangements.

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

On August 7, 2003, S&P affirmed its "BBB" corporate credit rating for FirstEnergy. However, S&P stated that although FirstEnergy generates substantial free cash, that its strategy for reducing debt had deviated substantially from the one presented to S&P around the time of the GPU merger when the current rating was assigned. S&P further noted that their affirmation of FirstEnergy's corporate credit rating was based on the assumption that FirstEnergy would take

appropriate steps quickly to maintain its investment grade ratings including the issuance of equity or possible sale of assets. Key issues being monitored by S&P include the restart of Davis-Besse, FirstEnergy's liquidity position, its ability to forecast provider-of-last-resort load and the performance of its hedged portfolio and continued capture of merger synergies. On August 11, 2003, S&P stated that a recent U.S. District Court ruling (see Environmental Matters below) with respect to the Sammis Plant is negative for FirstEnergy's credit quality.

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

Pension and Other Postretirement Benefits

As a result of GPU Service Inc. merging with FirstEnergy Service Company in the second quarter of 2003, operating company employees of GPU Service were transferred to JCP&L, Met-Ed and Penelec. Accordingly, FirstEnergy requested an actuarial study to update the pension and other post-employment benefit (OPEB) assets and liabilities for each of its subsidiaries. Based on the actuary's report, Penn's accrued pension and OPEB costs as of June 30, 2003 increased by $15.9 million and $9.8 million, respectively.

EQUITY PRICE RISK

Included in Penn's nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $43 million and $38 million as of June 30, 2003 and December 31, 2002, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $4 million reduction in fair value as of June 30, 2003.

OUTLOOK

Beginning in 1999, Penn's customers were able to select alternative energy suppliers and customer rates have been restructured into separate components to support customer choice. Currently, a number of customers previously electing to be served by alternative energy providers returned to Penn for their energy needs. Penn has a continuing responsibility to provide power to those 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. Penn continues to deliver power to residential homes and businesses through its existing distribution system, which remains regulated.

Regulatory Matters

Regulatory assets are costs which have been authorized by the PPUC and the Federal Energy Regulatory Commission, for recovery from customers in future periods and, without such authorization, would have been charged to income when incurred. Regulatory assets declined $96.6 million to $60.3 million on June 30, 2003 from the balance as of December 31, 2002, with $69.2 million of the decrease related to the cumulative entry adopting SFAS 143. All of Penn's regulatory assets are expected to continue to be recovered under the provisions of its regulatory plan.

As part of Penn's transition plan it is obligated to supply electricity to customers who do not choose an alternative supplier. Penn's competitive retail sales affiliate, FES, acts as an alternate supplier for a portion of the load in Penn's franchise area.

Environmental Matters

Penn believes it is 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 Penn's Ohio and Pennsylvania facilities. Various regulatory and judicial actions have since sought to further define NO_x reduction requirements (see Note 2 - Environmental Matters). Penn continues to evaluate its 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. Penn cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

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In 1999 and 2000, the EPA issued Notices of Violation (NOV) or a Compliance Order to nine utilities covering 44 power plants, including the W.H. Sammis Plant. In addition, the U.S. Department of Justice filed eight civil complaints against various investor-owned utilities, which included a complaint against OE and Penn in the U.S. District Court for the Southern District of Ohio. The NOV and complaint allege violations of the Clean Air Act (CAA). The civil complaint against OE and Penn requests installation of "best available control technology" as well as civil penalties of up to $27,500 per day of violation. On August 7, the United States District Court for the Southern District of Ohio ruled that 11 projects undertaken at the Sammis Plant between 1984 and 1998 required pre-construction permits under the Clean Air Act. The ruling concludes the liability phase of the case, which deals with applicability of Prevention of Significant Deterioration provisions of the Clean Air Act. The remedy phase, which is currently scheduled to be ready for trial beginning March 15, 2004, will address civil penalties and what, if any, actions should be taken to further reduce emissions at the plant. In the ruling, the Court indicated that the remedies it "may consider and impose involved a much broader, equitable analysis, requiring the Court to consider air quality, public health, economic impact and employment consequences. The Court may also consider the less than consistent efforts of the EPA to apply and further enforce the Clean Air Act." The potential penalties that may be imposed, as well as the capital expenditures necessary to comply with substantive remedial measures they may be required, may have a material adverse impact on the Company's financial condition and results of operations. Management is unable to predict the ultimate outcome of this matter.

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.

Penn believes it is in compliance with the current SO(2) and 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 its 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 New Jersey, 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 required compliance with the NO(x) budgets at Penn's Pennsylvania facilities by May 1, 2003.

The effects of compliance on Penn with regard to environmental matters could have a material adverse effect on its earnings and competitive position. These environmental regulations affect Penn'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. Penn believes it is in material compliance with existing regulations, but are unable to predict how and when applicable environmental regulations may change and what, if any, the effects of any such change would be.

Legal Matters

Various lawsuits, claims and proceedings relayed to Penn's normal business operations are pending against Penn, the most significant of which are described above.

SIGNIFICANT ACCOUNTING POLICIES

Penn prepares its consolidated financial statements in accordance with accounting principles that are generally accepted in the United States. Application of these principles often requires a high degree of judgment, estimates and assumptions that affect Penn's financial results. All of Penn's assets are subject to their own specific risks and uncertainties and are regularly reviewed for impairment. Penn's more significant accounting policies are described below.

Regulatory Accounting

Penn is subject to regulation that sets the prices (rates) it is permitted to charge its customers based on the costs that the regulatory agencies determine Penn is 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 Pennsylvania, a significant amount of regulatory assets have been recorded. As of June 30, 2003, Penn's regulatory assets totaled $60 million. Penn regularly reviews 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

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

- Net energy generated or purchased for retail load

- Losses of energy over distribution lines

- Allocations to distribution companies within the FirstEnergy system o Mix of kilowatt-hour usage by residential, commercial and industrial customers o Kilowatt-hour usage of customers receiving electricity from alternative suppliers

Pension and Other Postretirement Benefits Accounting

FirstEnergy's reported costs of providing non-contributory defined pension benefits and 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 FirstEnergy makes 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 for 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, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. Due to the significant decline in corporate bond yields and interest rates in general during 2002, FirstEnergy reduced the assumed discount rate as of December 31, 2002 to 6.75% from 7.25% used in 2001.

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by its pension trusts. The market values of FirstEnergy's pension assets have been affected by sharp declines in the equity markets since mid-2000. In 2002 and 2001, plan assets earned (11.3)% and (5.5)%, respectively. FirstEnergy's 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 FirstEnergy's 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, FirstEnergy will not be required to fund its 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 the 2002 assumption of approximately 10% in 2002, gradually decreasing to 4%-6% in later years. In determining its trend rate assumptions, FirstEnergy included the specific provisions of its health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in its health care plans, and projections of future medical trend rates.

Long-Lived Assets

In accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," Penn periodically evaluates its 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, Penn recognizes a loss - calculated as the difference between the carrying value and the estimated fair value of the asset (discounted future net cash flows).

RECENTLY ISSUED ACCOUNTING STANDARD NOT YET IMPLEMENTED

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

Penn 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, Penn classified as debt its preferred stock subject to mandatory redemptions with a carrying value of approximately $13.5 million as of June 30, 2003. Therefore, the application of SFAS 150 will require the reclassification of such preferred dividends to net interest charges.

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

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JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	THREE MONTHS ENDED JUNE 30,		
	2003	2002	
			(IN THOUSANDS
OPERATING REVENUES	$ 542,771	$ 501,232	$ 1
OPERATING EXPENSES AND TAXES:			
Fuel	1,432	1,298	
Purchased power	444,978	249,466	
Other operating costs	82,302	74,100	
Total operation and maintenance expenses	528,712	324,864	
Provision for depreciation and amortization	52,983	55,371	
General taxes	12,964	4,294	
Income taxes	(28,390)	38,543	
Total operating expenses and taxes	566,269	423,072	1
OPERATING INCOME (LOSS)	(23,498)	78,160	
OTHER INCOME	2,264	2,196	
INCOME (LOSS) BEFORE NET INTEREST CHARGES	(21,234)	80,356	

NET INTEREST CHARGES:			
Interest on long-term debt............................	22,667	22,768	
Allowance for borrowed funds used during construction..	(111)	(97)	
Deferred interest.....................................	(2,924)	(1,834)	
Other interest expense (credit).......................	104	(533)	
Subsidiary's preferred stock dividend requirements.....	2,674	2,672	
Net interest charges..............................	22,410	22,976	
NET INCOME (LOSS)......................................	(43,644)	57,380	
PREFERRED STOCK DIVIDEND REQUIREMENTS....................	(488)	431	
EARNINGS (LOSS) ATTRIBUTABLE TO COMMON STOCK.............	$ (43,156)	$ 56,949	$

The preceding Notes to Financial Statements as they relate to Jersey Central Power & Light Company are an integral part of these statements.

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JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED BALANCE SHEETS

	(UNAUDITED) JUNE 30, 2003
	(IN THOU
ASSETS	
UTILITY PLANT:	
In service..	$3,595,739
Less--Accumulated provision for depreciation............................	1,481,357
	2,114,382
Construction work in progress - electric plant..........................	32,079
	2,146,461
OTHER PROPERTY AND INVESTMENTS:	
Nuclear plant decommissioning trusts....................................	116,249
Nuclear fuel disposal trust...	154,748
Long-term notes receivable from associated companies....................	20,333
Other...	22,173
	313,503
CURRENT ASSETS:	
Cash and cash equivalents...	6,027
Receivables-	

Customers (less accumulated provisions of $4,215,680 and $4,509,000 respectively, for uncollectible accounts)	243,740
Associated companies	123,039
Other	19,835
Notes receivable from associated companies	--
Materials and supplies, at average cost	2,114
Prepayments and other	108,165
	502,920
DEFERRED CHARGES:	
Regulatory assets	3,004,421
Goodwill	2,000,875
Other	9,494
	5,014,790
	$7,977,674

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JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED BALANCE SHEETS

	(UNAUDITED) JUNE 30, 2003
	(IN THOU
CAPITALIZATION AND LIABILITIES	
CAPITALIZATION:	
Common stockholder's equity-	
Common stock, $10 par value, authorized 16,000,000 shares - 15,371,270 shares outstanding	$ 153,713
Other paid-in capital	3,029,218
Accumulated other comprehensive loss	(64,858)
Retained earnings (accumulated deficit)	(25,396)
Total common stockholder's equity	3,092,677
Preferred stock not subject to mandatory redemption	12,649
Company-obligated mandatorily redeemable preferred securities	--
Long-term debt	1,270,602
	4,375,928
CURRENT LIABILITIES:	
Currently payable long-term debt	93,857
Accounts payable-	
Associated companies	187,882
Other	126,634
Notes payable to associated companies	196,126
Accrued taxes	18,653

Accrued interest	18,733
Other	106,024
	747,909
DEFERRED CREDITS:	
Accumulated deferred income taxes	631,079
Accumulated deferred investment tax credits	8,789
Power purchase contract loss liability	1,651,294
Nuclear fuel disposal costs	167,159
Asset retirement obligation	106,856
Retirement benefits	169,753
Nuclear decommissioning costs	4,814
Other	114,093
	2,853,837
COMMITMENTS, GUARANTEES AND CONTINGENCIES (NOTE 2)	
	$7,977,674

The preceding Notes to Financial Statements as they relate to Jersey Central Power & Light Company are an integral part of these balance sheets.

