NATIONAL FUEL GAS CO
Form 8-K
January 09, 2012

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the

Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): January 9, 2012

NATIONAL FUEL GAS COMPANY

(Exact name of registrant as specified in its charter)

New Jersey	1-3880	13-1086010
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

6363 Main Street,

Williamsville, New York **14221**
(Address of principal executive offices) **(Zip Code)**
Registrant s telephone number, including area code: (716) 857-7000

Former name or former address, if changed since last report: Not Applicable

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (*see* General Instruction A.2. below):

¨ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

¨ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

¨ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

¨ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 7.01 Regulation FD Disclosure.

National Fuel Gas Company (the Company) will participate in the BMO Capital Markets 9th Annual Unconventional Resource Conference in New York, New York on January 10, 2012. The Company also plans to hold meetings with certain industry analysts, money managers and other members of the financial community. A copy of materials to be presented by the Company during the conference and provided to participants in the Company s meetings is furnished as part of this Current Report as Exhibit 99.

Neither the furnishing of the presentation as an exhibit to this Current Report nor the inclusion in such presentation of any reference to the Company s internet address shall, under any circumstances, be deemed to incorporate the information available at such internet address into this Current Report. The information available at the Company s internet address is not part of this Current Report or any other report filed or furnished by the Company with the Securities and Exchange Commission.

In addition to financial measures calculated in accordance with generally accepted accounting principles (GAAP), the presentation furnished as part of this Current Report as Exhibit 99 contains certain non-GAAP financial measures. The Company believes that such non-GAAP financial measures are useful to investors because they provide an alternative method for assessing the Company s operating results in a manner that is focused on the performance of the Company s ongoing operations. The Company s management uses these non-GAAP financial measures for the same purpose, and for planning and forecasting purposes. The presentation of non-GAAP financial measures is not meant to be a substitute for financial measures prepared in accordance with GAAP.

Certain statements contained herein or in the materials furnished as part of this Current Report, including statements regarding estimated future earnings and statements that are identified by the use of the words anticipates, estimates, expects, forecasts, intends, plans, predicts, p believes, seeks, will and may and similar expressions, are forward-looking statements as defined by the Private Securities Litigation Reform of 1995. There can be no assurance that the Company s projections will in fact be achieved nor do these projections reflect any acquisitions or divestitures that may occur in the future. While the Company s expectations, beliefs and projections are expressed in good faith and are believed to have a reasonable basis, actual results may differ materially from those projected in forward-looking statements. Furthermore, each forward-looking statement speaks only as of the date on which it is made. In addition to other factors, the following are important factors that could cause actual results to differ materially from those discussed in the forward-looking statements: factors affecting the Company s ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including among others geology, lease availability, title disputes, weather conditions, shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and transportation capacity, the need to obtain governmental approvals and permits, and compliance with environmental laws and regulations; changes in laws, regulations or judicial interpretations to which the Company is subject, including those involving derivatives, taxes, safety, employment, climate change, other environmental matters, real property, and exploration and production activities such as hydraulic fracturing; uncertainty of oil and gas reserve estimates; significant differences between the Company s projected and actual production levels for natural gas or oil; changes in the price of natural gas or oil; changes in the availability, price or accounting treatment of derivative financial instruments; governmental/regulatory actions, initiatives and proceedings, including those involving rate cases (which address, among other things, allowed rates of return, rate design and retained natural gas), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal; delays or changes in costs or plans with respect to Company projects or related projects of other companies, including difficulties or delays in obtaining necessary governmental approvals, permits or orders or in obtaining the cooperation of interconnecting facility operators; financial and economic conditions, including the availability of credit, and occurrences affecting the Company s ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments, including any downgrades in the Company s credit ratings and changes in interest rates and other capital market conditions; changes in economic conditions, including global, national or regional recessions, and their effect on the demand for, and customers ability to pay for, the Company s products and services; the creditworthiness or performance of the Company s key suppliers, customers and counterparties; economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities, acts of war, cyber attacks or pest infestation; changes in price differential between similar quantities of natural gas at different geographic locations, and the effect of such changes on the demand for pipeline transportation capacity to or from such locations; other changes in price differentials between similar quantities of oil or natural gas having different quality, heating value, geographic location or delivery date; impairments under the SEC s full cost ceiling test for natural gas and oil reserves; significant differences between the Company s projected and actual capital expenditures and operating expenses; changes in actuarial assumptions, the interest rate environment and the return on plan/trust assets related to the Company s pension and other post-retirement benefits, which can affect future funding obligations and costs and plan liabilities; changes in demographic patterns and weather conditions; the cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company; increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits; or increasing costs of insurance, changes in coverage and the ability to obtain insurance. The Company disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date thereof.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits

Exhibit 99 Furnished presentation materials dated January 10, 2012

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

NATIONAL FUEL GAS COMPANY

By: /s/ JAMES R. PETERSON
James R. Peterson
Assistant Secretary

Dated: January 9, 2012

EXHIBIT INDEX

Exhibit Number	Description
99	Furnished presentation materials dated January 10, 2012

pt; FONT-FAMILY: Arial">

32,984

Other paid-in capital

7,033,726

7,055,676

Accumulated other comprehensive loss

(323,601
)

(313,112
)

Retained earnings

2,115,434

1,856,863

Unallocated employee stock ownership plan common stock -

1,642,223 and 2,032,800 shares, respectively

(30,584
)

(43,117
)

Total common stockholders' equity

8,827,959

8,589,294

Preferred stock of consolidated subsidiaries

183,719

335,123

Long-term debt and other long-term obligations	
	9,418,734
	10,013,349
	18,430,412
	18,937,766
NONCURRENT LIABILITIES:	
Accumulated deferred income taxes	
	2,345,281
	2,324,097
Asset retirement obligations	
	1,130,194
	1,077,557
Power purchase contract loss liability	
	1,920,358
	2,001,006
Retirement benefits	
	1,343,461
	1,238,973
Lease market valuation liability	
	872,650
	936,200
Other	
	1,486,740
	1,243,910
	9,098,684

8,821,743

COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 13)

$

31,373,942

$

31,067,944

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

balance sheets.

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FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	**2004**	**2005**	**2004**
	(In thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 332,360	$ 298,622	$ 670,078	$ 676,666
Adjustments to reconcile net income to net cash from operating activities -				
Provision for depreciation	152,786	147,052	444,443	439,017
Amortization of regulatory assets	364,337	324,300	981,750	905,488
Deferral of new regulatory assets	(123,827)	(78,767)	(303,496)	(191,487)
Nuclear fuel and lease amortization	25,785	26,776	63,363	71,782
Amortization of electric service obligation	(8,630)	(3,336)	(24,135)	(12,877)
Deferred purchased power and other costs	(39,215)	(118,409)	(231,438)	(263,290)
Deferred income taxes and investment tax credits, net	(37,851)	37,138	24,034	(56,995)
Deferred rents and lease market valuation liability	29,834	28,402	(71,275)	(52,182)
Accrued retirement benefit obligations	56,116	42,397	104,488	106,897
Accrued compensation, net	4,380	25,864	(32,895)	48,186
Commodity derivative transactions, net	(55,101)	17,336	(40,993)	(37,443)
Cash collateral from suppliers	76,978	-	76,978	-
Income from discontinued operations (Note 6)	(528)	(2,497)	(18,451)	(6,332)
Pension trust contribution	-	(500,000)	-	(500,000)
Decrease (increase) in operating assets -				
Receivables	(90,673)	16,288	(225,982)	187,730
Materials and supplies	11,976	6,210	(39,876)	7,173
Prepayments and other current assets	102,025	46,969	(57,192)	(42,625)
Increase (decrease) in operating liabilities -				
Accounts payable	(44,369)	(37,049)	59,662	(145,691)

Accrued taxes	167,851	152,009	207,006	296,668
Accrued interest	95,721	82,221	91,934	75,158
Prepayment for electric service - education programs	-	-	241,685	-
Other	(38,799)	15,979	(7,416)	32,370
Net cash provided from operating activities	981,156	527,505	1,912,272	1,538,213
CASH FLOWS FROM FINANCING ACTIVITIES:				
New Financing -				
Long-term debt	88,950	86,754	334,300	961,474
Short-term borrowings, net	-	228,072	77,295	-
Redemptions and Repayments -				
Preferred stock	(30,000)	(1,000)	(169,650)	(1,000)
Long-term debt	(162,939)	(772,451)	(851,687)	(1,752,394)
Short-term borrowings, net	(308,319)	-	-	(219,032)
Net controlled disbursement activity	(27,118)	(19,129)	(27,594)	(36,400)
Common stock dividend payments	(141,023)	(123,965)	(411,507)	(367,751)
Net cash used for financing activities	(580,449)	(601,719)	(1,048,843)	(1,415,103)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions	(294,443)	(211,243)	(756,118)	(545,743)
Proceeds from asset sales	-	1,662	61,207	213,109
Proceeds from certificates of deposit	-	277,763	-	277,763
Nonutility generation trust contributions	-	-	-	(50,614)
Contributions to nuclear decommissioning trusts	(25,370)	(25,370)	(76,112)	(76,112)
Cash investments	(13,950)	(7,316)	21,171	19,640
Other	23,120	7,072	(26,706)	(7,236)
Net cash provided from (used for) investing activities	(310,643)	42,568	(776,558)	(169,193)
Net change in cash and cash equivalents	90,064	(31,646)	86,871	(46,083)
Cash and cash equivalents at beginning of period	49,748	99,538	52,941	113,975
Cash and cash equivalents at end of period	$ 139,812	$ 67,892	$ 139,812	$ 67,892

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

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Report of Independent Registered Public Accounting Firm

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 September 30, 2005, and the related consolidated statements of income, comprehensive income and cash flows for each of the three-month and nine-month periods ended September 30, 2005 and 2004. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 the standards of the Public Company Accounting Oversight Board, 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 the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2004, and the related consolidated statements of income, capitalization, common stockholders' equity, preferred stock, cash flows and taxes for the year then ended, management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004 and the effectiveness of the Company's internal control over financial reporting as of December 31, 2004; and in our report (which contained references to the Company's change in its method of accounting for asset retirement obligations as of January 1, 2003 as discussed in Note 2(K) to those consolidated financial statements and the Company's change in its method of accounting for the consolidation of variable interest entities as of December 31, 2003 as discussed in Note 7 to those consolidated financial statements) dated March 7, 2005, we expressed unqualified opinions thereon. The consolidated financial statements and management's assessment of the effectiveness of internal control over financial reporting referred to above are not presented herein. In our opinion, the information set forth in the accompanying consolidated balance sheet information as of December 31, 2004, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio

November 1, 2005

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FIRSTENERGY CORP.

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

EXECUTIVE SUMMARY

Net income in the third quarter of 2005 was $332 million, or basic and diluted earnings of $1.01 per share of common stock, compared to net income of $299 million, or basic and diluted earnings of $0.91 per share of common stock for the third quarter of 2004. Net income in the first nine months of 2005 was $670 million, or basic earnings of $2.04 per share of common stock ($2.03 diluted) compared to $677 million in the first nine months of 2004, or basic earnings of $2.07 per share of common stock ($2.06 diluted). The following Non-GAAP Reconciliation displays the unusual items resulting in the difference between GAAP and non-GAAP earnings.

Reconciliation of non-GAAP to GAAP	**2005**		**2004**	
	After-tax Amount	**Basic Earnings**	**After-tax Amount**	**Basic Earnings**
Three Months Ended September 30,	**(Millions)**	**Per Share**	**(Millions)**	**Per Share**
Earnings Before Unusual Items (Non-GAAP)	$ 342	$ 1.04	$ 319	$ 0.97
Unusual Items:				
Non-core asset sales gains/losses, net	-	-	(16)	(0.05)
JCP&L arbitration decision	(10)	(0.03)	-	-
Other	-	-	(4)	(0.01)
Net Income (GAAP)	$ 332	$ 1.01	$ 299	$ 0.91
Nine Months Ended September 30,				
Earnings Before Unusual Items (Non-GAAP)	$ 730	$ 2.22	$ 753	$ 2.30
Unusual Items:				
Non-core asset sales gains/losses, net	22	0.07	(23)	(0.07)
Davis-Besse impacts	-	-	(38)	(0.12)

EPA settlement		(14)		(0.04)		-		-
NRC fine		(3)		(0.01)		-		-
JCP&L rate settlement		16		0.05		-		-
JCP&L arbitration decision		(10)		(0.03)		-		-
Ohio tax write-off		(71)		(0.22)		-		-
Class-action lawsuit settlement		-		-		(11)		(0.03)
Other		-		-		(4)		(0.01)
Net Income (GAAP)	$	670	$	2.04	$	677	$	2.07

The Non-GAAP measure above, earnings before unusual items, is not calculated in accordance with GAAP because it excludes the impact of "unusual items." Unusual items reflect the impact on earnings of events that are not routine or for which management believes the financial impact will disappear or become immaterial within a near-term finite period. By removing the earnings effect of such issues that have been resolved or are expected to be resolved over the near term, management and investors can better measure FirstEnergy’s business and earnings potential. In particular, the non-core asset sales item refers to a finite set of energy-related assets that have been previously disclosed as held for sale, a substantial portion of which has already been sold. In addition, as Davis-Besse restarted in 2004, further impacts from its extended outage are not expected. Similarly, further litigation settlements similar to the class action settlements in 2004 are not reasonably expected over the near term. Furthermore, FirstEnergy believes presenting normalized earnings calculated in this manner provides useful information to investors in evaluating the ongoing results of its businesses, over the longer term and assists investors in comparing FirstEnergy’s operating performance to the operating performance of others in the energy sector.

On October 3, 2005, S&P raised its corporate credit rating on FirstEnergy and the EUOC to 'BBB' from 'BBB-'. At the same time, S&P raised the senior unsecured ratings at the holding company to 'BBB-' from 'BB+' and each of the EUOC by one notch above the previous rating. S&P noted that the upgrade followed the continuation of a good operating track record, specifically for the nuclear fleet through the third quarter of 2005. S&P also stated that FirstEnergy’s rating reflects the benefits of supportive regulation, low-cost base load generation fleet, low-risk transmission and distribution operations and rate certainty in Ohio. FirstEnergy’s ability to consistently generate free cash flow, good liquidity, and an improving financial profile were also noted as strengths.

On September 20, 2005, FirstEnergy raised its quarterly dividend to $0.43 per share of outstanding common stock - 4.2% higher than the previous quarterly rate of $0.4125 per share. This action represents the second dividend payment increase this year. The dividend payment was last increased by 10% for the dividend paid on March 1, 2005. The new dividend is payable December 1, 2005 to shareholders of record on November 7, 2005. The Company's dividend policy, established on November 30, 2004, targets sustainable annual dividend increases after 2005, generally reflecting an annual growth rate of 4% to 5%, and an earnings payout ratio generally within the range of 50% to 60%. The Board of Directors will continue to review the Company's dividend policy regularly. The amount and timing of all dividend payments are subject to the Board's consideration of business conditions, results of operations, financial condition and other factors.

On September 9, 2005, FirstEnergy filed on behalf of the Ohio Companies an RCP that, if approved by the PUCO, would essentially maintain current electricity prices through 2008. The RCP was developed as a result of concerns about potential impacts to customer rates due to rising fuel prices and other factors. A stipulated agreement in support of the plan has been signed by the cities of Cleveland and Akron, along with the Industrial Energy Users - Ohio and the Ohio Energy Group. Also, the Mayor of the City of Parma has agreed to support the stipulation. The Parma City Council passed a resolution in support of the RCP plan on September 19, 2005.

During the third quarter of 2005, several FirstEnergy operating companies reached employment agreements with various local unions. On July 13, 2005, UWUA 118 and 126 - representing 445 workers - ratified an agreement with OE. On August 17, 2005, UWUA Local 180 - representing 170 workers - ratified an agreement with Penelec. On August 25, 2005, IBEW Local 1194 - representing 240 employees - ratified an agreement with OE. The collective bargaining agreement with IBEW Local 29 representing approximately 450 workers at the Beaver Valley Nuclear Power Station expired pursuant to its terms on September 30, 2005. The parties are currently negotiating a new agreement.

On September 14, 2005, FENOC announced that it would pay the $5.45 million fine proposed in April 2005 by the NRC related to the reactor head issue at the Davis-Besse Nuclear Power Station. FirstEnergy accrued $2.0 million of the fine in 2004 and the remaining amount in the first quarter of 2005. In a letter to the NRC, the Company noted that paying the fine brings regulatory closure to this issue and enables it to continue focusing on safe, reliable plant operations. The letter also reiterated that FENOC acknowledges full responsibility for the significant performance deficiencies that led to the reactor head issue, and that the NRC has indicated that the cited violations regarding the past plant operations do not represent current performance.

FirstEnergy announced on September 22, 2005, that FGCO plans to install an Electro-Catalytic Oxidation (ECO) system on the 215-megawatt Unit 4 of its Bay Shore Plant in Oregon, Ohio. ECO is a multipollutant-control technology for coal-based electric utility plants that was developed by Powerspan Corp., a clean energy technology company in which FirstEnergy has a minority ownership interest.

ECO is currently being demonstrated at FGCO's R. E. Burger Plant, and has proven effective in reducing NO_x, SO_2, mercury, acid gases, and fine particulates (soot). The ECO process also produces a highly marketable ammonium sulfate fertilizer co-product, currently being sold to the fertilizer market.

FGCO expects design engineering of the Bay Shore ECO system to commence in the first quarter of 2006, and estimates the overall cost of the system, including a fertilizer processing plant, to be approximately $100 million.

FIRSTENERGY'S BUSINESS

FirstEnergy is a registered public utility holding company headquartered in Akron, Ohio that operates primarily through two core business segments.

- **Regulated Services** transmits, distributes and sells electricity through eight utility operating companies that collectively comprise the nation's fifth largest investor-owned electric system, serving 4.5 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey. This business segment primarily derives its revenue from the delivery of electricity, including transition cost recovery.

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- **Power Supply Management Services** supplies the electric power needs of end-use customers (principally in Ohio, Pennsylvania and New Jersey) through retail and wholesale arrangements, including sales to meet the PLR requirements of FirstEnergy's Ohio Companies and Penn. This business segment operates FirstEnergy's generating facilities and purchases from the wholesale market to meet its sales obligations. Pursuant to an asset transfer on October 24, 2005, it now owns as well as operates FirstEnergy's fossil and hydroelectric generation facilities previously owned by the EUOC. It also purchases the entire output of the nuclear plants currently owned or leased by the EUOC. This business segment principally derives its revenues from electric generation sales.

Other operating segments provide a wide range of services, including heating, ventilation, air-conditioning, refrigeration, electrical and facility control systems, high-efficiency electrotechnologies and telecommunication services. FirstEnergy is in the process of divesting non-core businesses. See Note 6 to the consolidated financial statements. The assets and revenues for the other business operations are below the quantifiable threshold for operating segments for separate disclosure as "reportable segments".

FIRSTENERGY INTRA-SYSTEM GENERATION ASSET TRANSFERS

On May 13, 2005, Penn, and on May 18, 2005 the Ohio Companies, entered into certain agreements implementing a series of intra-system generation asset transfers. When fully completed, the asset transfers will result in the respective undivided ownership interests of the Ohio Companies and Penn in FirstEnergy's nuclear and non-nuclear plants being owned by NGC, and FGCO, respectively. The generating plant interests that are being transferred do not include leasehold interests of CEI, TE and OE in certain of the plants that are currently subject to sale and leaseback arrangements with non-affiliates.

On October 24, 2005, the Ohio Companies and Penn completed the intra-system transfer of non-nuclear generation assets to FGCO. Prior to the transfer, FGCO, as lessee under a Master Facility Lease with the Ohio Companies and Penn, leased, operated and maintained the non-nuclear generation assets that it now owns. The asset transfers were consummated pursuant to the May 13 and May 18, 2005 agreements and FGCO's purchase option under the Master Facility Lease.

As contemplated by the agreements entered into in May 2005, the Ohio Companies and Penn intend to transfer their respective interests in the nuclear generation assets to NGC through, in the case of OE and Penn, a spin-off by way of dividend and, in the case of CEI and TE, a sale at net book value. FENOC currently operates and maintains the nuclear generation assets to be transferred. FirstEnergy currently expects to complete the nuclear asset transfers in the fourth quarter of 2005, subject to the receipt of required regulatory approvals.

These transactions are pursuant to the Ohio Companies' and Penn's restructuring plans that were approved by the PUCO and the PPUC, respectively, under applicable Ohio and Pennsylvania electric utility restructuring legislation. Consistent with the restructuring plans, generation assets that had been owned by the Ohio Companies and Penn were required to be separated from the regulated delivery business of those companies through transfer to a separate corporate entity. The transactions will essentially complete the divestitures contemplated by the restructuring plans by transferring the ownership interests to NGC and FGCO without impacting the operation of the plants.

See Note 17 for disclosure of the assets held for sale by the Ohio Companies and Penn as of September 30, 2005.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among FirstEnergy's business segments. A reconciliation of segment financial results is provided in Note 16 to the consolidated financial statements. The FSG business segment is included in “Other and Reconciling Adjustments” in this discussion due to its immaterial impact on current period financial results, but is presented separately in segment information provided in Note 16 to the consolidated financial statements. Net income (loss) by major business segment is as follows:

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Increase (Decrease)	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004	Increase (Decrease)
	(In millions, except per share amounts)					
Net Income (Loss) By Business Segment:						
Regulated Services	$ 366	$ 315	$ 51	$ 856	$ 761	$ 95
Power supply management services	10	44	(34)	(15)	79	(94)
Other and reconciling adjustments*	(44)	(60)	16	(171)	(163)	(8)
Total	$ 332	$ 299	$ 33	$ 670	$ 677	$ (7)
Basic Earnings Per Share:						
Income before discontinued operations	$ 1.01	$ 0.90	$ 0.11	$ 1.99	$ 2.05	$ (0.06)
Discontinued operations	--	0.01	(0.01)	0.05	0.02	0.03
Net earnings per basic share	$ 1.01	$ 0.91	$ 0.10	$ 2.04	$ 2.07	$ (0.03)
Diluted Earnings Per Share:						
Income before discontinued operations	$ 1.01	$ 0.90	$ 0.11	$ 1.98	$ 2.04	$ (0.06)
Discontinued operations	--	0.01	(0.01)	0.05	0.02	0.03
Net earnings per diluted share	$ 1.01	$ 0.91	$ 0.10	$ 2.03	$ 2.06	$ (0.03)

* Represents other operating segments and reconciling items including interest expense on holding company debt and corporate support services revenues and expenses.

Net income in the regulated services segment for the three months and nine months ended September 30, 2005 increased due to additional customer demand. However, net income for the power supply management services segment was lower in both the three months and nine months ended September 30, 2005 compared to the same periods in 2004, as a result of higher costs for fossil fuel, purchased power (excluding 2004 PJM transactions on a gross basis) and nuclear refueling costs which, in aggregate, more than offset the revenue from increased electric generation sales.

A decrease in wholesale electric revenues and purchased power costs in the 2005 periods compared to the corresponding periods last year primarily resulted from FES recording PJM sales and purchased power transactions on an hourly net position basis beginning in the first quarter of 2005 compared with recording each discrete transaction (on a gross basis) in 2004 (See Note 2 - Accounting for Wholesale Energy Transactions). This change had no impact on earnings and resulted from the dedication of FirstEnergy's Beaver Valley Power Station to PJM in January 2005. Wholesale electric revenues and purchased power costs in the three months and nine months ended September 30, 2004 each included additional amounts of $264 million and $828 million, respectively, due to recording those transactions on a gross basis.

Excluding the effect of recording the wholesale electric revenue transactions in PJM on a gross basis in 2004, total operating revenues in the three months and nine months ended September 30, 2005 increased 14.9% and 8.7%, respectively, reflecting in large part warmer than normal temperatures during the summer of 2005 compared to 2004.

Summary of Results of Operations - Third Quarter of 2005 compared with the Third Quarter of 2004

Financial results for FirstEnergy and its major business segments in the third quarter of 2005 and 2004 were as follows:

3rd Quarter 2005 Quarterly Financial Results	**Regulated Services**	**Power Supply Management Services**	**Other and Reconciling Adjustments**	**FirstEnergy Consolidated**
		(In millions)		
Revenue:				
External				
Electric	$ 1,432	$ 1,684	$ --	$ 3,116
Other	244	28	199	471
Internal	79	--	(79)	--
Total Revenues	1,755	1,712	120	3,587
Expenses:				
Fuel and purchased power	--	1,287	--	1,287
Other operating	511	364	118	993
Provision for depreciation	137	9	7	153
Amortization of regulatory assets	364	--	--	364
Deferral of new regulatory assets	(124)	--	--	(124)
General taxes	159	24	5	188
Total Expenses	1,047	1,684	130	2,861
Net interest charges	88	11	59	158
Income taxes	254	7	(24)	237
Income before discontinued operations	366	10	(45)	331
Discontinued operations	--	--	1	1
Net Income (Loss)	$ 366	$ 10	$ (44)	$ 332

3rd Quarter 2004 Quarterly Financial Results	**Regulated Services**	**Power Supply Management Services**	**Other and Reconciling Adjustments**	**FirstEnergy Consolidated**
		(In millions)		
Revenue:				

External				
Electric	$ 1,309	$ 1,721	$ --	$ 3,030
Other	172	35	148	355
Internal	80	--	(80)	--
Total Revenues	1,561	1,756	68	3,385
Expenses:				
Fuel and purchased power	--	1,285	--	1,285
Other operating	414	356	99	869
Provision for depreciation	129	9	9	147
Amortization of regulatory assets	324	--	--	324
Deferral of new regulatory assets	(79)	--	--	(79)
General taxes	150	23	5	178
Total Expenses	938	1,673	113	2,724
Net interest charges	82	9	60	151
Income taxes	226	30	(42)	214
Income before discontinued operations	315	44	(63)	296
Discontinued operations	--	--	3	3
Net Income (Loss)	$ 315	$ 44	$ (60)	$ 299

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Change Between 3rd Quarter 2005 and 2004 Quarterly Financial Results Increase (Decrease)	**Regulated Services**	**Power Supply Management Services**	**Other and Reconciling Adjustments[1]**	**FirstEnergy Consolidated**
			(In millions)	
Revenue:				
External				
Electric	$ 123	$ (37)	$ --	$ 86
Other	72	(7)	51	116
Internal	(1)	--	1	--
Total Revenues	194	(44)	52	202
Expenses:				
Fuel and purchased power	--	2	--	2
Other operating	97	8	19	124
Provision for depreciation	8	--	(2)	6
Amortization of regulatory assets	40	--	--	40
Deferral of new regulatory assets	(45)	--	--	(45)
General taxes	9	1	--	10
Total Expenses	109	11	17	137
Net interest charges	6	2	(1)	7
Income taxes	28	(23)	18	23
Income before discontinued operations	51	(34)	18	35
Discontinued operations	--	--	(2)	(2)
Net Income (Loss)	$ 51	$ (34)	$ 16	$ 33

[1] The impact of the new Ohio tax legislation is included with FirstEnergy's other operating segments and reconciling adjustments.

Regulated Services - Third Quarter 2005 Compared with Third Quarter 2004

Net income increased $51 million, or 16% to $366 million, in the third quarter of 2005 compared to $315 million in the third quarter of 2004, as a result of increased customer usage.

Revenues -

Total revenues increased by $194 million in the third quarter 2005 compared to the same period in 2004, resulting from the following sources:

Revenues by Type of Service	**Three Months Ended September 30,**		
	2005	**2004**	**Increase**
		(In millions)	
Distribution services	$ 1,432	$ 1,309	$ 123
Transmission services	117	81	36
Lease revenue from affiliates	79	79	--
Other	127	92	35
Total Revenues	$ 1,755	$ 1,561	$ 194

Changes in distribution deliveries by customer class in the third quarter of 2005 compared with the third quarter of 2004 are summarized in the following table:

Electric Distribution Deliveries	**Increase**
Residential	15.4%
Commercial	7.8%
Industrial	5.2%
Total Distribution Deliveries	9.6%

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Increased consumption offset in part by lower composite prices to customers resulted in higher distribution delivery revenue. The following table summarizes major factors contributing to the $123 million increase in distribution services revenue in the third quarter of 2005:

Sources of Change in Distribution Revenues	**Increase (Decrease)**
	(In millions)
Changes in customer usage	$ 135
Changes in prices:	
Rate changes	--
Ohio shopping credits	(11)
JCP&L rate settlements	21
Billing component reallocations	(22)
Net Increase in Distribution Revenues	$ 123

Distribution revenues benefited from warmer summer temperatures in the third quarter of 2005, compared to 2004, that increased the air-conditioning load of residential and commercial customers. While industrial deliveries also increased, that impact was more than offset by lower unit prices to that sector. Higher base rates from JCP&L's stipulated rate settlements were more than offset by additional credits provided to customers under the Ohio transition plan and a reallocation of billing components primarily related to special contracts. Shopping credits do not affect current period earnings due to deferral of the incentives for future recovery from customers.

Transmission revenues increased $36 million in the third quarter of 2005 from the same period last year due in part to increased loads due to warmer weather and higher transmission usage prices. Other revenues increased $35 million primarily due to higher gains realized on nuclear decommissioning trust investments.

Expenses-

The increase in total revenues discussed above was partially offset by the following increases in total expenses:

- Other operating expenses increased by $97 million in the third quarter of 2005 compared to the same period in 2004 primarily due to increased transmission expenses resulting in part from increased loads and higher transmission system usage charges;

- Increased provision for depreciation of $8 million that resulted from property additions and increased leasehold improvement amortization;

- Additional amortization of regulatory assets of $40 million, principally Ohio transition costs;

- Higher general taxes of $9 million resulting from increased EUOC sales which increased the Ohio KWH tax and the Pennsylvania gross receipts tax;

- Increased interest charges of $6 million primarily due to the absence of $11 million in interest rate swap savings achieved in the third quarter of 2004; and

- Higher income taxes of $28 million due to increased taxable income.

Partially offsetting those increases was the effect of additional deferred regulatory assets of $45 million, primarily due to the PUCO-approved deferral of MISO administrative costs, shopping incentives and related interest.

Power Supply Management Services - Third Quarter 2005 Compared with Third Quarter 2004

Net income for this segment decreased $34 million to $10 million in the third quarter of 2005 from $44 million in the same period last year, due to a decrease in the gross generation margin and higher operating costs.

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Revenues -

Excluding the effect of the change in recording PJM wholesale transactions on a gross basis in 2004 ($264 million), electric generation revenues increased $227 million in the third quarter of 2005 compared to the same period of 2004 primarily as a result of a 5.2% increase in KWH sales due to higher retail customer usage and a 21% rise in unit prices in the wholesale market. The increase in retail sales reduced energy available for sale to the wholesale market, resulting in a 9% reduction in wholesale sales (before the PJM adjustment).

The change in reported segment revenues resulted from the following:

Revenues by Type of Service	**Three Months Ended September 30, 2005**	**2004**	**Increase (Decrease)**
	(In millions)		
Electric generation sales:			
Retail	$ 1,254	$ 1,069	$ 185
Wholesale	430	388	42
Total electric generation sales	1,684	1,457	227
Transmission	16	20	(4)
Other	12	15	(3)
Total	1,712	1,492	220
PJM gross transactions	--	264	(264)
Total Revenues	$ 1,712	$ 1,756	$ (44)

The following table summarizes the price and volume factors contributing to increased sales to retail and wholesale customers.