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JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	THREE MONTHS ENDED JUNE 30,		
	2003	2002	
		(IN THOUSANDS)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (43,644)	$ 57,380	$
Adjustments to reconcile net income (loss) to net cash from operating activities-			
Provision for depreciation and amortization	52,983	55,371	
Other amortization	(102)	940	
Deferred costs, net	(49,251)	(43,340)	
Deferred income taxes, net	(31,981)	27,862	
Investment tax credits, net	(575)	(900)	
Disallowed regulatory assets (see Note 4)	152,500	--	
Receivables	(87,390)	(34,185)	
Materials and supplies	(546)	39	
Accounts payable	102,517	37,910	
Prepayments and other	(86,491)	(76,554)	
Accrued taxes	(40,255)	(63,030)	
Accrued interest	(14,200)	(5,863)	
Other	9,730	1,164	

Net cash provided from (used for) operating activities	(36,705)	(43,206)	
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	158,789	318,106	
Short-term borrowings, net from associated companies	196,126	--	
Redemptions and Repayments-			
Preferred stock	(125,244)	(5,000)	(
Long-term debt	(163,725)	--	(
Short-term borrowings, net	--	--	
Dividend Payments-			
Common stock	(39,000)	(66,000)	(
Preferred stock	125	(991)	
Net cash provided from (used for) financing activities	27,071	246,115	
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(30,528)	(20,932)	
Decommissioning trust investments	(1,189)	(608)	
Loan repayments from associated companies	52,608	--	
Other	(7,066)	(1,690)	
Net cash provided from (used for) investing activities	13,825	(23,230)	
Net increase in cash and cash equivalents	4,191	179,679	
Cash and cash equivalents at beginning of period	1,836	67,617	
Cash and cash equivalents at end of period	$ 6,027	$ 247,296	$

The preceding Notes to Financial Statements as they relate to Jersey Power & Light Company are an integral part of these statements.

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REPORT OF INDEPENDENT AUDITORS

To the Stockholders and Board
of Directors of Jersey Central
Power & Light Company:

We have reviewed the accompanying consolidated balance sheet of Jersey Central Power & Light Company and its subsidiaries as of June 30, 2003, and the related consolidated statements of income and cash flows for each of the three-month and six-month periods ended June 30, 2003 and 2002. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with generally accepted auditing standards, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited in accordance with auditing standards generally accepted in the United States of America, the consolidated balance sheet and the consolidated statement of capitalization as of December 31, 2002, and the related consolidated statements of income, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report dated February 28, 2003 we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2002, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio
August 18, 2003

JERSEY CENTRAL POWER & LIGHT COMPANY

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

JCP&L provides regulated transmission and distribution services in northern, western and east central New Jersey. New Jersey customers are able to choose their electricity suppliers as a result of legislation which restructured the electric utility industry. JCP&L's regulatory plan required unbundling the price for electricity into its component elements - including generation, transmission, distribution and transition charges. Also under the regulatory plan, JCP&L continues to deliver power to homes and businesses through its existing distribution system and is required to maintain the "provider of last resort" (PLR) obligation known as Basic Generation Services (BGS) for customers who elect to retain JCP&L as their power supplier.

RESULTS OF OPERATIONS

In the second quarter of 2003, JCP&L incurred a loss attributable to common stock of $43.2 million as compared to earnings on common stock of $56.9 million in the second quarter of 2002, as a result of non-cash charges aggregating $158.5 million ($94 million after tax) due to a rate case decision disallowing such costs from recovery (see Regulatory Matters). Excluding the impact of those non-cash charges, earnings on common stock were $50.7 million. Earnings on common stock during the first six months of 2003 were $10.6 million as compared to $96.2 million for the same period of 2002. Earnings before the non-cash charges related to the rate case decision were $104.4 million for the first six months of 2003.

Operating revenues increased $41.5 million or 8.3% in the second quarter and $247.8 million or 26.0% in the first six months of 2003, respectively, compared with the same periods in 2002. The higher revenues resulted from higher wholesale revenues that increased by $39.7 million and

$178.9 million, respectively, over the second quarter and first six months of 2002. JCP&L's BGS obligation was transferred to external parties through a February 2002 auction process authorized by the New Jersey Board of Public Utilities (NJBPU). The auction removed JCP&L's BGS obligation for the period from August 1, 2002 through July 31, 2003, and as a result, it has been selling all of its self-supplied energy (from non-utility generation power contracts and owned generation) into the wholesale market. The NJBPU subsequently approved the February 2003 BGS auction results for the period beginning August 1, 2003.

Distribution deliveries decreased by 2.0% in the second quarter of 2003 from the corresponding quarter of 2002, which was caused by cooler-than-normal temperatures in the second quarter 2003. The impact of the reduced volume was more than offset by higher unit prices, which increased electricity throughput revenues by $3.4 million. Weather also contributed to the $40.7 million (8.1%) revenue increase from higher distribution deliveries to retail customers in the first half of 2003 from the same period last year. Colder temperatures in the first quarter of 2003 resulted, in large part, in higher residential and commercial demand, which was partially offset by a decrease in industrial demand. Changes in distribution deliveries in the second quarter and first half of 2003 compared with the same periods of 2002 are summarized in the following table:

CHANGES IN KILOWATT-HOUR DELIVERIES	THREE MONTHS	SIX MONTHS
INCREASE (DECREASE)		
Residential....................	(4.9)%	6.6%
Commercial.....................	3.0%	10.2%
Industrial.....................	(7.1)%	(5.0)%
TOTAL DISTRIBUTION DELIVERIES....	(2.0)%	6.0%

Operating Expenses and Taxes

Total operating expenses and taxes increased by $143.2 million in the second quarter and $335.5 million in the first six months of 2003 compared to the same periods of 2002. These increases include the non-cash charges in the second quarter of 2003 for amounts disallowed in the JCP&L rate case decision (see Regulatory Matters), consisting of $152.5 million of deferred purchased power costs, $3.5 million relating to depreciation and amortization and $2.5 million included in other operating costs. The following table presents changes from the prior year by expense category.

OPERATING EXPENSES AND TAXES - CHANGES	THREE MONTHS	SIX MONTHS
	(IN MILLIONS)	
INCREASE (DECREASE)		
Fuel..	$ 0.1	$ 0.3
Purchased power costs...........................	195.5	383.6
Other operating costs...........................	8.2	9.4
TOTAL OPERATION AND MAINTENANCE EXPENSES.......	203.8	393.3

Provision for depreciation and amortization......	(2.4)	(6.1)
General taxes..................................	8.7	7.5
Income taxes....................................	(66.9)	(59.2)
NET INCREASE IN OPERATING EXPENSES AND TAXES...	$143.2	$335.5

Excluding the disallowed deferred energy costs of $152.5 million, the higher purchased power costs of $43.0 million in the second quarter and $231.1 million in the first half of 2003, compared to the corresponding periods of 2002, were due primarily to increased kilowatt-hour purchases through two-party agreements and changes in the deferred energy and capacity costs. Excluding the disallowed costs discussed above, the decreases in depreciation and amortization charges of $5.9 million in the second quarter and $9.6 million in the first six months of 2003, compared to the corresponding 2002 periods were due to the cessation of amortization of regulatory assets related to the previously divested Oyster Creek Nuclear Generating Station and demand side management program deferrals. General taxes increased $8.7 million in the second quarter and $7.5 million in the first six months of 2003, compared to the corresponding periods in 2002, principally due to the absence of a $9 million energy assessment accrual reduction in the second quarter of 2002.

Net Interest Charges

Net interest charges decreased by $0.6 million in the second quarter of 2003 and $2.2 million in the first six months compared with the same periods of 2002, reflecting debt redemptions since the end of the first half of 2002. Those decreases were partially offset by interest on $320 million of transition bonds issued in June 2002 (see Note 1) and $150 million of senior notes issued in May 2003 to be used for redeeming currently outstanding securities later in 2003.

CAPITAL RESOURCES AND LIQUIDITY

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

Changes in Cash Position

As of June 30, 2003, JCP&L had $6.0 million of cash and cash equivalents, compared with $4.8 million as of December 31, 2002. The major sources of changes in these balances are summarized below.

Cash Flows From Operating Activities

Cash provided from operating activities during the second quarter and first six months of 2003 compared to the corresponding periods of 2002 were as follows:

	THREE MONTHS ENDED JUNE 30,	SIX MONTHS ENDED JUNE 30,

OPERATING CASH FLOWS	2003	2002	2003	2002
		(IN MILLIONS)		
Cash earnings (1)...........	$ 80	$ 97	$ 174	$144
Working capital and other...	(117)	(140)	(115)	(55)
TOTAL......................	$ (37)	$ (43)	$ 59	$ 89

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

Net cash used for operating activities was $37 million in the second quarter 2003 compared to $43 million in the same quarter of 2002 and net cash from operating activities was $59 million in the first half of 2003 from $89 million in the corresponding period of 2002. The second quarter increase was due to a $23 million decrease in funds used for

working capital and other, partially offset by a $17 million decrease in cash earnings. The change in working capital reflects a $65 million net increase in accounts payable.

Cash Flows From Financing Activities

In the second quarter of 2003, net cash provided from financing activities of $27 million primarily reflected the issuance of $196 million of short-term debt and a $27 million decrease in common stock dividend payments to FirstEnergy. In the second quarter of 2002, net cash provided from financing activities totaled $246 million, primarily due to the issuance of transition bonds.

As of June 30, 2003, JCP&L had approximately $6.0 million of cash and temporary investments and no short-term indebtedness. JCP&L may borrow from its affiliates on a short-term basis. JCP&L will not issue first mortgage bonds (FMB) other than as collateral for senior notes, since its senior note indentures prohibit (subject to certain exceptions) it from issuing any debt which is senior to the senior notes. As of June 30, 2003. JCP&L had the capability to issue $578 million of additional senior notes based upon FMB collateral. Based upon applicable earnings coverage tests JCP&L could issue a total of $1.78 billion of preferred stock (assuming no additional debt was issued) as of June 30, 2003.

Cash Flows From Investing Activities

Net cash provided from investing activities totaled $14 million in the second quarter and in the first six months of 2003, compared with net cash used of $23 million and $51 million in the second quarter and first six months of 2002. Net cash provided from investing in 2003 represented loan repayments from associated companies offset by expenditures for property additions. Net cash used in investing activities in 2002 were principally for property additions.

During the remaining half of 2003, capital requirements for property additions are expected to be about $62 million. JCP&L has additional requirements of approximately $9 million for maturing long-term debt during the remainder of 2003. These cash requirements are expected to be satisfied from internal cash and short-term credit arrangements.

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

On August 7, 2003, S&P affirmed its "BBB" corporate credit rating for FirstEnergy. However, S&P stated that although FirstEnergy generates substantial free cash, that its strategy for reducing debt had deviated substantially from the one presented to S&P around the time of the GPU merger when the current rating was assigned. S&P further noted that their affirmation of FirstEnergy's corporate credit rating was based on the assumption that FirstEnergy would take appropriate steps quickly to maintain its investment grade ratings including the issuance of equity or possible sale of assets. Key issues being monitored by S&P include the restart of Davis-Besse, FirstEnergy's liquidity position, its ability to forecast provider-of-last-resort load and the performance of its hedged portfolio, and continued capture of merger synergies. On August 11, 2003, S&P stated that a recent U.S. District Court ruling (see Environmental Matters below) with respect to the Sammis Plant is negative for FirstEnergy's credit quality.

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

Pension and Other Postretirement Benefits

As a result of GPU Service Inc. merging with FirstEnergy Service Company in the second quarter of 2003, operating company employees of GPU Service were transferred to JCP&L, Met-Ed and Penelec. Accordingly, FirstEnergy requested an actuarial study to update the pension and other post-employment benefit (OPEB) assets and liabilities for each of its subsidiaries. Based on the actuary's report, JCP&L's accrued pension and OPEB costs as of June 30, 2003 increased by $78.5 million and $86.3 million, respectively.

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MARKET RISK INFORMATION

JCP&L uses various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price fluctuations. FirstEnergy's Risk Policy Committee, comprised of executive officers, exercises an independent risk oversight function to ensure compliance with corporate risk management policies and prudent risk management practices.

Commodity Price Risk

JCP&L is exposed to market risk primarily due to fluctuations in electricity and natural gas prices. To manage the volatility relating to these exposures, it uses a variety of non-derivative and derivative instruments, including forward contracts, options and future contracts. The derivatives are used for hedging purposes. Most of JCP&L's non-hedge derivative contracts represent non-trading positions that do not qualify for hedge treatment under SFAS 133. The change in the fair value of commodity derivative contracts related to energy production during the second quarter and first six months of 2003 is summarized in the following table:

INCREASE (DECREASE) IN THE FAIR VALUE OF COMMODITY DERIVATIVE CONTRACTS	THREE MONTHS ENDED JUNE 30, 2003 NON-HEDGE	HEDGE	TOTAL	N
			(IN MILLI	
CHANGE IN THE FAIR VALUE OF COMMODITY DERIVATIVE CONTRACTS				
Net asset at beginning of period......................	$12.8	$ --	$12.8	
New contract value when entered.......................	--	--	--	
Changes in value of existing contracts................	0.1	(0.1)	--	
Change in techniques/assumptions......................	--	--	--	
Settled contracts.....................................	--	--	--	
NET ASSETS - DERIVATIVE CONTRACTS AT END OF PERIOD (1).	$12.9	$(0.1)	$12.8	
IMPACT OF CHANGES IN COMMODITY DERIVATIVE CONTRACTS (2)				
Income Statement Effects (Pre-Tax)....................	$ 0.2	$ --	$ 0.2	
Balance Sheet Effects:				
Other Comprehensive Income (Pre-Tax)...............	$ --	$(0.1)	$(0.1)	
Regulatory Liability...............................	$(0.1)	$ --	$(0.1)	

(1) Includes $12.9 million in non-hedge commodity derivative contracts which are offset by a regulatory liability.

(2) Represents the increase in value of existing contracts, settled contracts and changes in techniques/assumptions.

Derivatives included on the Consolidated Balance Sheet as of June 30, 2003:

	NON-HEDGE	HEDGE	TOTAL
	(IN MILLIONS)		
CURRENT-			
Other Assets...........................	$ --	$ --	$ --
Other Liabilities......................	--	(0.1)	(0.1)
NON-CURRENT-			
Other Deferred Charges..................	12.9	--	12.9
Other Deferred Credits..................	--	--	--
NET ASSETS.............................	$12.9	$(0.1)	$12.8

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

SOURCE OF INFORMATION - FAIR VALUE BY CONTRACT YEAR	2003(1)	2004	2005	2006	THEREAFTE
			(IN MILLIONS)		
Prices based on external sources(2)...	$0.2	$2.0	$2.5	$ --	$ --
Prices based on models................	--	--	--	1.2	6.9
TOTAL(3)..........................	$0.2	$2.0	$2.5	$ 1.2	$6.9

(1) For the remaining quarters of 2003.

(2) Broker quote sheets.

(3) Includes $12.9 million from an embedded option that is offset by a regulatory liability and does not affect earnings.

JCP&L performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% adverse shift in quoted market prices in the near term on derivative instruments would not have had a material effect on its consolidated financial position or cash flows as of June 30, 2003.

Equity Price Risk

Included in JCP&L's nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $59 million and $52 million as of June 30, 2003 and December 31, 2002, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $6 million reduction in fair value as of June 30, 2003.

OUTLOOK

Beginning in 1999, all of JCP&L's customers were able to select alternative energy suppliers. JCP&L continues to deliver power to homes and businesses through its existing distribution system, which remains regulated. To support customer choice, rates were restructured into unbundled service charges and additional non-bypassable charges to recover stranded costs.

Regulatory assets are costs which have been authorized by the NJBPU and the Federal Energy Regulatory Commission for recovery from customers in future periods and, without such authorization, would have been charged to income when incurred. All of JCP&L's regulatory assets are expected to continue to be recovered under the provisions of the regulatory proceedings discussed below. JCP&L's regulatory assets totaled $3.0 billion and $3.2 billion as of June 30, 2003 and December 31, 2002, respectively.

Regulatory Matters

Under New Jersey transition legislation, all electric distribution companies were required to file rate cases to determine the level of unbundled rate components to become effective August 1, 2003. JCP&L submitted two rate filings with the NJBPU in August 2002. The first filing requested increases in base electric rates of approximately $98 million annually. The second filing was a request to recover deferred costs that exceeded amounts being recovered under the current Market Transition Charge (MTC) and Societal Benefits Charge (SBC) rates; one proposed method of recovery of these costs is the securitization of the deferred balance. This securitization methodology is similar to the Oyster Creek securitization discussed above. On July 25, 2003, the NJBPU announced its JCP&L base electric rate proceeding decision which would reduce JCP&L's annual revenues by approximately $62 million effective August 1, 2003. The NJBPU decision also provided for an interim return on equity of 9.5 percent on JCP&L's rate base for the next 6 to 12 months. During that period, JCP&L will initiate another proceeding to request recovery of additional costs incurred to enhance system reliability. In that proceeding, the NJBPU could increase the return on equity to 9.75 percent or decrease it up to 9.25 percent, depending on its assessment of the reliability of JCP&L's service. Any reduction would be retroactive to August 1, 2003. The revenue decrease in the decision consists of a $223 million decrease in the electricity delivery charge, a $111 million increase due to the August 1, 2003 expiration of annual customer credits previously mandated by the New Jersey transition legislation, a $49 million increase in the MTC tariff component, and a net $1 million increase in the SBC charge. The MTC would allow for the recovery of $465 million in deferred energy costs over the next ten years on an interim basis, thus disallowing $152.5 million. In the second quarter of 2003, JCP&L recorded non-cash amounts aggregating to $158.5 million ($94 million after tax) consisting of the $153 million deferred energy costs and other regulatory assets. On July 25, 2003, the NJBPU approved a Stipulation of Settlement between the parties and authorized the recovery of the total $135 million of the Freehold buyout costs, eliminating the interim nature of the recovery.

Environmental Matters

JCP&L 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 June 30, 2003, based on estimates of the total costs of cleanup, JCP&L's proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay. In addition, JCP&L has accrued liabilities for environmental remediation of former manufactured gas plants in New Jersey; those costs are being recovered through the SBC. JCP&L has accrued liabilities aggregating approximately $47.1 million as of June 30, 2003. JCP&L does not believe environmental remediation costs will have a material adverse effect on its financial condition, cash flows or results of operations.

Legal Matters

Various lawsuits, claims and proceedings related to our normal business operations are pending against us, the most significant of which are described above and below.

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

A series of unexpected faults in the three transmission lines triggered a series of outages for approximately 34,000 customers from July 5-8, 2003. The NJBPU has launched an investigation into the causes of the outages, and JCP&L has filed an incident report with the NJBPU, detailing the timeline and causes for the outages. JCP&L has committed to accelerate $60 million in transmission system improvements. Additionally, JCP&L sited ten emergency generators at strategic locations within a few days of the outage. Without admitting liability, JCP&L has established a streamlined procedure to address customers' damage claims.

SIGNIFICANT ACCOUNTING POLICIES

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

Purchase Accounting

The merger between FirstEnergy and GPU was accounted for by the purchase method of accounting, which requires judgment regarding the allocation of the purchase price based on the fair values of the assets acquired (including intangible assets) and the liabilities assumed. The fair values of the acquired assets and assumed liabilities were based primarily on estimates. The adjustments reflected in JCP&L's records, which were finalized in the fourth quarter of 2002, primarily consist of: (1) revaluation of certain property, plant and equipment; (2) adjusting preferred stock subject to mandatory redemption and long-term debt to estimated fair value; (3) recognizing additional obligations related to retirement benefits; and (4) recognizing estimated severance and other compensation liabilities. The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill. Based on the guidance provided by SFAS 142, "Goodwill and Other Intangible Assets," JCP&L evaluates its goodwill for impairment at least annually and would make such an evaluation more frequently if indicators of impairment should arise. The forecasts used in JCP&L's evaluations of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on JCP&L's future evaluations of goodwill. As of June 30, 2003, JCP&L had recorded goodwill of approximately $2.0 billion related to the merger.

Regulatory Accounting

JCP&L is subject to regulation that sets the prices (rates) it is permitted to charge its customers based on the costs that the regulatory agencies determine JCP&L is 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 New Jersey, a significant amount of regulatory assets have been recorded. As of June 30, 2003, JCP&L's regulatory assets totaled $3.0 billion. JCP&L regularly reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future.

Derivative Accounting

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

Revenue Recognition

JCP&L follows the accrual method of accounting for revenues, recognizing revenue for kilowatt-hours that have been delivered but not yet been billed through the end of the accounting period. The determination of unbilled revenues requires management to make various estimates including:

- Net energy generated or purchased for retail load
- Losses of energy over 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

FirstEnergy's reported costs of providing non-contributory defined pension benefits and 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 FirstEnergy makes 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 for 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, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. Due to the significant decline in corporate bond yields and interest rates in general during 2002, FirstEnergy reduced the assumed discount rate as of December 31, 2002 to 6.75% from 7.25% used in 2001.

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by its pension trusts. The market values of FirstEnergy's pension assets have been affected by sharp declines in the equity markets since mid-2000. In 2002 and 2001, plan assets earned (11.3)% and (5.5)%, respectively. FirstEnergy's 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 FirstEnergy's 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, FirstEnergy will not be required to fund its 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 the 2002 assumption of approximately 10% in 2002, gradually decreasing to 4%-6% in later years. In determining its trend rate assumptions, FirstEnergy included the specific provisions of its health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in its health care plans, and projections of future medical trend rates.

Ohio Transition Cost Amortization

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

Long-Lived Assets

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," JCP&L periodically evaluates its 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, JCP&L recognizes a loss - calculated as the difference between the carrying value and the estimated fair value of the asset (discounted future net cash flows).

RECENTLY ISSUED ACCOUNTING STANDARDS NOT YET IMPLEMENTED

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 (JCP&L's third quarter of 2003). The FASB also identified transitional disclosure provisions for all financial statements issued after January 31, 2003.

JCP&L currently has transactions with entities in connection with the sale of preferred securities and debt secured by bondable property, and which are reasonably possible of meeting the definition of a VIE in accordance with FIN 46.

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

Issued by the FASB in April 2003, SFAS 149 further clarifies and amends accounting and reporting for derivative instruments. The statement amends SFAS133 for decisions made by the Derivative Implementation Group, as well as issues raised in connection with other FASB projects and implementation issues. The statement is effective for contracts entered into or modified after June 30, 2003 except for implementation issues that have been effective for quarters which began prior to June 15, 2003, which continue to be applied based on their original effective dates. JCP&L is currently assessing the new standard and has not yet determined the impact on its financial statements.

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

METROPOLITAN EDISON COMPANY

CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	THREE MONTHS ENDED JUNE 30,		SIX M
	2003	2002	2003
	(IN THOUSANDS)		
OPERATING REVENUES	$ 217,712	$ 240,003	$ 468,9
OPERATING EXPENSES AND TAXES:			
Purchased power	121,687	146,296	265,1
Other operating costs	35,068	33,570	67,5
Total operation and maintenance expenses	156,755	179,866	332,7
Provision for depreciation and amortization	22,076	15,046	49,2
General taxes	15,538	14,815	32,3
Income taxes	4,785	7,027	11,9
Total operating expenses and taxes	199,154	216,754	426,3
OPERATING INCOME	18,558	23,249	42,5
OTHER INCOME	5,307	5,456	10,4
INCOME BEFORE NET INTEREST CHARGES	23,865	28,705	53,0
NET INTEREST CHARGES:			
Interest on long-term debt	9,342	10,227	19,8
Allowance for borrowed funds used during construction	(85)	(280)	(1
Deferred interest	(555)	(42)	(9
Other interest expense	402	898	8
Subsidiary's preferred stock dividend requirements	1,889	1,941	3,7
Net interest charges	10,993	12,744	23,3
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	12,872	15,961	29,6
Cumulative effect of accounting change (net of income taxes of $154,000) (Note 5)	--	--	2
NET INCOME	$ 12,872	$ 15,961	$ 29,8

The preceding Notes to Financial Statements as they relate to Metropolitan Edison Company are an integral part of these statements.