Source of Change in Electric Generation Sales	**Increase (Decrease)**
	(In millions)
Retail:	
Effect of 9.9%	$ 113

increase in customer usage		
Change in prices		72
		185
Wholesale:		
Effect of 8.7% reduction in customer usage[1]		(41)
Change in prices		83
		42
Net Increase in Electric Generation Sales	$	227

[1] Decrease of 46.4% including the effect of the PJM revision.

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Expenses -

Excluding the effect of $264 million of PJM purchased power costs recorded on a gross basis in 2004, total operating expenses, net interest charges and income taxes increased in aggregate by $254 million in the third quarter of 2005 compared to the same period of 2004. Higher fuel and purchased power costs contributed $2 million ($266 million, net of $264 million PJM effect) of the increase, resulting from higher fuel costs of $121 million and increased purchased power costs of $145 million. Factors contributing to the higher costs are summarized in the following table:

Source of Change in Fuel and Purchased Power	**Increase (Decrease)** *(In millions)*
Fuel:	
Change due to increased unit costs	$ 92
Change due to volume consumed	29
	121
Purchased Power:	
Change due to increased unit costs	130
Change due to volume purchased	(16)
Reduction in costs deferred	31
	145
PJM gross transactions	(264)
Net Increase in Fuel and Purchased Power Costs	$ 2

FirstEnergy's generation fleet established an output record of 21.7 billion KWH in the third quarter of 2005. As a result, increased coal consumption and the related cost of emission allowances combined to increase fossil fuel expense. Higher coal costs resulted from increased market purchases, market adjustment provisions in coal contracts reflecting higher market prices and increased transportation costs. Emission allowance costs increased primarily from higher prices. To a lesser extent, fuel expense increased due to higher costs associated with the increase in generation from the fossil units relative to nuclear generation. Fossil generation output increased 16% in the third quarter of 2005 while nuclear output increased by 1%, compared to the same period in 2004.

Other operating costs increased $8 million in the third quarter of 2005 compared to the same period of 2004. This increase resulted from higher transmission costs due primarily to increased loads and higher transmission system usage charges. The higher costs this year were offset in part by lower non-fuel nuclear costs resulting from expenses incurred late in the third quarter of 2004 in preparation for the fourth quarter of 2004 Beaver Valley Unit 1 refueling outage.

Offsetting higher operating costs were lower income taxes of $23 million due to lower taxable income.

Other - Third Quarter 2005 Compared with Third Quarter 2004

FirstEnergy's financial results from other operating segments and reconciling adjustments, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a net increase of $16 million in net income in the third quarter of 2005 compared to the same quarter of 2004. The increase was primarily due to the absence this year of losses recognized in 2004 on the sale of securities and impairment of several partnership investments.

Summary of Results of Operations - Nine Months ended September 30, 2005 compared with the Nine Months ended September 30, 2004

Financial results for FirstEnergy and its major business segments for the nine months ended September 30, 2005 and 2004 were as follows:

Nine Months ended September 30, 2005 Financial Results	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenue:				
External				
Electric	$ 3,759	$ 4,273	$ -	$ 8,032
Other	607	73	565	1,245
Internal	237	-	(237)	-
Total Revenues	4,603	4,346	328	9,277
Expenses:				
Fuel and purchased power	-	3,115	-	3,115
Other operating	1,336	1,132	290	2,758
Provision for depreciation	397	26	21	444
Amortization of regulatory assets	982	-	-	982
Deferral of new regulatory assets	(303)	-	-	(303)
General taxes	455	69	17	541
Total Expenses	2,867	4,342	328	7,537
Net interest charges	285	29	175	489
Income taxes	595	(10)	14	599
Income before discontinued operations	856	(15)	(189)	652
Discontinued operations	-	-	18	18
Net Income (Loss)	$ 856	$ (15)	$ (171)	$ 670

Nine Months ended September	Regulated	Power Supply Management	Other and Reconciling	FirstEnergy

30, 2004 Financial Results	Services	Services	Adjustments	Consolidated
		(In millions)		
Revenue:				
External				
Electric	$ 3,588	$ 4,742	$ --	$ 8,330
Other	461	86	484	1,031
Internal	239	--	(239)	--
Total Revenues	4,288	4,828	245	9,361
Expenses:				
Fuel and purchased power	--	3,515	--	3,515
Other operating	1,155	1,058	288	2,501
Provision for depreciation	384	26	29	439
Amortization of regulatory assets	905	--	--	905
Deferral of new regulatory assets	(192)	--	--	(192)
General taxes	433	65	16	514
Total Expenses	2,685	4,664	333	7,682
Net interest charges	301	30	171	502
Income taxes	541	55	(90)	506
Income before discontinued operations	761	79	(169)	671
Discontinued operations	--	--	6	6
Net Income (Loss)	$ 761	$ 79	$ (163)	$ 677

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Change Between Nine Months ended September 30, 2005 vs. 2004 Financial Results Increase (Decrease)	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments[1]	FirstEnergy Consolidated
		(In millions)		
Revenue:				
External				
Electric	$ 171	$ (469)	$ -	$ (298)
Other	146	(13)	81	214
Internal	(2)	-	2	-
Total Revenues	315	(482)	83	(84)
Expenses:				
Fuel and purchased power	-	(400)	-	(400)
Other operating	181	74	2	257
Provision for depreciation	13	-	(8)	5
Amortization of regulatory assets	77	-	-	77
Deferral of new regulatory assets	(111)	-	-	(111)
General taxes	22	4	1	27
Total Expenses	182	(322)	(5)	(145)
Net interest charges	(16)	(1)	4	(13)
Income taxes	54	(65)	104	93
Income before discontinued operations	95	(94)	(20)	(19)
Discontinued operations	-	-	12	12
Net Income (Loss)	$ 95	$ (94)	$ (8)	$ (7)

[1] The impact of the new Ohio tax legislation is included with FirstEnergy's other operating segments and reconciling adjustments.

Regulated Services - Nine Months ended September 30, 2005 compared with Nine Months ended September 30, 2004

Net income increased $95 million to $856 million in the nine months ended September 30, 2005, from $761 million in the same period of 2004, due to increased revenues partially offset by higher expenses and taxes.

Revenues -

The increase in total revenues resulted from the following:

Revenues by Type of Service	Nine Months Ended September 30, 2005	2004	Increase (Decrease)
	(In millions)		
Distribution services	$ 3,759	$ 3,588	$ 171
Transmission services	314	210	104
Lease revenue from affiliates	237	239	(2)
Other	293	251	42
Total Revenues	$ 4,603	$ 4,288	$ 315

Changes in distribution deliveries by customer class are summarized in the following table:

Electric Distribution Deliveries	Increase
Residential	7.9%
Commercial	5.2%
Industrial	1.8%
Total Distribution Deliveries	5.0%

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Increased customer consumption offset in part by lower prices resulted in higher distribution delivery revenues. The following table summarizes major factors contributing to the $171 million increase in distribution services revenue in the first nine months of 2005:

Sources of Change in Distribution Revenues	**Increase (Decrease)** *(In millions)*
Changes in customer usage	$ 210
Changes in prices:	
Rate changes -	
Ohio shopping credits	(33)
JCP&L rate settlements	28
Billing component reallocation	(34)
Net Increase in Distribution Revenues	$ 171

Distribution revenues benefited from warmer temperatures in the summer months of 2005 compared to 2004 that increased the air-conditioning load of residential and commercial customers. The effect of higher base rates for JCP&L's stipulated rate settlements in 2005 were more than offset by additional credits provided to customers under the Ohio transition plan and a reallocation of billing components primarily related to special contracts. Shopping credits do not affect current period earnings due to deferral of the incentives for future recovery from customers. While industrial deliveries also increased they were more than offset by lower unit prices.

Transmission revenues increased $104 million in the nine months ended September 30, 2005 compared to the same period last year due in part to the June 2004 amended power supply agreement with FES and increased loads due to warmer summer weather and higher transmission usage prices. Other revenues increased $42 million primarily due to higher gains realized on nuclear decommissioning trust investments.

Expenses-

Total operating expenses, net of interest charges and income taxes increased in aggregate by $220 million in the nine months ended September 30, 2005 compared to the same period in 2004 due to the following:

- Other operating expenses increased $181 million principally due to higher transmission expenses resulting from an amended power supply agreement with FES, increased loads, and higher transmission system usage charges;

- Provision for depreciation increased $13 million reflecting the effect of property additions, additional costs for decommissioning the Saxton nuclear unit and increased leasehold improvement amortization, reflecting shorter lives associated with capital additions for leased generating plants of the Ohio Companies to correspond to the remaining lease terms;

- Additional amortization of regulatory assets of $77 million, principally Ohio transition costs;

- Higher general taxes of $22 million resulting from increased EUOC sales which increased the Ohio KWH tax and the Pennsylvania gross receipts tax and the absence in 2005 of Pennsylvania property tax refunds recognized in 2004; and

- Higher income taxes of $54 million due to increased taxable income.

The following partially offset these higher costs:

- Additional deferrals of regulatory assets of $111 million, stemming from the deferral of PUCO-approved MISO administrative costs, JCP&L reliability improvements, shopping incentive credits and relat interest on those deferrals (see Note 14 - Regulatory Matters - Transmission, New Jersey); and

- Lower interest charges of $16 million resulting from debt and preferred stock redemptions and refinancings.

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Power Supply Management Services - Nine Months ended September 30, 2005 compared with the Nine Months ended September 30, 2004

The net loss for this segment was $15 million for the nine months ended September 30, 2005 compared to net income of $79 million in the same period last year. A reduction in the gross generation margin, higher nuclear operating costs and amounts recognized for fines, penalties and obligations associated with proceedings involving the W.H. Sammis Plant and the Davis-Besse Nuclear Power Station contributed to the 2005 net loss.

Revenues -

Excluding the effect of the change in recording PJM wholesale transactions on a gross basis in 2004 ($828 million), electric generation revenues increased $359 million in the nine months ended September 30, 2005 compared to the same period of 2004 as a result of a 2.4% increase in KWH sales and higher unit prices.

The change in reported segment revenues resulted from the following:

Revenues by Type of Service	Nine Months Ended September 30, 2005	2004	Increase (Decrease)
	(In millions)		
Electric generation sales:			
Retail	$ 3,223	$ 2,933	$ 290
Wholesale[1]	1,050	981	69
Total Electric Generation Sales	4,273	3,914	359
Transmission	41	57	(16)
Other	32	29	3
Total	4,346	4,000	346
PJM gross transactions	-	828	(828)
Total Revenues	$ 4,346	$ 4,828	$ (482)

[1] Excluding 2004 PJM effect of gross transactions.

Higher electric generation sales resulted from increased unit prices and increased retail customer usage. The following table summarizes the price and volume factors contributing to the increased sales to retail and wholesale customers.

Source of Change in

Electric Generation Sales	
	(In millions)
Retail:	
Effect of 4.5% increase in customer usage	$ 140
Change in prices	150
	290
Wholesale:	
Effect of 4.4% reduction in customer usage[1]	(48)
Change in prices	117
	69
Net Increase in Electric Generation Sales	$ 359

[1] Decrease of 47.3% including the effect of the PJM revision.

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Expenses -

Excluding the effect of $828 million of PJM purchased power costs recorded on a gross basis in 2004, total operating expenses, net interest charges and income taxes increased in aggregate by $440 million in the nine months ended September 30, 2005 compared to the same period of 2004. Higher fuel and purchased power costs contributed $428 million of the increase, resulting from higher fuel costs of $245 million and increased purchased power costs of $183 million. Factors contributing to the higher costs are summarized in the following table:

Source of Change in Fuel and Purchased Power	**Increase (Decrease)** *(In millions)*
Fuel:	
Change due to unit costs	$ 212
Change due to volume consumed	33
	245
Purchased Power:	
Change due to unit costs	255
Change due to volume purchased	(53)
Increase in deferred costs	(19)
	183
PJM Gross Transactions	(828)
Net Decrease in Fuel and Purchased Power Costs	$ (400)

FirstEnergy's generation fleet established an output record of 59.5 billion KWH for the nine months ended September 30, 2005. Higher coal costs resulted from increased consumption, market adjustment provisions in coal contracts reflecting higher market prices and increased transportation costs. Emission allowance costs increased primarily from higher prices. To a lesser extent, fuel expense increased due to the mix of fossil versus nuclear generation resulting from the nuclear refueling outages in the first nine months of 2005 following a year with no scheduled nuclear refueling outages and improved performance of fossil generating units. Fossil generation increased 12% in the nine months ended September 30, 2005 while nuclear generation decreased by 8% compared to the same period of 2004.

Other operating costs increased $74 million in the nine months ended September 30, 2005 compared to the same period of 2004. This increase resulted from higher non-fuel nuclear costs. The increase in non-fuel nuclear costs resulted from 2005 refueling outages at Perry Unit 1 (including an unplanned extension) and Beaver Valley Unit 2 and a scheduled 23-day mid-cycle inspection outage at the Davis-Besse nuclear plant. There were no scheduled nuclear refueling outages in the first nine months of 2004. Also included in other operating costs for 2005 were the EPA settlement loss and NRC fine described above. Offsetting the higher other operating costs were reduced non-fuel fossil generation expense of $17 million due to reduced maintenance outages in 2005 and lower transmission costs of $15 million, due to an amended power supply agreement with Met-Ed and Penelec.

Partially offsetting the increase in other operating costs were lower income taxes of $65 million due to lower taxable income.

Other - Nine Months ended September 30, 2005 compared with the Nine Months ended September 30, 2004

FirstEnergy's financial results from other operating segments and reconciling adjustments, including interest expense on holding company debt and corporate support services revenues and expenses and the impacts of the new Ohio tax legislation (discussed below) resulted in a decrease in FirstEnergy's net income in the nine months ended September 30, 2005 compared to the same period of 2004. The decrease primarily reflected the effect of the new Ohio tax legislation partially offset by the effect of discontinued operations, which included an after-tax net gain of $17 million in 2005 (see Note 6). The following table summarizes the sources of income from discontinued operations:

	Nine Months Ended September 30, 2005	**2004**	**Increase (Decrease)**
	(In millions)		
Discontinued operations (net of tax)			
Gain on sale:			
Retail gas business	$ 5	$ -	$ 5
FSG and MYR Subsidiaries	12	-	12
Reclassification of operating income	2	6	(4)
Total	$ 19	$ 6	$ 13

On June 30, 2005, the State of Ohio enacted new tax legislation that created a new CAT tax, which is based on qualifying “taxable gross receipts” and will not consider any expenses or costs incurred to generate such receipts, except for items such as cash discounts, returns and allowances, and bad debts. The CAT tax was effective July 1, 2005, and replaces the Ohio income-based franchise tax and the Ohio personal property tax. The CAT tax is phased-in while the current income-based franchise tax is phased-out over a five-year period at a rate of 20% annually, beginning with the year ended 2005, and the personal property tax is phased-out over a four-year period at a rate of approximately 25% annually, beginning with the year ended 2005. For example, during the phase-out period the Ohio income-based franchise tax will be computed consistently with the prior tax law, except that the tax liability as computed will be multiplied by 4/5 in 2005; 3/5 in 2006; 2/5 in 2007 and 1/5 in 2008, therefore eliminating the current income-based franchise tax over a five-year period. As a result of the new tax structure, all net deferred tax benefits that are not expected to reverse during the five-year phase-in period were written-off as of June 30, 2005. The impact on income taxes associated with the required adjustment to net deferred taxes for the nine months ended September 30, 2005 was an additional tax expense of approximately $72 million, which was partially offset by the initial phase-out of the Ohio income-based franchise tax, which reduced income taxes by approximately $8 million in the nine months ended September 30, 2005. See Note 12 to the consolidated financial statements.

Postretirement Benefits

Postretirement benefits expense decreased by $17 million in the third quarter of 2005 and $54 million in the nine months ended September 30, 2005 compared to the corresponding periods of 2004. Pension costs represent most of the reduction due to a $500 million voluntary contribution made in 2004 and an increase in the market value of plan assets during 2004. The following table summarizes the net pension and OPEB expense (excluding amounts capitalized) for the three months and nine months ended September 30, 2005 and 2004.

Postretirement Benefits Expense *	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Increase (Decrease)	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004	Increase (Decrease)
			(In millions)			
Pension	$ 8	$ 21	$ (13)	$ 24	$ 64	$ (40)
OPEB	18	22	(4)	54	68	(14)
Total	$ 26	$ 43	$ (17)	$ 78	$ 132	$ (54)

* Excludes the capitalized portion of postretirement benefits costs (see Note 10 for total costs).

The decrease in pension and OPEB expenses are included in various cost categories and have contributed to other cost reductions discussed above.

CAPITAL RESOURCES AND LIQUIDITY

FirstEnergy’s cash requirements in 2005 for operating expenses, construction expenditures, scheduled debt maturities and preferred stock redemptions are expected to be met without increasing FirstEnergy’s net debt and preferred stock outstanding. Borrowing capacity under credit facilities is available to manage working capital requirements.

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 $2.0 billion of short-term financing under a revolving credit facility, subject to short-term debt limitations under current regulatory approvals of $1.5 billion and to outstanding borrowings by subsidiaries of FirstEnergy who are also parties to such facility. In the third quarter of 2005, FirstEnergy received $306 million of cash dividends from its subsidiaries and paid $141 million in cash dividends to its common shareholders - in the first nine months of 2005, it received and paid $846 million and $412 million, respectively. There are no material restrictions on the payment of cash dividends by FirstEnergy's subsidiaries.

As of September 30, 2005, FirstEnergy had $140 million of cash and cash equivalents ($3 million restricted as an indemnity reserve) compared with $53 million ($3 million restricted as an indemnity reserve) as of December 31, 2004. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

FirstEnergy's consolidated net cash from operating activities is provided primarily by its regulated and power supply businesses (see "RESULTS OF OPERATIONS" above). Net cash provided by operating activities was $981 million and $528 million in the third quarter of 2005 and 2004, respectively, and $1.9 billion and $1.5 billion in the first nine months of 2005 and 2004, respectively, summarized as follows:

Operating Cash Flows	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In millions)			
Cash earnings [1]	$ 777	$ 545	$ 1,642	$ 1,427
Pension trust contribution[2]	-	(300)	-	(300)
Working capital and other	204	283	270	411
Total cash flows from operating activities	$ 981	$ 528	$ 1,912	$ 1,538

[1] Cash earnings are a non-GAAP measure (see reconciliation below).

[2] Pension trust contribution net of $200 million of income tax benefits.

Cash earnings, as disclosed in the table above, are not a measure of performance calculated in accordance with GAAP. FirstEnergy believes that cash earnings is a useful financial measure because it provides investors and management with an additional means of evaluating its cash-based operating performance. The following table reconciles cash earnings with net income.

Reconciliation of Cash Earnings	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In millions)			
Net income (GAAP)	$ 332	$ 299	$ 670	$ 677
Non-cash charges (credits):				
Provision for depreciation	153	147	444	439

Amortization of regulatory assets	364	324	982	905
Deferral of new regulatory assets	(124)	(79)	(303)	(191)
Nuclear fuel and lease amortization	26	27	63	72
Deferred purchased power and other costs	(39)	(118)	(231)	(263)
Deferred income taxes and investment tax credits(1)	(38)	(163)	24	(257)
Deferred rents and lease market valuation liability	30	28	(71)	(52)
Accrued retirement benefit obligations	56	42	104	107
Income from discontinued operations	(1)	(2)	(18)	(6)
Other non-cash expenses	18	40	(22)	(4)
Cash earnings (non-GAAP)	$ 777	$ 545	$ 1,642	$ 1,427

(1) Excludes $200 million of deferred tax benefits from pension contribution in 2004.

In the three months and nine months ended September 30, 2005, cash earnings increased $232 million and $215 million, respectively. Both periods benefited from increased generation and distribution revenues aided by warmer summer temperatures that increased air conditioning load. In the third quarter of 2005 compared with the third quarter of 2004, cash provided from working capital decreased by $79 million, primarily due to changes in receivables. The use of cash for receivables resulted in part from the conversion of the CFC accounts receivable financing to an on-balance sheet transaction, which added $35 million of receivables to the balance sheet as of September 30, 2005. In the first nine months of 2005 compared to the first nine months of 2004, working capital changes provided $141 million less cash due in part to changes in receivables, materials and supplies, prepayments and accrued taxes, offset by accounts payable and the funds received as prepayment for electric usage, under the three-year Energy for Education II Program with the Ohio Schools Council.

Cash Flows From Financing Activities

In the third quarter and first nine months of 2005, cash used for financing activities was $580 million and $1.0 billion, respectively, compared to $602 million and $1.4 billion in the third quarter and first nine months of 2004, respectively. The following table summarizes security issuances and redemptions.

Securities Issued or Redeemed	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In millions)			
New issues				
Pollution control notes	$ 89	$ 77	$ 334	$ 261
Secured notes	-	-	-	550
Long-term revolving credit	-	10	-	-
Unsecured notes	-	-	-	150
	$ 89	$ 87	$ 334	$ 961
Redemptions				
First mortgage bonds	$ -	$ 206	$ 178	$ 588
Pollution control notes	130	80	377	80
Secured notes	25	374	74	447
Long-term revolving credit	-	-	215	300
Unsecured notes	8	112	8	337
Preferred stock	30	1	170	1
	$ 193	$ 773	$ 1,022	$ 1,753
Short-term borrowings, net increase (decrease)	$ (308)	$ 228	$ 77	$ (219)

FirstEnergy had approximately $247 million of short-term indebtedness as of September 30, 2005 compared to approximately $170 million as of December 31, 2004. Available bank borrowings as of September 30, 2005 included the following:

Borrowing Capability	FirstEnergy	Penelec	Total
		(In millions)	

Short-term credit[1]	$ 2,020	$ -	$ 2,020
Utilized	-	-	-
Letters of credit	(137)	-	(137)
Net	1,883	-	1,883
Short-term bank facilities[2]	-	75	75
Utilized	-	(75)	(75)
Net	-	-	-
Total unused borrowing capability	$ 1,883	$ -	$ 1,883

[1] A $2 billion revolving credit facility is available in various amounts to FirstEnergy and certain of its subsidiaries, including Penelec. A $20 million uncommitted line of credit facility added in September 2005 is available to FirstEnergy only.

[2] Penelec bank facility terminated on October 7, 2005.

As of October 24, 2005, the Ohio Companies and Penn had the aggregate capability to issue approximately $3.8 billion of additional FMB on the basis of property additions and retired bonds under the terms of their respective mortgage indentures following the recently completed intra-system transfer of fossil and hydroelectric generating plants (See Note 17). The issuance of FMB by OE and CEI are also subject to provisions of their senior note indentures generally limiting the incurrence of additional secured debt, subject to certain exceptions that would permit, among other things, the issuance of secured debt (including FMB) (i) supporting pollution control notes or similar obligations, or (ii) as an extension, renewal or replacement of previously outstanding secured debt. In addition, these provisions would permit OE and CEI to incur additional secured debt not otherwise permitted by a specified exception of up to $690 million and $582 million, respectively, as of October 24, 2005. Under the provisions of its senior note indenture, JCP&L may issue additional FMB only as collateral for senior notes. As of October 24, 2005, JCP&L had the capability to issue $673 million of additional senior notes upon the basis of FMB collateral. Based upon applicable earnings coverage tests in their respective charters, OE, Penn, TE and JCP&L could issue a total of $4.9 billion of preferred stock (assuming no additional debt was issued) as of September 30, 2005. It is estimated that the annualized impact of the intra-system transfer of fossil and hydroelectric generating plants will reduce the aggregate capability of OE, Penn, TE and JCP&L to issue preferred stock by approximately 10%. CEI, Met-Ed and Penelec have no restrictions on the issuance of preferred stock.

As of September 30, 2005, approximately $1 billion remained unused under an existing shelf registration statement, filed by FirstEnergy with the SEC in 2003, to support future securities issues. The shelf registration provides the flexibility to issue and sell various types of securities, including common stock, debt securities, and share purchase contracts and related share purchase units.

FirstEnergy's and its subsidiaries' working capital and short-term borrowing needs are met principally with a $2 billion five-year revolving credit facility (included in the table above). Borrowings under the facility are available to each borrower separately and will mature on the earlier of 364 days from the date of borrowing and the commitment termination date.

The following table summarizes the borrowing sub-limits for each borrower under the facility, as well as the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations.

Borrower	Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations[1]
	(In millions)	
FirstEnergy	$ 2,000	$ 1,500
OE	500	500
Penn	50	51
CEI	250	500
TE	250	500
JCP&L	425	416
Met-Ed	250	300
Penelec	250	300
FES	-[2]	n/a
ATSI	-[2]	26

(1) As of September 30, 2005.

(2) Borrowing sublimits for FES and ATSI may be increased to up to $250 million and $100 million, respectively, by delivering notice to the administrative agent that either (i) such borrower has senior unsecured debt ratings of at least BBB- by S&P and Baa3 by Moody's or (ii) FirstEnergy has guaranteed the obligations of such borrower under the facility.

The revolving credit facility, combined with an aggregate $550 million ($395 million unused as of September 30, 2005) of accounts receivable financing facilities for OE, CEI, TE, Met-Ed, Penelec and Penn, are intended to provide liquidity to meet short-term working capital requirements for FirstEnergy and its subsidiaries.

Under the revolving credit facility, borrowers may request the issuance of letters of credit expiring up to one year from the date of issuance. The stated amount of outstanding letters of credit will count against total commitments available under the facility and against the applicable borrower's borrowing sub-limit. Total unused borrowing capability under existing credit facilities and accounts receivable financing facilities totaled $2.36 billion as of September 30, 2005.

The revolving credit facility contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio of no more than 0.65 to 1.00. On October 3, 2005, FirstEnergy obtained a senior unsecured debt rating upgrade to BBB- by S&P removing the requirement under the revolving credit facility to maintain a fixed charge ratio of at least 2.00 to 1.00.

As of September 30, 2005, FirstEnergy and subsidiaries' debt to total capitalization as defined under the revolving credit facility, were as follows:

Borrower	Debt To Total Capitalization
FirstEnergy	0.54 to 1.00
OE	0.39 to 1.00
Penn	0.32 to 1.00
CEI	0.57 to 1.00
TE	0.43 to 1.00
JCP&L	0.29 to 1.00
Met-Ed	0.38 to 1.00
Penelec	0.34 to 1.00

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The facility does not contain any provisions that either restrict the ability to borrow or accelerate repayment of outstanding advances as a result of any change in credit ratings. Pricing is defined in “pricing grids”, whereby the cost of funds borrowed under the facility is related to the credit ratings of the company borrowing the funds.

FirstEnergy’s regulated companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy’s unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in the third quarter of 2005 was 3.50% for the regulated companies’ money pool and 3.46% for the unregulated companies' money pool.

On July 18, 2005, Moody’s revised its rating outlook on FirstEnergy and its subsidiaries to positive from stable. Moody’s stated that the revision to FirstEnergy’s outlook resulted from steady financial improvement and steps taken by management to improve operations, including the stabilization of its nuclear operations. Moody’s further stated that the revision in their outlook recognized management’s regional strategy of focusing on its core utility businesses and the improvement in FirstEnergy’s credit profile stemming from the application of free cash flow toward debt reduction. Moody’s noted that a ratings upgrade could be considered if FirstEnergy continues to achieve planned improvements in its operations and balance sheet.

On October 3, 2005, S&P raised its corporate credit rating on FirstEnergy and the EUOC to 'BBB' from 'BBB-'. At the same time, S&P raised the senior unsecured ratings at the holding company to 'BBB-' from 'BB+' and each of the EUOC by one notch above the previous rating. S&P noted that the upgrade followed the continuation of a good operating track record, specifically for the nuclear fleet through the third quarter 2005. S&P also stated that FirstEnergy’s rating reflects the benefits of supportive regulation, low-cost base load generation fleet, low-risk transmission and distribution operations and rate certainty in Ohio. FirstEnergy’s ability to consistently generate free cash flow, good liquidity, and an improving financial profile were also noted as strengths.

FirstEnergy’s access to capital markets and costs of financing are influenced by the ratings of its securities. The following table displays FirstEnergy’s and its EUOC’s securities ratings as of October 3, 2005. The ratings outlook from S&P and Fitch on all securities is stable. Moody’s outlook on all securities is Positive.

Ratings of Securities	**Securities**	**S&P**	**Moody’s**	**Fitch**
FirstEnergy	Senior unsecured	BBB-	Baa3	BBB-
OE	Senior unsecured	BBB-	Baa2	BBB
	Preferred stock	BB+	Ba1	BBB-
CEI	Senior secured	BBB	Baa2	BBB-
		BBB-	Baa3	BB

	Senior unsecured			
TE	Senior secured	BBB	Baa2	BBB-
	Preferred stock	BB+	Ba2	BB-
Penn	Senior secured	BBB+	Baa1	BBB+
	Senior unsecured (1)	BBB-	Baa2	BBB
	Preferred stock	BB+	Ba1	BBB-
JCP&L	Senior secured	BBB+	Baa1	BBB+
	Preferred stock	BB+	Ba1	BBB
Met-Ed	Senior secured	BBB+	Baa1	BBB+
	Senior unsecured	BBB	Baa2	BBB
Penelec	Senior unsecured	BBB	Baa2	BBB

(1) Penn's only senior unsecured debt obligations are notes underlying pollution control revenue refunding bonds issued
by the Ohio Air Quality Development Authority to which bonds this rating applies.

On July 1, 2005, TE redeemed all of its 1,200,000 outstanding shares of 7.00% Series A preferred stock at $25.00 per share, plus accrued dividends to the date of redemption. TE also repurchased $37 million of pollution control revenue bonds on September 1, 2005, with the intent to remarket them by the end of the first quarter of 2006.

Cash Flows From Investing Activities

Net cash flows used for investing activities resulted principally from property additions. Regulated services expenditures for property additions primarily include expenditures supporting the distribution of electricity. Capital expenditures by the power supply management services segment are principally generation-related. The following table summarizes the investment activities for the three months and nine months ended September 30, 2005 and 2004 by FirstEnergy's regulated services, power supply management services and other segments:

Summary of Cash Flows Used for Investing Activities Sources (Uses)	**Property Additions**	**Investments**	**Other**	**Total**
		(In millions)		
Three Months Ended September 30, 2005				
Regulated services	$ (207)	$ (17)	$ 2	$ (222)
Power supply management services	(79)	1	-	(78)
Other	(1)	-	1	-
Reconciling items	(7)	(9)	5	(11)
Total	$ (294)	$ (25)	$ 8	$ (311)
Three Months Ended September 30, 2004				
Regulated services	$ (157)	$ 242	$ (69)	$ 16
Power supply management services	(46)	(11)	-	(57)
Other	(1)	-	(2)	(3)
Reconciling items	(7)	10	84	87
Total	$ (211)	$ 241	$ 13	$ 43

Summary of Cash Flows Used for Investing Activities Sources (Uses)	**Property Additions**	**Investments**	**Other**	**Total**
		(In millions)		

Nine Months Ended September 30, 2005								
Regulated services	$	(506)	$	(13)	$	(5)	$	(524)
Power supply management services		(226)		-		-		(226)
Other		(6)		19		(18)		(5)
Reconciling items		(18)		(9)		5		(22)
Total	$	(756)	$	(3)	$	(18)	$	(777)
Nine Months Ended September 30, 2004								
Regulated services	$	(377)	$	196	$	(76)	$	(257)
Power supply management services		(149)		(14)		-		(163)
Other		(3)		173		2		172
Reconciling items		(17)		31		65		79
Total	$	(546)	$	386	$	(9)	$	(169)

Net cash used for investing activities was $311 million in the third quarter of 2005 compared to $43 million of cash provided from investing activities in the same period of 2004. The change was primarily due to an $83 million increase in property additions and the absence in 2005 of $278 million in cash proceeds from certificates of deposit (released collateral) received in the third quarter of 2004. Net cash used for investing activities increased by $608 million in the first nine months of 2005 compared to the same period of 2004. The increase principally resulted from a $210 million increase in property additions, lower proceeds from the sale of assets of $152 million and the absence in 2005 of $278 million of cash proceeds from certificates of deposit (released collateral) received in 2004.

In the last quarter of 2005, capital requirements for property additions and capital leases are expected to be approximately $378 million. FirstEnergy and the Companies have additional requirements of approximately $312 million for maturing long-term debt during the remainder of 2005. These cash requirements are expected to be satisfied from internal cash and short-term credit arrangements.

FirstEnergy's capital spending for the period 2005-2007 is expected to be about $3.5 billion (excluding nuclear fuel), of which $1.1 billion applies to 2005. Investments for additional nuclear fuel during the 2005-2007 periods are estimated to be approximately $285 million, of which approximately $59 million applies to 2005. During the same period, FirstEnergy's nuclear fuel investments are expected to be reduced by approximately $282 million and $86 million respectively, as the nuclear fuel is consumed.

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 LOCs. Some of the guaranteed contracts contain ratings contingent collateralization provisions.

As of September 30, 2005, the maximum potential future payments under outstanding guarantees and other assurances totaled $2.7 billion as summarized below:

Guarantees and Other Assurances	Maximum Exposure *(In millions)*
FirstEnergy guarantees of subsidiaries:	
Energy and energy-related contracts [(1)]	$ 785
Other [(2)]	503
	1,288
Surety bonds	307
Letters of credit [(3)(4)]	1,055
Total Guarantees and Other Assurances	$ 2,650

[(1)]Issued for a one-year term, with a 10-day termination right by FirstEnergy.
[(2)]Issued for various terms.
[(3)]Includes $137 million issued for various terms under LOC capacity available under FirstEnergy's revolving credit agreement and $299 million outstanding in support of pollution control revenue bonds issued with various maturities.
[(4)]Includes approximately $194 million pledged in

connection with the sale and leaseback of Beaver Valley Unit 2 by CEI and TE, $291 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $134 million pledged in connection with the sale and leaseback of Perry Unit 1 by OE.

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 financings where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, 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 ongoing energy-related contracts is remote.

While these types of guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating downgrade or "material adverse event," the immediate posting of cash collateral or provision of an LOC may be required of the subsidiary. The following table summarizes collateral provisions in effect as of September 30, 2005:

Collateral Provisions	**Total Exposure**	**Collateral Paid Cash**	**LOC**	**Remaining Exposure**
		(In millions)		
Credit rating downgrade	$ 445	$ 213	$ 18	$ 214
Adverse event	77	-	5	72
Total	$ 522	$ 213	$ 23	$ 286

As a result of S&P's credit rating upgrade described above, $109 million of cash collateral was returned to FirstEnergy in October 2005.

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.

FirstEnergy has guaranteed the obligations of the operators of the TEBSA project up to a maximum of $6 million (subject to escalation) under the project's operations and maintenance agreement. In connection with the sale of TEBSA in January 2004, the purchaser indemnified FirstEnergy against any loss under this guarantee. FirstEnergy has provided an LOC ($47 million as of September 30, 2005, which is included in the caption “Other” in the above table of Guarantees and Other Assurances), which is renewable and declines yearly based upon the senior outstanding debt of TEBSA. The LOC was reduced to $36 million on October 15, 2005.

OFF-BALANCE SHEET ARRANGEMENTS

FirstEnergy has obligations that are not included on its Consolidated Balance Sheet related to the sale and leaseback arrangements involving Perry Unit 1, Beaver Valley Unit 2 and the Bruce Mansfield Plant, which are satisfied through operating lease payments. The present value of these sale and leaseback operating lease commitments, net of trust investments, total $1.3 billion as of September 30, 2005.

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

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 members of senior management, provides general management oversight to risk management activities throughout the Company.

Commodity Price Risk

FirstEnergy is exposed to price risk primarily due to fluctuating electricity, natural gas, coal, nuclear fuel, emission allowance prices and energy transmission. 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. All derivatives that fall within the scope of SFAS 133 must be recorded at their fair market value and marked to market. The majority of FirstEnergy’s derivative hedging contracts qualify for the normal purchases and normal sales exception under SFAS 133 and are therefore excluded from the table below. Of those contracts not exempt from such treatment, most are non-trading contracts that do not qualify for hedge accounting treatment. The change in the fair value of commodity derivative contracts related to energy production during the third quarter and first nine months of 2005 is summarized in the following table:

Increase (Decrease) in the Fair Value Of Commodity Derivative Contracts	Three Months Ended September 30, 2005			Nine Months Ended September 30, 2005		
	Non-Hedge	Hedge	Total	Non-Hedge	Hedge	Total
			(In millions)			
Change in the Fair Value of Commodity Derivative Contracts:						
	$ 55	$ (2)	$ 53	$ 62	$ 2	$ 64

Outstanding net asset at beginning of period												
New contract when entered		-		-		-		-		-		-
Additions/change in value of existing contracts		(3)		3		-		(4)		5		1
Change in techniques/assumptions		-		-		-		-		-		-
Settled contracts		-		-		-		(7)		-		(7)
Sale of retail natural gas contracts		-		-		-		1		(6)		(5)
Outstanding net asset at end of period [1]	$	52	$	1	$	53	$	52	$	1	$	53
Non-commodity Net Assets at End of Period:												
Interest rate swaps [2]		-		(10)		(10)		-		(10)		(10)
Net Assets - Derivative Contracts at End of Period	$	52	$	(9)	$	43	$	52	$	(9)	$	43
Impact of Changes in Commodity Derivative Contracts[3]												
Income Statement effects (pre-tax)	$	(4)	$	-	$	(4)	$	(4)	$	-	$	(4)
Balance Sheet effects:												
Other comprehensive income (pre-tax)	$	-	$	3	$	3	$	-	$	(1)	$	(1)
Regulatory liability	$	1	$	-	$	1	$	(6)	$	-	$	(6)

(1) Includes $55 million in non-hedge commodity derivative contracts which are offset by a regulatory liability.
(2) Interest rate swaps are treated as cash flow or fair value hedges. (See Interest Rate Swap Agreements - Fair Value Hedges and Forward
Starting Swap Agreements - Cash Flow Hedges)
(3) Represents the change in value of existing contracts, settled contracts and changes in techniques/assumptions.

Derivatives are included on the Consolidated Balance Sheet as of September 30, 2005 as follows:

Balance Sheet Classification	Non-Hedge	Hedge	Total
		(In millions)	
Current -			
Other assets	$ -	$ 39	$ 39
Other liabilities	(1)	(39)	(40)
Non-Current -			
Other deferred charges	56	5	61
Other noncurrent liabilities	(3)	(14)	(17)
Net assets	$ 52	$ (9)	$ 43

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

Sources of Information - Fair Value by Contract Year	2005 (1)	2006	2007	2008	2009	Thereafter	Total
				(In millions)			
Prices actively quoted (2)	$ (3)	$ (3)	$ (2)	$ -	$ -	$ -	$ (8)
Other external sources (3)	19	7	10	-	-	-	36
Prices based on models	-	-	-	9	8	8	25
Total (4)	$ 16	$ 4	$ 8	$ 9	$ 8	$ 8	$ 53

(1) For the last quarter of 2005.
(2) Exchange traded.
(3) Broker quote sheets.

(4) Includes $55 million in non-hedge commodity derivative contracts which are offset by a regulatory liability.

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 September 30, 2005. Based on derivative contracts held as of September 30, 2005, an adverse 10% change in commodity prices would decrease net income by approximately $1 million for the next twelve months.

Interest Rate Swap Agreements - Fair Value Hedges

FirstEnergy utilizes 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, call options, fixed interest rates and interest payment dates match those of the underlying obligations. During the third quarter of 2005, FirstEnergy executed no new fixed-for-floating interest rate swaps and unwound swaps with a total notional amount of $350 million (see Note 7). As of September 30, 2005, the debt underlying the $1.05 billion outstanding notional amount of interest rate swaps had a weighted average fixed interest rate of 5.66%, which the swaps have effectively converted to a current weighted average variable interest rate of 5.23%.

	September 30, 2005			December 31, 2004		
Interest Rate Swaps	**Notional Amount**	**Maturity Date**	**Fair Value**	**Notional Amount**	**Maturity Date**	**Fair Value**
			(Dollars in millions)			
Fixed to Floating Rate	$ -	2006	$ -	$ 200	2006	$ (1)
(Fair value hedges)	100	2008	(3)	100	2008	(1)
	50	2010	-	100	2010	1
	50	2011	-	100	2011	2
	450	2013	-	400	2013	4
	-	2014	-	100	2014	2
	150	2015	(7)	150	2015	(7)
	150	2016	2	200	2016	1
	-	2018	-	150	2018	5
	-	2019	-	50	2019	2
	100	2031	(4)	100	2031	(4)
	$ 1,050		$ (12)	$ 1,650		$ 4

Forward Starting Swap Agreements - Cash Flow Hedges

During the third quarter, FirstEnergy entered into several forward starting swap agreements (forward swap) in order to hedge a portion of the consolidated interest rate risk associated with the planned issuance of fixed-rate, long-term debt securities for one or more of its consolidated entities in the fourth quarter of 2006. These derivatives are treated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. As of September 30, 2005, the forward swaps had a fair value of $2 million.

Equity Price Risk

Included in nuclear decommissioning trusts are marketable equity securities carried at their market value of approximately $1.038 billion and $951 million as of September 30, 2005 and December 31, 2004, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $104 million reduction in fair value as of September 30, 2005.

CREDIT RISK

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

FirstEnergy maintains credit policies with respect to its counterparties to manage overall credit risk. This includes performing independent risk evaluations, actively monitoring portfolio trends and using collateral and contract provisions to mitigate exposure. As part of its credit program, FirstEnergy aggressively manages the quality of its portfolio of energy contracts evidenced by a current weighted average risk rating for energy contract counterparties of BBB (S&P). As of September 30, 2005, the largest credit concentration was with one party, currently rated investment grade that represented 8% of FirstEnergy's total credit risk. Within its unregulated energy subsidiaries, 99% of credit exposures, net of collateral and reserves, were with investment-grade counterparties as of September 30, 2005.

Outlook

State Regulatory Matters

In Ohio, New Jersey and Pennsylvania, laws applicable to electric industry restructuring contain similar provisions that are reflected in the Companies' respective state regulatory plans. These provisions include:

- restructuring the electric generation business and allowing the Companies' customers to select a competitive electric generation supplier other than the Companies;

- establishing or defining the PLR obligations to customers in the Companies' service areas;

· providing the Companies with the opportunity to recover 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;

· continuing regulation of the Companies' transmission and distribution systems; and

· requiring corporate separation of regulated and unregulated business activities.

The EUOCs recognize, as regulatory assets, costs which the FERC, PUCO, PPUC and NJBPU have authorized for recovery from customers in future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets would have been charged to income as incurred. All regulatory assets are expected to be recovered from customers under the Companies' respective transition and regulatory plans. Based on those plans, the Companies continue to bill and collect cost-based rates for their transmission and distribution services, which remain regulated; accordingly, it is appropriate that the Companies continue the application of SFAS 71 to those operations.

Regulatory Assets*	September 30, 2005	December 31, 2004	Increase (Decrease)
		(In millions)	
OE	$ 845	$ 1,116	$ (271)
CEI	889	959	(70)
TE	310	375	(65)
JCP&L	2,311	2,176	135
Met-Ed	572	693	(121)
Penelec	99	200	(101)
ATSI	20	13	7
Total	$ 5,046	$ 5,532	$ (486)

*Penn had net regulatory liabilities of approximately $48 million and $18 million included in Noncurrent Liabilities on the Consolidated Balance Sheets as of September 30, 2005 and December 31, 2004, respectively.

Regulatory assets by source are as follows:

Regulatory Assets by Source	September 30, 2005	December 31, 2004	Increase (Decrease)
		(In millions)	
	$ 4,169	$ 4,889	$ (720)

Regulatory transition costs			
Customer shopping incentives	826	612	214
Customer receivables for future income taxes	289	246	43
Societal benefits charge	18	51	(33)
Loss on reacquired debt	83	89	(6)
Employee postretirement benefit costs	57	65	(8)
Nuclear decommissioning, decontamination and spent fuel disposal costs	(172)	(169)	(3)
Asset removal costs	(366)	(340)	(26)
Property losses and unrecovered plant costs	34	50	(16)
MISO transmission costs	52	-	52
JCP&L reliability costs	26	-	26
Other	30	39	(9)
Total	$ 5,046	$ 5,532	$ (486)

Reliability Initiatives

FirstEnergy is proceeding with the implementation of the recommendations regarding enhancements to regional reliability that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new, or material upgrades, to existing equipment. The FERC or other applicable government agencies and reliability coordinators, however, may take a different view as to recommended enhancements or may recommend additional enhancements in the future as the result of adoption of mandatory reliability standards pursuant to the Energy Policy Act of 2005 that could require additional, material expenditures. Finally, the PUCO is continuing to review FirstEnergy's filing that addressed upgrades to control room computer hardware and software and enhancements to the training of control room operators, before determining the next steps, if any, in the proceeding.

As a result of outages experienced in JCP&L's service area in 2002 and 2003, the NJBPU had implemented reviews into JCP&L's service reliability. On March 29, 2004, the NJBPU adopted an MOU that set out specific tasks related to service reliability to be performed by JCP&L and a timetable for completion and endorsed JCP&L's ongoing actions to implement the MOU. On June 9, 2004, the NJBPU approved a Stipulation that incorporates the final report of a Special Reliability Master who made recommendations on appropriate courses of action necessary to ensure system-wide reliability. The Stipulation also incorporates the Executive Summary and Recommendation portions of the final report of a focused audit of JCP&L's Planning and Operations and Maintenance programs and practices (Focused Audit). A Final Order in the Focused Audit docket was issued by the NJBPU on July 23, 2004. On February 11, 2005, JCP&L met with the Ratepayer Advocate to discuss reliability improvements. JCP&L continues to file compliance reports reflecting activities associated with the MOU and Stipulation.

The Energy Policy Act of 2005 provides for the creation of an ERO to establish and enforce reliability standards for the bulk power system, subject to FERC review. On September 1, 2005, the FERC issued a Notice of Proposed Rulemaking to establish certification requirements for the ERO, as well as regional entities envisioned to assume monitoring and compliance responsibility for the new reliability standards. The FERC expects to adopt a final rule on or before February 2006 regarding certification requirements for the ERO and regional entities.

The NERC is expected to reorganize its structure to meet the FERC’s certification requirements for the ERO. Following adoption of the final rule, the NERC will be required to make a filing with the FERC to obtain certification as the ERO. The proposed rule also provides for regional reliability organizations designed to replace the current regional councils. The “regional entity” may be delegated authority by the ERO, subject to FERC approval, for enforcing reliability standards adopted by the ERO and approved by the FERC. The ECAR, Mid-Atlantic Area Council, and Mid-American Interconnected Network reliability councils have signed an MOU designed to consolidate their regions into a new regional reliability organization known as ReliabilityFirst Corporation. Their intent is to file and obtain certification under the final rule as a “regional entity”. All of FirstEnergy’s facilities would be located within the ReliabilityFirst region.

On a parallel path, the NERC is establishing working groups to develop reliability standards to be filed for approval with the FERC following the NERC’s certification as an ERO. These reliability standards are expected to build on the current NERC Version 0 reliability standards. It is expected that the proposed reliability standards will be filed with the FERC in early 2006.

The impact of this effort on FirstEnergy is unclear. FirstEnergy believes that it is in compliance with all current NERC reliability standards. However, it is expected that the FERC will adopt stricter reliability standards than those contained in the current NERC Version 0 standards. The financial impact of complying with the new standards cannot be determined at this time. However, the Energy Policy Act of 2005 requires that all prudent costs incurred to comply with the new reliability standards be recovered in rates.

See Note 14 to the consolidated financial statements for a more detailed discussion of reliability initiatives, including actions by the PPUC, that impact Met-Ed, Penelec and Penn.

Ohio

On August 5, 2004, the Ohio Companies accepted the RSP as modified and approved by the PUCO in an August 4, 2004 Entry on Rehearing, subject to a competitive bid process. The RSP was filed by the Ohio Companies to establish generation service rates beginning January 1, 2006, in response to PUCO concerns about price and supply uncertainty following the end of the Ohio Companies' transition plan market development period. In October 2004, the OCC and NOAC filed appeals with the Supreme Court of Ohio to overturn the original June 9, 2004 PUCO order in this proceeding as well as the associated entries on rehearing. On September 28, 2005, the Ohio Supreme Court heard oral argument on the appeals.

On May 27, 2005, the Ohio Companies filed an application with the PUCO to establish a GCAF rider under the RSP. The application seeks to implement recovery of increased fuel costs from 2006 through 2008 applicable to the Ohio Companies' retail customers through a tariff rider to be implemented January 1, 2006. The application reflects projected increases in fuel costs in 2006 compared to 2002 baseline costs. The new rider, after adjustments made in testimony, is seeking to recover all costs above the baseline (approximately $88 million in 2006). Various parties including the OCC have intervened in this case and the case has been consolidated with the RCP application discussed below.

On September 9, 2005, the Ohio Companies filed an application with the PUCO that, if approved, would supplement their existing RSP with an RCP. On September 27, 2005, the PUCO granted FirstEnergy's motion to consolidate the GCAF rider application with the RCP proceedings and set hearings for the consolidated cases to begin November 29, 2005. The RCP is designed to provide customers with more certain rate levels than otherwise available under the RSP during the plan period. Major provisions of the RCP include:

· Maintain the existing level of base distribution rates through December 31, 2008 for OE and TE, and April 30, 2009 for CEI;

· Defer and capitalize certain distribution costs to be incurred during the period January 1, 2006 through December 31, 2008, not to exceed $150 million in each of the three years;

· Adjust the RTC and extended RTC recovery periods and rate levels so that full recovery of authorized costs will occur as of December 31, 2008 for OE and TE, and as of December 31, 2010 for CEI;

· Reduce the deferred shopping incentive balances as of January 1, 2006 by up to $75 million for OE, $45 million for TE, and $85 million for CEI by accelerating the application of each respective company's accumulated cost of removal regulatory liability; and

· Recover increased fuel costs of up to $75 million, $77 million, and $79 million, in 2006, 2007, and 2008, respectively, from all OE and TE distribution and transmission customers through a fuel recovery mechanism and OE, TE, and CEI may defer and capitalize increased fuel costs above the amount collected through the fuel recovery mechanism.

Under provisions of the RSP, the PUCO may require the Ohio Companies to undertake, no more often than annually, a competitive bid process to secure generation for the years 2007 and 2008. On July 22, 2005, FirstEnergy filed a competitive bid process for the period beginning in 2007 that is similar to the competitive bid process approved by the PUCO for the Ohio Companies in 2004 which resulted in the PUCO accepting no bids. Any acceptance of future competitive bid results would terminate the RSP pricing, with no accounting impacts to the RSP, and not until twelve months after the PUCO authorizes such termination. On September 28, 2005, the PUCO issued an Entry that essentially approved the Ohio Companies' filing but delayed the proposed timing of the competitive bid process by four months, calling for the auction to be held on March 21, 2006.

See Note 14 to the consolidated financial statements for further details and a complete discussion of regulatory matters in Ohio.

Pennsylvania

In accordance with PPUC directives, Met-Ed and Penelec have been negotiating with interested parties in an attempt to resolve the merger savings issues that are the subject of remand from the Commonwealth Court. Met-Ed’s and Penelec’s combined portion of total merger savings is estimated to be approximately $31.5 million. On April 13, 2005, the Commonwealth Court issued an interim order in the remand proceeding that the parties should report the status of the negotiations to the PPUC with a copy to the ALJ. The parties exchanged settlement proposals in May and June 2005 and continue to have settlement discussions.

Met-Ed and Penelec purchase a portion of their PLR requirements from FES through a wholesale power sales agreement. The PLR sale is 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 retains the supply obligation and the supply profit and loss risk for the portion of power supply requirements not self-supplied by Met-Ed and Penelec under their NUG contracts and other power contracts with nonaffiliated third party suppliers.

This arrangement reduces Met-Ed's and Penelec's exposure to high wholesale power prices by providing power at a fixed price for their uncommitted PLR energy costs during the term of the agreement with FES. Met-Ed and Penelec are authorized to defer differences between NUG contract costs and current market prices. On November 1, 2005, FES and the other parties to the wholesale power agreement amended the agreement to provide FES the right over the next year to terminate the agreement at any time upon 60 days notice. If the wholesale power agreement were terminated, Met-Ed and Penelec would need to satisfy the applicable portion of their PLR obligations from other sources at prevailing prices, which are likely to be higher than the current price charged by FES under the agreement and, as a result, Met-Ed’s and Penelec’s purchased power costs could materially increase.

On January 12, 2005, Met-Ed and Penelec filed, before the PPUC, a request for deferral of transmission-related costs beginning January 1, 2005, estimated to be approximately $8 million per month. The OCA, OSBA, OTS, MEIUG, PICA, Allegheny Electric Cooperative and Pennsylvania Rural Electric Association have all intervened in the case. To date no hearing schedule has been established, and neither company has yet implemented deferral accounting for these costs.

On October 11, 2005, Penn filed a plan with the PPUC to secure electricity supply for its customers at set rates following the end of its transition period on December 31, 2006. Penn is recommending that the Request for Proposal process cover the period of January 1, 2007 through May 31, 2008. Under Pennsylvania's electric competition law, Penn is required to secure generation supply for customers who do not choose alternative suppliers for their electricity.

See Note 14 to the consolidated financial statements for further details and a complete discussion of regulatory matters in Pennsylvania.

New Jersey

The 2003 NJBPU decision on JCP&L's base electric rate proceeding (Phase I order) disallowed certain regulatory assets and provided for an interim return on equity of 9.5% on JCP&L's rate base. The Phase I Order also provided for a Phase II proceeding in which the NJBPU would review whether JCP&L is in compliance with current service reliability and quality standards and determine whether the expenditures and projects undertaken by JCP&L to increase its system reliability are prudent and reasonable for rate recovery. Depending on its assessment of JCP&L's service reliability, the NJBPU could have increased JCP&L’s return on equity to 9.75% or decreased it to 9.25%. On August 15, 2003 and June 1, 2004, JCP&L filed with the NJBPU an interim motion and a supplemental and amended motion for rehearing and reconsideration of the Phase I Order, respectively. On July 7, 2004, the NJBPU granted limited reconsideration and rehearing on the following issues: (1) deferred cost disallowances; (2) the capital structure including the rate of return; (3) merger savings, including amortization of costs to achieve merger savings; and (4) decommissioning costs.

On July 16, 2004, JCP&L filed the Phase II petition and testimony with the NJBPU, requesting an increase in base rates of $36 million for the recovery of system reliability costs and a 9.75% return on equity. The filing also requested an increase to the MTC deferred balance recovery of approximately $20 million annually.

On May 25, 2005, the NJBPU approved two stipulated settlement agreements. The first stipulation between JCP&L and the NJBPU staff resolves all of the issues associated with JCP&L's motion for reconsideration of the 2003 NJBPU order Phase I Order. The second stipulation between JCP&L, the NJBPU staff and the Ratepayer Advocate resolves all of the issues associated with JCP&L's Phase II proceeding. The stipulated settlements provide for, among other things, the following:

· An annual increase in distribution revenues of $23 million, effective June 1, 2005, associated with the Phase I Order reconsideration;

· An annual increase in distribution revenues of $36 million, effective June 1, 2005, related to JCP&L's Phase II Petition;

· An annual reduction in both rates and amortization expense of $8 million, effective June 1, 2005, in anticipation of an NJBPU order regarding JCP&L's request to securitize up to $277 million of its deferred cost balance;

· An increase in JCP&L's authorized return on common equity from 9.5% to 9.75%; and

· A commitment by JCP&L to maintain a target level of customer service reliability with a reduction in JCP&L's authorized return on common equity from 9.75% to 9.5% if the target is not met for two consecutive quarters. The authorized return on common equity would then be restored to 9.75% if the target is met for two consecutive quarters.

The Phase II stipulation included an agreement that the distribution revenue increase also reflects a three-year amortization of JCP&L's one-time service reliability improvement costs incurred in 2003-2005. This resulted in the creation of a regulatory asset associated with accelerated tree trimming and other reliability costs which were expensed in 2003 and 2004. The establishment of the new regulatory asset of approximately $28 million resulted in an increase to net income of approximately $16 million ($0.05 per share of FirstEnergy common stock) in the second quarter of 2005.

JCP&L sells all self-supplied energy (NUGs and owned generation) to the wholesale market with offsetting credits to its deferred energy balance with the exception of 300 MW from JCP&L's NUG committed supply currently being used to serve BGS customers pursuant to NJBPU order for the period June 1, 2005 through May 31, 2006. New BGS tariffs reflecting the results of a February 2005 auction for the BGS supply became effective June 1, 2005. On July 1, 2005, JCP&L filed its BGS procurement proposals for post transition year four. The auction is scheduled to take place in February 2006 for the annual supply period beginning June 1, 2006.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004 supporting a continuation of the current level and duration of the funding of TMI-2 decommissioning costs by New Jersey customers without a reduction, termination or capping of the funding. On September 30, 2004, JCP&L filed an updated TMI-2 decommissioning study. This study resulted in an updated total decommissioning cost estimate of $729 million (in 2003 dollars) compared to the estimated $528 million (in 2003 dollars) from the prior 1995 decommissioning study. The Ratepayer Advocate filed comments on February 28, 2005. On March 18, 2005, JCP&L filed a response to those comments. A schedule for further proceedings has not yet been set.

See Note 14 to the consolidated financial statements for further details and a complete discussion of regulatory matters in New Jersey.

Transmission

On December 30, 2004, the Ohio Companies filed with the PUCO two applications related to the recovery of transmission and ancillary service related costs. The first application seeks recovery of these costs beginning January 1, 2006. At the time of filing the application, these costs were estimated to be approximately $30 million per year; however, the Ohio Companies anticipate that this amount will increase. The Ohio Companies requested that these costs be recovered through a rider that would be effective on January 1, 2006 and adjusted each July 1 thereafter. The Ohio Companies reached a settlement with OCC, PUCO staff, Industrial Energy Users - Ohio and OPAE. The only other party in this proceeding, Dominion Retail, Inc., agreed not to oppose the settlement. This settlement, which was filed with the PUCO on July 22, 2005, provides for the rider recovery requested by the Ohio Companies, with carrying charges applied in the subsequent year's rider for any over or under collection while the then-current rider is in effect. The PUCO approved the settlement stipulation on August 31, 2005. The incremental Transmission and Ancillary service revenues expected to be recovered from January through June 2006 are approximately $61.2 million. This value includes the recovery of the 2005 deferred MISO expenses as described below. In May 2006, the Ohio Companies will file a modification to the rider which will determine revenues from July 2006 through June 2007.

The second application sought authority to defer costs associated with transmission and ancillary service related costs incurred during the period from October 1, 2003 through December 31, 2005. On May 18, 2005, the PUCO granted the accounting authority for the Ohio Companies to defer incremental transmission and ancillary service-related charges incurred as a participant in the MISO, but only for those costs incurred during the period December 30, 2004 through December 31, 2005. Permission to defer costs incurred prior to December 31, 2004 was denied. The PUCO also authorized the Ohio Companies to accrue carrying charges on the deferred balances. An application filed with the PUCO to recover these deferred charges over a five-year period through the rider, beginning in 2006, was approved in a PUCO order issued on August 31, 2005 approving the stipulation referred to above. The OCC, OPAE and the Ohio Companies each filed applications for rehearing. The Ohio Companies sought authority to defer the transmission and ancillary service related costs incurred during the period October 1, 2003 through December 29, 2004, while both OCC and OPAE sought to have the PUCO deny deferral of all costs. On July 6, 2005, the PUCO denied the Ohio Companies' and OCC's applications and, at the request of the Ohio Companies, struck as untimely OPAE's application. The OCC filed a notice of appeal with the Ohio Supreme Court on August 31, 2005. On September 30, 2005, in accordance with appellate procedure, the PUCO filed with the Ohio Supreme Court the record in this case. The Companies' brief will be due thirty days after the OCC files its brief, which, absent any time extensions, must be filed no later than November 9, 2005.

On January 31, 2005, certain PJM transmission owners made three filings pursuant to a settlement agreement previously approved by the FERC. JCP&L, Met-Ed and Penelec were parties to that proceeding and joined in two of the filings. In the first filing, the settling transmission owners submitted a filing justifying continuation of their existing rate design within the PJM RTO. In the second filing, the settling transmission owners proposed a revised Schedule 12 to the PJM tariff designed to harmonize the rate treatment of new and existing transmission facilities. Interventions and protests were filed on February 22, 2005. In the third filing, Baltimore Gas and Electric Company and Pepco Holdings, Inc. requested a formula rate for transmission service provided within their respective zones. On

May 31, 2005, the FERC issued an order on these cases. First, it set for hearing the existing rate design and indicated that it will issue a final order within six months. Second, the FERC approved the proposed Schedule 12 rate harmonization. Third, the FERC accepted the proposed formula rate, subject to referral and hearing procedures. On September 30, 2005, the PJM transmission owners filed a request for rehearing of the May 31, 2005 order. The rate design and formula rate filings continue to be litigated before the FERC. The outcome of these two cases cannot be predicted.

Environmental Matters

The Companies accrue environmental liabilities only when they conclude that it is probable that they have an obligation for such costs and can reasonably estimate the amount of such costs. Unasserted claims are reflected in the Companies' determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

FirstEnergy plans to issue a report regarding its response to air emission requirements. FirstEnergy expects to complete the report by December 1, 2005.

National Ambient Air Quality Standards

In July 1997, the EPA promulgated changes in the NAAQS for ozone and proposed a new NAAQS for fine particulate matter. On March 10, 2005, the EPA finalized the "Clean Air Interstate Rule" covering a total of 28 states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on proposed findings that air emissions from 28 eastern states and the District of Columbia significantly contribute to nonattainment of the NAAQS for fine particles and/or the "8-hour" ozone NAAQS in other states. CAIR provides each affected state until 2006 to develop implementing regulation to achieve additional reductions of NO_x and SO_2 emissions in two phases (Phase I in 2009 for NO_x, 2010 for SO_2 and Phase II in 2015 for both NO_x and SO_2) in all cases from the 2003 levels. The Companies' Michigan, Ohio and Pennsylvania fossil-fired generation facilities will be subject to the caps on SO_2 and NO_x emissions, whereas their New Jersey fossil-fired generation facilities will be subject to a cap on NO_x emissions only. According to the EPA, SO_2 emissions will be reduced by 45% (from 2003 levels) by 2010 across the states covered by the rule, with reductions reaching 73% (from 2003 levels) by 2015, capping SO_2 emissions in affected states to just 2.5 million tons annually. NO_x emissions will be reduced by 53% (from 2003 levels) by 2009 across the states covered by the rule, with reductions reaching 61% (from 2003 levels) by 2015, achieving a regional NO_x cap of 1.3 million tons annually. The future cost of compliance with these regulations may be substantial and will depend on how they are ultimately implemented by the states in which the Companies operate affected facilities.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. On March 14, 2005, the EPA finalized the "Clean Air Mercury Rule," which provides for a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases. Initially, mercury emissions will be capped nationally at 38 tons by 2010 (as a "co-benefit" from implementation of SO_2 and NO_x emission caps under the EPA's CAIR program). Phase II of the mercury cap-and-trade program will cap nationwide mercury emissions from coal-fired power plants at 15 tons per year by 2018. However, the final rules give states substantial discretion in developing rules to implement these programs. In addition, both the CAIR and the Clean Air Mercury rule have been challenged in the United States Court of Appeals for the District of Columbia. FirstEnergy's future cost of compliance with these regulations may be substantial.