METROPOLITAN EDISON COMPANY

CONSOLIDATED BALANCE SHEETS

	(UNAUDITED) JUNE 30, 2003
	(IN THOU
ASSETS	
UTILITY PLANT:	
In service	$ 1,821,853
Less--Accumulated provision for depreciation	754,696
	1,067,157
Construction work in progress	18,835
	1,085,992
OTHER PROPERTY AND INVESTMENTS:	
Nuclear plant decommissioning trusts	171,965
Long-term notes receivable from associated companies	12,418
Other	27,415
	211,798
CURRENT ASSETS:	
Cash and cash equivalents	330
Receivables-	
Customers (less accumulated provisions of $4,929,000 and $4,810,000 respectively, for uncollectible accounts)	117,440
Associated companies	70,490
Other	19,387
Notes receivable from associated companies	24,710
Material and supplies, at average cost	139
Prepayments and other	28,366
	260,862
DEFERRED CHARGES:	
Regulatory assets	1,090,957
Goodwill	885,832
Other	35,951
	2,012,740
	$ 3,571,392

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METROPOLITAN EDISON COMPANY

CONSOLIDATED BALANCE SHEETS

	(UNAUDITED) JUNE 30, 2003
	(IN THOU
CAPITALIZATION AND LIABILITIES	
CAPITALIZATION:	
Common stockholder's equity-	
Common stock, without par value, authorized 900,000 shares - 859,500 shares outstanding	$ 1,297,785
Accumulated other comprehensive loss	(36,358)
Retained earnings	27,729
Total common stockholder's equity	1,289,156
Company-obligated trust preferred securities	92,513
Long-term debt	609,551
	1,991,220
CURRENT LIABILITIES:	
Currently payable long-term debt	467
Accounts payable-	
Associated companies	154,368
Other	30,255
Notes payable to associated companies	20,665
Accrued taxes	3,422
Accrued interest	12,658
Other	20,429
	242,264
DEFERRED CREDITS:	
Accumulated deferred income taxes	270,764
Accumulated deferred investment tax credits	12,108
Purchase power contract loss liability	632,342
Nuclear fuel disposal costs	37,760
Asset retirement obligation	215,114
Retirement benefits	109,064
Other	60,756
	1,337,908
COMMITMENTS, GUARANTEES AND CONTINGENCIES (NOTE 2)	
	$ 3,571,392

The preceding Notes to Financial Statements as they relate to Metropolitan Edison Company are an integral part of these balance sheets.

METROPOLITAN EDISON COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(UNAUDITED)

	THREE MONTHS ENDED JUNE 30,		SIX M
	2003	2002	2003
	(IN THOUSANDS)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 12,872	$ 15,961	$ 29,8
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation and amortization	22,076	15,046	49,2
Deferred costs, net	(9,658)	(2,491)	(13,4
Deferred income taxes, net	8,280	4,308	9,6
Investment tax credits, net	(205)	(212)	(4
Receivables	(28,290)	(26,722)	(9,9
Materials and supplies	--	--	(1
Accounts payable	52,329	17,887	84,2
Cumulative effect of accounting change (Note 5)	--	--	(3
Accrued taxes	(758)	(3,738)	(12,6
Accrued interest	1,008	7,269	(3,7
Prepayments and other	11,504	15,471	(18,6
Other	2,674	(5,083)	(9,0
Net cash provided from operating activities	71,832	37,696	104,6
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	--	49,750	247,6
Redemptions and Repayments-			
Long-term debt	(190,435)	--	(230,4
Short-term borrowings, net	(44,547)	(56,406)	(67,6
Dividend Payments-			
Common stock	(20,000)	(30,000)	(20,0
Net cash used for financing activities	(254,982)	(36,656)	(70,3
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(9,569)	(11,691)	(19,9
Decommissioning trust investments	(2,432)	(4,826)	(4,8
Loans to associated companies	(16,705)	--	(24,7
Other	(385)	--	(1
Net cash used for investing activities	(29,091)	(16,517)	(49,5
Net decrease in cash and cash equivalents	(212,241)	(15,477)	(15,3
Cash and cash equivalents at beginning of period	212,571	20,812	15,6
Cash and cash equivalents at end of period	$ 330	$ 5,335	$ 3

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The preceding Notes to Financial Statements as they relate to Metropolitan Edison Company are an integral part of these statements.

REPORT OF INDEPENDENT AUDITORS

To the Stockholders and Board
of Directors of Metropolitan
Edison Company:

We have reviewed the accompanying consolidated balance sheet of Metropolitan Edison Company and its subsidiaries as of June 30, 2003, and the related consolidated statements of income and cash flows for each of the three-month and six-month periods ended June 30, 2003 and 2002. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with generally accepted auditing standards, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited in accordance with auditing standards generally accepted in the United States of America, the consolidated balance sheet and the consolidated statement of capitalization as of December 31, 2002, and the related consolidated statements of income, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report dated February 28, 2003 we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2002, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio
August 18, 2003

METROPOLITAN EDISON COMPANY

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

Met-Ed provides regulated transmission and distribution services in eastern and south central Pennsylvania. Pennsylvania customers are able to choose their electricity suppliers as a result of legislation which restructured the electric utility industry. Met-Ed's regulatory plan required unbundling the price for electricity into its component elements - including generation, transmission, distribution and transition charges. Met-Ed continues to deliver power to homes and businesses through its existing distribution system and maintains provider of last resort (PLR) obligations to customers who elect to retain Met-Ed as their power supplier.

RESULTS OF OPERATIONS

Net income in the second quarter of 2003 decreased to $12.9 million from $16.0 million in the second quarter of 2002. During the first six months of 2003, net income decreased to $29.9 million from $42.6 million in the first six months of 2002. The first half of 2003 net income included an after-tax credit of $0.2 million from the cumulative effect of an accounting change due to the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations." Income before the first quarter 2003 cumulative effect was $29.7 million in the first half of 2003 compared with $42.6 million in the corresponding period of 2002.

Electric Sales

Operating revenues decreased by $22.3 million, or 9.3% in the second quarter of 2003 compared with the same period of 2002. The lower revenues resulted from decreased generation sales and distribution deliveries to all retail sectors, as well as sales to the wholesale market. Lower retail generation sales (9.2%) and distribution deliveries (3.2%) decreased revenues by $11.4 million and $2.4 million, respectively, as a result of cooler-than-normal temperatures in the second quarter of 2003. Wholesale revenue decreased by $8.5 million, which reflected lower sales to affiliated companies. Operating revenues were lower by $16.9 million, or 3.5% in the first half of 2003 compared with the first half of 2002. Retail generation kilowatt-hour sales increased overall by 3.8%, which consisted of lower industrial sales (29.4%), higher residential (10.6%) and nearly flat commercial sales -- producing decreased revenues of $9.1 million. The lower generation sales reflected more commercial and industrial customers choosing an alternate power supplier compared with the same period of 2002. Wholesale sales revenues decreased $15.5 million principally due to a reduction in kilowatt-hour sales to affiliated companies. Distribution deliveries increased 3.3% in the first six months of 2003 from the same period of the prior year, increasing revenues from electricity throughput by $6.6 million. Distribution deliveries benefited from higher residential and commercial demand, due in large part to colder temperatures in the first quarter of 2003, which was partially offset by a decrease in industrial demand from the continued effect of a sluggish economy.

Changes in electric generation sales and distribution deliveries in the second quarter and first six months of 2003 from the same periods of 2002 are summarized in the following table:

CHANGES IN KILOWATT-HOUR SALES	THREE MONTHS	SIX MONTHS
INCREASE (DECREASE)		
Electric Generation:		
Retail	(9.2)%	(3.8)%
Wholesale	(100.0)%	(101.3)%
TOTAL ELECTRIC GENERATION SALES	(18.4)%	(12.9)%

Distribution Deliveries:		
Residential	(4.0)%	10.4%
Commercial	0.8%	5.9%
Industrial	(6.1)%	(6.2)%
TOTAL DISTRIBUTION DELIVERIES	(3.2)%	3.3%

Operating Expenses and Taxes

Total operating expenses and taxes decreased $17.6 million in the second quarter of 2003 and $2.6 million in the first half of 2003 compared to the same periods of 2002, primarily due to lower purchased power costs that were partially offset by higher depreciation and amortization charges. The following table presents changes from the prior year by expense category.

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OPERATING EXPENSES AND TAXES - CHANGES	THREE MONTHS	SIX MONTHS
INCREASE (DECREASE)	(IN MILLIONS)	
Purchased power costs..........................	$ (24.6)	$ (17.3)
Other operating costs..........................	1.5	5.0
TOTAL OPERATION AND MAINTENANCE EXPENSES........	(23.1)	(12.3)
Provision for depreciation and amortization.......	7.0	18.9
General taxes..................................	0.7	0.7
Income taxes...................................	(2.2)	(9.9)
NET DECREASE IN OPERATING EXPENSES AND TAXES....	$ (17.6)	$ (2.6)

Lower purchased power costs in the second quarter and first half of 2003, compared with the second quarter and first half of 2002, were primarily attributed to lower required kilowatt-hour purchases driven by lower generation sales. The increase in depreciation and amortization charges reflected increases in amortization of regulatory assets being recovered through the competitive transition charge (CTC). Other operating costs increased by $1.5 million and $5.0 million in the three months and six months ended June 30, 2003, compared with the same periods of 2002, as a result of higher pension and other employee benefit costs.

Net Interest Charges

Net interest charges decreased by $1.8 million in the second quarter of 2003 and $1.5 million in the first six months of 2003 compared with 2002. The decrease reflects the refinancing of higher rate debt in the second quarter of 2003 with the issuance of $250 million of new senior notes issued in March 2003 and the redemption of $40 million of notes in the first quarter of 2003.

Cumulative Effect of Accounting Change

Upon adoption of SFAS 143 in the first quarter of 2003, Met-Ed recorded an after-tax credit to net income of approximately $0.2 million. Met-Ed identified applicable legal obligations as defined under the new accounting standard for nuclear power plant decommissioning. As a result of adopting SFAS 143 in January 2003, asset retirement costs of $186 million were recorded as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $186 million. The asset retirement obligation (ARO) liability at the date of adoption was $198 million, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. As of December 31, 2002, Met-Ed had recorded decommissioning liabilities of $260 million. Met-Ed expects substantially all of its nuclear decommissioning costs to be recoverable in rates over time. Therefore, Met-Ed recognized a regulatory liability of $61 million upon adoption of SFAS 143 for the transition amounts related to establishing the ARO for nuclear decommissioning. The remaining cumulative effect adjustment for unrecognized depreciation and accretion offset by the reduction in the liabilities was a $0.4 million increase to income, or $0.2 million net of income taxes.

CAPITAL RESOURCES AND LIQUIDITY

Met-Ed's cash requirements in 2003 for operating expenses, construction expenditures, scheduled debt maturities and optional debt redemptions are expected to be met without materially increasing its net debt and preferred stock outstanding. Over the next three years, Met-Ed expects to meet its contractual obligations with cash from operations. Thereafter, Met-Ed expects to use a combination of cash from operations and funds from the capital markets.

Changes in Cash Position

As of June 30, 2003, Met-Ed had $0.3 million of cash and cash equivalents compared with $15.7 million as of December 31, 2002. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Cash provided from operating activities during the second quarter and first six months of 2003, compared with corresponding periods of 2002 were as follows:

OPERATING CASH FLOWS	THREE MONTHS ENDED JUNE 30, 2003	THREE MONTHS ENDED JUNE 30, 2002	SIX MONTHS ENDED JUNE 30, 2003	SIX MONTHS ENDED JUNE 30, 2002
	(IN MILLIONS)			
Cash earnings (1).......	$ 33	$ 32	$ 75	$ 74
Working capital and other	39	6	30	(54)
TOTAL..................	$ 72	$ 38	$ 105	$ 20

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

Net cash from operating activities increased to $72 million in the second quarter and $105 in the first half of 2003 compared with the corresponding periods in 2002 of $38 million and $20, respectively. The second quarter increase was due to a $39 million increase in funds from working capital and other, primarily from changes in accounts payable.

Cash Flows From Financing Activities

In the second quarter of 2003, net cash used for financing activities of $255 million reflected the redemption of $190 million of senior notes and $45 million of short-term debt. In the second quarter of 2002, net cash used for financing activities totaled $37 million, due to dividends to FirstEnergy.

As of June 30, 2003, Met-Ed had approximately $25.0 million of cash and temporary investments, including $24.7 million of notes receivable from associated companies and approximately $20.7 million of short-term indebtedness. Met-Ed may borrow from its affiliates on a short-term basis. Met-Ed will not issue first mortgage bonds (FMB) other than as collateral for senior notes, since its senior note indentures prohibit (subject to certain exceptions) it from issuing any debt which is senior to the senior notes. As of June 30, 2003, Met-Ed had the capability to issue $149 million of additional senior notes based upon FMB collateral. Met-Ed had no restrictions on the issuance of preferred stock.

Cash Flows From Investing Activities

Net cash used for investing activities totaled $29 million in the second quarter and $50 in the first six months of 2003,. The net cash flows used for investing resulted from property additions and loans to associated companies. Expenditures for property additions primarily support Met-Ed's energy delivery operations. In the second quarter and first six months of 2002, net cash flows used for investing activities totaled $17 million and $29 million, respectively, principally due to property additions

During the second half of 2003, capital requirements for property additions are expected to be about $33 million. Met-Ed has additional requirements of approximately $0.1 million for maturing long-term debt during the remainder of 2003. These cash requirements are expected to be satisfied from internal cash and short-term credit arrangements.

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

On August 7, 2003, S&P affirmed its "BBB" corporate credit rating for FirstEnergy. However, S&P stated that although FirstEnergy generates substantial free cash, that its strategy for reducing debt had deviated substantially from the one presented to S&P around the time of the GPU merger when the current rating was assigned. S&P further noted that their affirmation of FirstEnergy's corporate credit rating was based on the assumption that FirstEnergy would take appropriate steps quickly to maintain its investment grade ratings including the issuance of equity or possible sale of assets. Key issues being monitored by S&P include the restart of Davis-Besse, FirstEnergy's liquidity position, its ability to forecast provider-of-last-resort load and the performance of its hedged portfolio, and continued capture of merger synergies. On August 11, 2003, S&P stated that a recent U.S. District Court ruling (see Environmental Matters below) with respect to the Sammis Plant is negative for FirstEnergy's credit quality.

On August 14, 2003, Moody's Investors Service placed the debt ratings of FirstEnergy and all of its subsidiaries under review for possible downgrade. Moody's stated that the review was prompted by: (1) weaker than expected operating performance and cash flow generation; (2) less progress than expected in reducing debt; (3) continuing high leverage relative to its peer group; and (4) negative impact on cash flow and earnings from the continuing nuclear plant outage at Davis-Besse. Moody's further stated that, in anticipation of Davis-Besse returning to service in

the near future and FirstEnergy's continuing to significantly reduce debt and improve its financial profile, "Moody's does not expect that the outcome of the review will result in FirstEnergy's senior unsecured debt rating falling below investment-grade."

Pension and Other Postretirement Benefits

As a result of GPU Service Inc. merging with FirstEnergy Service Company in the second quarter of 2003, operating company employees of GPU Service were transferred to JCP&L, Met-Ed and Penelec. Accordingly, FirstEnergy requested an actuarial study to update the pension and other post-employment benefit (OPEB) assets and liabilities for each of its subsidiaries. Based on the actuary's report, Met-Ed's accrued pension and OPEB costs as of June 30, 2003 increased by $47.2 million and $59.4 million, respectively.

MARKET RISK INFORMATION

Met-Ed uses various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price fluctuations. FirstEnergy's Risk Policy Committee, comprised of executive officers, exercises an independent risk oversight function to ensure compliance with corporate risk management policies and prudent risk management practices.

Commodity Price Risk

Met-Ed is exposed to market risk primarily due to fluctuations in electricity and natural gas prices. To manage the volatility relating to these exposures, it uses a variety of non-derivative and derivative instruments, including options and future contracts. The derivatives are used for hedging purposes. Most of Met-Ed's non-hedge derivative contracts represent non-trading positions that do not qualify for hedge treatment under SFAS 133. The change in the fair value of commodity derivative contracts related to energy production during the second quarter and the first six months of 2003 is summarized in the following table:

INCREASE (DECREASE) IN THE FAIR VALUE OF COMMODITY DERIVATIVE CONTRACTS	THREE MONTHS ENDED JUNE 30, 2003		
	NON-HEDGE	HEDGE	TOTAL
			(IN MI

CHANGE IN THE FAIR VALUE OF COMMODITY DERIVATIVE CONTRACTS			
Outstanding net asset at beginning of period	$ 25.6	$ --	$ 25.6
New contract value when entered	--	--	--
Additions/Increase in value of existing contracts	0.3	--	0.3
Change in techniques/assumptions	--	--	--
Settled contracts	--	--	--
NET ASSETS - DERIVATIVE CONTRACTS AS OF JUNE 30, 2003 (1)	$ 25.9	$ --	$ 25.9
IMPACT OF CHANGES IN COMMODITY DERIVATIVE CONTRACTS (2)			
Income Statement Effects (Pre-Tax)	$ 0.5	$ --	$ 0.5
Balance Sheet Effects:			
Other Comprehensive Income (Pre-Tax)	$ --	$ --	$ --
Regulatory Liability	$ (0.2)	$ --	$ (0.2)

(1) Includes $25.7 million in non-hedge commodity derivative contracts which are offset by a regulatory liability.

(2) Represents the increase in value of existing contracts, settled contracts and changes in techniques/assumptions.

DERIVATIVES INCLUDED ON THE CONSOLIDATED BALANCE SHEET AS OF JUNE 30, 2003:

	NON-HEDGE	HEDGE	TOTAL
(IN MILLIONS)			
CURRENT-			
Other Assets..........................	$ --	$ --	$ --
Other Liabilities.....................	--	--	--
NON-CURRENT-			
Other Deferred Charges.................	25.9	--	25.9
Other Deferred Credits.................	--	--	--
NET ASSETS............................	$ 25.9	$ --	$ 25.9

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, Met-Ed relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. Met-Ed uses

these results to develop estimates of fair value for financial reporting purposes and for internal management decision making. Sources of information for the valuation of derivative contracts by year are summarized in the following table:

SOURCE OF INFORMATION - FAIR VALUE BY CONTRACT YEAR	2003(1)	2004	2005	2006	THEREAFTER
			(IN MILLIONS)		
Prices based on external sources(2)	$ 0.5	$ 4.1	$ 5.1	$ --	$ --
Prices based on models	--	--	--	2.3	13.9
TOTAL(3)	$ 0.5	$ 4.1	$ 5.1	$ 2.3	$ 13.9

(1) For the last two quarters of 2003.

(2) Broker quote sheets.

(3) Includes $25.7 million from an embedded option that is offset by a regulatory liability and does not affect earnings.

Met-Ed performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% adverse shift in quoted market prices in the near term on derivative instruments would not have had a material effect on its consolidated financial position or cash flows as of June 30, 2003.

Equity Price Risk

Included in Met-Ed's nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $93 million and $81 million as of June 30, 2003 and December 31, 2002, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $9 million reduction in fair value as of June 30, 2003.

OUTLOOK

Beginning in 1999, all of Met-Ed's customers were able to select alternative energy suppliers. Met-Ed continues to deliver power to homes and businesses through its existing distribution system, which remains regulated. The Pennsylvania Public Utility Commission (PPUC) authorized Met-Ed's rate restructuring plan, establishing separate charges for transmission, distribution, generation and stranded cost recovery, which is recovered through a CTC. Customers electing to obtain power from an alternative supplier have their bills reduced based on the regulated generation component, and the customers receive a generation charge from the alternative supplier. Met-Ed has a continuing responsibility to provide power to those customers not choosing to receive power from an alternative energy supplier, subject to certain limits, which is referred to as its PLR obligation.

Regulatory assets are costs which have been authorized by the PPUC and the Federal Energy Regulatory Commission for recovery from customers in future periods and, without such authorization, would have been charged to income when incurred. All of Met-Ed's regulatory assets are expected to continue to be recovered under the provisions of the regulatory plan as discussed below. Met-Ed's regulatory assets totaled $1.1 billion and $1.2 billion as of June 30, 2003 and December 31, 2002, respectively.

Regulatory Matters

Effective September 1, 2002, Met-Ed assigned its PLR responsibility to its unregulated supply affiliate, FirstEnergy Solutions Corp. (FES), through a wholesale power sale agreement which expires in December 2003 and may be extended for each successive calendar year. Under the terms of the wholesale agreement, FES assumed the supply obligation, and the energy supply profit and loss risk, for the portion of power supply requirements that Met-Ed does not self-supply under its non-utility generation (NUG) contracts and other existing power contracts with nonaffiliated third party suppliers. This arrangement reduces its exposure to high wholesale power prices by providing power at or below the shopping credit for its uncommitted PLR energy costs during the term of the agreement to FES. Met-Ed will continue to defer the cost differences between NUG contract rates and the rates reflected in its capped generation rates.

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

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

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

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

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

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

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

Environmental Matters

Met-Ed 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 June 30, 2003, based on estimates of the total costs of cleanup, Met-Ed's proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay. Met-Ed has accrued liabilities aggregating approximately $0.2 million as of June 30, 2003. Met-Ed does not believe environmental remediation costs will have a material adverse effect on its financial condition, cash flows or results of operations.

Legal Matters

Various lawsuits, claims and proceedings related to our normal business operations are pending against Met-Ed, the most significant of which are described above.

SIGNIFICANT ACCOUNTING POLICIES

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

Purchase Accounting

The merger between FirstEnergy and GPU was accounted for by the purchase method of accounting, which requires judgment regarding the allocation of the purchase price based on the fair values of the assets acquired (including intangible assets) and the liabilities assumed. The fair values of the acquired assets and assumed liabilities were based primarily on estimates. The adjustments reflected in Met-Ed's records, which were finalized in the fourth quarter of 2002, primarily consist of: (1) revaluation of certain property, plant and equipment; (2) adjusting preferred stock

subject to mandatory redemption and long-term debt to estimated fair value; (3) recognizing additional obligations related to retirement benefits; and (4) recognizing estimated severance and other compensation liabilities. The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill. Based on the guidance provided by SFAS 142, "Goodwill and Other Intangible Assets," Met-Ed evaluates its goodwill for impairment at least annually and would make such an evaluation more frequently if indicators of impairment should arise. The forecasts used in Met-Ed's evaluations of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on its future evaluations of goodwill. As of June 30, 2003, Met-Ed had recorded goodwill of approximately $885.8 million related to the merger.

Regulatory Accounting

Met-Ed is subject to regulation that sets the prices (rates) it is permitted to charge its customers based on the costs that the regulatory agencies determine it is 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 Pennsylvania, a significant amount of regulatory assets have been recorded. As of June 30, 2003, Met-Ed's regulatory assets totaled $1.1 billion. Met-Ed regularly reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future.

Derivative Accounting

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

Revenue Recognition

Met-Ed follows the accrual method of accounting for revenues, recognizing revenue for kilowatt-hours that have been delivered but not yet been billed through the end of the accounting period. The determination of unbilled revenues requires management to make various estimates including:

- Net energy generated or purchased for retail load
- Losses of energy over 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

FirstEnergy's reported costs of providing non-contributory defined pension benefits and 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 FirstEnergy makes 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 for 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, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. Due to the significant decline in corporate bond yields and interest rates in general during 2002, FirstEnergy reduced the assumed discount rate as of December 31, 2002 to 6.75% from 7.25% used in 2001.

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by its pension trusts. The market values of FirstEnergy's pension assets have been affected by sharp declines in the equity markets since mid-2000. In 2002 and 2001, plan assets earned (11.3)% and (5.5)%, respectively. FirstEnergy's 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 FirstEnergy's 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, FirstEnergy will not be required to fund its 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 FirstEnergy's 2002 assumption of approximately 10% in 2002, gradually decreasing to 4%-6% in later years. In determining its trend rate assumptions, FirstEnergy included the specific provisions of its health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in its health care plans, and projections of future medical trend rates.

Long-Lived Assets

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," Met-Ed periodically evaluates its 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, Met-Ed would recognize a loss - calculated as the difference between the carrying value and the estimated fair value of the asset (discounted future net cash flows).

RECENTLY ISSUED ACCOUNTING STANDARDS NOT YET IMPLEMENTED

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 (Met-Ed's third quarter of 2003). The FASB also identified transitional disclosure provisions for all financial statements issued after January 31, 2003.

Met-Ed currently has transactions with entities in connection with the sale of preferred securities, 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.

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

Issued by the FASB in April 2003, SFAS 149 further clarifies and amends accounting and reporting for derivative instruments. The statement amends SFAS 133 for decisions made by the Derivative Implementation Group (DIG), as well as issues raised in connection with other FASB projects and implementation issues. The statement is effective for contracts entered into or modified after June 30, 2003 except for implementation issues that have been effective for reporting periods beginning before June 15, 2003, which continue to be applied based on their original effective dates. Met-Ed is currently assessing the new standard and has not yet determined the impact on its financial statements.

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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 immediately 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 (Met-Ed's third quarter of 2003) for all other financial instruments.

Met-Ed did not enter into or modify any financial instruments within the scope of SFAS 150 during June 2003. Adoption of SFAS 150, effective July 1, 2003, did not change the accounting treatment of company-obligated trust preferred securities ($92.5 million) which continue to be treated as an obligation and their dividends as interest charges on Met-Ed's Consolidated Statements of Income. 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. Met-Ed 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 Emerging Issues Task Force (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. Met-Ed is currently assessing the new EITF consensus and has not yet determined the impact on its financial position or results of operations following adoption.

PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF INCOME

(UNAUDITED)

	THREE MONTHS ENDED JUNE 30, 2003	THREE MONTHS ENDED JUNE 30, 2002	
		(IN THOUSANDS)	
OPERATING REVENUES	$ 231,926	$ 237,576	$
OPERATING EXPENSES AND TAXES:			
Purchased power	140,549	150,723	
Other operating costs	40,477	38,418	
Total operation and maintenance expenses	181,026	189,141	
Provision for depreciation and amortization	13,603	14,814	
General taxes	15,854	14,426	
Income taxes	5,561	3,300	
Total operating expenses and taxes	216,044	221,681	
OPERATING INCOME	15,882	15,895	
OTHER INCOME	534	789	
INCOME BEFORE NET INTEREST CHARGES	16,416	16,684	
NET INTEREST CHARGES:			
Interest on long-term debt	7,352	7,907	
Allowance for borrowed funds used during construction	(99)	(163)	
Deferred interest	(1,149)	(691)	
Other interest expense	119	834	
Subsidiary's preferred stock dividend requirements	1,889	1,942	
Net interest charges	8,112	9,829	
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	8,304	6,855	
Cumulative effect of accounting change (net of income taxes of $777,000) (Note 5)	--	--	
NET INCOME	$ 8,304	$ 6,855	$

The preceding Notes to Financial Statements as they relate to Pennsylvania Electric Company are an integral part of these statements.

PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED BALANCE SHEETS

	(UNAUDITED) JUNE 30, 2003
	(IN THOUS
ASSETS	
UTILITY PLANT:	
In service	$1,952,605
Less--Accumulated provision for depreciation	764,984
	1,187,621
Construction work in progress-	
Electric plant	20,787
	1,208,408
OTHER PROPERTY AND INVESTMENTS:	
Non-utility generation trusts	3,984
Nuclear plant decommissioning trusts	94,867
Long-term notes receivable from associated companies	15,515
Other	13,416
	127,782
CURRENT ASSETS:	
Cash and cash equivalents	366
Receivables-	
Customers (less accumulated provisions of $6,153,000 and $6,216,000 respectively, for uncollectible accounts)	120,675
Associated companies	94,139
Other	17,633
Notes receivable from associated companies	61,987
Prepayments and other	8,364
	303,164
DEFERRED CHARGES:	
Regulatory assets	557,420
Goodwill	898,086
Accumulated deferred income tax benefits	90,250
Other	19,407
	1,565,163
	$3,204,517

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PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED BALANCE SHEETS

	(UNAUDITED) JUNE 30, 2003
	(IN THOU
CAPITALIZATION AND LIABILITIES	
CAPITALIZATION:	
Common stockholder's equity-	
Common stock, par value $20 per share, authorized 5,400,000 shares, 5,290,596 shares outstanding	$ 105,812
Other paid-in capital	1,215,256
Accumulated other comprehensive loss	(53,861)
Retained earnings	30,299
Total common stockholder's equity	1,297,506
Company-obligated trust preferred securities	92,321
Long-term debt	344,321
	1,734,148
CURRENT LIABILITIES:	
Currently payable long-term debt	125,843
Accounts payable-	
Associated companies	168,052
Other	34,643
Notes payable to associated companies	27,569
Accrued taxes	20,863
Accrued interest	12,809
Other	19,265
	409,044
DEFERRED CREDITS:	
Accumulated deferred investment tax credits	10,430
Nuclear fuel disposal costs	18,880
Power purchase contract loss liability	739,162
Asset retirement obligation	107,366
Retirement benefits	160,645
Other	24,842
	1,061,325
COMMITMENTS, GUARANTEES AND CONTINGENCIES (NOTE 2)	
	$ 3,204,517

The preceding Notes to Financial Statements as they relate to the Pennsylvania Electric Company are an integral part of these balance sheets.

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PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	THREE MONTHS ENDED JUNE 30, 2003	THREE MONTHS ENDED JUNE 30, 2002
	(IN THOUSANDS)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 8,304	$ 6,855
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation and amortization	13,603	14,814
Other amortization	14	(595)
Deferred costs, net	(11,787)	(9,266)
Deferred income taxes, net	4,131	4,866
Investment tax credits, net	(247)	(286)
Receivables	3,352	(21,455)
Accounts payable	13,306	12,915
Cumulative effect of accounting change (Note 5)	--	--
Accrued taxes	(27,692)	(35,087)
Accrued interest	(5,565)	(5,725)
Prepayments and other	28,965	16,147
Pension and retirement obligation	11,964	--
Other	24,756	4,826
Net cash provided from (used for) operating activities	63,104	(11,991)
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Short-term borrowings, net	27,569	65,438
Redemptions and Repayments-		
Long-term debt	(289)	(24,973)
Short-term borrowings, net	--	--
Dividend Payments-		
Common stock	(16,000)	(14,000)
Net cash provided from (used for) financing activities	11,280	26,465
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(12,465)	(12,623)
Decommissioning trust investments	(78)	--
Proceeds from non-utility generation trusts	--	--
Loans to associated companies	(61,987)	--
Other	202	--
Net cash provided from (used for) investing activities	(74,328)	(12,623)
Net increase (decrease) in cash and cash equivalents	56	1,851
Cash and cash equivalents at beginning of period	310	18,460
Cash and cash equivalents at end of period	$ 366	$ 20,311

The preceding Notes to Financial Statements as they relate to Pennsylvania Electric Company are an integral part of these statements.

REPORT OF INDEPENDENT AUDITORS

To the Stockholders and Board
of Directors of Pennsylvania
Electric Company:

We have reviewed the accompanying consolidated balance sheet of Pennsylvania Electric Company and its subsidiaries as of June 30, 2003, and the related consolidated statements of income and cash flows for each of the three-month and six-month periods ended June 30, 2003 and 2002. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with generally accepted auditing standards, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited in accordance with auditing standards generally accepted in the United States of America, the consolidated balance sheet and the consolidated statement of capitalization as of December 31, 2002, and the related consolidated statements of income, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report dated February 28, 2003 we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2002, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio
August 18, 2003

PENNSYLVANIA ELECTRIC COMPANY

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

Penelec provides regulated transmission and distribution services in northern, western and south central Pennsylvania. Pennsylvania customers are able to choose their electricity suppliers as a result of legislation which restructured the electric utility industry. Penelec's regulatory plan required unbundling the price for electricity into its component elements - including generation, transmission, distribution and transition charges. Penelec continues to deliver power to homes and businesses through its existing distribution system and maintains provider of last resort (PLR) obligations to customers who elect to retain Penelec as their power supplier.

RESULTS FROM OPERATIONS

Net income in the second quarter of 2003 increased to $8.3 million from $6.9 million in the second quarter of 2002. Reduced purchased power costs in the second quarter of 2003 were partially offset by lower operating revenues and higher other operating costs as compared to the second quarter of 2002. During the first six months of 2003, net income decreased to $13.6 million compared to $25.7 million in the first six months of 2002. Net income in the first half of 2003 included an after-tax credit of $1.1 million from the cumulative effect of an accounting change due to the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations." Income before the cumulative effect was $12.5 million in the first half of 2003 compared with $25.7 million for the corresponding period of 2002. In the first six months of 2003, higher operating expenses, primarily due to purchased power costs, were partially offset by higher operating revenues.

Electric Sales

Operating revenues decreased by $5.7 million, or 2.4% in the second quarter of 2003 compared with the same period in 2002, primarily as a result of lower wholesale and industrial kilowatt-hour sales, partially offset by increased residential and commercial kilowatt-hour sales. Wholesale sales revenues decreased by $4.6 million, which was attributable to lower sales to affiliated companies. Retail generation kilowatt-hour sales decreased by 2.6% ($2.7 million decrease in revenue) as a result of a 20.2% decrease in industrial sales offset by higher residential and commercial sales (4.9% and 8.4%, respectively). The substantial decrease in industrial sales was primarily due to more industrial customers being served by alternative suppliers in the second quarter of 2003 compared to 2002. Distribution deliveries increased 2.3% in the second quarter of 2003 from the same quarter of the prior year, increasing revenues from electricity throughput by $1.8 million. Distribution deliveries benefited from higher residential and commercial demand, which was partially offset by a decrease in industrial demand from the continued effect of a sluggish economy. Operating revenues increased $6.4 million, or 1.3% in the first six months of 2003 over the same period in 2002, reflecting a 4.6% increase in distribution deliveries and a corresponding increase in revenues of $8.9 million. Higher distribution deliveries to residential and commercial customers were partially offset by lower industrial demands. The higher distribution revenues were partially offset by lower wholesale sales revenues of $5.2 million, due to lower sales to affiliated companies.

Changes in electric generation sales and distribution deliveries in the second quarter and the first six months of 2003 from the corresponding periods of 2002 are summarized in the following table:

CHANGES IN KILOWATT-HOUR SALES	THREE MONTHS	SIX MONTHS
INCREASE (DECREASE)		
Electric Generation:		
Retail................................	(2.6)%	0.1%
Wholesale.............................	(92.1)%	(99.2)%
TOTAL ELECTRIC GENERATION SALES.........	(7.2)%	(4.1)%
Distribution Deliveries:		
Residential...........................	4.8%	11.5%
Commercial............................	9.7%	10.3%

Industrial..........................	(6.0)%	(6.3)%
TOTAL DISTRIBUTION DELIVERIES..........	2.3%	4.6%

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Operating Expenses and Taxes

Total operating expenses and taxes decreased $5.6 million or 2.5% in the second quarter of 2003 and increased $22.3 million, or 5.1% in the first six months of 2003 from the same periods of 2002. The following table presents changes from the prior year by expense category.

OPERATING EXPENSES AND TAXES - CHANGES	THREE MONTHS	SIX MONTHS
INCREASE (DECREASE)	(IN MILLIONS)	
Purchased power costs...........................	$ (10.2)	$ 24.9
Other operating costs...........................	2.1	4.8
TOTAL OPERATION AND MAINTENANCE EXPENSES.......	(8.1)	29.7
Provision for depreciation and amortization......	(1.2)	(2.3)
General taxes....................................	1.4	2.2
Income taxes.....................................	2.3	(7.3)
TOTAL CHANGE IN OPERATING EXPENSES AND TAXES...	$ (5.6)	$ 22.3

Reduced purchased power costs in the second quarter of 2003, compared with the same quarter of 2002, were due to lower required kilowatt-hour purchases driven by lower generation sales. The higher purchased power costs in the first half of 2003 were principally due to higher average unit costs. The increase in other operating costs in the second quarter and first half of 2003 over 2002 was primarily due to higher pension and other employee benefit costs.

Net Interest Charges

Net interest charges decreased by $1.7 million in the second quarter of 2003 and $3.4 million in the first half of 2003 compared with 2002, reflecting debt redemptions since the beginning of the second quarter of 2002.

Cumulative Effect of Accounting Change

Upon adoption of SFAS 143 in the first quarter of 2003, Penelec recorded an after-tax credit to net income of $1.1 million. Penelec identified applicable legal obligations as defined under the new standard for nuclear power plant decommissioning. As a result of adopting SFAS 143 in January 2003, asset retirement costs of $93 million were recorded as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $93 million. The asset retirement obligation (ARO) liability at the date of adoption was $99 million, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. As of December 31, 2002, Penelec had recorded decommissioning liabilities of $130 million. Penelec expects substantially all of its nuclear decommissioning costs to be recoverable in rates over time. Therefore, Penelec recognized a regulatory liability of $29 million upon adoption of SFAS 143 for the transition amounts related to establishing the ARO for nuclear decommissioning. The remaining cumulative effect adjustment for unrecognized depreciation and accretion offset by the reduction in the liabilities was a $1.9 million increase to income, or $1.1 million net of income taxes.

CAPITAL RESOURCES AND LIQUIDITY

Penelec's cash requirements in 2003 for operating expenses, construction expenditures and scheduled debt maturities are expected to be met without materially increasing its net debt and preferred stock outstanding. Over the next three years, Penelec expects to meet its contractual obligations with cash from operations. Thereafter, Penelec expects to use a combination of cash from operations and funds from the capital markets.