W. H. Sammis Plant

In 1999 and 2000, the EPA issued NOV or Compliance Orders to nine utilities alleging violations of the Clean Air Act based on operation and maintenance of 44 power plants, including the W. H. Sammis Plant, which is owned by OE and Penn. In addition, the DOJ filed eight civil complaints against various investor-owned utilities, including a complaint against OE and Penn in the U.S. District Court for the Southern District of Ohio. These cases are referred to as New Source Review cases. On March 18, 2005, OE and Penn announced that they had reached a settlement with the EPA, the DOJ and three states (Connecticut, New Jersey, and New York) that resolved all issues related to the W. H. Sammis Plant New Source Review litigation. This settlement agreement, which is in the form of a Consent Decree, was approved by the Court on July 11, 2005, requires OE and Penn to reduce NOx and SO_2 emission at the W. H. Sammis Plant and other coal-fired plants through the installation of pollution control devices. Capital expenditures necessary to meet those requirements are currently estimated to be $1.5 billion (the primary portion of which is expected to be spent in the 2008 to 2011 time period). As disclosed in FirstEnergy's Form 8-K dated August 26, 2005, FGCO entered into an agreement with Bechtel Power Corporation (Bechtel), under which Bechtel will engineer, procure, and construct air quality control systems for the reduction of sulfur dioxide emissions. The settlement agreement also requires OE and Penn to spend up to $25 million toward environmentally beneficial projects, which include wind energy purchased power agreements over a 20-year term. OE and Penn agreed to pay a civil penalty of $8.5 million. Results for the first quarter of 2005 included the penalties payable by OE and Penn of $7.8 million and $0.7 million, respectively. OE and Penn also recognized liabilities of $9.2 million and $0.8 million, respectively, for probable future cash contributions toward environmentally beneficial projects during the first quarter of 2005.

Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol (Protocol), to address global warming by reducing the amount of man-made greenhouse gases emitted by developed countries by 5.2% from 1990 levels between 2008 and 2012. The United States signed the Protocol in 1998 but it failed to receive the two-thirds vote of the United States Senate required for ratification. However, the Bush administration has committed the United States to a voluntary climate change strategy to reduce domestic greenhouse gas intensity - the ratio of emissions to economic output - by 18 percent through 2012. The Energy Policy Act of 2005 established a Committee on Climate change Technology to coordinate federal climate change activities and promote the development and deployment of GHG reducing technologies.

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

Regulation of Hazardous Waste

The Companies have been named as 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 are liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of September 30, 2005, 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 SBC. Total liabilities of approximately $64 million (JCP&L - $46.8 million, CEI - $2.3 million, TE - $0.2 million, Met-Ed - $0.1 million and other - $14.6 million) have been accrued through September 30, 2005.

See Note 13(B) to the consolidated financial statements for further details and a complete discussion of environmental matters.

Other Legal Proceedings

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The other material items not otherwise discussed above are described below.

On August 14, 2003, various states and parts of southern Canada experienced widespread power outages. The outages affected approximately 1.4 million customers in FirstEnergy's service area. The U.S. - Canada Power System Outage Task Force’s final report in April 2004 on the outages concludes, among other things, that the problems leading to the outages began in FirstEnergy’s Ohio service area. Specifically, the final report concluded, among other things, that the initiation of the August 14, 2003 power outages resulted from an alleged failure of both FirstEnergy and ECAR to assess and understand perceived inadequacies within the FirstEnergy system; inadequate situational awareness of the developing conditions; and a perceived failure to adequately manage tree growth in certain transmission rights of way. The Task Force also concluded that there was a failure of the interconnected grid's reliability organizations (MISO and PJM) to provide effective real-time diagnostic support. The final report is publicly available through the Department of Energy’s website (www.doe.gov). FirstEnergy believes that the final report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14, 2003 power outages and that it does not adequately address the underlying causes of the outages. FirstEnergy remains convinced that the outages cannot be explained by events on any one utility's system. The final report contained 46 “recommendations to prevent or minimize the scope of future blackouts.” Forty-five of those recommendations related to broad industry or policy matters while one, including subparts, related to activities the Task Force recommended be undertaken by FirstEnergy, MISO, PJM, ECAR, and other parties to correct the causes of the August 14, 2003 power outages. FirstEnergy implemented several initiatives, both prior to and since the August 14, 2003 power outages, which were independently verified by NERC as complete in 2004 and were consistent with these and other recommendations and collectively enhance the reliability of its electric system. FirstEnergy’s implementation of these recommendations in 2004 included completion of the Task Force recommendations that were directed toward FirstEnergy. FirstEnergy also is proceeding with the implementation of the recommendations regarding enhancements to regional reliability that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new, or material upgrades, to existing equipment, and therefore FirstEnergy has not accrued a liability as of September 30, 2005 for any expenditures in excess of those actually incurred through that date. FirstEnergy notes, however, that the FERC or other applicable government agencies and reliability coordinators may take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures. Finally, the PUCO is continuing to review FirstEnergy’s filing that addressed upgrades to control room computer hardware and software and enhancements to the training of control room operators, before determining the next steps, if any, in the proceeding.

FirstEnergy companies also are defending six separate complaint cases before the PUCO relating to the August 14, 2003 power outage. Two such cases were originally filed in Ohio State courts but subsequently dismissed for lack of subject matter jurisdiction and further appeals were unsuccessful. In both such cases the individual complainants—three in one case and four in the other—sought to represent others as part of a class action. The PUCO dismissed the class allegations, stating that its rules of practice do not provide for class action complaints. Of the four other pending PUCO complaint cases, three were filed by various insurance carriers either in their own name or as subrogees in the name of their insured. In each such case, the carriers seek reimbursement against various FirstEnergy companies (and, in one case, against PJM, MISO and American Electric Power Co. as well) for claims they paid to their insureds allegedly due to the loss of power on August 14, 2003. The listed insureds in these cases, in many instances, are not customers of any FirstEnergy company. The fourth case involves the claim of a non-customer seeking reimbursement for losses incurred when its store was burglarized on August 14, 2003. In addition to these six cases, the Ohio Companies were named as respondents in a regulatory proceeding that was initiated at the PUCO in response to complaints alleging failure to provide reasonable and adequate service stemming primarily from the August 14, 2003 power outages. No estimate of potential liability has been undertaken for any of these cases.

One complaint was filed on August 25, 2004 against FirstEnergy in the New York State Supreme Court. In this case, several plaintiffs in the New York City metropolitan area allege that they suffered damages as a result of the August 14, 2003 power outages. None of the plaintiffs are customers of any FirstEnergy affiliate. FirstEnergy's motion to dismiss the case was granted on September 26, 2005. Additionally, FirstEnergy Corp. was named in a complaint filed in Michigan State Court by an individual who is not a customer of any FirstEnergy company. A responsive pleading to this matter is not due until on or about December 1, 2005. No estimate of potential liability has been undertaken in this matter.

FirstEnergy is vigorously defending these actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be initiated against the Companies. In particular, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

FENOC received a subpoena in late 2003 from a grand jury sitting in the United States District Court for the Northern District of Ohio, Eastern Division requesting the production of certain documents and records relating to the inspection and maintenance of the reactor vessel head at the Davis-Besse Nuclear Power Station. On December 10, 2004, FirstEnergy received a letter from the United States Attorney's Office stating that FENOC is a target of the federal grand jury investigation into alleged false statements made to the NRC in the Fall of 2001 in response to NRC Bulletin 2001-01. The letter also said that the designation of FENOC as a target indicates that, in the view of the prosecutors assigned to the matter, it is likely that federal charges will be returned against FENOC by the grand jury. On February 10, 2005, FENOC received an additional subpoena for documents related to root cause reports regarding reactor head degradation and the assessment of reactor head management issues at Davis-Besse. On May 11, 2005, FENOC received a subpoena for documents related to outside meetings attended by Davis-Besse personnel on corrosion and cracking of control rod drive mechanisms and additional root cause evaluations.

On April 21, 2005, the NRC issued a NOV and proposed a $5.45 million civil penalty related to the degradation of the Davis-Besse reactor vessel head issue described above. FirstEnergy accrued $2.0 million for a potential fine prior to 2005 and accrued the remaining liability for the proposed fine during the first quarter of 2005. On September 14, 2005, FENOC filed its response to the NOV with the NRC. FENOC accepted full responsibility for the past failure to properly implement its boric acid corrosion control and corrective action programs. The NRC NOV indicated that the violations do not represent current licensee performance. FirstEnergy paid the penalty in the third quarter of 2005.

If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability based on the events surrounding Davis-Besse, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

Effective July 1, 2005 the NRC oversight panel for Davis-Besse was terminated and Davis-Besse returned to the standard NRC reactor oversight process. At that time, NRC inspections were augmented to include inspections to support the NRC's Confirmatory Order dated March 8, 2004 that was issued at the time of startup and to address an NRC White Finding related to the performance of the emergency sirens.

On August 12, 2004, the NRC notified FENOC that it would increase its regulatory oversight of the Perry Nuclear Power Plant as a result of problems with safety system equipment over the preceding two years. FENOC operates the Perry Nuclear Power Plant, which currently is owned and/or leased by OE, CEI, TE and Penn (however, see Note 17 regarding FirstEnergy's pending intra-system generation asset transfers, which include owned portions of the plant). On April 4, 2005, the NRC held a public forum to discuss FENOC's performance at the Perry Nuclear Power Plant as identified in the NRC's annual assessment letter to FENOC. Similar public meetings are held with all nuclear power plant licensees following issuance by the NRC of their annual assessments. According to the NRC, overall the Perry Plant operated "in a manner that preserved public health and safety" and met all cornerstone objectives although it remained under heightened NRC oversight since August 2004. During the public forum and in the annual assessment, the NRC indicated that additional inspections will continue and that the plant must improve performance to be removed from the Multiple/Repetitive Degraded Cornerstone Column of the Action Matrix. On May 26, 2005, the NRC held a public meeting to discuss its oversight of the Perry Plant. While the NRC stated that the plant continued to operate safely, the NRC also stated that the overall performance had not substantially improved since the heightened inspection was initiated. The NRC reiterated this conclusion in its mid-year assessment letter dated August 30, 2005. On September 28, 2005, the NRC sent a CAL to FENOC describing commitments that FENOC had made to improve the performance of Perry and stated that the CAL would remain open until substantial improvement was demonstrated. The CAL was anticipated as part of the NRC's Reactor Oversight Process. If performance does not improve, the NRC has a range of options under the Reactor Oversight Process, from increased oversight to possible impact to the plant's operating authority. As a result, these matters could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

On October 20, 2004, FirstEnergy was notified by the SEC that the previously disclosed informal inquiry initiated by the SEC's Division of Enforcement in September 2003 relating to the restatements in August 2003 of previously reported results by FirstEnergy and the Ohio Companies, and the Davis-Besse extended outage, have become the subject of a formal order of investigation. The SEC's formal order of investigation also encompasses issues raised during the SEC's examination of FirstEnergy and the Companies under the PUHCA. Concurrent with this notification, FirstEnergy received a subpoena asking for background documents and documents related to the restatements and Davis-Besse issues. On December 30, 2004, FirstEnergy received a subpoena asking for documents relating to issues raised during the SEC's PUHCA examination. On August 24, 2005 additional information was requested regarding Davis-Besse. FirstEnergy has cooperated fully with the informal inquiry and will continue to do so with the formal investigation.

On August 22, 2005, a class action complaint was filed against OE in Jefferson County, Ohio Common Pleas Court seeking compensatory and punitive damages to be determined at trial based on claims of negligence and eight other tort counts alleging damages from the W.H. Sammis Plant air emissions. The two named plaintiffs are also seeking injunctive relief to eliminate harmful emissions and repair property damage and the institution of a medical monitoring program for class members.

JCP&L's bargaining unit employees filed a grievance challenging JCP&L's 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties' collective bargaining agreement. At the conclusion of the June 1, 2005, hearing, the Arbitrator decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the Arbitrator issued an opinion to award approximately $16.1 million to the bargaining unit employees. JCP&L initiated an appeal of this award by filing a motion to vacate in Federal court in New Jersey on October 18, 2005. JCP&L recognized a liability for the potential $16.1 million award during the three months ended September 30, 2005.

The City of Huron filed a complaint against OE with the PUCO challenging the ability of electric distribution utilities to collect transition charges from a customer of a newly formed municipal electric utility. The complaint was filed on

May 28, 2003, and OE timely filed its response on June 30, 2003. In a related filing, the Ohio Companies filed for approval with the PUCO a tariff that would specifically allow the collection of transition charges from customers of municipal electric utilities formed after 1998. An adverse ruling could negatively affect full recovery of transition charges by the utility. Hearings on the matter were held in August 2005. Initial briefs from all parties were filed on September 22, 2005 and reply briefs were filed on October 14, 2005. It is unknown when the PUCO will rule on this case.

If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on the above matters, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

See Note 13(C) to the consolidated financial statements for further details and a complete discussion of other legal proceedings.

NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

FSP No. FAS 13-1, "Accounting for Rental Costs Incurred during the Construction Period"

Issued in October 2005, FSP No. FAS 13-1 requires rental costs associated with ground or building operating leases that are incurred during a construction period to be recognized as rental expense. The effective date of the FSP guidance is the first reporting period beginning after December 15, 2005. FirstEnergy is currently evaluating this FSP, and its impact on the financial statements.

EITF Issue 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty"

In September 2005, the EITF reached a final consensus on Issue 04-13 concluding that two or more legally separate exchange transactions with the same counterparty should be combined and considered as a single arrangement for purposes of applying APB 29, when the transactions were entered into "in contemplation" of one another. If two transactions are combined and considered a single arrangement, the EITF reached a consensus that an exchange of inventory should be accounted for at fair value. Although electric power is not capable of being held in inventory, there is no substantive conceptual distinction between exchanges involving power and other storable inventory. Therefore, FirstEnergy will adopt this EITF effective for new arrangements entered into, or modifications or renewals of existing arrangements, in interim or annual periods beginning after March 15, 2006. See Note 2 for an example of FirstEnergy's application of this Issue.

EITF Issue No. 05-6, "Determining the Amortization Period for Leasehold Improvements Purchased after Lease Inception or Acquired in a Business Combination"

In June 2005, the EITF reached a consensus on the application guidance for Issue 05-6. EITF 05-6 addresses the amortization period for leasehold improvements that were either acquired in a business combination or placed in service significantly after and not contemplated at or near the beginning of the initial lease term. For leasehold improvements acquired in a business combination, the amortization period is the shorter of the useful life of the assets or a term that includes required lease periods and renewals that are deemed to be reasonably assured at the date of acquisition. Leasehold improvements that are placed in service significantly after and not contemplated at or near the beginning of the lease term should be amortized over the shorter of the useful life of the assets or a term that includes required lease periods and renewals that are deemed to be reasonably assured at the date the leasehold improvements are purchased. This EITF was effective July 1, 2005 and is consistent with FirstEnergy's current accounting.

FIN 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143"

On March 30, 2005, the FASB issued FIN 47 to clarify the scope and timing of liability recognition for conditional asset retirement obligations. Under this interpretation, companies are required to recognize a liability for the fair value of an asset retirement obligation that is conditional on a future event, if the fair value of the liability can be reasonably estimated. In instances where there is insufficient information to estimate the liability, the obligation is to be recognized in the first period in which sufficient information becomes available to estimate its fair value. If the fair value cannot be reasonably estimated, that fact and the reasons why must be disclosed. This Interpretation is effective for FirstEnergy in the fourth quarter of 2005. FirstEnergy and the Companies are currently evaluating the effect this Interpretation will have on their financial statements.

SFAS 154 - "Accounting Changes and Error Corrections - a replacement of APB Opinion No. 20 and FASB Statement No. 3"

In May 2005, the FASB issued SFAS 154 to change the requirements for accounting and reporting a change in accounting principle. It applies to all voluntary changes in accounting principle and to changes required by an accounting pronouncement when that pronouncement does not include specific transition provisions. This Statement requires retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. In those instances, this Statement requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that period rather than being reported in the Consolidated Statements of Income. This Statement also requires that a change in depreciation, amortization, or depletion method for long-lived, nonfinancial assets be accounted for as a change in accounting estimate affected by a change in accounting principle. The provisions of this Statement are effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. FirstEnergy and the Companies will adopt this Statement effective January 1, 2006.

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SFAS 153, "Exchanges of Nonmonetary Assets - an amendment of APB Opinion No. 29"

In December 2004, the FASB issued SFAS 153 amending APB 29, which was based on the principle that nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance in APB 29 included certain exceptions to that principle. SFAS 153 eliminates the exception from fair value measurement for nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges that do not have commercial substance. This Statement specifies that a nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of this Statement are effective January 1, 2006 for FirstEnergy. This FSP is not expected to have a material impact on FirstEnergy's financial statements.

SFAS 123(R), "Share-Based Payment"

In December 2004, the FASB issued SFAS 123(R), a revision to SFAS 123, which requires expensing stock options in the financial statements. Important to applying the new standard is understanding how to (1) measure the fair value of stock-based compensation awards and (2) recognize the related compensation cost for those awards. For an award to qualify for equity classification, it must meet certain criteria in SFAS 123(R). An award that does not meet those criteria will be classified as a liability and remeasured each period. SFAS 123(R) retains SFAS 123's requirements on accounting for income tax effects of stock-based compensation. In April 2005, the SEC delayed the effective date of SFAS 123(R) to annual, rather than interim, periods that begin after June 15, 2005. The SEC's new rule results in a six-month deferral for companies with a fiscal year beginning January 1. Therefore, FirstEnergy will adopt this Statement effective January 1, 2006. FirstEnergy expects to adopt modified prospective application, without restatement of prior interim periods. Potential cumulative adjustments, if any, have not yet been determined. FirstEnergy uses the Black-Scholes option-pricing model to value options for disclosure purposes only and expects to apply this pricing model upon adoption of SFAS 123(R).

SFAS 151, "Inventory Costs - an amendment of ARB No. 43, Chapter 4"

In November 2004, the FASB issued SFAS 151 to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage). Previous guidance stated that in some circumstances these costs may be "so abnormal" that they would require treatment as current period costs. SFAS 151 requires abnormal amounts for these items to always be recorded as current period costs. In addition, this Statement requires that allocation of fixed production overheads to the cost of conversion be based on the normal capacity of the production facilities. The provisions of this statement are effective for inventory costs incurred by FirstEnergy beginning January 1, 2006. FirstEnergy is currently evaluating this Standard and does not expect it to have a material impact on the financial statements.

FSP FAS 115-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"

In September 2005, the FASB finalized and renamed EITF 03-1 and 03-1-a to FSP FAS 115-1. FSP FAS 115-1 will (1) supersede Issue 03-1 and EITF topic No. D-44, "Recognition of Other Than Temporary Impairment upon the Planned Sale of a Security Whose Cost Exceeds Fair Value," (2) clarify that an investor should recognize an impairment loss no later than when the impairment is deemed other than temporary, even if a decision to sell has not been made, and (3) be effective for other-than-temporary impairment and analyses conducted in periods beginning after September 15, 2005. The FASB expects to issue this FSP in the fourth quarter of 2005, which would require prospective application with an effective date for reporting periods beginning after December 15, 2005. FirstEnergy is currently evaluating this FSP and any impact on its investments.

FSP 109-1, "Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction and Qualified Production Activities Provided by the American Jobs Creation Act of 2004"

Issued in December 2004, FSP 109-1 provides guidance related to the provision within the American Jobs Creation Act of 2004 (Act) that provides a tax deduction on qualified production activities. The Act includes a tax deduction of up to nine percent (when fully phased-in) of the lesser of (a) "qualified production activities income," as defined in the Act, or (b) taxable income (after the deduction for the utilization of any net operating loss carryforwards). The FASB believes that the deduction should be accounted for as a special deduction in accordance with SFAS 109, "Accounting for Income Taxes", which is consistent with FirstEnergy's accounting.

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OHIO EDISON COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	**2004**	**2005**	**2004**
	(In thousands)			
STATEMENTS OF INCOME				
OPERATING REVENUES	$ 825,790	$ 766,336	$ 2,268,760	$ 2,227,978
OPERATING EXPENSES AND TAXES:				
Fuel	15,158	15,244	39,080	44,158
Purchased power	229,561	242,835	703,658	730,542
Nuclear operating costs	76,254	81,244	264,514	235,277
Other operating costs	114,762	99,132	293,530	276,289
Provision for depreciation	30,169	30,702	87,875	90,846
Amortization of regulatory assets	126,439	103,211	347,880	317,030
Deferral of new regulatory assets	(43,929)	(25,728)	(107,750)	(69,790)
General taxes	51,945	47,634	146,066	135,688
Income taxes	99,778	76,502	245,942	203,863
Total operating expenses and taxes	700,137	670,776	2,020,795	1,963,903
OPERATING INCOME	125,653	95,560	247,965	264,075
OTHER INCOME (net of income taxes)	20,069	17,141	37,352	50,285
NET INTEREST CHARGES:				
Interest on long-term debt	12,989	10,657	44,330	43,641
Allowance for borrowed funds used during construction and capitalized interest	(3,014)	(1,950)	(8,255)	(4,924)
Other interest expense	4,193	640	12,457	7,576
Subsidiary's preferred stock dividend requirements	156	639	1,534	1,919
Net interest charges	14,324	9,986	50,066	48,212
NET INCOME	131,398	102,715	235,251	266,148
PREFERRED STOCK DIVIDEND REQUIREMENTS	659	623	1,976	1,843
	$ 130,739	$ 102,092	$ 233,275	$ 264,305

EARNINGS ON COMMON STOCK								
STATEMENTS OF COMPREHENSIVE INCOME								
NET INCOME	$	131,398	$	102,715	$	235,251	$	266,148
OTHER COMPREHENSIVE INCOME (LOSS):								
Unrealized loss on available for sale securities		(3,402)		(6,913)		(19,079)		(2,767)
Income tax benefit related to other comprehensive income		2,043		2,850		7,713		1,141
Other comprehensive loss, net of tax		(1,359)		(4,063)		(11,366)		(1,626)
TOTAL COMPREHENSIVE INCOME	$	130,039	$	98,652	$	223,885	$	264,522

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

OHIO EDISON COMPANY

CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2005	December 31, 2004
	(In thousands)	
ASSETS		
UTILITY PLANT:		
In service	$ 5,573,996	$ 5,440,374
Less - Accumulated provision for depreciation	2,793,343	2,716,851
	2,780,653	2,723,523
Construction work in progress -		
Electric plant	246,325	203,167
Nuclear fuel	17,972	21,694
	264,297	224,861
	3,044,950	2,948,384
OTHER PROPERTY AND INVESTMENTS:		
Investment in lease obligation bonds	341,335	354,707
Nuclear plant decommissioning trusts	462,439	436,134
Long-term notes receivable from associated companies	207,089	208,170
Other	44,623	48,579
	1,055,486	1,047,590
CURRENT ASSETS:		
Cash and cash equivalents	900	1,230
Receivables -		
Customers (less accumulated provisions of $7,312,000 and $6,302,000, respectively, for uncollectible accounts)	285,462	274,304
Associated companies	121,262	245,148
Other (less accumulated provisions of $14,000 and $64,000, respectively, for uncollectible accounts)	20,653	18,385
Notes receivable from associated companies	798,513	538,871
Materials and supplies, at average cost	92,610	90,072
Prepayments and other	17,336	13,104
	1,336,736	1,181,114
DEFERRED CHARGES:		
Regulatory assets	844,590	1,115,627
Property taxes	61,419	61,419
Unamortized sale and leaseback costs	56,477	60,242
Other	67,093	68,275
	1,029,579	1,305,563
	$ 6,466,751	$ 6,482,651
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common stockholder's equity -		

Common stock, without par value, authorized 175,000,000 shares - 100 shares outstanding	$	2,099,099	$	2,098,729
Accumulated other comprehensive loss		(58,484)		(47,118)
Retained earnings		434,473		442,198
Total common stockholder's equity		2,475,088		2,493,809
Preferred stock		60,965		60,965
Preferred stock of consolidated subsidiary		14,105		39,105
Long-term debt and other long-term obligations		1,099,147		1,114,914
		3,649,305		3,708,793
CURRENT LIABILITIES:				
Currently payable long-term debt		273,656		398,263
Short-term borrowings -				
Associated companies		120,971		11,852
Other		123,584		167,007
Accounts payable -				
Associated companies		81,980		187,921
Other		11,289		10,582
Accrued taxes		213,843		153,400
Other		117,268		74,663
		942,591		1,003,688
NONCURRENT LIABILITIES:				
Accumulated deferred income taxes		688,702		766,276
Accumulated deferred investment tax credits		52,108		62,471
Asset retirement obligation		364,525		339,134
Retirement benefits		320,044		307,880
Other		449,476		294,409
		1,874,855		1,770,170
COMMITMENTS AND CONTINGENCIES (Note 13)				
	$	6,466,751	$	6,482,651

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

OHIO EDISON COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 131,398	$ 102,715	$ 235,251	$ 266,148
Adjustments to reconcile net income to net cash from operating activities -				
Provision for depreciation	30,169	30,702	87,875	90,846
Amortization of regulatory assets	126,439	103,211	347,880	317,030
Deferral of new regulatory assets	(43,929)	(25,728)	(107,750)	(69,790)
Nuclear fuel and lease amortization	11,867	11,914	30,530	33,766
Amortization of lease costs	32,963	33,037	30,011	30,585
Amortization of electric service obligation	(4,565)	-	(8,556)	-
Deferred income taxes and investment tax credits, net	(17,787)	(11,374)	(22,929)	(61,961)
Accrued retirement benefit obligations	5,503	7,253	12,164	24,482
Accrued compensation, net	1,254	1,106	(1,903)	5,138
Pension trust contribution	-	(72,763)	-	(72,763)
Decrease (increase) in operating assets -				
Receivables	32,715	(86,506)	110,460	(10,734)
Materials and supplies	15,611	(2,930)	(2,538)	(8,796)
Prepayments and other current assets	2,988	4,878	(4,232)	(1,636)
Increase (decrease) in operating liabilities -				
Accounts payable	(20,007)	115,690	(105,234)	21,905
Accrued taxes	41,365	(4,464)	60,443	(346,918)
Accrued interest	2,458	3,028	1,667	2,918
Prepayment for electric service - education programs	-	-	136,142	-
Other	(11,504)	2,572	1,372	(8,624)
Net cash provided from operating activities	336,938	212,341	800,653	211,596

CASH FLOWS FROM FINANCING ACTIVITIES:				
New Financing -				
Long-term debt	-	-	146,450	30,000
Short-term borrowings, net	18,254	91,072	65,696	13,258
Redemptions and Repayments -				
Preferred stock	-	-	(37,750)	-
Long-term debt	(17,819)	(36,090)	(278,327)	(152,900)
Dividend Payments -				
Common stock	(64,000)	(68,000)	(241,000)	(239,000)
Preferred stock	(659)	(623)	(1,976)	(1,843)
Net cash used for financing activities	(64,224)	(13,641)	(346,907)	(350,485)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions	(69,346)	(61,682)	(190,804)	(146,645)
Contributions to nuclear decommissioning trusts	(7,885)	(7,885)	(23,655)	(23,655)
Loan repayments from (loans to) associated companies, net	(200,021)	(378,081)	(258,561)	30,709
Proceeds from certificates of deposit	-	277,763	-	277,763
Other	4,155	(29,200)	18,944	113
Net cash provided from (used for) investing activities	(273,097)	(199,085)	(454,076)	138,285
Net decrease in cash and cash equivalents	(383)	(385)	(330)	(604)
Cash and cash equivalents at beginning of period	1,283	1,664	1,230	1,883
Cash and cash equivalents at end of period	$ 900	$ 1,279	$ 900	$ 1,279

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

Report of Independent Registered Public Accounting Firm

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 September 30, 2005, and the related consolidated statements of income and comprehensive income and cash flows for each of the three-month and nine-month periods ended September 30, 2005 and 2004. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 the standards of the Public Company Accounting Oversight Board, 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 the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2004, and the related consolidated statements of income, capitalization, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended, management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004 and the effectiveness of the Company's internal control over financial reporting as of December 31, 2004; and in our report (which contained references to the Company's change in its method of accounting for asset retirement obligations as of January 1, 2003 as discussed in Note 2(G) to those consolidated financial statements and the Company's change in its method of accounting for the consolidation of variable interest entities as of December 31, 2003 as discussed in Note 7 to those consolidated financial statements) dated March 7, 2005, we expressed unqualified opinions thereon. The consolidated financial statements and management's assessment of the effectiveness of internal control over financial reporting referred to above are not presented herein. In our opinion, the information set forth in the accompanying consolidated balance sheet information as of December 31, 2004, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio

November 1, 2005

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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. The OE Companies also provide generation services to those customers electing to retain the OE Companies as their power supplier. The OE Companies provide power directly to wholesale customers under previously negotiated contracts, as well as to some 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.

Results of Operations

Earnings on common stock in the third quarter of 2005 increased to $131 million from $102 million in the third quarter of 2004. The increase in earnings resulted primarily from higher operating revenues and lower purchased power and nuclear operating costs, partially offset by increases in regulatory asset amortization, other operating costs and income taxes. During the first nine months of 2005, earnings on common stock decreased to $233 million from $264 million in the same period of 2004. The decrease in earnings for the first nine months of 2005 primarily resulted from increases in nuclear operating costs, regulatory asset amortization and a one-time income tax charge that occurred in the second quarter of 2005, as well as a decrease in other income. These reductions to earnings were partially offset by higher operating revenues and lower fuel and purchased power costs.

Operating revenues increased by $59 million or 7.8% in the third quarter of 2005 compared with the same period in 2004. Higher revenues for the quarter primarily resulted from increased retail generation and distribution revenues of $23 million and $33 million, respectively. During the first nine months of 2005 compared to the same period in 2004, operating revenues increased by $41 million or 1.8%. Higher revenues for the first nine months of 2005 were due to increases in retail generation and distribution revenues of $36 million and $40 million, respectively, partially offset by a $37 million decrease in wholesale sales.

Lower wholesale revenues for the first nine months of 2005 reflected decreased sales to FES of $57 million (12.1% KWH sales decrease), due to reduced nuclear generation available for sale. The decreased sales to FES were partially offset by increased sales of $21 million to non-affiliated customers (including MSG sales). Under its Ohio transition plan, OE is required to provide MSG to non-affiliated alternative suppliers (see Outlook - Regulatory Matters).

Increased retail generation revenues for the third quarter of 2005 resulted from higher sales to residential, commercial and industrial customers of $10 million, $2 million and $11 million, respectively. The increased generation KWH sales to residential (14.0%) and commercial (6.1%) customers were due to warmer than normal temperatures in the third quarter of 2005. Increased industrial revenues reflected a 6.5% increase in generation KWH sales. Partially offsetting the increase in residential KWH sales was an increase in customer shopping. Generation services provided to residential customers by alternative suppliers as a percent of total residential sales delivered in OE's service area increased by 1.2 percentage points compared with the third quarter of 2004. Commercial and industrial customer shopping remained relatively unchanged.

Retail generation revenues increased for the first nine months of 2005 compared to the same period of 2004 in all customer sectors (residential - $15 million, commercial - $7 million and industrial - $14 million). The higher revenues were due to increased generation KWH sales (residential - 6.8%, commercial - 4.2% and industrial - 1.0%).