Changes in Cash Position

As of June 30, 2003, Penelec had $0.4 million of cash and cash equivalents, compared with $10.3 million as of December 31, 2002. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Net cash provided from (used for) operating activities during the second quarter and first six months of 2003 compared with the corresponding periods of 2002 were as follows:

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
OPERATING CASH FLOWS	2003	2002	2003	2002
	(IN MILLIONS)			
Cash earnings (loss) (1).....	$14	$ 16	$(11)	$ 26
Working capital and other....	49	(28)	54	(43)
Total.......................	$63	$(12)	$ 43	$(17)

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

Net cash provided from operating activities increased to $63 million in the second quarter and $43 million in the first half of 2003 compared with net cash used for operating activities in the corresponding periods of 2002 of $12 million and $17 million, respectively. This increase was primarily due to the increase of working capital and other.

Cash Flows From Financing Activities

In the second quarter of 2003, the decrease in net cash provided from financing activities of $11 million as compared to $26 million in the same period of 2002 resulted from a reduction in net short-term borrowings.

As of June 30, 2003, Penelec had about $62.4 million of cash and temporary cash investments and approximately $27.6 million of short-term indebtedness. Penelec may borrow from its affiliates on a short-term basis. Penelec will not issue first mortgage bonds (FMB) other than as collateral for senior notes, since its senior note indentures prohibit (subject to certain exceptions) it from issuing any debt which is senior to the senior notes. As of June 30, 2003, Penelec had the capability to issue $10 million of additional senior notes based upon FMB collateral. Penelec had no restrictions on the issuance of preferred stock.

Cash Flows From Investing Activities

Net cash used for investing activities totaled $74 million in the second quarter of 2003 compared to $13 million in the second quarter of 2002. Net cash provided from investing activities was $26 million in the first six months of 2003, compared with $11 million in the same period of 2002. The net cash provided from investing activities resulted from proceeds from nonutility generation trusts, slightly offset by expenditures for property additions in both periods. Expenditures for property additions primarily support Penelec's energy delivery operations.

During the second half of 2003, capital requirements for property additions are expected to be about $30 million. Penelec has additional requirements of approximately $0.2 million for maturing long-term debt during the remainder of 2003. These cash requirements are expected to be satisfied from internal cash and short-term credit arrangements.

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

On August 7, 2003, S&P affirmed its "BBB" corporate credit rating for FirstEnergy. However, S&P stated that although FirstEnergy generates substantial free cash, that its strategy for reducing debt had deviated substantially from the one presented to S&P around the time of the GPU merger when the current rating was assigned. S&P further noted that their affirmation of FirstEnergy's corporate credit rating was based on the assumption that FirstEnergy would take appropriate steps quickly to maintain its investment grade ratings including the issuance of equity or possible sale of assets. Key issues being monitored by S&P include restart of Davis-Besse, FirstEnergy's liquidity position, its ability to forecast provider-of-last-resort load and the performance of its hedged portfolio, and continued capture of merger synergies. On August 11, 2003, S&P stated that a recent U.S. District Court ruling (see Environmental Matters below) with respect to the Sammis Plant is negative for FirstEnergy's credit quality.

On August 14, 2003, Moody's Investors Service placed the debt ratings of FirstEnergy and all of its subsidiaries under review for possible downgrade. Moody's stated that the review was prompted by: (1) weaker than expected operating performance and cash flow generation; (2) less progress than expected in reducing debt; (3) continuing high leverage relative to its peer group; and (4) negative impact on cash flow and earnings from the continuing nuclear plant outage at Davis-Besse. Moody's further stated that, in anticipation of Davis-Besse returning to service in the near future and FirstEnergy's continuing to significantly reduce debt and improve its financial profile, "Moody's does

not expect that the outcome of the review will result in FirstEnergy's senior unsecured debt rating falling below investment-grade."

Pension and Other Postretirement Benefits

As a result of GPU Service Inc. merging with FirstEnergy Service Company in the second quarter of 2003, operating company employees of GPU Service were transferred to JCP&L, Met-Ed and Penelec. Accordingly, FirstEnergy requested an actuarial study to update the pension and other post-employment benefit (OPEB) assets and liabilities for each of its subsidiaries. Based on the actuary's report, Penelec's accrued pension and OPEB costs as of June 30, 2003 increased by $70.7 million and $87.3 million, respectively.

MARKET RISK INFORMATION

Penelec uses various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price fluctuations. FirstEnergy's Risk Policy Committee, comprised of executive officers, exercises an independent risk oversight function to ensure compliance with corporate risk management policies and prudent risk management practices.

Commodity Price Risk

Penelec is exposed to market risk primarily due to fluctuations in electricity and natural gas prices. To manage the volatility relating to these exposures, it uses a variety of non-derivative and derivative instruments, including options and future contracts. The derivatives are used for hedging purposes. Most of Penelec's non-hedge derivative contracts represent non-trading positions that do not qualify for hedge treatment under SFAS 133. The change in the fair value of commodity derivative contracts related to energy production during the second quarter and first six months of 2003 is summarized in the following table:

INCREASE (DECREASE) IN THE FAIR VALUE OF COMMODITY DERIVATIVE CONTRACTS	THREE MONTHS ENDED JUNE 30, 2003			
	NON-HEDGE	HEDGE	TOTAL	N
			(IN MILLION	
CHANGE IN THE FAIR VALUE OF COMMODITY DERIVATIVE CONTRACTS				
Net asset at beginning of period............................	$12.8	$ --	$12.8	
New contract value when entered............................	--	--	--	
Additions/Increase in value of existing contracts...........	0.1	--	0.1	
Change in techniques/assumptions...........................	--	--	--	
Settled contracts..	--	--	--	
NET ASSETS - DERIVATIVE CONTRACTS AS OF JUNE 30, 2003 (1)...	$12.9	$ --	$12.9	
IMPACT OF CHANGES IN COMMODITY DERIVATIVE CONTRACTS (2)				
Income Statement Effects (Pre-Tax)..........................	$ 0.2	$ --	$ 0.2	
Balance Sheet Effects:				

Other Comprehensive Income (Pre-Tax)....................	$ --	$ --	$ --
Regulatory Liability....................................	$(0.1)	$ --	$(0.1)

(1) Includes $12.2 million in non-hedge commodity derivative contracts which are offset by a regulatory liability.

(2) Represents the increase in value of existing contracts, settled contracts and changes in techniques/assumptions.

Derivatives included on the Consolidated Balance Sheet as of June 30, 2003:

	NON-HEDGE	HEDGE	TOTAL
	(IN MILLIONS)		
CURRENT-			
Other Assets...................	$ --	$ --	$ --
Other Liabilities..............	--	--	--
NON-CURRENT-			
Other Deferred Charges..........	12.9	--	12.9
Other Deferred Credits..........	--	--	--
NET ASSETS.....................	$12.9	$ --	$12.9

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, Penelec relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. Penelec uses these results to develop estimates of fair value for financial reporting purposes and for internal management

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decision making. Sources of information for the valuation of derivative contracts by year are summarized in the following table:

SOURCE OF INFORMATION - FAIR VALUE BY CONTRACT YEAR	2003(1)	2004	2005	2006	THEREAFTER
			(IN MILLIONS)		
Prices based on external sources(2)	$0.3	$2.0	$2.5	$ --	$ --
Prices based on models	--	--	--	1.2	6.9
TOTAL(3)	$0.3	$2.0	$2.5	$1.2	$6.9

(1) For the remaining quarters of 2003.

(2) Broker quote sheets.

(3) Includes $12.2 million from an embedded option that is offset by a regulatory liability and does not affect earnings.

Penelec performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% adverse shift in quoted market prices in the near term on derivative instruments would not have had a material effect on its consolidated financial position or cash flows as of June 30, 2003.

Equity Price Risk

Included in Penelec's nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $47 million and $42 million as of June 30, 2003 and December 31, 2002, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $5 million reduction in fair value as of June 30, 2003.

OUTLOOK

Beginning in 1999, all of Penelec's customers were able to select alternative energy suppliers. Penelec continues to deliver power to homes and businesses through its existing distribution system, which remains regulated. The Pennsylvania Public Utility Commission (PPUC) authorized Penelec's rate restructuring plan, establishing separate charges for transmission, distribution, generation and stranded cost recovery, which is recovered through a competitive transition charge (CTC). Customers electing to obtain power from an alternative supplier have their bills reduced based on the regulated generation component, and the customers receive a generation charge from the alternative supplier. Penelec has a continuing responsibility to provide power to those customers not choosing to receive power from an alternative energy supplier, subject to certain limits, which is referred to as its PLR obligation.

Regulatory assets are costs which have been authorized by the PPUC and the Federal Energy Regulatory Commission for recovery from customers in future periods and, without such authorization, would have been charged to income when incurred. All of Penelec's regulatory assets are expected to continue to be recovered under the provisions of the regulatory plan as discussed below. Penelec's regulatory assets totaled $557 million and $600 million as of June 30, 2003 and December 31, 2002, respectively.

Regulatory Matters

Effective September 1, 2002, Penelec assigned its provider of last resort (PLR) responsibility obligation to its unregulated supply affiliate, FirstEnergy Solutions Corp. (FES), through a wholesale power sale agreement which expires in December 2003 and may be extended for each successive calendar year. Under the terms of the wholesale agreement, FES assumed the supply obligation, and the energy supply profit and loss risk, for the portion of power supply requirements that Penelec does not self-supply under its non-utility generation (NUG) contracts and other existing power contracts with nonaffiliated third party suppliers. This arrangement reduces its exposure to high wholesale power prices by providing power at or below the shopping credit for its uncommitted PLR energy costs during the term of the agreement to FES. Penelec will continue to defer those cost differences between NUG contract rates and the rates reflected in its capped generation rates.

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

On April 2, 2003, the PPUC remanded the merger savings issue to the Office of Administrative Law for hearings and directed Met-Ed and Penelec to file a position paper on the effect of the Commonwealth Court's order on

the Settlement Stipulation by May 2, 2003 and for the other parties to file their responses to the Met-Ed and Penelec position paper by June 2, 2003. In summary, the Met-Ed and Penelec position paper essentially stated the following:

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

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

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

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

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

Environmental Matters

Penelec 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 June 30, 2003, based on estimates of the total costs of cleanup, Penelec's proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay. Penelec has total accrued liabilities aggregating approximately $0.2 million as of June 30, 2003. Penelec does not believe environmental remediation costs will have a material adverse effect on its financial condition, cash flows or results of operations.

Legal Matters

Various lawsuits, claims and proceedings related to Penelec's normal business operations are pending against it, the most significant of which are described above.

SIGNIFICANT ACCOUNTING POLICIES

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

Purchase Accounting

The merger between FirstEnergy and GPU was accounted for by the purchase method of accounting, which requires judgment regarding the allocation of the purchase price based on the fair values of the assets acquired (including intangible assets) and the liabilities assumed. The fair values of the acquired assets and assumed liabilities were based primarily on estimates. The adjustments reflected in Penelec's records, which were finalized in the fourth quarter of 2002, primarily consist of: (1) revaluation of certain property, plant and equipment; (2) adjusting preferred stock subject to mandatory redemption and long-term debt to estimated fair value; (3) recognizing additional obligations related to retirement benefits; and (4) recognizing estimated severance and other compensation liabilities. The excess of the

purchase price over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill. Based on the guidance provided by SFAS 142, "Goodwill and Other Intangible Assets," Penelec evaluates its goodwill for impairment at least annually and would make such an evaluation more frequently if indicators of impairment should arise. The forecasts used in its evaluations of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on Penelec's future evaluations of goodwill. As of June 30, 2003, Penelec had recorded goodwill of approximately $898.1 million related to the merger.

Regulatory Accounting

Penelec is subject to regulation that sets the prices (rates) it is permitted to charge its customers based on the costs that the regulatory agencies determine it is 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 Pennsylvania, a significant amount of regulatory assets have been recorded. As of June 30, 2003, Penelec's regulatory assets totaled $557 million. Penelec regularly reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future.

Derivative Accounting

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

Revenue Recognition

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

- Net energy generated or purchased for retail load
- Losses of energy over 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

FirstEnergy's reported costs of providing non-contributory defined pension benefits and 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 FirstEnergy makes 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 for 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, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. Due to the significant decline in corporate bond yields and interest rates in general during 2002, FirstEnergy reduced the assumed discount rate as of December 31, 2002 to 6.75% from 7.25% used in 2001.