Residential and industrial KWH sales increases were partially offset by increases in customer shopping by 1.1 and 1.7 percentage points, respectively, while commercial shopping remained relatively unchanged.

Revenues from distribution throughput increased $33 million in the third quarter of 2005 compared with the same period in 2004. Distribution deliveries to residential, commercial and industrial customers increased by $26 million, $4 million and $3 million, respectively, due to increased KWH deliveries. The increases from distribution deliveries were partially offset by lower composite unit prices in all sectors.

Revenues from distribution throughput increased $40 million in the first nine months of 2005 compared with the same period in 2004 due to higher revenues from residential and commercial customers, partially offset by lower industrial sector revenues. Residential and commercial distribution revenues increased $40 million and $3 million, respectively, reflecting higher KWH deliveries partially offset by lower composite prices. Industrial distribution revenues decreased by $3 million due to lower composite unit prices, partially offset by an increase in KWH distribution deliveries.

Under the Ohio transition plan, OE provides incentives to customers to encourage switching to alternative energy providers. OE's revenues were reduced by $3 million from additional credits in the third quarter and $7 million in the first nine months of 2005 compared to the same periods in 2004. These revenue reductions are deferred for future recovery from customers under OE's transition plan and do not affect current period earnings (See Regulatory Matters below).

Changes in KWH sales by customer class in the three months and nine months ended September 30, 2005 from the corresponding periods of 2004 are summarized in the following table:

Changes in KWH Sales Increase (Decrease)	**Three Months**	**Nine Months**
Electric Generation:		
Retail	9.1%	3.9%
Wholesale	(1.2)%	(9.4)%
Total Electric Generation Sales	**4.0%**	**(2.6)%**
Distribution Deliveries:		
Residential	15.9%	8.3%
Commercial	6.3%	4.2%
Industrial	6.9%	3.4%
Total Distribution Deliveries	**9.8%**	**5.3%**

Operating Expenses and Taxes

Total operating expenses and taxes increased by $29 million in the third quarter and $57 million in the first nine months of 2005 from the same periods of 2004. The following table presents changes from the prior year by expense category.

Operating Expenses and Taxes - Changes Increase (Decrease)	**Three Months**	**Nine Months**
	(In millions)	
Fuel costs	$ --	$ (5)
Purchased power costs	(13)	(27)
	(5)	29

Nuclear operating costs		
Other operating costs	16	17
Provision for depreciation	(1)	(3)
Amortization of regulatory assets	23	31
Deferral of new regulatory assets	(18)	(38)
General taxes	4	11
Income taxes	23	42
Net increase in operating expenses and taxes	$ 29	$ 57

Lower fuel costs in the first nine months of 2005, compared with the same periods of 2004, resulted from decreased nuclear generation - down 12.1%. Purchased power costs were lower in both periods of 2005, reflecting lower unit costs partially offset by higher KWH purchases in the third quarter of 2005. KWH purchases were relatively unchanged in the first nine months of 2005. Nuclear operating costs decreased in the third quarter of 2005 compared to the same quarter in 2004 primarily due to a decrease in non-fuel nuclear operating costs at Perry Unit 1 and Beaver Valley Unit 2. Nuclear operating costs increased during the first nine months of 2005 primarily due to the costs from the Beaver Valley Unit 2 refueling outage (started April 4, 2005) and to a lesser extent from the Perry Unit 1 outage initiated in the first quarter of 2005 that was completed on May 6, 2005. There were no nuclear refueling outages in the same periods last year. The increases in other operating costs in the third quarter and first nine months of 2005, compared to the same periods of 2004, resulted primarily from increased MISO transmission expenses, partially offset by lower employee benefits expenses.

The decrease in depreciation expense in the first nine months of 2005 compared with the same period of 2004 was attributable to revised estimated service life assumptions for fossil generating plants (see Note 3). Higher regulatory asset amortization in the three-month and nine-month periods was primarily due to increased amortization of transition costs being recovered under the RSP. Increases in regulatory asset deferrals for both periods resulted from higher shopping incentive deferrals and related interest ($4 million and $11 million, respectively), and the PUCO-approved MISO administrative cost deferrals and related interest ($14 million and $27 million, respectively, see Outlook - Regulatory Matters).

General taxes increased in the third quarter and first nine months of 2005 compared to the same periods of 2004 due to the effect of higher KWH sales which increased Ohio KWH excise taxes in both periods. The increase in the first nine months of 2005 also reflected the absence of a $6 million Pennsylvania property tax refund recognized in the second quarter of 2004.

Income taxes increased in the first nine months of 2005 compared to the same periods of 2004, primarily due to the effects of new tax legislation in Ohio. On June 30, 2005, the State of Ohio enacted new tax legislation that created a new CAT tax, which is based on qualifying “taxable gross receipts” and will not consider any expenses or costs incurred to generate such receipts, except for items such as cash discounts, returns and allowances, and bad debts. The CAT tax was effective July 1, 2005, and replaces the Ohio income-based franchise tax and the Ohio personal property tax. The CAT tax is phased-in while the current income-based franchise tax is phased-out over a five-year period at a rate of 20% annually, beginning with the year ended 2005, and personal property tax is phased-out over a four-year period at a rate of approximately 25% annually, beginning with the year ended 2005. During the phase-out period the Ohio income tax will be computed consistently with the prior tax law, except that the tax liability as computed will be multiplied by 4/5 in 2005; 3/5 in 2006; 2/5 in 2007 and 1/5 in 2008, therefore eliminating the current income-based franchise tax over a five-year period.

As a result of the new tax structure, all net deferred tax benefits that are not expected to reverse during the five-year phase-in period were written-off as of June 30, 2005. The impact on income taxes associated with the required adjustment to net deferred taxes for the nine months ended September 30, 2005 was an additional tax expense of approximately $36 million, which was partially offset by the initial phase-out of the Ohio income-based franchise tax, which reduced income taxes by approximately $7 million in the nine months ended September 30, 2005. See Note 12 to the consolidated financial statements.

Other Income

Other income decreased $13 million in the first nine months of 2005 compared with the same period of 2004, primarily due to an $8.5 million civil penalty payable to the Department of Justice and a $10 million liability for environmental projects recognized in connection with the W.H. Sammis Plant settlement (see Outlook - Environmental Matters), partially offset by higher nuclear decommissioning trust realized gains.

Net Interest Charges

Net interest charges increased by $4 million in the third quarter and $2 million in the first nine months of 2005 compared with the same periods of 2004, reflecting increased short-term borrowings from associated companies at a higher rate of interest.

Capital Resources and Liquidity

OE’s cash requirements for the remainder of 2005 for operating expenses, construction expenditures, scheduled debt maturities and preferred stock redemptions are expected to be met without increasing OE’s net debt and preferred stock outstanding. Borrowing capacity under credit facilities is available to manage working capital requirements. Thereafter, OE expects to use a combination of cash from operations and funds from the capital markets.

Changes in Cash Position

As of September 30, 2005, OE's cash and cash equivalents of approximately $1 million remained unchanged from December 31, 2004.

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Cash Flows From Operating Activities

Cash provided from operating activities during the third quarter and first nine months of 2005, compared with the corresponding periods in 2004 were as follows:

Operating Cash Flows	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In millions)			
Cash earnings [1]	$ 273	$ 224	$ 603	$ 607
Pension trust contribution [2]	--	(44)	--	(44)
Working capital and other	64	32	198	(351)
Total cash flows from operating activities	$ 337	$ 212	$ 801	$ 212

[1] Cash earnings is a non-GAAP measure (see reconciliation below).
[2] Pension trust contribution net of $29 million of income tax benefits.

Cash earnings, as disclosed in the table above, are not a measure of performance calculated in accordance with GAAP. OE believes that cash earnings is a useful financial measure because it provides investors and management with an additional means of evaluating its cash-based operating performance. The following table reconciles cash earnings with net income.

Reconciliation of Cash Earnings	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In millions)			
Net income (GAAP)	$ 131	$ 103	$ 235	$ 266
Non-cash charges (credits):				
Provision for depreciation	30	31	88	91
Amortization of regulatory assets	126	103	348	317
Amortization of lease costs	33	33	30	31
Nuclear fuel and capital lease amortization	12	12	31	34
Deferral of new regulatory assets	(44)	(26)	(108)	(70)
Deferred income taxes and investment tax credits, net	(18)	(40)	(23)	(91)
Other non-cash items	3	8	2	29
Cash earnings (Non-GAAP)	$ 273	$ 224	$ 603	$ 607

Net cash provided from operating activities increased $125 million in the third quarter of 2005, compared with the third quarter of 2004, due to a $32 million increase from changes in working capital, the absence of a $44 million after-tax voluntary pension trust contribution made in the third quarter of 2004 and a $49 million increase in cash earnings as described above and under “Results from Operations”. The increase in working capital primarily reflects changes in accrued taxes of $46 million (including a $249 million reallocation of tax liabilities among the FirstEnergy subsidiaries pursuant to the tax sharing agreement), partially offset by changes in accounts payable and accounts receivable of $16 million.

Net cash provided from operating activities increased $589 million in the first nine months of 2005, compared with the same period in 2004, due to a $549 million increase from changes in working capital, the absence of a $44 million after-tax voluntary pension trust contribution made in the third quarter of 2004, partially offset by a $4 million decrease in cash earnings as described above and under “Results from Operations”. The increase in working capital primarily reflects changes in accrued taxes of $407 million (including a $249 million reallocation of tax liabilities among the FirstEnergy subsidiaries pursuant to the tax sharing agreement) and $136 million of funds received for the Energy for Education program in the second quarter of 2005.

Cash Flows From Financing Activities

Net cash used for financing activities increased to $64 million in the third quarter of 2005 from $14 million in the third quarter of 2004. The increase primarily resulted from a $72 million decrease in new short-term borrowings, partially offset by an $18 million decrease in redemptions and repayments. Net cash used for financing activities decreased to $347 million in the first nine months of 2005 from $350 million in the same period of 2004. The decrease was due to a $169 million increase in new debt and short term borrowings partially offset by a $163 million increase in net debt and preferred stock redemptions.

On May 16, 2005, Penn redeemed all 127,500 outstanding shares of 7.625% preferred stock at $102.29 per share and all 250,000 outstanding shares of 7.75% preferred stock at $100 per share, including accrued dividends to the date of redemption.

OE had approximately $799 million of cash and temporary cash investments (which include short-term notes receivable from associated companies) and $245 million of short-term indebtedness as of September 30, 2005. OE has authorization from the PUCO to incur short-term debt of up to $500 million (including bank facilities and the utility money pool described below). Penn has authorization from the SEC to incur short-term debt up to its charter limit of $51 million (including the utility money pool).

OES Capital is a wholly owned subsidiary of OE whose borrowings are secured by customer accounts receivable purchased from OE. OES Capital can borrow up to $170 million under a receivables financing arrangement. As a separate legal entity with separate creditors, OES Capital would have to satisfy its obligations to creditors before any of its remaining assets could be made available to OE. As of September 30, 2005, the facility was drawn for $120 million.

Penn Power Funding LLC (Penn Funding), a wholly owned subsidiary of Penn, is a limited liability company whose borrowings are secured by customer accounts receivable purchased from Penn. Penn Funding can borrow up to $25 million under a receivables financing arrangement. As a separate legal entity with separate creditors, Penn Funding would have to satisfy its obligations to creditors before any of its remaining assets could be made available to Penn. As of September 30, 2005, the facility was not drawn. On July 15, 2005, the facility was renewed until June 29, 2006. The annual facility fee is 0.25% on the entire finance limit.

As of October 24, 2005, OE and Penn had the aggregate capability to issue approximately $1.1 billion of additional FMB on the basis of property additions and retired bonds under the terms of their respective mortgage indentures following the recently completed intra-system transfer of fossil generating plants (see Note 17). The issuance of FMB by OE is also subject to provisions of its senior note indentures generally limiting the incurrence of additional secured debt, subject to certain exceptions that would permit, among other things, the issuance of secured debt (including FMB) (i) supporting pollution control notes or similar obligations, or (ii) as an extension, renewal or replacement of previously outstanding secured debt. In addition, these provisions would permit OE to incur additional secured debt not otherwise permitted by a specified exception of up to $690 million as of October 24, 2005. Based upon applicable earnings coverage tests in their respective charters, OE and Penn could issue a total of $2.8 billion of preferred stock (assuming no additional debt was issued) as of September 30, 2005. It is estimated that the annualized impact of the intra-system transfer of fossil generating plants will reduce the aggregate capability of OE and Penn to issue preferred stock by approximately 17%.

On June 14, 2005, FirstEnergy, OE, Penn, CEI, TE, JCP&L, Met-Ed, Penelec, FES and ATSI, as Borrowers, entered into a syndicated $2 billion five-year revolving credit facility. Borrowings under the facility are available to each Borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. OE's and Penn’s borrowing limits under the facility are $550 million.

OE and Penn have the ability to borrow from their regulated affiliates and FirstEnergy to meet their short-term working capital requirements. FESC administers this money pool and tracks surplus funds of FirstEnergy and its regulated subsidiaries. Companies receiving a loan under the money pool agreements must repay the principal amount, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from the pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in the third quarter of 2005 was 3.50%.

OE's access to capital markets and costs of financing are dependent on the ratings of its securities and the securities of FirstEnergy.

On July 18, 2005, Moody's revised its rating outlook on FirstEnergy and its subsidiaries to positive from stable. Moody's stated that the revision to FirstEnergy's outlook resulted from steady financial improvement and steps taken by management to improve operations, including the stabilization of its nuclear operations. Moody's further stated that the revision in their outlook recognized management's regional strategy of focusing on its core utility businesses and the improvement in FirstEnergy's credit profile stemming from the application of free cash flow toward debt reduction. Moody's noted that a ratings upgrade could be considered if FirstEnergy continues to achieve planned improvements in its operations and balance sheet.

On October 3, 2005, S&P raised its corporate credit rating on FirstEnergy and the EUOC to 'BBB' from 'BBB-'. At the same time, S&P raised the senior unsecured ratings at the holding company to 'BBB-' from 'BB+' and each of the EUOC by one notch above the previous rating. S&P noted that the upgrade followed the continuation of a good operating track record, specifically for the nuclear fleet through the third quarter 2005. S&P also stated that FirstEnergy's rating reflects the benefits of supportive regulation, low-cost base load generation fleet, low-risk transmission and distribution operations and rate certainty in Ohio. FirstEnergy's ability to consistently generate free cash flow, good liquidity, and an improving financial profile were also noted as strengths.

Cash Flows From Investing Activities

Net cash used for investing activities increased by $74 million in the third quarter of 2005 and $592 million in the first nine months of 2005, from the same periods of 2004. These increases resulted primarily from $278 million in cash proceeds from certificates of deposit during the third quarter 2004. Loans to associated companies decreased $178 million in the third quarter of 2005, partially offsetting the proceeds from certificates of deposit, and increased $289 million in the first nine months of 2005.

In the last quarter of 2005, capital requirements for property additions and capital leases are expected to be approximately $82 million. OE has additional requirements of approximately $8 million to meet sinking fund requirements for preferred stock and maturing long-term debt (excluding Penn's optional redemptions disclosed above) during the remainder of 2005. These cash requirements are expected to be satisfied from internal cash and short-term credit arrangements. OE's capital spending for the period 2005-2007 is expected to be about $667 million of which approximately $233 million applies to 2005.

FirstEnergy Intra-System Generation Asset Transfers

On May 13, 2005, Penn, and on May 18, 2005, OE, CEI and TE, entered into certain agreements implementing a series of intra-system generation asset transfers. When fully completed, the asset transfers will result in the respective undivided ownership interests of the Ohio Companies and Penn in FirstEnergy's nuclear and non-nuclear plants being owned by NGC, and FGCO, respectively. The generating plant interests that are being transferred do not include OE's leasehold interests in certain of the plants that are currently subject to sale and leaseback arrangements with non-affiliates.

On October 24, 2005, the OE Companies completed the transfer of non-nuclear generation assets to FGCO. The OE Companies currently expect to complete the transfer of nuclear generation assets to NGC through a spin-off by way of dividend before the end of 2005. Consummation of the nuclear transfer remains subject to necessary regulatory approvals.

These transactions are being undertaken in connection with the Ohio Companies' and Penn's restructuring plans that were approved by the PUCO and the PPUC, respectively, under applicable Ohio and Pennsylvania electric utility restructuring legislation. Consistent with the restructuring plans, generation assets that had been owned by the Ohio Companies and Penn were required to be separated from the regulated delivery business of those companies through transfer to a separate corporate entity. FENOC currently operates and maintains the nuclear generation assets to be transferred. FGCO, as lessee under a Master Facility Lease, leased, operated and maintained the non-nuclear generation assets that it now owns. The transactions will essentially complete the divestitures contemplated by the restructuring plans by transferring the ownership interests to NGC and FGCO, respectively, without impacting the operation of the plants.

See Note 17 to the consolidated financial statements for OE's and Penn's disclosure of the assets held for sale as of September 30, 2005.

Off-Balance Sheet Arrangements

Obligations not included on OE's Consolidated Balance Sheets primarily consist of sale and leaseback arrangements involving Perry Unit 1 and Beaver Valley Unit 2. The present value of these operating lease commitments, net of trust investments, was $678 million as of September 30, 2005.

Equity Price Risk

Included in OE's nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $262 million and $248 million as of September 30, 2005 and December 31, 2004, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $26 million reduction in fair value as of September 30, 2005. Changes in the fair value of these investments are recorded in OCI unless recognized as a result of a sale or recognized as regulatory assets or liabilities.

Outlook

The electric industry continues to transition to a more competitive environment and all of the OE Companies' customers can select alternative energy suppliers. The OE Companies continue to deliver power to residential homes and businesses through their 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.

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 customers elects to obtain power from an alternative supplier, OE reduces the customer's bill with a "generation shopping credit," based on the 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, 2008 unless the PUCO accepts future competitive bid results prior to the end of that period under the revised RSP.

As part of OE's transition plan, it is obligated to supply electricity to customers who do not choose an alternative supplier. OE is also required to provide 560 MW of low cost supply (MSG) to unaffiliated alternative suppliers who serve customers within its service area. FES acts as an alternate supplier for a portion of the load in OE's franchise area.

On August 5, 2004, the Ohio Companies accepted the RSP as modified and approved by the PUCO in an August 4, 2004 Entry on Rehearing, subject to a competitive bid process. The RSP was filed by the Ohio Companies to establish generation service rates beginning January 1, 2006, in response to PUCO concerns about price and supply uncertainty following the end of the Ohio Companies' transition plan market development period. In October 2004, the OCC and NOAC filed appeals with the Supreme Court of Ohio to overturn the original June 9, 2004 PUCO order in this proceeding as well as the associated entries on rehearing. On September 28, 2005, the Ohio Supreme Court heard oral argument on the appeals.

On May 27, 2005, OE filed an application with the PUCO to establish a GCAF rider under the RSP. The application seeks to implement recovery of increased fuel costs from 2006 through 2008 applicable to OE's retail customers through a tariff rider to be implemented January 1, 2006. The application reflects projected increases in fuel costs in 2006 compared to 2002 baseline costs. The new rider, after adjustments made in testimony, is seeking to recover all costs above the baseline (approximately $88 million in 2006 for all of the Ohio Companies). Various parties including the OCC have intervened in this case and the case has been consolidated with the RCP application discussed below.

On September 9, 2005, OE filed an application with the PUCO that, if approved, would supplement its existing RSP with an RCP. On September 27, 2005, the PUCO granted FirstEnergy's motion to consolidate the GCAF rider application with the RCP proceedings and set hearings for the consolidated cases to begin November 29, 2005. The RCP is designed to provide customers with more certain rate levels than otherwise available under the RSP during the plan period, and to provide OE with financial results generally comparable to those attained under the RSP. Major provisions of the RCP include:

- Maintain the existing level of base distribution rates through December 31, 2008 for OE;

- Defer and capitalize certain distribution costs to be incurred by all of the Ohio Companies during the period January 1, 2006 through December 31, 2008, not to exceed $150 million in each of the three years;

- Adjust the RTC and extended RTC recovery periods and rate levels so that full recovery of authorized costs will occur as of December 31, 2008 for OE;

- Reduce the deferred shopping incentive balance as of January 1, 2006 by up to $75 million for OE by accelerating the application of its accumulated cost of removal regulatory liability; and

- Recover increased fuel costs of up to $75 million, $77 million, and $79 million, in 2006, 2007, and 2008, respectively, from all OE and TE distribution and transmission customers through a fuel recovery mechanism. OE may defer and capitalize increased fuel costs above the amount collected through the fuel recovery mechanism.

Under provisions of the RSP, the PUCO may require OE to undertake, no more often than annually, a competitive bid process to secure generation for the years 2007 and 2008. On July 22, 2005, FirstEnergy filed a competitive bid process for the period beginning in 2007 that is similar to the competitive bid process approved by the PUCO for OE in 2004, which resulted in the PUCO accepting no bids. Any acceptance of future competitive bid results would terminate the RSP pricing, with no accounting impacts to the RSP, and not until twelve months after the PUCO authorizes such termination. On September 28, 2005, the PUCO issued an Entry that essentially approved the Ohio Companies' filing but delayed the proposed timing of the competitive bid process by four months, calling for the auction to be held on March 21, 2006.

On December 30, 2004, OE filed with the PUCO two applications related to the recovery of transmission and ancillary service related costs. The first application seeks recovery of these costs beginning January 1, 2006. At the time of filing the application, these costs were estimated to be approximately $14 million per year; however, OE anticipates that this amount will increase. OE requested that these costs be recovered through a rider that would be effective on January 1, 2006 and adjusted each July 1 thereafter. OE reached a settlement with OCC, PUCO staff, Industrial Energy Users - Ohio and OPAE. The only other party in this proceeding, Dominion Retail, Inc., agreed not to oppose the settlement. This settlement, which was filed with the PUCO on July 22, 2005, provides for the rider recovery requested by OE, with carrying charges applied in the subsequent year's rider for any over or under collection while the then-current rider is in effect. The PUCO approved the settlement stipulation on August 31, 2005. The incremental Transmission and Ancillary service revenues expected to be recovered from January through June 2006 are approximately $30.6 million. This value includes the recovery of the 2005 deferred MISO expenses as described below. In May 2006, OE will file a modification to the rider which will determine revenues from July 2006 through June 2007.

The second application seeks authority to defer costs associated with transmission and ancillary service related costs incurred during the period from October 1, 2003 through December 31, 2005. On May 18, 2005, the PUCO granted the accounting authority for OE to defer incremental transmission and ancillary service-related charges incurred as a participant in MISO, but only for those costs incurred during the period December 30, 2004 through December 31, 2005. Permission to defer costs incurred prior to December 31, 2004 was denied. The PUCO also authorized OE to accrue carrying charges on the deferred balances. An application filed with the PUCO to recover these deferred charges over a five-year period through the rider, beginning in 2006, was approved in a PUCO order issued on August 31, 2005 approving the stipulation referred to above. The OCC, OPAE and OE each filed applications for rehearing. OE sought authority to defer the transmission and ancillary service related costs incurred during the period October 1, 2003 through December 29, 2004, while both OCC and OPAE sought to have the PUCO deny deferral of all costs. On July 6, 2005, the PUCO denied OE's and OCC's applications and, at the request of OE, struck as untimely OPAE's application. The OCC filed a notice of appeal with the Ohio Supreme Court on August 31, 2005. On September 30, 2005, in accordance with appellate procedure, the PUCO filed with the Ohio Supreme Court the record in this case. The Companies' brief will be due thirty days after the OCC files its brief, which, absent any time extensions, must be filed no later than November 9, 2005.

OE and Penn record as regulatory assets costs which have been authorized by the PUCO, the PPUC and the FERC for recovery from customers in future periods and, without such authorization, the costs would have been charged to income when incurred. OE's regulatory assets as of September 30, 2005 and December 31, 2004, were $0.8 billion and $1.1 billion, respectively. OE is deferring customer shopping incentives and interest costs as new regulatory assets in accordance with its transition and rate stabilization plans. These regulatory assets total $302 million as of September 30, 2005 and, under the RSP, will be recovered through a surcharge rate equal to the RTC rate in effect when the transition costs have been fully recovered. See Note 14 "Regulatory Matters - Ohio" for the estimated net amortization of regulatory transition costs and deferred shopping incentive balances under the proposed RCP and current RSP. Penn's net regulatory asset components aggregate as net regulatory liabilities of approximately $48 million and $18 million, and are included in Other Noncurrent Liabilities on the Consolidated Balance Sheet as of

September 30, 2005 and December 31, 2004, respectively.

On October 11, 2005, Penn filed a plan with the PPUC to secure electricity supply for its customers at set rates following the end of its transition period on December 31, 2006. Penn is recommending that the Request for Proposal process cover the period of January 1, 2007 through May 31, 2008. Under Pennsylvania's electric competition law, Penn is required to secure generation supply for customers who do not choose alternative suppliers for their electricity.

See Note 14 to the consolidated financial statements for further details and a complete discussion of regulatory matters in Ohio and Pennsylvania and a detailed discussion of reliability initiatives, including actions by the PPUC, that impact Penn.

Environmental Matters

OE accrues environmental liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. Unasserted claims are reflected in OE's determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

FirstEnergy plans to issue a report regarding its response to air emission requirements. FirstEnergy expects to complete the report by December 1, 2005.

National Ambient Air Quality Standards

In July 1997, the EPA promulgated changes in the NAAQS for ozone and proposed a new NAAQS for fine particulate matter. On March 10, 2005, the EPA finalized the "Clean Air Interstate Rule" covering a total of 28 states (including Ohio and Pennsylvania) and the District of Columbia based on proposed findings that air emissions from 28 eastern states and the District of Columbia significantly contribute to nonattainment of the NAAQS for fine particles and/or the "8-hour" ozone NAAQS in other states. CAIR provides each affected state until 2006 to develop implementing regulation to achieve additional reductions of NO_x and SO_2 emissions in two phases (Phase I in 2009 for NO_x, 2010 for SO_2 and Phase II in 2015 for both NO_x and SO_2) in all cases from the 2003 levels. The OE Companies' Ohio and Pennsylvania fossil-fuel generation facilities will be subject to the caps on SO_2 and NO_x emissions. According to the EPA, SO_2 emissions will be reduced by 45% (from 2003 levels) by 2010 across the states covered by the rule, with reductions reaching 73% (from 2003 levels) by 2015, capping SO_2 emissions in affected states to just 2.5 million tons annually. NO_x emissions will be reduced by 53% (from 2003 levels) by 2009 across the states covered by the rule, with reductions reaching 61% (from 2003 levels) by 2015, achieving a regional NO_x cap of 1.3 million tons annually. The future cost of compliance with these regulations may be substantial and will depend on how they are ultimately implemented by the states in which the OE Companies operate affected facilities.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. On March 14, 2005, the EPA finalized the "Clean Air Mercury Rule," which provides for a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases. Initially, mercury emissions will be capped nationally at 38 tons by 2010 as a "co-benefit" from implementation of SO_2 and NO_x emission caps under the EPA's CAIR program. Phase II of the mercury cap-and-trade program will cap nationwide mercury emissions from coal-fired power plants at 15 tons per year by 2018. However, the final rules give states substantial discretion in developing rules to implement these programs. In addition, both the CAIR and the Clean Air Mercury rule have been challenged in the United States Court of Appeals for the District of Columbia. Future cost of compliance with these regulations may be substantial.

W. H. Sammis Plant

In 1999 and 2000, the EPA issued NOV or Compliance Orders to nine utilities alleging violations of the Clean Air Act based on operation and maintenance of 44 power plants, including the W. H. Sammis Plant, which is owned by OE and Penn. In addition, the DOJ filed eight civil complaints against various investor-owned utilities, including a complaint against OE and Penn in the U.S. District Court for the Southern District of Ohio. These cases are referred to as New Source Review cases. On March 18, 2005, OE and Penn announced that they had reached a settlement with the EPA, the DOJ and three states (Connecticut, New Jersey, and New York) that resolved all issues related to the W. H. Sammis Plant New Source Review litigation. This settlement agreement, which is in the form of a Consent Decree, was approved by the Court on July 11, 2005, requires OE and Penn to reduce NO_x and SO_2 emissions at the W. H. Sammis Plant and other coal-fired plants through the installation of pollution control devices. Capital expenditures necessary to meet those requirements are currently estimated to be $1.5 billion (the primary portion of which is expected to be spent in the 2008 to 2011 time period). The settlement agreement also requires OE and Penn to spend up to $25 million toward environmentally beneficial projects, which include wind energy purchased power agreements over a 20-year term. OE and Penn agreed to pay a civil penalty of $8.5 million. Results for the first quarter of 2005 included the penalties payable by OE and Penn of $7.8 million and $0.7 million, respectively. OE and Penn also recognized liabilities of $9.2 million and $0.8 million, respectively, for probable future cash contributions toward environmentally beneficial projects during the first quarter of 2005.

Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol (Protocol), to address global warming by reducing the amount of man-made GHG emitted by developed countries by 5.2% from 1990 levels between 2008 and 2012. The United States signed the Protocol in 1998 but it failed to receive the two-thirds vote of the United States Senate required for ratification. However, the Bush administration has committed the United States to a voluntary climate change strategy to reduce domestic GHG intensity - the ratio of emissions to economic output - by 18 percent through 2012. The Energy Policy Act of 2005 established a Committee on Climate Change Technology to coordinate federal climate change activities and promote the development and deployment of GHG reducing technologies.

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

Regulation of Hazardous Waste

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

See Note 13(B) to the consolidated financial statements for further details and a complete discussion of environmental matters.

Other Legal Proceedings

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to OE's normal business operations pending against OE and its subsidiaries. The other material items not otherwise discussed above are described below.

On August 14, 2003, various states and parts of southern Canada experienced widespread power outages. The outages affected approximately 1.4 million customers in FirstEnergy's service area. The U.S. - Canada Power System Outage Task Force’s final report in April 2004 on the outages concludes, among other things, that the problems leading to the outages began in FirstEnergy’s Ohio service area. Specifically, the final report concluded, among other things, that the initiation of the August 14, 2003 power outages resulted from an alleged failure of both FirstEnergy and ECAR to assess and understand perceived inadequacies within the FirstEnergy system; inadequate situational awareness of the developing conditions; and a perceived failure to adequately manage tree growth in certain transmission rights of way. The Task Force also concluded that there was a failure of the interconnected grid's reliability organizations (MISO and PJM) to provide effective real-time diagnostic support. The final report is publicly available through the Department of Energy’s website (www.doe.gov). FirstEnergy believes that the final report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14, 2003 power outages and that it does not adequately address the underlying causes of the outages. FirstEnergy remains convinced that the outages cannot be explained by events on any one utility's system. The final report contained 46 “recommendations to prevent or minimize the scope of future blackouts.” Forty-five of those recommendations related to broad industry or policy matters while one, including subparts, related to activities the Task Force recommended be undertaken by FirstEnergy, MISO, PJM, ECAR, and other parties to correct the causes of the August 14, 2003 power outages.

FirstEnergy implemented several initiatives, both prior to and since the August 14, 2003 power outages, which were independently verified by NERC as complete in 2004 and were consistent with these and other recommendations and collectively enhance the reliability of its electric system. FirstEnergy's implementation of these recommendations in 2004 included completion of the Task Force recommendations that were directed toward FirstEnergy. FirstEnergy also is proceeding with the implementation of the recommendations regarding enhancements to regional reliability that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new, or material upgrades, to existing equipment, and therefore FirstEnergy has not accrued a liability as of September 30, 2005 for any expenditures in excess of those actually incurred through that date. FirstEnergy notes, however, that the FERC or other applicable government agencies and reliability coordinators may take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures. Finally, the PUCO is continuing to review FirstEnergy's filing that addressed upgrades to control room computer hardware and software and enhancements to the training of control room operators, before determining the next steps, if any, in the proceeding.

FirstEnergy companies also are defending six separate complaint cases before the PUCO relating to the August 14, 2003 power outage. Two such cases were originally filed in Ohio State courts but subsequently dismissed for lack of subject matter jurisdiction and further appeals were unsuccessful. In both such cases the individual complainants—three in one case and four in the other—sought to represent others as part of a class action. The PUCO dismissed the class allegations, stating that its rules of practice do not provide for class action complaints. Of the four other pending PUCO complaint cases, three were filed by various insurance carriers either in their own name as subrogees or in the name of their insured. In each such case, the carriers seek reimbursement against various FirstEnergy companies (and, in one case, against PJM, MISO and American Electric Power Co. as well) for claims they paid to their insureds allegedly due to the loss of power on August 14, 2003. The listed insureds in these cases, in many instances, are not customers of any FirstEnergy company. The fourth case involves the claim of a non-customer seeking reimbursement for losses incurred when its store was burglarized on August 14, 2003. In addition to these six cases, the Ohio Companies were named as respondents in a regulatory proceeding that was initiated at the PUCO in response to complaints alleging failure to provide reasonable and adequate service stemming primarily from the August 14, 2003 power outages. No estimate of potential liability has been undertaken for any of these cases.

One complaint was filed on August 25, 2004 against FirstEnergy in the New York State Supreme Court. In this case, several plaintiffs in the New York City metropolitan area allege that they suffered damages as a result of the August 14, 2003 power outages. None of the plaintiffs are customers of any FirstEnergy affiliate. FirstEnergy's motion to dismiss the case was granted on September 26, 2005. Additionally, FirstEnergy Corp. was named in a complaint filed in Michigan State Court by an individual who is not a customer of any FirstEnergy company. A responsive pleading to this matter is not due until on or about December 1, 2005. No estimate of potential liability has been undertaken in this matter.

FirstEnergy is vigorously defending these actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be initiated against the Companies. In particular, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

On August 12, 2004, the NRC notified FENOC that it would increase its regulatory oversight of the Perry Nuclear Power Plant as a result of problems with safety system equipment over the preceding two years and the licensee's failure to take prompt and effective corrective action. FENOC operates the Perry Nuclear Power Plant, in which the OE Companies have a 35.24% interest (however, see Note 17 regarding FirstEnergy’s pending intra-system generation asset transfers, which include owned portions of the plant).

On April 4, 2005, the NRC held a public meeting to discuss FENOC’s performance at the Perry Nuclear Power Plant as identified in the NRC's annual assessment letter to FENOC. Similar public meetings are held with all nuclear power plant licensees following issuance by the NRC of their annual assessments. According to the NRC, overall the Perry Plant operated "in a manner that preserved public health and safety" even though it remained under heightened NRC oversight. During the public meeting and in the annual assessment, the NRC indicated that additional inspections will continue and that the plant must improve performance to be removed from the Multiple/Repetitive Degraded Cornerstone Column of the Action Matrix.

On May 26, 2005, the NRC held a public meeting to discuss its oversight of the Perry Plant. While the NRC stated that the plant continued to operate safely, the NRC also stated that the overall performance had not substantially improved since the heightened inspection was initiated. The NRC reiterated this conclusion in its mid-year assessment letter dated August 30, 2005. On September 28, 2005, the NRC sent a CAL to FENOC describing commitments that FENOC had made to improve the performance of Perry and stated that the CAL would remain open until substantial improvement was demonstrated. The CAL was anticipated as part of the NRC's Reactor Oversight Process. If performance does not improve, the NRC has a range of options under the Reactor Oversight Process from increased oversight to possible impact to the plant’s operating authority. As a result, these matters could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

On October 20, 2004, FirstEnergy was notified by the SEC that the previously disclosed informal inquiry initiated by the SEC's Division of Enforcement in September 2003 relating to the restatements in August 2003 of previously reported results by FirstEnergy and OE, and the Davis-Besse extended outage (OE has no interest in Davis-Besse), have become the subject of a formal order of investigation. The SEC's formal order of investigation also encompasses issues raised during the SEC's examination of FirstEnergy and the Companies under the PUHCA. Concurrent with this notification, FirstEnergy received a subpoena asking for background documents and documents related to the restatements and Davis-Besse issues. On December 30, 2004, FirstEnergy received a subpoena asking for documents relating to issues raised during the SEC's PUHCA examination. On August 24, 2005 additional information was requested regarding Davis-Besse. FirstEnergy has cooperated fully with the informal inquiry and will continue to do so with the formal investigation.

On August 22, 2005, a class action complaint was filed against OE in Jefferson County, Ohio Common Pleas Court seeking compensatory and punitive damages to be determined at trial based on claims of negligence and eight other tort counts alleging damages from the W.H. Sammis Plant air emissions. The two named plaintiffs are also seeking injunctive relief to eliminate harmful emissions and repair property damage and the institution of a medical monitoring program for class members.

The City of Huron filed a complaint against OE with the PUCO challenging the ability of electric distribution utilities to collect transition charges from a customer of a newly formed municipal electric utility. The complaint was filed on May 28, 2003, and OE timely filed its response on June 30, 2003. In a related filing, the Ohio Companies filed for approval with the PUCO of a tariff that would specifically allow the collection of transition charges from customers of municipal electric utilities formed after 1998. An adverse ruling could negatively affect full recovery of transition charges by the utility. Hearings on the matter were held in August 2005. Initial briefs from all parties were filed on September 22, 2005 and reply briefs were filed on October 14, 2005. It is unknown when the PUCO will rule on this case.

If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on the above matters, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

See Note 13(C) to the consolidated financial statements for further details and a complete discussion of other legal proceedings.

New Accounting Standards and Interpretations

EITF Issue 04-13,"Accounting for Purchases and Sales of Inventory with the Same Counterparty"

In September 2005, the EITF reached a final consensus on Issue 04-13 concluding that two or more legally separate exchange transactions with the same counterparty should be combined and considered as a single arrangement for purposes of applying APB 29, when the transactions were entered into "in contemplation" of one another. If two transactions are combined and considered a single arrangement, the EITF reached a consensus that an exchange of inventory should be accounted for at fair value. Although electric power is not capable of being held in inventory, there is no substantive conceptual distinction between exchanges involving power and other storable inventory. Therefore, OE will adopt this EITF effective for new arrangements entered into, or modifications or renewals of existing arrangements, in interim or annual periods beginning after March 15, 2006.

EITF Issue No. 05-6, "Determining the Amortization Period for Leasehold Improvements Purchased after Lease Inception or Acquired in a Business Combination"

In June 2005, the EITF reached a consensus on the application guidance for Issue 05-6. EITF 05-6 addresses the amortization period for leasehold improvements that were either acquired in a business combination or placed in service significantly after and not contemplated at or near the beginning of the initial lease term. For leasehold improvements acquired in a business combination, the amortization period is the shorter of the useful life of the assets or a term that includes required lease periods and renewals that are deemed to be reasonably assured at the date of acquisition. Leasehold improvements that are placed in service significantly after and not contemplated at or near the beginning of the lease term should be amortized over the shorter of the useful life of the assets or a term that includes required lease periods and renewals that are deemed to be reasonably assured at the date the leasehold improvements are purchased. This EITF was effective July 1, 2005 and is consistent with the OE current accounting.

FIN 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143"

On March 30, 2005, the FASB issued FIN 47 to clarify the scope and timing of liability recognition for conditional asset retirement obligations. Under this interpretation, companies are required to recognize a liability for the fair value of an asset retirement obligation that is conditional on a future event, if the fair value of the liability can be reasonably estimated. In instances where there is insufficient information to estimate the liability, the obligation is to be recognized in the second period in which sufficient information becomes available to estimate its fair value. If the fair value cannot be reasonably estimated, that fact and the reasons why must be disclosed. This Interpretation is effective no later than the end of fiscal years ending after December 15, 2005. Therefore, OE will adopt this Interpretation in the fourth quarter of 2005. OE is currently evaluating the effect this standard will have on its financial statements.

SFAS 154 - "Accounting Changes and Error Corrections - a replacement of APB Opinion No. 20 and FASB Statement No. 3"

In May 2005, the FASB issued SFAS 154 to change the requirements for accounting and reporting a change in accounting principle. It applies to all voluntary changes in accounting principle and to changes required by an accounting pronouncement when that pronouncement does not include specific transition provisions. This Statement requires retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. In those instances, this Statement requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that period rather than being reported in an income statement. This Statement also requires that a change in depreciation, amortization, or depletion method for long-lived, nonfinancial assets be accounted for as a change in accounting estimate affected by a change in accounting principle. The provisions of this Statement are effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. OE will adopt this Statement effective January 1, 2006.

SFAS 153, "Exchanges of Nonmonetary Assets - an amendment of APB Opinion No. 29"

In December 2004, the FASB issued SFAS 153 amending APB 29, which was based on the principle that nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance in APB 29 included certain exceptions to that principle. SFAS 153 eliminates the exception from fair value measurement for nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges that do not have commercial substance. This Statement specifies that a nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of this Statement are effective for nonmonetary exchanges occurring in fiscal periods beginning after June 15, 2005 and are to be applied prospectively. As a result, OE will adopt this Statement effective January 1, 2006, and does not expect it to have a material impact on its financial statements.

SFAS 151, "Inventory Costs - an amendment of ARB No. 43, Chapter 4"

In November 2004, the FASB issued SFAS 151 to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage). Previous guidance stated that in some circumstances these costs may be "so abnormal" that they would require treatment as current period costs. SFAS 151 requires abnormal amounts for these items to always be recorded as current period costs. In addition, this Statement requires that allocation of fixed production overheads to the cost of conversion be based on the normal capacity of the production facilities. The provisions of this statement are effective for inventory costs incurred by OE beginning January 1, 2006. OE is currently evaluating this Standard and does not expect it to have a material impact on the financial statements.

FSP FAS 115-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"

In September 2005, the FASB finalized and renamed EITF 03-1 and 03-1-a to FSP FAS 115-1. FSP FAS 115-1 will (1) supersede Issue 03-1 and EITF topic No. D-44, "Recognition of Other Than Temporary Impairment upon the Planned Sale of a Security Whose Cost Exceeds Fair Value," (2) clarify that an investor should recognize an impairment loss no later than when the impairment is deemed other than temporary, even if a decision to sell has not been made, and (3) be effective for other-than-temporary impairment and analyses conducted in periods beginning after September 15, 2005. The FASB expects to issue this FSP in the fourth quarter of 2005, which would require prospective application with an effective date for reporting periods beginning after December 15, 2005. OE is currently evaluating this FSP and any impact on its investments.

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THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
		(In thousands)		
STATEMENTS OF INCOME				
OPERATING REVENUES	$ 526,421	$ 504,848	$ 1,408,341	$ 1,372,259
OPERATING EXPENSES AND TAXES:				
Fuel	24,701	21,011	64,138	57,583
Purchased power	129,640	140,988	411,366	412,170
Nuclear operating costs	26,252	28,766	121,765	80,002
Other operating costs	89,475	76,196	227,759	219,857
Provision for depreciation	36,100	33,096	100,602	98,060
Amortization of regulatory assets	68,455	53,732	177,497	151,822
Deferral of new regulatory assets	(60,519)	(40,596)	(126,508)	(92,032)
General taxes	40,054	37,348	115,546	110,646
Income taxes	55,286	51,883	94,897	81,057
Total operating expenses and taxes	409,444	402,424	1,187,062	1,119,165
OPERATING INCOME	116,977	102,424	221,279	253,094
OTHER INCOME (net of income taxes)	24,117	8,264	37,691	29,485
NET INTEREST CHARGES:				
Interest on long-term debt	27,090	24,061	83,452	92,967
Allowance for borrowed funds used during construction	(1,129)	(1,056)	(2,012)	(3,782)
Other interest expense	4,696	5,239	12,952	12,750
Net interest charges	30,657	28,244	94,392	101,935
NET INCOME	110,437	82,444	164,578	180,644
PREFERRED STOCK DIVIDEND REQUIREMENTS	-	1,754	2,918	5,253
EARNINGS ON COMMON STOCK	$ 110,437	$ 80,690	$ 161,660	$ 175,391

<u>**STATEMENTS OF COMPREHENSIVE INCOME**</u>								
NET INCOME	$	110,437	$	82,444	$	164,578	$	180,644
OTHER COMPREHENSIVE INCOME (LOSS):								
Unrealized gain (loss) on available for sale securities		(6,574)		991		(9,144)		(1,332)
Income tax expense (benefit) related to other comprehensive income		(2,510)		406		(3,433)		(546)
Other comprehensive income (loss), net of tax		(4,064)		585		(5,711)		(786)
TOTAL COMPREHENSIVE INCOME	$	106,373	$	83,029	$	158,867	$	179,858

The preceding Notes to Consolidated 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)

	September 30, 2005	December 31, 2004
	(In thousands)	
ASSETS		
UTILITY PLANT:		
In service	$ 4,498,876	$ 4,418,313
Less - Accumulated provision for depreciation	2,020,868	1,961,737
	2,478,008	2,456,576
Construction work in progress -		
Electric plant	90,911	85,258
Nuclear fuel	8,632	30,827
	99,543	116,085
	2,577,551	2,572,661
OTHER PROPERTY AND INVESTMENTS:		
Investment in lessor notes	564,169	596,645
Nuclear plant decommissioning trusts	427,920	383,875
Long-term notes receivable from associated companies	8,774	97,489
Other	16,028	17,001
	1,016,891	1,095,010
CURRENT ASSETS:		
Cash and cash equivalents	207	197
Receivables-		
Customers (less accumulated provision of $5,309,000 for uncollectible accounts in 2005)	255,769	11,537
Associated companies	19,883	33,414
Other (less accumulated provisions of $6,000 and $293,000, respectively, for uncollectible accounts)	9,651	152,785
Notes receivable from associated companies	-	521
Materials and supplies, at average cost	72,506	58,922
Prepayments and other	2,769	2,136
	360,785	259,512
DEFERRED CHARGES:		
Goodwill	1,688,966	1,693,629
Regulatory assets	889,127	958,986
Property taxes	77,792	77,792
Other	29,995	32,875
	2,685,880	2,763,282
	$ 6,641,107	$ 6,690,465
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common stockholder's equity-		

Common stock, without par value, authorized 105,000,000 shares -				
79,590,689 shares outstanding	$	1,356,998	$	1,281,962
Accumulated other comprehensive income		12,148		17,859
Retained earnings		574,394		553,740
Total common stockholder's equity		1,943,540		1,853,561
Preferred stock		-		96,404
Long-term debt and other long-term obligations		1,939,730		1,970,117
		3,883,270		3,920,082
CURRENT LIABILITIES:				
Currently payable long-term debt		75,706		76,701
Short-term borrowings-				
Associated companies		518,784		488,633
Other		35,000		-
Accounts payable-				
Associated companies		33,802		150,141
Other		6,702		9,271
Accrued taxes		156,630		129,454
Accrued interest		27,242		22,102
Lease market valuation liability		60,200		60,200
Other		39,094		61,131
		953,160		997,633
NONCURRENT LIABILITIES:				
Accumulated deferred income taxes		552,072		540,211
Accumulated deferred investment tax credits		58,736		60,901
Lease market valuation liability		623,100		668,200
Asset retirement obligation		280,765		272,123
Retirement benefits		86,597		82,306
Other		203,407		149,009
		1,804,677		1,772,750
COMMITMENTS AND CONTINGENCIES (Note 13)				
	$	6,641,107	$	6,690,465

The preceding Notes to Consolidated 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 September 30,		Nine Months Ended September 30,	
	2005	**2004**	**2005**	**2004**
		(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 110,437	$ 82,444	$ 164,578	$ 180,644
Adjustments to reconcile net income to net cash from operating activities -				
Provision for depreciation	36,100	33,096	100,602	98,060
Amortization of regulatory assets	68,455	53,732	177,497	151,822
Deferral of new regulatory assets	(60,519)	(40,596)	(126,508)	(92,032)
Nuclear fuel and capital lease amortization	8,236	7,804	19,017	20,420
Amortization of electric service obligation	(2,155)	(3,336)	(12,278)	(12,877)
Deferred rents and lease market valuation liability	(13,439)	(14,324)	(67,130)	(56,182)
Deferred income taxes and investment tax credits, net	10,484	13,019	14,934	11,392
Accrued retirement benefit obligations	2,169	2,854	4,291	10,900
Accrued compensation, net	1,201	1,303	(1,294)	3,232
Pension trust contribution	-	(31,718)	-	(31,718)
Decrease (increase) in operating assets-				
Receivables	10,507	(3,422)	(87,567)	106,421
Materials and supplies	15,207	(2,238)	(13,584)	(7,711)
Prepayments and other current assets	(821)	1,512	(633)	3,409
Increase (decrease) in operating liabilities-				
Accounts payable	(157,188)	60,237	(118,908)	1,889
Accrued taxes	33,955	(15,630)	27,176	(52,495)
Accrued interest	5,460	(3,218)	5,140	(2,371)
Prepayment for electric service - education programs	-	-	67,589	-
Other	(18,457)	(3,335)	(26,328)	(40,193)
Net cash provided from operating activities	49,632	138,184	126,594	292,610

CASH FLOWS FROM FINANCING ACTIVITIES:				
New Financing-				
Long-term debt	87,772	44,330	141,056	125,238
Short-term borrowings, net	-	213,682	53,369	132,770
Equity contributions from parent	-	-	75,000	-
Redemptions and Repayments-				
Preferred stock	-	(1,000)	(101,900)	(1,000)
Long-term debt	(90,859)	(327,171)	(147,789)	(335,272)
Short-term borrowings, net	(5,505)	-	-	-
Dividend Payments-				
Common stock	(17,000)	-	(141,000)	(145,000)
Preferred stock	-	(1,755)	(2,260)	(5,253)
Net cash used for financing activities	(25,592)	(71,914)	(123,524)	(228,517)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions	(37,809)	(32,238)	(98,053)	(70,967)
Loan repayments from (loans to) associated companies, net	22,309	(850)	89,236	9,964
Investments in lessor notes	3	(11,699)	32,476	9,266
Contributions to nuclear decommissioning trusts	(7,256)	(7,256)	(21,768)	(21,768)
Other	(1,287)	(14,227)	(4,951)	(15,170)
Net cash used for investing activities	(24,040)	(66,270)	(3,060)	(88,675)
Net change in cash and cash equivalents	-	-	10	(24,582)
Cash and cash equivalents at beginning of period	207	200	197	24,782
Cash and cash equivalents at end of period	$ 207	$ 200	$ 207	$ 200

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

Report of Independent Registered Public Accounting Firm

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 September 30, 2005, and the related consolidated statements of income and comprehensive income and cash flows for each of the three-month and nine-month periods ended September 30, 2005 and 2004. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 the standards of the Public Company Accounting Oversight Board, 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 the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2004, and the related consolidated statements of income, capitalization, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended, management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004 and the effectiveness of the Company's internal control over financial reporting as of December 31, 2004; and in our report (which contained references to the Company's change in its method of accounting for asset retirement obligations as of January 1, 2003 as discussed in Note 2(G) to those consolidated financial statements and the Company's change in its method of accounting for the consolidation of variable interest entities as of December 31, 2003 as discussed in Note 6 to those consolidated financial statements) dated March 7, 2005, we expressed unqualified opinions thereon. The consolidated financial statements and management's assessment of the effectiveness of internal control over financial reporting referred to above are not presented herein. In our opinion, the information set forth in the accompanying consolidated balance sheet information as of December 31, 2004, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio

November 1, 2005

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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 CEI 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.

Results of Operations

Earnings on common stock in the third quarter of 2005 increased to $110 million from $81 million in the third quarter of 2005. Increased earnings in the third quarter of 2005 resulted primarily from higher operating revenues and lower purchased power costs, which were partially offset by higher regulatory asset amortization and higher other operating costs. For the first nine months of 2005, earnings on common stock decreased to $162 million from $175 million in the same period of 2004. Lower earnings for the first nine months of 2005 resulted primarily from higher nuclear operating costs, higher regulatory asset amortization and other operating costs and a one-time income tax charge; those effects were partially offset by increased operating revenues and lower net interest charges.

Operating revenues increased by $22 million or 4.3% in the third quarter of 2005 from the same period in 2004. Higher revenues resulted primarily from increases in retail generation and distribution revenues of $3 million and $19 million, respectively, and a $5 million increase in revenues from wholesale sales. During the first nine months of 2005, operating revenues increased by $36 million or 2.6%, compared to the same period in 2004. Higher revenues were due to increases in retail generation and distribution revenues of $13 million and $23 million, respectively, and a $2 million increase in revenues from wholesale sales.

Increased retail generation revenues for the third quarter of 2005 resulted from higher industrial unit prices and higher residential KWH sales, partially offset by lower unit prices and KWH sales for commercial customers. An 18.7% increase in residential KWH sales during the third quarter was primarily due to warmer weather in CEI's service area, as compared to last year. An increase in residential customer shopping by 1.7 percentage points in the third quarter of 2005 partially offset the higher generation KWH sales as compared to 2004. Increased retail generation revenues for the first nine months of 2005 resulted from higher industrial unit prices and higher residential KWH sales, partially offset by lower commercial and industrial KWH sales. The decrease in residential customer shopping by 0.7 percentage points in the first nine months of 2005 contributed slightly to the higher generation KWH sales for the period as compared to last year.

Revenue from wholesale sales increased by $5 million during the third quarter of 2005, reflecting the effect of a 2.5% increase in KWH sales. The increase in wholesale sales was primarily due to a 13.6% KWH increase in MSG sales to non-affiliated wholesale customers ($3.5 million). Under its Ohio transition plan, CEI is required to provide MSG to non-affiliated alternative suppliers (see Outlook - Regulatory Matters). Increased sales to FES of $1.5 million (1.3% KWH increase) also contributed to the third quarter results. In the first nine months of 2005, wholesale sales revenue increased by $2 million. A $20 million increase (23.0% KWH increase) in MSG sales to non-affiliated wholesale customers was partially offset by an $18 million decrease in sales (6.7% KWH decrease) to FES.

Revenues from distribution throughput increased $19 million in the third quarter of 2005 compared with the same quarter of 2004. The increase was due to higher residential and industrial revenues ($18 million and $5 million, respectively), reflecting increased distribution deliveries in the third quarter of 2005, in part due to warmer weather. These increases were partially offset by lower commercial revenues of $4 million as a result of lower unit prices.

Revenues from distribution throughput increased $23 million in the first nine months of 2005 compared with the same period in 2004 due to higher revenues in the residential sector ($28 million), partially offset by lower industrial revenues ($4 million). Higher distribution deliveries in the residential sector were partially offset by lower unit prices and decreased KWH deliveries to industrial customers. Revenues in the commercial sector increased slightly ($0.4 million) as higher distribution deliveries were almost totally offset by lower unit prices.

Changes in KWH sales by customer class in the three months and nine months ended September 30, 2005 from the corresponding periods of 2004 are summarized in the following table:

Changes in KWH Sales Increase (Decrease)	Three Months	Nine Months
Electric Generation:		
Retail	0.6%	(0.3)%
Wholesale	2.5%	(4.0)%
Total Electric Generation Sales	**1.7%**	**(2.5)%**
Distribution Deliveries:		
Residential	18.7%	9.7%
Commercial	1.5%	3.3%
Industrial	2.8%	(1.0)%
Total Distribution Deliveries	**6.6%**	**2.9%**

Operating Expenses and Taxes

Total operating expenses and taxes increased by $7 million in the third quarter and $68 million in the first nine months of 2005 from the same periods of 2004. The following table presents changes from the prior year by expense category.

Operating Expenses and Taxes - Changes Increase (Decrease)	Three Months	Nine Months
	(In millions)	
Fuel costs	$ 3	$ 6
Purchased power costs	(11)	(1)
Nuclear operating costs	(2)	42
Other operating costs	13	8
Provision for depreciation	3	3
Amortization of regulatory assets	15	26
Deferral of new regulatory assets	(20)	(35)
General taxes	3	5

Income taxes	3	14
Net increase in operating expenses and taxes	$ 7	$ 68

Higher fuel costs in the third quarter and first nine months of 2005, compared to the same periods last year, were primarily due to increased fossil fuel expenses associated with higher fossil generation levels in 2005. Lower purchased power costs in the third quarter of 2005, compared with the third quarter of 2004, reflected both lower unit costs and lower KWH purchased. The increase in nuclear operating costs in the first nine months of 2005, compared to the same period last year, was primarily due to a refueling outage (including an unplanned extension) at the Perry Plant in 2005 and a refueling outage at Beaver Valley Unit 2. A mid-cycle inspection outage at the Davis-Besse Plant in the first quarter of 2005 also contributed to higher nuclear operating costs in the first nine months of 2005. There were no scheduled outages in the first nine months of 2004. Higher other operating costs in the third quarter and first nine months of 2005, compared to the same periods last year, were primarily due to transmission expenses related to MISO Day 2 transactions that began on April 1, 2005.

Higher regulatory asset amortization in the third quarter and first nine months of 2005, compared to the same periods last year, was primarily due to increased amortization of transition costs being recovered under the RSP. Increases in regulatory asset deferrals for both the third quarter and first nine months in 2005, compared to the same periods in 2004, resulted from higher shopping incentive deferrals and related interest, and the PUCO-approved MISO administrative cost deferrals, including interest, that began in the second quarter of 2005 (see Outlook - Regulatory Matters).

On June 30, 2005, the State of Ohio enacted new tax legislation that created a new CAT tax, which is based on qualifying “taxable gross receipts” and will not consider any expenses or costs incurred to generate such receipts, except for items such as cash discounts, returns and allowances, and bad debts. The CAT tax was effective July 1, 2005, and replaces the Ohio income-based franchise tax and the Ohio personal property tax. The CAT tax is phased-in while the current income-based franchise tax is phased-out over a five-year period at a rate of 20% annually, beginning with the year ended 2005, and personal property tax is phased-out over a four-year period at a rate of 25% annually, beginning with the year ended 2005. For example, during the phase-out period the Ohio income-based franchise tax will be computed consistently with prior tax law, except that the tax liability as computed will be multiplied by 4/5 in 2005; 3/5 in 2006; 2/5 in 2007 and 1/5 in 2008, therefore eliminating the current income-based franchise tax over a five-year period. As a result of the new tax structure, all net deferred tax benefits that are not expected to reverse during the five-year phase-in period were written-off as of June 30, 2005. The impact on income taxes associated with the new tax legislation for the first nine months of 2005 was additional tax expense of approximately $8 million to adjust net deferred taxes and $2 million associated with the phase-out of the Ohio income-based franchise tax. See Note 12 to the consolidated financial statements.

Other Income

Other income increased by $16 million in the third quarter of 2005 compared with the same period of 2004, primarily due to higher nuclear decommissioning trust realized gains.

Net Interest Charges

Net interest charges in the first nine months of 2005 decreased by $8 million compared with the same period last year, reflecting the effects of net redemptions and refinancings since October 1, 2004.

Capital Resources and Liquidity

CEI's cash requirements for the remainder of 2005 for operating expenses and construction expenditures are expected to be met without increasing net debt. Thereafter, CEI expects to use a combination of cash from operations and funds from the capital markets.

Changes in Cash Position

As of September 30, 2005, CEI had $207,000 of cash and cash equivalents, compared with $197,000 as of December 31, 2004. The major sources of changes in these balances are summarized below.

Cash Flows from Operating Activities

Cash provided by operating activities during the third quarter and first nine months of 2005, compared with the corresponding periods in 2004, were as follows:

Operating Cash Flows	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In millions)			
Cash earnings [1]	$ 161	$ 123	$ 274	$ 302
Pension trust contribution [2]	--	(19)	--	(19)
Working capital and other	(111)	35	(147)	10
Total cash flows from operating activities	$ 50	$ 139	$ 127	$ 293

[1] Cash earnings is a non-GAAP measure (see reconciliation below).
[2] Pension contribution net of $13 million of income tax benefits

Cash earnings, as disclosed in the table above, are not a measure of performance calculated in accordance with GAAP. CEI believes that cash earnings is a useful financial measure because it provides investors and management with an additional means of evaluating its cash-based operating performance. The following table reconciles cash earnings with net income.

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Reconciliation of Cash Earnings	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In millions)			
Net income (GAAP)	$ 110	$ 83	$ 164	$ 181
Non-cash charges (credits):				
Provision for depreciation	36	33	101	98
Amortization of regulatory assets	68	54	177	152
Deferral of new regulatory assets	(60)	(41)	(126)	(92)
Nuclear fuel and capital lease amortization	8	7	19	20
Amortization of electric service obligation	(2)	(3)	(12)	(13)
Deferred rents and lease market valuation liability	(13)	(14)	(67)	(56)
Deferred income taxes and investment tax credits, net	10	--	15	(2)
Accrued retirement benefit obligations	2	3	4	11
Accrued compensation, net	2	1	(1)	3
Cash earnings (Non-GAAP)	$ 161	$ 123	$ 274	$ 302

The increase in cash earnings of $38 million for the third quarter and the decrease of $28 million for the first nine months of 2005, as compared to the respective periods of 2004, are described above under "Results of Operations". The primary factors contributing to the changes in working capital and other for the third quarter of 2005 are changes in accounts payable of $217 million, partially offset by changes in accrued taxes of $50 million. The primary factors contributing to the changes in working capital and other for the first nine months of 2005 are changes in accounts receivable of $194 million and accounts payable of $121 million, partially offset by changes in accrued taxes of $80 million and the $68 million received in the second quarter of 2005 for prepaid electric service under the Ohio Schools Council's Energy for Education Program.

Cash Flows from Financing Activities

Net cash used for financing activities decreased $46 million in the third quarter of 2005 from the third quarter of 2004. The decrease resulted from a $62 million decrease in net debt redemptions, partially offset by higher common stock dividends to FirstEnergy of $17 million. Net cash used for financing activities decreased $105 million in the first nine months of 2005 from the same period last year. The decrease resulted primarily from lower net debt redemptions and common stock dividends to FirstEnergy and a $75 million equity contribution from FirstEnergy in the second quarter of 2005, partially offset by an increase in preferred stock redemptions.

CEI had $207,000 of cash and temporary investments and approximately $554 million of short-term indebtedness as of September 30, 2005. CEI has obtained authorization from the PUCO to incur short-term debt of up to $500 million (including the utility money pool described below). As of October 24, 2005, CEI had the capability to issue $1.6 billion of additional FMB on the basis of property additions and retired bonds under the terms of its mortgage indenture following the recently completed intra-system transfer of fossil and hydroelectric generating plants (See Note 17). The issuance of FMB by CEI is subject to a provision of its senior note indenture generally limiting the incurrence of additional secured debt, subject to certain exceptions that would permit, among other things, the issuance of secured debt (including FMB) (i) supporting pollution control notes or similar obligations, or (ii) as an extension, renewal or replacement of previously outstanding secured debt. In addition, this provision would permit CEI to incur additional secured debt not otherwise permitted by a specified exception of up to $582 million as of September 30, 2005. CEI has no restrictions on the issuance of preferred stock.

CFC is a wholly owned subsidiary of CEI whose borrowings are secured by customer accounts receivable purchased from CEI and TE. CFC can borrow up to $200 million under a receivables financing arrangement. As a separate legal entity with separate creditors, CFC would have to satisfy its obligations to creditors before any of its remaining assets could be made available to CEI. As of September 30, 2005, the facility was drawn for $35 million.