FirstEnergy's assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by its pension trusts. The market values of FirstEnergy's pension assets have been affected by sharp declines in the equity markets since mid-2000. In 2002 and 2001, plan assets have earned (11.3)% and (5.5)%, respectively. FirstEnergy's 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 FirstEnergy's 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, FirstEnergy will not be required to fund its 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 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 FirstEnergy's 2002 assumption of approximately 10% in 2002, gradually decreasing to 4%-6% in later years. In determining its trend rate assumptions, FirstEnergy included the specific provisions of its health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in its health care plans, and projections of future medical trend rates.

Long-Lived Assets

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," Penelec periodically evaluates its 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, Penelec would recognize a loss - calculated as the difference between the carrying value and the estimated fair value of the asset (discounted future net cash flows).

RECENTLY ISSUED ACCOUNTING STANDARDS NOT YET IMPLEMENTED

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 (Penelec's third quarter of 2003). The FASB also identified transitional disclosure provisions for all financial statements issued after January 31, 2003.

Penelec currently has involvement with entities in connection with the sale of preferred securities, 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.

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

Issued by the FASB in April 2003, SFAS 149 further clarifies and amends accounting and reporting for derivative instruments. The statement amends SFAS 133 for decisions made by the Derivative Implementation Group (DIG), as well as issues raised in connection with other FASB projects and implementation issues. The statement is effective for contracts entered into or modified after June 30, 2003 except for implementation issues that have been effective for reporting periods which began prior to June 15, 2003, which continue to be applied based on their original effect dates. Penelec is currently assessing the new standard and has not yet determined the impact on its financial statements.

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

In May 2003, the FASB issued SFAS 150, which establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. In accordance with the standard, certain financial instruments that embody obligations for the issuer are required to be classified as liabilities. SFAS 150 is effective immediately 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 (Penelec's third quarter of 2003) for all other financial instruments.

Penelec did not enter into or modify any financial instruments within the scope of SFAS 150 during June 2003. Adoption of SFAS 150, effective July 1, 2003, did not change the accounting treatment of company-obligated trust preferred securities ($92.3 million) which continue to be treated as obligations and their dividends as interest charges on Penelec's Consolidated Statements of Income. 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. Penelec 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 Emerging Issues Task Force (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. Penelec is currently assessing the new EITF consensus and has not yet determined the impact on its financial position or results of operations following adoption.

CONTROLS AND PROCEDURES

(a) EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The applicable registrant's chief executive officer and chief financial officer have reviewed and evaluated the registrant's disclosure controls and procedures, as defined in the Securities Exchange Act of 1934 Rules 13a-14(c) and 15d-14(c), as of a date within 90 days prior to the filing date of this report (Evaluation Date). Based on that evaluation those officers have concluded that the registrant's disclosure controls and procedures are effective and were designed to bring to their attention, during the period in which this quarterly report was being prepared, material information relating to the registrant and its consolidated subsidiaries by others within those entities.

(b) CHANGES IN INTERNAL CONTROLS

Effective June 1, 2003, the registrants implemented a new Enterprise Resource Planning (ERP) system. While the associated business process changes transform the internal control structure, management believes adequate controls have been properly integrated into the reengineered ERP enabled processes and that internal controls will be enhanced.

PART II. OTHER INFORMATION

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

(a) The annual meeting of FirstEnergy shareholders was held on May 20, 2003.

(b) At this meeting, the following persons were elected to FirstEnergy's Board of Directors:

	NUMBER OF VOTES	
	FOR	WITHHELD
Paul T. Addison..................	249,474,343	9,379,634
Dr. Carol A. Cartwright...........	215,455,549	43,398,428
William T. Cottle.................	249,690,431	9,163,546
Paul J. Powers....................	215,158,961	43,695,016
George M. Smart...................	213,788,961	45,065,016
Dr. Patricia K. Woolf............	214,937,572	43,916,405

(c) At this meeting, the appointment of PricewaterhouseCoopers LLP, independent public accountants, as auditor for the year 2003 was ratified:

NUMBER OF VOTES		
FOR	AGAINST	ABSTENTIONS
248,044,248	7,804,863	3,004,866

(d) At this meeting, material terms of performance goals under the Executive and Director Incentive Compensation Plan were reapproved (reapproval required a majority of votes cast):

NUMBER OF VOTES		
FOR	AGAINST	ABSTENTIONS
235,422,226	18,576,274	4,855,477

(e) At this meeting, a shareholder proposal designed to result in the election of the entire Board of Directors each year was rejected (passage required 80% of the 297,636,276 common shares outstanding):

NUMBER OF VOTES			
FOR	AGAINST	ABSTENTIONS	BROKER NON-VOTES
138,780,623	79,888,135	8,793,222	31,391,997

(f) At this meeting, a shareholder proposal requesting that a policy be adopted in which all future stock option grants to employees be expensed in FirstEnergy's annual income statement was rejected:

NUMBER OF VOTES			
FOR	AGAINST	ABSTENTIONS	BROKER NON-VOTES
101,621,396	116,226,152	9,610,633	31,395,796

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(g) At this meeting, a shareholder proposal requesting that a policy be adopted in which the exercise price of all future stock options granted to senior executives be linked to a peer group index was rejected:

NUMBER OF VOTES			
FOR	AGAINST	ABSTENTIONS	BROKER NON-VOTES
35,672,175	185,188,114	6,598,190	31,395,498

(h) At this meeting, a shareholder proposal recommending that FirstEnergy's shareholder rights plan be redeemed and any future plan to be approved by shareholders was passed (passage required a majority of votes cast):

NUMBER OF VOTES			
FOR	AGAINST	ABSTENTIONS	BROKER NON-VOTES
143,458,470	77,265,103	6,738,406	31,391,998

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) EXHIBITS

EXHIBIT NUMBER	
MET-ED	
12	Fixed charge ratios
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.
32.1	Certification letter from chief executive officer and chief financial officer, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act.
PENELEC	
12	Fixed charge ratios
15	Letter from independent auditors
31.1	Certification letter from chief executive officer, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act.
31.2	Certification letter from chief financial officer, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act.
32.1	Certification letter from chief executive officer and chief financial officer, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act.
JCP&L	
12	Fixed charge ratios
15	Letter from independent auditors
31.2	Certification letter from chief financial officer, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act.
31.3	Certification letter from chief executive officer, as adopted pursuant to Section 302 of the Sarbances-Oxley Act.
32.2	Certification letter from chief executive officer and chief financial officer, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act.

FIRSTENERGY, OE AND PENN

15	Letter from independent public auditors
31.1	Certification letter from chief executive officer, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act.
31.2	Certification letter from chief financial officer, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act.
32.1	Certification letter from chief executive officer and chief financial officer, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act.

CEI AND TE

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.
32.1	Certification letter from chief executive officer and chief financial officer, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act.

Pursuant to reporting requirements of respective financings, JCP&L, Met-Ed and Penelec are required to file fixed charge ratios as an exhibit to this Form 10-Q. FirstEnergy, OE, CEI, TE and Penn do not have similar financing reporting requirements and have not filed their respective fixed charge ratios.

Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, neither FirstEnergy, OE, CEI, TE, Penn, JCP&L, Met-Ed nor Penelec have filed as an exhibit to this Form 10-Q any instrument with respect to long-term debt if the respective total amount of securities authorized thereunder does not exceed 10% of their respective total assets of FirstEnergy and its subsidiaries on a consolidated basis, or respectively, OE, CEI, TE, Penn, JCP&L, Met-Ed or Penelec but hereby agree to furnish to the Commission on request any such documents.

(b) REPORTS ON FORM 8-K

FIRSTENERGY-

FirstEnergy filed fifteen reports on Form 8-K since March 31, 2003. A report dated April 16, 2003 reported updated Davis-Besse information. A report dated April 18, 2003 reported FirstEnergy's divestiture of its Argentina operations through the abandonment of its investment resulting in a second quarter 2003 charge to net income of $63 million. A report dated May 1, 2003 reported FirstEnergy's first quarter 2003 results and other updated information including Davis-Besse ready for restart schedule. A report dated May 9, 2003 reported updated Davis-Besse information and a JCP&L rate proceeding update. A report dated May 9, 2003 reported that FirstEnergy had amended its Form 10-K for the year ended December 31, 2002 for a change in classification of a $57.1

million net of tax charge with no effect on previously reported net income. A report dated May 22, 2003 reported that FirstEnergy had reached an agreement to sell its remaining 20.1 percent interest in Avon. A report dated June 5, 2003 reported updated Davis-Besse information. A report dated June 11, 2003 reported that FirstEnergy subsidiaries, Met-Ed and Penelec, filed a letter with a Pennsylvania Public Utility Commission Administrative Law Judge which voids the 2001 settlement stipulation previously entered into by Met-Ed and Penelec. A report dated June 27, 2003 reported a JCP&L settlement agreement with all the parties in its base rate case proceeding except for the Board of Public Utilities Regulatory Staff and the Division of the Ratepayer Advocate. A report dated July 24, 2003 reported an updated Davis-Besse ready for restart schedule and cost estimates. A report dated July 25, 2003 reported the New Jersey Board of Public Utilities decision on JCP&L's rate proceedings. A report dated August 5, 2003 reported FirstEnergy's second quarter 2003 earnings results and other information. A report dated August 5, 2003 reported the pending restatement of 2002 FE, OE, CEI and TE financial statements and restatement and reaudit of 2001 CEI and TE financial statements. A report dated August 7, 2003 reported the pending restatement and reaudit of 2000 CEI and TE financial statements. A report dated August 8, 2003 reported a U.S. District Court ruling with respect to the W. H. Sammis Plant under the Clean Air Act.

OE

OE filed two reports on Form 8-K since March 31, 2003. A report dated August 5, 2003 reported the pending restatement of 2002 FE, OE, CEI and TE financial statements. A report dated August 8, 2003 reported a U.S. District Court ruling with respect to the W. H. Sammis Plant under the Clean Air Act.

PENN

Penn filed one report on Form 8-K since March 31, 2003. A report dated August 8, 2003 reported a U.S. District Court ruling with respect to the W. H. Sammis Plant under the Clean Air Act.

CEI

CEI filed seven reports on Form 8-K since March 31, 2003. A report dated April 16, 2003 reported Davis-Besse information. A report dated May 1, 2003 reported an updated Davis-Besse 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 an updated Davis-Besse ready for restart schedule and cost estimates. 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.

TE

TE filed seven reports on Form 8-K since March 31, 2003. A report dated April 16, 2003 reported Davis-Besse information. A report dated May 1, 2003 reported an updated Davis-Besse 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 an updated Davis-Besse ready for restart schedule and cost estimates. 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.

MET-ED

Met-Ed filed one report on Form 8-K since March 31, 2003. A report dated June 11, 2003 reported that Met-Ed and Penelec filed a letter with a Pennsylvania Public Utility Commission Administrative Law Judge which voids the 2001 settlement stipulation previously entered into by Met-Ed and Penelec.

PENELEC

Penelec filed one report on Form 8-K since March 31, 2003. A report dated June 11, 2003 reported that Met-Ed and Penelec filed a letter with a Pennsylvania Public Utility Commission Administrative Law Judge which voids the 2001 settlement stipulation previously entered into by Met-Ed and Penelec.

JCP&L

JCP&L filed three reports on Form 8-K since March 31, 2003. A report dated May 9, 2003 reported a JCP&L rate proceeding update. A report dated June 27, 2003 reported a JCP&L settlement agreement with all the parties in its base rate case proceeding except for the Board of Public Utilities Regulatory Staff and the Division of the Ratepayer Advocate. A report dated July 25, 2003 reported the New Jersey Board of Public Utilities decision on JCP&L's rate proceedings.

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

August 18, 2003

FIRSTENERGY CORP.

Registrant

OHIO EDISON COMPANY

Registrant

THE CLEVELAND ELECTRIC

ILLUMINATING COMPANY

Registrant

THE TOLEDO EDISON COMPANY

Registrant

PENNSYLVANIA POWER COMPANY

Registrant

JERSEY CENTRAL POWER & LIGHT COMPANY

Registrant

METROPOLITAN EDISON COMPANY

Registrant

PENNSYLVANIA ELECTRIC COMPANY

Registrant

/s/ Harvey L. Wagner

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

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