On June 14, 2005, FirstEnergy, OE, Penn, CEI, TE, JCP&L, Met-Ed, Penelec, FES and ATSI, as Borrowers, entered into a syndicated $2 billion five-year revolving credit facility. Borrowings under the facility are available to each Borrower separately and will mature on the earlier of 364 days from the date of borrowing and the commitment termination date, as the same may be extended. CEI’s borrowing limit under the facility is $250 million.

CEI has the ability to borrow from its regulated affiliates and FirstEnergy to meet its short-term working capital requirements. FESC administers this money pool and tracks surplus funds of FirstEnergy and its regulated subsidiaries. Companies receiving a loan under the money pool agreements must repay the principal amount, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from the pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in the third quarter of 2005 was 3.50%.

CEI’s access to capital markets and costs of financing are dependent on the ratings of its securities and the securities of FirstEnergy.

On July 18, 2005, Moody’s revised its rating outlook on FirstEnergy and its subsidiaries to positive from stable. Moody’s stated that the revision to FirstEnergy’s outlook resulted from steady financial improvement and steps taken by management to improve operations, including the stabilization of its nuclear operations. Moody’s further stated that the revision in their outlook recognized management’s regional strategy of focusing on its core utility businesses and the improvement in FirstEnergy’s credit profile stemming from the application of free cash flow toward debt reduction. Moody’s noted that a ratings upgrade could be considered if FirstEnergy continues to achieve planned improvements in its operations and balance sheet.

On October 3, 2005, S&P raised its corporate credit rating on FirstEnergy and the EUOC to 'BBB' from 'BBB-'. At the same time, S&P raised the senior unsecured ratings at the holding company to 'BBB-' from 'BB+' and each of the EUOC by one notch above the previous rating. S&P noted that the upgrade followed the continuation of a good operating track record, specifically for the nuclear fleet through the third quarter 2005. S&P also stated that FirstEnergy’s rating reflects the benefits of supportive regulation, low-cost base load generation fleet, low-risk transmission and distribution operations and rate certainty in Ohio. FirstEnergy’s ability to consistently generate free cash flow, good liquidity, and an improving financial profile were also noted as strengths.

Cash Flows from Investing Activities

In the third quarter and first nine months of 2005, net cash used for investing activities decreased $42 million and $86 million, respectively, from the corresponding periods of 2004. The decrease in funds used for investing activities for both periods primarily reflected increases in loan payments received from associated companies, partially offset by increased property additions.

In the last quarter of 2005, capital requirements for property additions are expected to be about $37 million. These cash requirements are expected to be satisfied from internal cash and short-term credit arrangements. CEI has no additional requirements for sinking fund requirements for preferred stock and debt during the remainder of 2005. CEI’s capital spending for the period 2005-2007 is expected to be about $368 million of which approximately $124 million applies to 2005.

FirstEnergy Intra-System Generation Asset Transfers

On May 18, 2005, OE, CEI and TE, entered into certain agreements implementing a series of intra-system generation asset transfers. When fully completed, the asset transfers will result in the respective undivided ownership interests of the Ohio Companies in FirstEnergy’s nuclear and non-nuclear plants being owned by NGC, and FGCO, respectively. The generating plant interests that are being transferred do not include CEI’s leasehold interests in certain of the plants that are currently subject to sale and leaseback arrangements with non-affiliates.

On October 24, 2005, CEI completed the transfer of non-nuclear generation assets to FGCO. CEI currently expects to complete the transfer of nuclear generation assets to NGC at book value before the end of 2005. Consummation of the nuclear transfer remains subject to necessary regulatory approvals.

These transactions are being undertaken in connection with the Ohio Companies' restructuring plans that were approved by the PUCO under applicable Ohio electric utility restructuring legislation. Consistent with the restructuring plans, generation assets that had been owned by the Ohio Companies were required to be separated from the regulated delivery business of those companies through transfer to a separate corporate entity. FENOC currently operates and maintains the nuclear generation assets to be transferred. FGCO, as lessee under a Master Facility Lease, leased, operated and maintained the non-nuclear generation assets that it now owns. The transactions will essentially complete the divestitures contemplated by the restructuring plans by transferring the ownership interests to NGC and FGCO, respectively, without impacting the operation of the plants.

See Note 17 to the consolidated financial statements for CEI's disclosure of the assets held for sale as of September 30, 2005.

Off-Balance Sheet Arrangements

Obligations not included on CEI’s Consolidated Balance Sheet primarily consist of sale and leaseback arrangements involving the Bruce Mansfield Plant. As of September 30, 2005, the present value of these operating lease commitments, net of trust investments, total $103 million.

CEI sells substantially all of its retail customer receivables to CFC, its wholly owned subsidiary. As of June 16, 2005, the CFC receivables financing structure was renewed and restructured from an off-balance sheet transaction to an on-balance sheet transaction. Under the new structure, any borrowings under the facility appear on the balance sheet as short-term debt.

Equity Price Risk

Included in CEI’s nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $277 million and $242 million as of September 30, 2005 and December 31, 2004, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $28 million reduction in fair value as of September 30, 2005.

Outlook

The electric industry continues to transition to a more competitive environment and all of CEI's customers can select alternative energy suppliers. CEI 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. 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.

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 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, 2008 unless the PUCO accepts future competitive bid results prior to the end of that period under the revised RSP.

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

On August 5, 2004, the Ohio Companies accepted the RSP as modified and approved by the PUCO in an August 4, 2004 Entry on Rehearing, subject to a competitive bid process. The RSP was filed by the Ohio Companies to establish generation service rates beginning January 1, 2006, in response to PUCO concerns about price and supply uncertainty following the end of the Ohio Companies' transition plan market development period. In October 2004, the OCC and NOAC filed appeals with the Supreme Court of Ohio to overturn the original June 9, 2004 PUCO order in this proceeding as well as the associated entries on rehearing. On September 28, 2005, the Ohio Supreme Court heard oral argument on the appeals.

On May 27, 2005, CEI filed an application with the PUCO to establish a GCAF rider under the RSP. The application seeks to implement recovery of increased fuel costs from 2006 through 2008 applicable to CEI's retail customers through a tariff rider to be implemented January 1, 2006. The application reflects projected increases in fuel costs in 2006 compared to 2002 baseline costs. The new rider, after adjustments made in testimony, is seeking to recover all costs above the baseline (approximately $88 million in 2006 for all of the Ohio Companies). Various parties including the OCC have intervened in this case and the case has been consolidated with the RCP application discussed below.

On September 9, 2005, CEI filed an application with the PUCO that, if approved, would supplement its existing RSP with an RCP. On September 27, 2005, the PUCO granted FirstEnergy's motion to consolidate the GCAF rider application with the RCP proceedings and set hearings for the consolidated cases to begin November 29, 2005. The RCP is designed to provide customers with more certain rate levels than otherwise available under the RSP during the plan period. Major provisions of the RCP include:

· Maintain the existing level of base distribution rates through April 30, 2009 for CEI;

· Defer and capitalize certain distribution costs to be incurred by all of the Ohio Companies during the period January 1, 2006 through December 31, 2008, not to exceed $150 million in each of the three years;

· Adjust the RTC and extended RTC recovery periods and rate levels so that full recovery of authorized costs will occur as of December 31, 2010 for CEI;

· Reduce the deferred shopping incentive balances as of January 1, 2006 by up to $85 million for CEI by accelerating the application of its accumulated cost of removal regulatory liability; and

· Defer and capitalize all of CEI's allowable fuel cost increases until January 1, 2009.

Under provisions of the RSP, the PUCO may require CEI to undertake, no more often than annually, a competitive bid process to secure generation for the years 2007 and 2008. On July 22, 2005, FirstEnergy filed a competitive bid process for the period beginning in 2007 that is similar to the competitive bid process approved by the PUCO for CEI in 2004, which resulted in the PUCO accepting no bids. Any acceptance of future competitive bid results would terminate the RSP pricing, with no accounting impacts to the RSP, and not until twelve months after the PUCO authorizes such termination. On September 28, 2005, the PUCO issued an Entry that essentially approved the Ohio Companies' filing but delayed the proposed timing of the competitive bid process by four months, calling for the auction to be held on March 21, 2006.

On December 30, 2004, CEI filed with the PUCO two applications related to the recovery of transmission and ancillary service related costs. The first application seeks recovery of these costs beginning January 1, 2006. At the time of filing the application, these costs were estimated to be approximately $16 million per year; however, CEI anticipates that this amount will increase. CEI requested that these costs be recovered through a rider that would be effective on January 1, 2006 and adjusted each July 1 thereafter. CEI reached a settlement with OCC, PUCO staff, Industrial Energy Users - Ohio and OPAE. The only other party in this proceeding, Dominion Retail, Inc., agreed not to oppose the settlement. This settlement, which was filed with the PUCO on July 22, 2005, provides for the rider recovery requested by CEI, with carrying charges applied in the subsequent year’s rider for any over or under collection while the then-current rider is in effect. The PUCO approved the settlement stipulation on August 31, 2005. The incremental Transmission and Ancillary service revenues expected to be recovered from January through June 2006 are approximately $23.9 million. This value includes the recovery of the 2005 deferred MISO expenses as described below. In May 2006, CEI will file a modification to the rider which will determine revenues from July 2006 through June 2007.

The second application sought authority to defer costs associated with transmission and ancillary service related costs incurred during the period from October 1, 2003 through December 31, 2005. On May 18, 2005, the PUCO granted the accounting authority for CEI to defer incremental transmission and ancillary service-related charges incurred as a participant in MISO, but only for those costs incurred during the period December 30, 2004 through December 31, 2005. Permission to defer costs incurred prior to December 30, 2004 was denied. The PUCO also authorized CEI to accrue carrying charges on the deferred balances. An application filed with the PUCO to recover these deferred charges over a five-year period through the rider, beginning in 2006, was approved in a PUCO order issued on August 31, 2005, approving the stipulation referred to above. The OCC, OPAE and CEI each filed applications for rehearing. CEI sought authority to defer the transmission and ancillary service-related costs incurred during the period October 1, 2003 through December 29, 2004, while both OCC and OPAE sought to have the PUCO deny deferral of all costs. On July 6, 2005, the PUCO denied CEI’s and OCC’s applications and, at the request of CEI, struck as untimely OPAE’s application. The OCC filed a notice of appeal with the Ohio Supreme Court on August 31, 2005. On September 30, 2005, in accordance with appellate procedure, the PUCO filed with the Ohio Supreme Court the record in this case. The Companies' brief will be due thirty days after the OCC files its brief, which, absent any time extensions, must be filed no later than November 9, 2005.

CEI records as regulatory assets costs which have been authorized by the PUCO and the FERC for recovery from customers in future periods and, without such authorization, the costs would have been charged to income when incurred. CEI's regulatory assets as of September 30, 2005 and December 2004 were $0.9 billion and $1.0 billion, respectively. CEI is deferring customer shopping incentives and interest costs as new regulatory assets in accordance with its transition and rate stabilization plans. These regulatory assets total $402 million as of September 30, 2005 and under the RSP, will be recovered through a surcharge rate equal to the RTC rate in effect when the transition costs have been fully recovered. See Note 14 “Regulatory Matters - Ohio” for the estimated net amortization of regulatory transition costs and deferred shopping incentive balances under the proposed RCP and current RSP.

See Note 14 to the consolidated financial statements for further details and a complete discussion of regulatory matters in Ohio.

Environmental Matters

CEI accrues environmental liabilities only when it concludes that it is probable that they have an obligation for such costs and can reasonably estimate the amount of such costs. Unasserted claims are reflected in CEI's determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

FirstEnergy plans to issue a report regarding its response to air emission requirements. FirstEnergy expects to complete the report by December 1, 2005.

National Ambient Air Quality Standards

In July 1997, the EPA promulgated changes in the NAAQS for ozone and proposed a new NAAQS for fine particulate matter. On March 10, 2005, the EPA finalized the "Clean Air Interstate Rule" covering a total of 28 states (including Ohio and Pennsylvania) and the District of Columbia based on proposed findings that air emissions from 28 eastern states and the District of Columbia significantly contribute to nonattainment of the NAAQS for fine particles and/or the "8-hour" ozone NAAQS in other states. CAIR provides each affected state until 2006 to develop implementing regulation to achieve additional reductions of NO_x and SO_2 emissions in two phases (Phase I in 2009 for NO_x, 2010 for SO_2 and Phase II in 2015 for both NO_x and SO_2) in all cases from the 2003 levels. CEI's Ohio and Pennsylvania fossil-fuel generation facilities will be subject to the caps on SO_2 and NO_x emissions. According to the EPA, SO_2 emissions will be reduced by 45% (from 2003 levels) by 2010 across the states covered by the rule, with reductions reaching 73% (from 2003 levels) by 2015, capping SO_2 emissions in affected states to just 2.5 million tons annually. NO_x emissions will be reduced by 53% (from 2003 levels) by 2009 across the states covered by the rule, with reductions reaching 61% (from 2003 levels) by 2015, achieving a regional NO_x cap of 1.3 million tons annually. The future cost of compliance with these regulations may be substantial and will depend on how they are ultimately implemented by the states in which CEI operates affected facilities.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. On March 14, 2005, the EPA finalized the "Clean Air Mercury Rule," which provides for a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases. Initially, mercury emissions will be capped nationally at 38 tons by 2010 as a "co-benefit" from implementation of SO_2 and NO_x emission caps under the EPA's CAIR program. Phase II of the mercury cap-and-trade program will cap nationwide mercury emissions from coal-fired power plants at 15 tons per year by 2018. However, the final rules give states substantial discretion in developing rules to implement these programs. In addition, both the CAIR and the Clean Air Mercury rule have been challenged in the United States Court of Appeals for the District of Columbia. Future cost of compliance with these regulations may be substantial.

Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol (Protocol), to address global warming by reducing the amount of man-made GHG emitted by developed countries by 5.2% from 1990 levels between 2008 and 2012. The United States signed the Protocol in 1998 but it failed to receive the two-thirds vote of the United States Senate required for ratification. However, the Bush administration has committed the United States to a voluntary climate change strategy to reduce domestic GHG intensity - the ratio of emissions to economic output - by 18 percent through 2012. The Energy Policy Act of 2005 established a Committee on Climate Change Technology to coordinate federal climate change activities and promote the development and deployment of GHG reducing technologies.

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

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Regulation of Hazardous Waste

CEI has been named a 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 are liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of September 30, 2005, 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. Included in Other Noncurrent Liabilities are accrued liabilities aggregating approximately $2.3 million as of September 30, 2005.

See Note 13(B) to the consolidated financial statements for further details and a complete discussion of environmental matters.

Other Legal Proceedings

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to CEI's normal business operations pending against CEI and its subsidiaries. The other material items not otherwise discussed above are described below.

On August 14, 2003, various states and parts of southern Canada experienced widespread power outages. The outages affected approximately 1.4 million customers in FirstEnergy's service area. The U.S. - Canada Power System Outage Task Force’s final report in April 2004 on the outages concludes, among other things, that the problems leading to the outages began in FirstEnergy’s Ohio service area. Specifically, the final report concluded, among other things, that the initiation of the August 14, 2003 power outages resulted from an alleged failure of both FirstEnergy and ECAR to assess and understand perceived inadequacies within the FirstEnergy system; inadequate situational awareness of the developing conditions; and a perceived failure to adequately manage tree growth in certain transmission rights of way. The Task Force also concluded that there was a failure of the interconnected grid's reliability organizations (MISO and PJM) to provide effective real-time diagnostic support. The final report is publicly available through the Department of Energy’s website (www.doe.gov). FirstEnergy believes that the final report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14, 2003 power outages and that it does not adequately address the underlying causes of the outages. FirstEnergy remains convinced that the outages cannot be explained by events on any one utility's system. The final report contained 46 “recommendations to prevent or minimize the scope of future blackouts.” Forty-five of those recommendations related to broad industry or policy matters while one, including subparts, related to activities the Task Force recommended be undertaken by FirstEnergy, MISO, PJM, ECAR, and other parties to correct the causes of the August 14, 2003 power outages. FirstEnergy implemented several initiatives, both prior to and since the August 14, 2003 power outages, which were independently verified by NERC as complete in 2004 and were consistent with these and other recommendations and collectively enhance the reliability of its electric system. FirstEnergy’s implementation of these recommendations in 2004 included completion of the Task Force recommendations that were directed toward FirstEnergy. FirstEnergy also is proceeding with the implementation of the recommendations regarding enhancements to regional reliability that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new, or material upgrades, to existing equipment, and therefore FirstEnergy has not accrued a liability as of September 30, 2005 for any expenditures in excess of those actually incurred through that date. FirstEnergy notes, however, that FERC or other applicable government agencies and reliability coordinators may take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures. Finally, the PUCO is continuing to review FirstEnergy’s filing that addressed upgrades to control room computer hardware and software and enhancements to the training of control room operators, before determining the next steps, if any, in the proceeding.

FirstEnergy companies also are defending six separate complaint cases before the PUCO relating to the August 14, 2003 power outage. Two such cases were originally filed in Ohio State courts but subsequently dismissed for lack of subject matter jurisdiction and further appeals were unsuccessful. In both such cases the individual complainants—three in one case and four in the other—sought to represent others as part of a class action. The PUCO dismissed the class allegations, stating that its rules of practice do not provide for class action complaints. Of the four other pending PUCO complaint cases, three were filed by various insurance carriers either in their own name or as subrogees in the name of their insureds. In each such case, the carriers seek reimbursement against various FirstEnergy companies (and, in one case, against PJM, MISO and American Electric Power Co. as well) for claims they paid to their insureds allegedly due to the loss of power on August 14, 2003. The listed insureds in these cases, in many instances, are not customers of any FirstEnergy company. The fourth case involves the claim of a non-customer seeking reimbursement for losses incurred when its store was burglarized on August 14, 2003. In addition to these six cases, the Ohio Companies were named as respondents in a regulatory proceeding that was initiated at the PUCO in response to complaints alleging failure to provide reasonable and adequate service stemming primarily from the August 14, 2003 power outages. No estimate of potential liability has been undertaken for any of these cases.

One complaint was filed on August 25, 2004 against FirstEnergy in the New York State Supreme Court. In this case, several plaintiffs in the New York City metropolitan area allege that they suffered damages as a result of the August 14, 2003 power outages. None of the plaintiffs are customers of any FirstEnergy affiliate. FirstEnergy's motion to dismiss the case was granted on September 26, 2005. Additionally, FirstEnergy Corp. was named in a complaint filed in Michigan State Court by an individual who is not a customer of any FirstEnergy company. A responsive pleading to this matter is not due until on or about December 1, 2005. No estimate of potential liability has been undertaken in this matter.

FirstEnergy is vigorously defending these actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be initiated against the Companies. In particular, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

FENOC received a subpoena in late 2003 from a grand jury sitting in the United States District Court for the Northern District of Ohio, Eastern Division requesting the production of certain documents and records relating to the inspection and maintenance of the reactor vessel head at the Davis-Besse Nuclear Power Station, in which CEI has a 51.38% interest. On December 10, 2004, FirstEnergy received a letter from the United States Attorney's Office stating that FENOC is a target of the federal grand jury investigation into alleged false statements made to the NRC in the Fall of 2001 in response to NRC Bulletin 2001-01. The letter also said that the designation of FENOC as a target indicates that, in the view of the prosecutors assigned to the matter, it is likely that federal charges will be returned against FENOC by the grand jury. On February 10, 2005, FENOC received an additional subpoena for documents related to root cause reports regarding reactor head degradation and the assessment of reactor head management issues at Davis-Besse. On May 11, 2005, FENOC received a subpoena for documents related to outside meetings attended by Davis-Besse personnel on corrosion and cracking of control rod drive mechanisms and additional root cause evaluations.

On April 21, 2005, the NRC issued a NOV and proposed a $5.45 million civil penalty related to the degradation of the Davis-Besse reactor vessel head issue described above. CEI accrued $1.0 million for a potential fine prior to 2005 and accrued the remaining liability for its share of the proposed fine of $1.8 million during the first quarter of 2005. On September 14, 2005, FENOC filed its response to the NOV with the NRC. FENOC accepted full responsibility for the past failure to properly implement its boric acid corrosion control and corrective action programs. The NRC NOV indicated that the violations do not represent current licensee performance. FirstEnergy paid the penalty in the third quarter of 2005.

If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability based on the events surrounding Davis-Besse, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

Effective July 1, 2005 the NRC oversight panel for Davis-Besse was terminated and Davis-Besse returned to the standard NRC reactor oversight process. At that time, NRC inspections were augmented to include inspections to support the NRC's Confirmatory Order dated March 8, 2004 that was issued at the time of startup and to address an NRC White Finding related to emergency sirens.

On August 12, 2004, the NRC notified FENOC that it would increase its regulatory oversight of the Perry Nuclear Power Plant as a result of problems with safety system equipment over the preceding two years and the licensee's failure to take prompt and effective corrective action. FENOC operates the Perry Nuclear Power Plant, in which CEI has a 44.85% interest (however, see Note 17 regarding FirstEnergy’s pending intra-system generation asset transfers, which include owned portions of the plant).

On April 4, 2005, the NRC held a public meeting to discuss FENOC's performance at the Perry Nuclear Power Plant as identified in the NRC's annual assessment letter to FENOC. Similar public meetings are held with all nuclear power plant licensees following issuance by the NRC of their annual assessments. According to the NRC, overall the Perry Plant operated "in a manner that preserved public health and safety" even though it remained under heightened NRC oversight. During the public meeting and in the annual assessment, the NRC indicated that additional inspections will continue and that the plant must improve performance to be removed from the Multiple/Repetitive Degraded Cornerstone Column of the Action Matrix.

On May 26, 2005, the NRC held a public meeting to discuss its oversight of the Perry Plant. While the NRC stated that the plant continued to operate safely, the NRC also stated that the overall performance had not substantially improved since the heightened inspection was initiated. The NRC reiterated this conclusion in its mid-year assessment letter dated August 30, 2005. On September 28, 2005, the NRC sent a CAL to FENOC describing commitments that FENOC had made to improve the performance of Perry and stated that the CAL would remain open until substantial improvement was demonstrated. The CAL was anticipated as part of the NRC's Reactor Oversight Process. If performance does not improve, the NRC has a range of options under the Reactor Oversight Process, from increased oversight to possible impact to the plant's operating authority. As a result, these matters could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

On October 20, 2004, FirstEnergy was notified by the SEC that the previously disclosed informal inquiry initiated by the SEC's Division of Enforcement in September 2003 relating to the restatements in August 2003 of previously reported results by FirstEnergy and CEI, and the Davis-Besse extended outage, have become the subject of a formal order of investigation. The SEC's formal order of investigation also encompasses issues raised during the SEC's examination of FirstEnergy and the Companies under the PUHCA. Concurrent with this notification, FirstEnergy received a subpoena asking for background documents and documents related to the restatements and Davis-Besse issues. On December 30, 2004, FirstEnergy received a subpoena asking for documents relating to issues raised during the SEC's PUHCA examination. On August 24, 2005 additional information was requested regarding Davis Besse. FirstEnergy has cooperated fully with the informal inquiry and will continue to do so with the formal investigation.

The City of Huron filed a complaint against OE with the PUCO challenging the ability of electric distribution utilities to collect transition charges from a customer of a newly formed municipal electric utility. The complaint was filed on May 28, 2003, and OE timely filed its response on June 30, 2003. In a related filing, the Ohio Companies filed for approval with the PUCO of a tariff that would specifically allow the collection of transition charges from customers of municipal electric utilities formed after 1998. An adverse ruling could negatively affect full recovery of transition charges by CEI. Hearings on the matter were held in August 2005. Initial briefs from all parties were filed on September 22, 2005 and reply briefs were filed on October 14, 2005. It is unknown when the PUCO will rule on this case.

If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on the above matters, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

See Note 13(C) to the consolidated financial statements for further details and a complete discussion of other legal proceedings.

New Accounting Standards and Interpretations

EITF Issue 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty"

In September 2005, the EITF reached a final consensus on Issue 04-13 concluding that two or more legally separate exchange transactions with the same counterparty should be combined and considered as a single arrangement for purposes of applying APB 29, when the transactions were entered into "in contemplation" of one another. If two transactions are combined and considered a single arrangement, the EITF reached a consensus that an exchange of inventory should be accounted for at fair value. Although electric power is not capable of being held in inventory, there is no substantive conceptual distinction between exchanges involving power and other storable inventory. Therefore, CEI will adopt this EITF effective for new arrangements entered into, or modifications or renewals of existing arrangements, in interim or annual periods beginning after March 15, 2006.

EITF Issue No. 05-6, "Determining the Amortization Period for Leasehold Improvements Purchased after Lease Inception or Acquired in a Business Combination"

In June 2005, the EITF reached a consensus on the application guidance for Issue 05-6. EITF 05-6 addresses the amortization period for leasehold improvements that were either acquired in a business combination or placed in service significantly after and not contemplated at or near the beginning of the initial lease term. For leasehold improvements acquired in a business combination, the amortization period is the shorter of the useful life of the assets or a term that includes required lease periods and renewals that are deemed to be reasonably assured at the date of acquisition. Leasehold improvements that are placed in service significantly after and not contemplated at or near the beginning of the lease term should be amortized over the shorter of the useful life of the assets or a term that includes required lease periods and renewals that are deemed to be reasonably assured at the date the leasehold improvements are purchased. This EITF was effective July 1, 2005 and is consistent with CEI’s current accounting.

FIN 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143"

On March 30, 2005, the FASB issued FIN 47 to clarify the scope and timing of liability recognition for conditional asset retirement obligations. Under this interpretation, companies are required to recognize a liability for the fair value of an asset retirement obligation that is conditional on a future event, if the fair value of the liability can be reasonably estimated. In instances where there is insufficient information to estimate the liability, the obligation is to be recognized in the first period in which sufficient information becomes available to estimate its fair value. If the fair value cannot be reasonably estimated, that fact and the reasons why must be disclosed. This Interpretation is effective for CEI in the fourth quarter of 2005. CEI is currently evaluating the effect this Interpretation will have on its financial statements.

SFAS 154 - "Accounting Changes and Error Corrections - a replacement of APB Opinion No. 20 and FASB Statement No. 3"

In May 2005, the FASB issued SFAS 154 to change the requirements for accounting and reporting a change in accounting principle. It applies to all voluntary changes in accounting principle and to changes required by an accounting pronouncement when that pronouncement does not include specific transition provisions. This Statement requires retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. In those instances, this Statement requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that period rather than being reported in the Consolidated Statements of Income. This Statement also requires that a change in depreciation, amortization, or depletion method for long-lived, nonfinancial assets be accounted for as a change in accounting estimate affected by a change in accounting principle. The provisions of this Statement are effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. CEI will adopt this Statement effective January 1, 2006.

SFAS 153, "Exchanges of Nonmonetary Assets - an amendment of APB Opinion No. 29"

In December 2004, the FASB issued SFAS 153 amending APB 29, which was based on the principle that nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance in APB 29 included certain exceptions to that principle. SFAS 153 eliminates the exception from fair value measurement for nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges that do not have commercial substance. This Statement specifies that a nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of this Statement are effective January 1, 2006 for CEI. This FSP is not expected to have a material impact on CEI's financial statements.

SFAS 151, "Inventory Costs - an amendment of ARB No. 43, Chapter 4"

In November 2004, the FASB issued SFAS 151 to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage). Previous guidance stated that in some circumstances these costs may be "so abnormal" that they would require treatment as current period costs. SFAS 151 requires abnormal amounts for these items to always be recorded as current period costs. In addition, this Statement requires that allocation of fixed production overheads to the cost of conversion be based on the normal capacity of the production facilities. The provisions of this statement are effective for inventory costs incurred by CEI beginning January 1, 2006. CEI is currently evaluating this Standard and does not expect it to have a material impact on its financial statements.

FSP FAS 115-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"

In September 2005, the FASB finalized and renamed EITF 03-1 and 03-1-a to FSP FAS 115-1. FSP FAS 115-1 will (1) supersede Issue 03-1 and EITF topic No. D-44, "Recognition of Other Than Temporary Impairment upon the Planned Sale of a Security Whose Cost Exceeds Fair Value," (2) clarify that an investor should recognize an impairment loss no later than when the impairment is deemed other than temporary, even if a decision to sell has not been made, and (3) be effective for other-than-temporary impairment and analyses conducted in periods beginning after September 15, 2005. The FASB expects to issue this FSP in the fourth quarter of 2005, which would require prospective application with an effective date for reporting periods beginning after December 15, 2005. CEI is currently evaluating this FSP and any impact on its investments.

THE TOLEDO EDISON COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In thousands)			
STATEMENTS OF INCOME				
OPERATING REVENUES	$ 286,960	$ 276,342	$ 787,824	$ 755,106
OPERATING EXPENSES AND TAXES:				
Fuel	16,501	13,908	43,474	37,195
Purchased power	73,144	79,774	225,600	236,869
Nuclear operating costs	39,207	43,827	145,059	122,685
Other operating costs	48,164	43,865	123,823	121,228
Provision for depreciation	18,835	14,588	48,724	43,021
Amortization of regulatory assets	39,576	41,037	107,672	102,065
Deferral of new regulatory assets	(19,379)	(12,442)	(41,473)	(29,664)
General taxes	14,159	14,924	41,960	41,252
Income taxes	20,311	11,963	44,160	18,465
Total operating expenses and taxes	250,518	251,444	738,999	693,116
OPERATING INCOME	36,442	24,898	48,825	61,990
OTHER INCOME (net of income taxes)	12,283	4,172	18,173	14,724
NET INTEREST CHARGES:				
Interest on long-term debt	3,912	4,015	12,655	23,057
Allowance for borrowed funds used during construction	(372)	(741)	(117)	(2,843)
Other interest expense	2,958	1,350	4,192	2,945
Net interest charges	6,498	4,624	16,730	23,159
NET INCOME	42,227	24,446	50,268	53,555
PREFERRED STOCK DIVIDEND REQUIREMENTS	1,687	2,211	6,109	6,633
EARNINGS ON COMMON STOCK	$ 40,540	$ 22,235	$ 44,159	$ 46,922
STATEMENTS OF COMPREHENSIVE INCOME				

NET INCOME	$	42,227	$	24,446	$	50,268	$	53,555
OTHER COMPREHENSIVE INCOME (LOSS):								
Unrealized gain (loss) on available for sale securities		(4,511)		913		(6,695)		(379)
Income tax expense (benefit) related to other comprehensive income		(1,743)		375		(2,534)		(155)
Other comprehensive income (loss), net of tax		(2,768)		538		(4,161)		(224)
TOTAL COMPREHENSIVE INCOME	$	39,459	$	24,984	$	46,107	$	53,331

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

THE TOLEDO EDISON COMPANY

CONSOLIDATED BALANCE SHEETS
(Unaudited)

		September 30, 2005		December 31, 2004
		(In thousands)		
ASSETS				
UTILITY PLANT:				
In service	$	1,906,941	$	1,856,478
Less - Accumulated provision for depreciation		820,562		778,864
		1,086,379		1,077,614
Construction work in progress -				
Electric plant		55,376		58,535
Nuclear fuel		7,370		15,998
		62,746		74,533
		1,149,125		1,152,147
OTHER PROPERTY AND INVESTMENTS:				
Investment in lessor notes		178,765		190,692
Nuclear plant decommissioning trusts		335,553		297,803
Long-term notes receivable from associated companies		39,964		39,975
Other		1,741		2,031
		556,023		530,501
CURRENT ASSETS:				
Cash and cash equivalents		15		15
Receivables -				
Customers (less accumulated provision of $2,000 for uncollectible accounts in 2004)		2,412		4,858
Associated companies		10,168		36,570
Other		8,658		3,842
Notes receivable from associated companies		52,639		135,683
Materials and supplies, at average cost		42,404		40,280
Prepayments and other		1,712		1,150
		118,008		222,398
DEFERRED CHARGES:				
Goodwill		501,022		504,522
Regulatory assets		309,835		374,814
Property taxes		24,100		24,100
Other		26,520		25,424
		861,477		928,860
	$	2,684,633	$	2,833,906
CAPITALIZATION AND LIABILITIES				
CAPITALIZATION:				

Common stockholder's equity -				
Common stock, $5 par value, authorized 60,000,000 shares -				
39,133,887 shares outstanding	$	195,670	$	195,670
Other paid-in capital		428,572		428,559
Accumulated other comprehensive income		15,878		20,039
Retained earnings		225,218		191,059
Total common stockholder's equity		865,338		835,327
Preferred stock		96,000		126,000
Long-term debt		296,373		300,299
		1,257,711		1,261,626
CURRENT LIABILITIES:				
Currently payable long-term debt		53,650		90,950
Accounts payable -				
Associated companies		28,456		110,047
Other		3,252		2,247
Notes payable to associated companies		378,190		429,517
Accrued taxes		72,214		46,957
Lease market valuation liability		24,600		24,600
Other		28,735		53,055
		589,097		757,373
NONCURRENT LIABILITIES:				
Accumulated deferred income taxes		222,985		221,950
Accumulated deferred investment tax credits		24,697		25,102
Lease market valuation liability		249,550		268,000
Retirement benefits		42,998		39,227
Asset retirement obligation		200,078		194,315
Other		97,517		66,313
		837,825		814,907
COMMITMENTS AND CONTINGENCIES (Note 13)				
	$	2,684,633	$	2,833,906

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

THE TOLEDO EDISON COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 42,227	$ 24,446	$ 50,268	$ 53,555
Adjustments to reconcile net income to net cash from operating activities -				
Provision for depreciation	18,835	14,588	48,724	43,021
Amortization of regulatory assets	39,576	41,037	107,672	102,065
Deferral of new regulatory assets	(19,379)	(12,442)	(41,473)	(29,664)
Nuclear fuel and capital lease amortization	5,682	7,058	13,816	17,596
Amortization of electric service obligation	(1,910)	-	(3,301)	-
Deferred rents and lease market valuation liability	10,310	9,689	(34,156)	(26,585)
Deferred income taxes and investment tax credits, net	(12,798)	(4,608)	(4,605)	(9,290)
Accrued retirement benefit obligations	1,534	1,324	3,771	4,733
Accrued compensation, net	404	516	(333)	1,477
Pension trust contribution	-	(12,572)	-	(12,572)
Decrease (increase) in operating assets -				
Receivables	3,423	69,908	15,962	95,383
Materials and supplies	3,788	(725)	(2,124)	(4,376)
Prepayments and other current assets	(970)	677	(562)	5,971
Increase (decrease) in operating liabilities -				
Accounts payable	(6,215)	6,202	(80,586)	(9,568)
Accrued taxes	14,748	(3,508)	25,257	227
Accrued interest	(369)	(7,169)	(565)	(7,540)
Prepayment for electric service -- education programs	-	-	37,954	-
Other	(14,392)	(10,020)	(22,999)	(9,679)
Net cash provided from operating activities	84,494	124,401	112,720	214,754

CASH FLOWS FROM FINANCING ACTIVITIES:				
New Financing -				
Long-term debt	-	30,500	45,000	103,500
Short-term borrowings, net	45,054	146,370	-	29,310
Redemptions and Repayments -				
Preferred stock	(30,000)	-	(30,000)	-
Long-term debt	(36,821)	(246,591)	(83,754)	(261,591)
Short-term borrowings, net	-	-	(51,327)	-
Dividend Payments -				
Common stock	-	-	(10,000)	-
Preferred stock	(1,687)	(2,211)	(6,109)	(6,633)
Net cash used for financing activities	(23,454)	(71,932)	(136,190)	(135,414)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions	(17,951)	(16,950)	(50,119)	(36,377)
Loan repayments from (loans to) associated companies, net	(36,490)	(20,389)	83,055	(21,046)
Investments in lessor notes	32	-	11,927	10,280
Contributions to nuclear decommissioning trusts	(7,135)	(7,135)	(21,406)	(21,406)
Other	504	(7,995)	13	(13,013)
Net cash provided from (used for) investing activities	(61,040)	(52,469)	23,470	(81,562)
Net change in cash and cash equivalents	-	-	-	(2,222)
Cash and cash equivalents at beginning of period	15	15	15	2,237
Cash and cash equivalents at end of period	$ 15	$ 15	$ 15	$ 15

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

Report of Independent Registered Public Accounting Firm

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 September 30, 2005, and the related consolidated statements of income and comprehensive income and cash flows for each of the three-month and nine-month periods ended September 30, 2005 and 2004. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 the standards of the Public Company Accounting Oversight Board, 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 the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2004, and the related consolidated statements of income, capitalization, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended, management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004 and the effectiveness of the Company's internal control over financial reporting as of December 31, 2004; and in our report (which contained references to the Company's change in its method of accounting for asset retirement obligations as of January 1, 2003 as discussed in Note 2(G) to those consolidated financial statements and the Company's change in its method of accounting for the consolidation of variable interest entities as of December 31, 2003 as discussed in Note 6 to those consolidated financial statements) dated March 7, 2005, we expressed unqualified opinions thereon. The consolidated financial statements and management's assessment of the effectiveness of internal control over financial reporting referred to above are not presented herein. In our opinion, the information set forth in the accompanying consolidated balance sheet information as of December 31, 2004, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio
November 1, 2005

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 northwestern Ohio, providing regulated electric distribution services. TE also provides generation services to those customers electing to retain TE as their power supplier. TE provides power directly to some 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. TE's power supply requirements are provided by FES - an affiliated company.

Results of Operations

Earnings on common stock in the third quarter of 2005 increased to $41 million from $22 million in the third quarter of 2004. The increase in earnings resulted primarily from higher operating revenues and other income, partially offset by increased financing costs. Earnings on common stock in the first nine months of 2005 decreased to $44 million from $47 million in the first nine months of 2004. The decrease in earnings resulted primarily from higher nuclear operating costs and a one-time income tax charge, partially offset by higher operating revenues and lower financing costs.

Operating revenues increased by $11 million, or 3.8%, in the third quarter of 2005 compared to the third quarter of 2004. Higher revenues in the third quarter of 2005 resulted from increased retail generation revenues of $13 million and distribution revenues of $2 million, partially offset by a decrease in wholesales sales (primarily to FES) of $4 million and an increase in shopping incentive credits of $1 million. Retail generation revenues increased as a result of increased KWH sales (residential - $1 million, commercial - $1 million and industrial - $11 million). Higher residential and commercial revenues reflected increased KWH sales (8.0% and 9.2%, respectively) and higher unit prices. KWH sales to residential and commercial customers increased primarily due to warmer weather which increased air-conditioning loads. Additionally, generation services provided to commercial customers by alternative suppliers as a percent of total commercial sales delivered in TE's service area decreased by 2.1 percentage points compared with the third quarter of 2004. Industrial revenues increased as a result of higher unit prices and a 4.2% increase in KWH sales.

Revenues from distribution throughput increased by $2 million in the third quarter of 2005 from the corresponding quarter of 2004. The increase was due to higher residential and commercial revenues ($8 million and $0.2 million, respectively), partially offset by a decrease in industrial revenues ($7 million). The impact of higher residential and commercial KWH sales contributed to the increase; lower industrial unit prices more than offset an increase in KWH sales to industrial customers.

Operating revenues increased by $33 million, or 4.3%, in the first nine months of 2005 compared to the same period of 2004. The higher revenues resulted from increased retail generation revenues of $35 million and wholesales sales of $2 million, partially offset by an increase in shopping incentive credits of $3 million. Retail generation revenues increased as a result of higher KWH sales (residential - $2 million, commercial - $4 million, industrial - $29 million). Higher residential and commercial revenues reflected increased KWH sales (6.9% and 12.2%, respectively) and higher unit prices. Residential and commercial sales volumes increased primarily due to warmer weather. The increase in commercial revenues also reflects a reduction by 2.5 percentage points in customer shopping compared with the same period of 2004. Industrial revenues increased as a result of higher unit prices and a 0.6% increase in KWH sales.

Revenues from distribution throughput decreased by $0.4 million in the first nine months of 2005 from the same period in 2004. The decrease was due to lower industrial revenues ($22 million), partially offset by increases in residential and commercial revenues ($15 million and $6 million, respectively). The impact from lower industrial unit prices more than offset the higher KWH sales in all customer classes.

Under the Ohio transition plan, TE provides incentives to customers to encourage switching to alternative energy providers. TE’s revenues were reduced by $1 million from additional credits in the third quarter and $3 million in the first nine months of 2005 compared with the same periods of 2004. These revenue reductions are deferred for future recovery under TE’s transition plan and do not affect current period earnings (see Regulatory Matters below).

Changes in KWH sales by customer class in the three months and nine months ended September 30, 2005 from the corresponding periods of 2004, are summarized in the following table:

Changes in KWH Sales Increase (Decrease)	**Three Months**	**Nine Months**
Electric Generation:		
Retail	6.0%	3.9%
Wholesale	3.5%	3.4%
Total Electric Generation Sales	**4.6%**	**3.7%**
Distribution Deliveries:		
Residential	16.7%	12.0%
Commercial	4.7%	6.8%
Industrial	4.8%	1.2%
Total Distribution Deliveries	**7.7%**	**5.3%**

Operating Expenses and Taxes

Total operating expenses and taxes decreased $1 million in the third quarter and increased $46 million in the first nine months of 2005 from the same periods in 2004. The following table presents changes from the prior year by expense category.

Operating Expenses and Taxes - Changes Increase (Decrease)	**Three Months**	**Nine Months**
	(In millions)	
Fuel costs	$ 3	$ 6
Purchased power costs	(7)	(11)
Nuclear operating costs	(4)	22
Other operating costs	4	3
Provision for depreciation	4	6
Amortization of regulatory assets	(1)	6
	(7)	(12)

Deferral of new regulatory assets		
General taxes	(1)	1
Income taxes	8	25
Net increase (decrease) in operating expenses and taxes	$ (1)	$ 46

Higher fuel costs in the third quarter and first nine months of 2005, compared with the same periods of 2004, resulted primarily from increased fossil-fired generation from the Mansfield Plant, up 5.7% and 7.1% during the respective periods. Purchased power costs decreased in both periods due to lower unit costs and reduced KWH purchases. Nuclear operating costs decreased in the third quarter of 2005 primarily from lower employee benefit costs and operating expenses for the nuclear generating units. Nuclear operating costs increased in the nine-month period due to a scheduled refueling outage (including an unplanned extension) at the Perry Plant, a mid-cycle inspection outage at the Davis-Besse Plant during the first quarter of 2005, and the Beaver Valley Unit 2 refueling outage in the second quarter of 2005, compared to no scheduled outages in the first nine months of 2004. Other operating costs increased in both periods of 2005 compared to the same periods of 2004 primarily because of MISO Day 2 expenses that began on April 1, 2005, partially offset by lower Beaver Valley Unit 2 letter of credit fees, insurance settlements and lower employee benefits costs.

Depreciation charges increased by $4 million in the third quarter and $6 million in first nine months of 2005 compared to the same periods of 2004 primarily due to property additions and reduced amortization periods for expenditures on leased generating plants to conform to the lease terms. These increases were partially offset by the effect of revised service life assumptions for fossil generating plants (See Note 3). Regulatory asset amortization increased in the first nine months of 2005 due to the increased amortization of transition costs being recovered under the RSP. Deferrals of new regulatory assets increased in the third quarter and first nine months of 2005 compared to the same periods of 2004, primarily due to higher shopping incentives and related interest ($2 million and $5 million, respectively) and the deferral of the PUCO-approved MISO administrative expenses and related interest ($5 million and $6 million, respectively).

On June 30, 2005, the State of Ohio enacted new tax legislation that created a new CAT tax, which is based on qualifying “taxable gross receipts” and will not consider any expenses or costs incurred to generate such receipts, except for items such as cash discounts, returns and allowances, and bad debts. The CAT tax is effective July 1, 2005, and replaces the Ohio income-based franchise tax and the Ohio personal property tax. The CAT tax is phased-in while the current income-based franchise tax is phased-out over a five-year period at a rate of 20% annually, beginning with the year ended 2005, and personal property tax is phased-out over a four-year period at a rate of approximately 25%, annually beginning with the year ended 2005. For example, during the phase-out period the Ohio income-based franchise tax will be computed consistently with the prior tax law, except that the tax liability as computed will be multiplied by 4/5 in 2005; 3/5 in 2006; 2/5 in 2007 and 1/5 in 2008, therefore eliminating the current income-based franchise tax over a five-year period. As a result of the new tax structure, all net deferred tax benefits that are not expected to reverse during the five-year phase-in period were written-off as of June 30, 2005. The impact on income taxes associated with the required adjustment to net deferred taxes for the nine months ended September 30, 2005 was additional tax expense of $17.5 million, which was partially offset by the phase-out of the Ohio income tax which reduced income taxes by $0.7 million in the third quarter of 2005 and $1.2 million for the nine months ended September 30, 2005. See Note 12 to the consolidated financial statements.

Other Income

Other income increased by $8 million in the third quarter of 2005 and $3 million in the first nine months of 2005 compared with the same periods of 2004, primarily due to higher nuclear decommissioning trust realized gains, partially offset by lower interest income earned on associated company notes receivable that were repaid in May 2005. Additionally, the recognition of a $1.6 million NRC fine related to the Davis-Besse Plant (see Outlook - Other Legal Proceedings) during the first quarter of 2005 partially offset the increase in other income during the first nine months of 2005.

Net Interest Charges

Net interest charges increased by $2 million in the third quarter of 2005 compared with the same period in 2004, primarily related to higher interest rates charged for money pool borrowings from associated companies in 2005. The average interest rate for borrowings in the third quarter of 2005 was 3.50% versus 1.28% in the same period in 2004. However, net interest charges decreased by $6 million in the first nine months of 2005 compared with the same period of 2004, reflecting redemptions and refinancings since October 1, 2004.

Capital Resources and Liquidity

TE's cash requirements for the remainder of 2005 for operating expenses and construction expenditures are expected to be met without increasing its net debt and preferred stock outstanding. Thereafter, TE expects to meet its contractual obligations with a combination of cash from operations and funds from the capital markets.

Changes in Cash Position

As of September 30, 2005, TE's cash and cash equivalents of $15,000 remained unchanged from December 31, 2004.

Cash Flows From Operating Activities

Cash provided from operating activities during the third quarter and first nine months of 2005, compared with the corresponding period of 2004 were as follows:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
Operating Cash Flows	**2005**	**2004**	**2005**	**2004**
	(In millions)			
Cash earnings[(1)]	$ 84	$ 77	$ 140	$ 152
Pension trust contribution[(2)]	--	(8)	--	(8)
Working capital and other	--	55	(27)	71
Total cash flows from operating activities	$ 84	$ 124	$ 113	$ 215

[1] Cash earnings are a non-GAAP measure (see reconciliation below).
[2] Pension trust contribution net of $5 million of income tax benefits.

Cash earnings, as disclosed in the table above, are not a measure of performance calculated in accordance with GAAP. TE believes that cash earnings is a useful financial measure because it provides investors and management with an additional means of evaluating its cash-based operating performance. The following table reconciles cash earnings with net income.

Reconciliation of Cash Earnings	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In millions)			
Net income (GAAP)	$ 42	$ 24	$ 50	$ 54
Non-cash charges (credits):				
Provision for depreciation	19	15	49	43
Amortization of regulatory assets	40	41	108	102
Deferral of new regulatory assets	(20)	(12)	(42)	(30)
Nuclear fuel and capital lease amortization	6	7	14	18
Amortization of electric service obligation	(2)	--	(3)	-
Deferred rents and above-market lease liability	10	10	(34)	(27)
Deferred income taxes and investment tax credits, net	(13)	(8)	(5)	(14)
Accrued retirement benefits obligations	2	1	4	5
Accrued compensation, net	-	(1)	(1)	1
Cash earnings (Non-GAAP)	$ 84	$ 77	$ 140	$ 152

Net cash provided from operating activities decreased by $40 million in the third quarter of 2005 from the third quarter of 2004 as a result of a $55 million decrease from working capital, partially offset by a $7 million increase in cash earnings as described above and under “Results of Operations” and the absence of an $8 million after-tax voluntary pension trust contribution made in the third quarter of 2004. Net cash provided from operating activities decreased by $102 million in the first nine months of 2005 compared to the same period last year as a result of a $98 million change in working capital and a $12 million decrease in cash earnings as described above and under “Results of Operations,” partially offset by the absence of an $8 million after-tax voluntary pension trust contribution made in 2004. The change in working capital for both periods was primarily due to changes in accounts payable, accrued taxes and receivables, partially offset in the nine-month period of 2005 by funds received for prepaid electric service under the Ohio Schools Council’s Energy for Education Program that began in the second quarter of 2005.

Cash Flows From Financing Activities

Net cash used for financing activities decreased by $48 million and increased by $1 million in the third quarter and first nine months of 2005, respectively, as compared to the same periods of 2004. The activities in both periods reflect an increase in net debt redemptions and preferred stock redemptions. The increase in the nine-month period of 2005 also included a $10 million increase in common stock dividends to FirstEnergy.

On July 1, 2005, TE redeemed all of its 1,200,000 outstanding shares of 7.00% Series A preferred stock at $25.00 per share, plus accrued dividends to the date of redemption. TE also repurchased $37 million of pollution control revenue bonds on September 1, 2005, with the intent to remarket them by the end of the first quarter of 2006.

TE had $53 million of cash and temporary investments (which included short-term notes receivable from associated companies) and $378 million of short-term indebtedness as of September 30, 2005. TE has authorization from the PUCO to incur short-term debt of up to $500 million (including the utility money pool described below). As of October 24, 2005, TE had the capability to issue $1.0 billion of additional FMB on the basis of property additions and retired bonds under the terms of its mortgage indenture following the recently completed intra-system transfer of fossil generating plants (See Note 17). Based upon applicable earnings coverage tests, TE could issue up to $1.15 billion of preferred stock (assuming no additional debt was issued) as of September 30, 2005. It is estimated that the annualized impact of the intra-system transfer of fossil generating plants will reduce the capability of TE to issue preferred stock by approximately $16 million.

On June 14, 2005, FirstEnergy, OE, Penn, CEI, TE, JCP&L, Met-Ed, Penelec, FES and ATSI, as Borrowers, entered into a syndicated $2 billion five-year revolving credit facility. Borrowings under the facility are available to each Borrower separately and will mature on the earlier of 364 days from the date of borrowing and the commitment termination date, as the same may be extended. TE's borrowing limit under the facility is $250 million.

TE has the ability to borrow from its regulated affiliates and FirstEnergy to meet its short-term working capital requirements. FESC administers this money pool and tracks surplus funds of FirstEnergy and its regulated subsidiaries. Companies receiving a loan under the money pool agreements must repay the principal, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from the pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in the third quarter of 2005 was 3.50%.

TE’s access to capital markets and costs of financing are dependent on the ratings of its securities and the securities of FirstEnergy.

On July 18, 2005, Moody’s revised its rating outlook on FirstEnergy and its subsidiaries to positive from stable. Moody’s stated that the revision to FirstEnergy’s outlook resulted from steady financial improvement and steps taken by management to improve operations, including the stabilization of its nuclear operations. Moody’s further stated that the revision in their outlook recognized management’s regional strategy of focusing on its core utility businesses and the improvement in FirstEnergy’s credit profile stemming from the application of free cash flow toward debt reduction. Moody’s noted that a ratings upgrade could be considered if FirstEnergy continues to achieve planned improvements in its operations and balance sheet.

On October 3, 2005, S&P raised its corporate credit rating on FirstEnergy and the EUOC to 'BBB' from 'BBB-'. At the same time, S&P raised the senior unsecured ratings at the holding company to 'BBB-' from 'BB+' and each of the EUOC by one notch above the previous rating. S&P noted that the upgrade followed the continuation of a good operating track record, specifically for the nuclear fleet through the third quarter 2005. S&P also stated that FirstEnergy’s rating reflects the benefits of supportive regulation, low-cost base load generation fleet, low-risk transmission and distribution operations and rate certainty in Ohio. FirstEnergy’s ability to consistently generate free cash flow, good liquidity, and an improving financial profile were also noted as strengths.

Cash Flows From Investing Activities

Net cash used for investing activities increased by $9 million in the third quarter of 2005 compared with from the same period of 2004. Net cash provided from investing activities increased by $105 million in the first nine months of 2005, from the same period of 2004. These increases were primarily due to changes from loan activity with associated companies during the periods, partially offset by increased property additions in the nine-month period.

In the last quarter of 2005, TE’s capital spending is expected to be about $25 million. These cash requirements are expected to be satisfied from internal cash and short-term borrowings. TE’s capital spending for the period 2005-2007 is expected to be about $192 million, of which approximately $64 million applies to 2005.

FirstEnergy Intra-System Generation Asset Transfers

On May 18, 2005, OE, CEI and TE, entered into certain agreements implementing a series of intra-system generation asset transfers. When fully completed, the asset transfers will result in the respective undivided ownership interests of the Ohio Companies in FirstEnergy’s nuclear and non-nuclear plants being owned by NGC and FGCO, respectively. The generating plant interests that are being transferred do not include TE’s leasehold interests in certain of the plants that are currently subject to sale and leaseback arrangements with non-affiliates.

On October 24, 2005, TE completed the transfer of non-nuclear generation assets to FGCO. TE currently expects to complete the transfer of nuclear generation assets to NGC at book value before the end of 2005. Consummation of the nuclear transfer remains subject to necessary regulatory approvals.

These transactions are being undertaken in connection with the Ohio Companies’ restructuring plans that were approved by the PUCO under applicable Ohio electric utility restructuring legislation. Consistent with the restructuring plans, generation assets that had been owned by the Ohio Companies were required to be separated from the regulated delivery business of those companies through transfer to a separate corporate entity. FENOC currently operates and maintains the nuclear generation assets to be transferred. FGCO, as lessee under a Master Facility Lease, leased, operated and maintained the non-nuclear generation assets that it now owns. The transactions will essentially complete the divestitures contemplated by the restructuring plans by transferring the ownership interests to NGC and

FGCO, respectively, without impacting the operation of the plants.

See Note 17 to the consolidated financial statements for TE's disclosure of the assets held for sale as of September 30, 2005.

Off-Balance Sheet Arrangements

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 September 30, 2005, the present value of these operating lease commitments, net of trust investments, totaled $541 million.

TE sells substantially all of its retail customer receivables to CFC, a wholly owned subsidiary of CEI. As of June 16, 2005, the CFC receivables financing structure was renewed and restructured from an off-balance sheet transaction to an on-balance sheet transaction. Under the new structure, any borrowings under the facility appear on the balance sheet as short-term debt.

Equity Price Risk

Included in TE's nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $217 million and $188 million as of September 30, 2005 and December 31, 2004, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $22 million reduction in fair value as of September 30, 2005. Changes in the fair value of these investments are recorded in OCI unless recognized as a result of sales.

Outlook

The electric industry continues to transition to a more competitive environment and all of TE's customers can 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.

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 customers elects to obtain power from an alternative supplier, TE reduces the customer's bill with a "generation shopping credit," based on the 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, 2008 unless the PUCO accepts future competitive bid results prior to the end of that period under the revised RSP.

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 MW of low cost supply (MSG) to unaffiliated alternative suppliers who serve customers within its service area. FES acts as an alternate supplier for a portion of the load in TE's franchise area.

On August 5, 2004, the Ohio Companies accepted the RSP as modified and approved by the PUCO in an August 4, 2004 Entry on Rehearing, subject to a competitive bid process. The RSP was filed by the Ohio Companies to establish generation service rates beginning January 1, 2006, in response to PUCO concerns about price and supply uncertainty following the end of the Ohio Companies' transition plan market development period. In October 2004, the OCC and NOAC filed appeals with the Supreme Court of Ohio to overturn the original June 9, 2004 PUCO order in this proceeding as well as the associated entries on rehearing. On September 28, 2005, the Ohio Supreme Court heard oral argument on the appeals.

On May 27, 2005, TE filed an application with the PUCO to establish a GCAF rider under its RSP. The application seeks to implement recovery of increased fuel costs from 2006 through 2008 applicable to TE's retail customers through a tariff rider to be implemented January 1, 2006. The application reflects projected increases in fuel costs in 2006 compared to 2002 baseline costs. The new rider, after adjustments made in testimony, is seeking to recover all costs above the baseline (approximately $88 million in 2006 for all the Ohio Companies). Various parties including the OCC have intervened in this case and the case has been consolidated with the RCP application discussed below.

On September 9, 2005, TE filed an application with the PUCO that, if approved, would supplement its existing RSP with an RCP. On September 27, 2005, the PUCO granted FirstEnergy's motion to consolidate the GCAF rider application with the RCP proceedings and set hearings for the consolidated cases to begin November 29, 2005. The RCP is designed to provide customers with more certain rate levels than otherwise available under the RSP during the plan period. Major provisions of the RCP include:

- Maintain the existing level of base distribution rates through December 31, 2008 for TE;
- Defer and capitalize certain distribution costs to be incurred by all of the Ohio Companies during the period January 1, 2006 through December 31, 2008, not to exceed $150 million in each of the three years;
- Adjust the RTC and extended RTC recovery periods and rate levels so that full recovery of authorized costs will occur as of December 31, 2008 for TE;
- Reduce the deferred shopping incentive balances as of January 1, 2006 by up to $45 million for TE by accelerating the application of its accumulated cost of removal regulatory liability; and

- Recover increased fuel costs of up to $75 million, $77 million, and $79 million, in 2006, 2007, and 2008, respectively, from all OE and TE distribution and transmission customers through a fuel recovery mechanism. TE may defer and capitalize increased fuel costs above the amount collected through the fuel recovery mechanism.

Under provisions of the RSP, the PUCO may require TE to undertake, no more often than annually, a competitive bid process to secure generation for the years 2007 and 2008. On July 22, 2005, FirstEnergy filed a competitive bid process for the period beginning in 2007 that is similar to the competitive bid process approved by the PUCO for TE in 2004, which resulted in the PUCO accepting no bids. Any acceptance of future competitive bid results would terminate the RSP pricing, with no accounting impacts to the RSP, and not until twelve months after the PUCO authorizes such termination. On September 28, 2005, the PUCO issued an Entry that essentially approved the Ohio Companies' filing but delayed the proposed timing of the competitive bid process by four months, calling for the auction to be held on March 21, 2006.

On December 30, 2004, TE filed with the PUCO two applications related to the recovery of transmission and ancillary service related costs. The first application seeks recovery of these costs beginning January 1, 2006. At the time of filing the application, these costs were estimated to be approximately $0.1 million per year; however, TE anticipates that this amount will increase. TE requested that these costs be recovered through a rider that would be effective on January 1, 2006 and adjusted each July 1 thereafter. TE reached a settlement with OCC, PUCO staff, Industrial Energy Users - Ohio and OPAE. The only other party in this proceeding, Dominion Retail, Inc., agreed not to oppose the settlement. This settlement, which was filed with the PUCO on July 22, 2005, provides for the rider recovery requested by TE, with carrying charges applied in the subsequent year's rider for any over or under collection while the then-current rider is in effect. The PUCO approved the settlement stipulation on August 31, 2005. The incremental Transmission and Ancillary service revenues expected to be recovered from January through June 2006 are approximately $6.7 million. This value includes the recovery of the 2005 deferred MISO expenses as described below. In May 2006, TE will file a modification to the rider which will determine revenues from July 2006 through June 2007.

The second application seeks authority to defer costs associated with transmission and ancillary service related costs incurred during the period from October 1, 2003 through December 31, 2005. On May 18, 2005, the PUCO granted the accounting authority for TE to defer incremental transmission and ancillary service-related charges incurred as a participant in the MISO, but only for those costs incurred during the period December 30, 2004 through December 31, 2005. Permission to defer costs incurred prior to December 31, 2004 was denied. The PUCO also authorized TE to accrue carrying charges on the deferred balances. An application filed with the PUCO to recover these deferred charges over a five-year period through the rider, beginning in 2006, was approved in a PUCO order issued on August 31, 2005. The OCC, OPAE and TE each filed applications for rehearing. TE sought authority to defer the transmission and ancillary service related costs incurred during the period October 1, 2003 through December 29, 2004, while both OCC and OPAE sought to have the PUCO deny deferral of all costs. On July 6, 2005, the PUCO denied TE's and OCC's applications and, at the request of TE, struck as untimely OPAE's application. The OCC filed a notice of appeal with the Ohio Supreme Court on August 31, 2005. On September 30, 2005, in accordance with appellate procedure, the PUCO filed with the Ohio Supreme Court the record in this case. The Companies' brief will be due thirty days after the OCC files its brief, which, absent any time extensions, must be filed no later than November 9, 2005.

TE records as regulatory assets costs which have been authorized by the PUCO and the FERC for recovery from customers in future periods and, without such authorization, the costs would have been charged to income when incurred. TE's regulatory assets as of September 30, 2005 and December 31, 2004, were $310 million and $375 million, respectively. TE is deferring customer shopping incentives and interest costs as new regulatory assets in accordance with its transition and rate stabilization plans. These regulatory assets total $122 million as of

September 30, 2005 and, under the RSP, will be recovered through a surcharge rate equal to the RTC rate in effect when the transition costs have been fully recovered. See Note 14 “Regulatory Matters - Ohio” for the estimated net amortization of regulatory transition costs and deferred shopping incentive balances under the proposed RCP and current RSP.

See Note 14 to the consolidated financial statements for further details and a complete discussion of regulatory matters in Ohio.

Environmental Matters

TE accrues environmental liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. Unasserted claims are reflected in TE's determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

FirstEnergy plans to issue a report regarding its response to air emission requirements. FirstEnergy expects to complete the report by December 1, 2005.

National Ambient Air Quality Standards

In July 1997, the EPA promulgated changes in the NAAQS for ozone and proposed a new NAAQS for fine particulate matter. On March 10, 2005, the EPA finalized the "Clean Air Interstate Rule" covering a total of 28 states (including Ohio and Pennsylvania) and the District of Columbia based on proposed findings that air emissions from 28 eastern states and the District of Columbia significantly contribute to nonattainment of the NAAQS for fine particles and/or the "8-hour" ozone NAAQS in other states. CAIR provides each affected state until 2006 to develop implementing regulation to achieve additional reductions of NO_x and SO_2 emissions in two phases (Phase I in 2009 for NO_x, 2010 for SO_2 and Phase II in 2015 for both NO_x and SO_2) in all cases from the 2003 levels. TE's Ohio and Pennsylvania fossil-fired generation facilities will be subject to the caps on SO_2 and NO_x emissions. According to the EPA, SO_2 emissions will be reduced by 45% (from 2003 levels) by 2010 across the states covered by the rule, with reductions reaching 73% (from 2003 levels) by 2015, capping SO_2 emissions in affected states to just 2.5 million tons annually. NO_x emissions will be reduced by 53% (from 2003 levels) by 2009 across the states covered by the rule, with reductions reaching 61% (from 2003 levels) by 2015, achieving a regional NO_x cap of 1.3 million tons annually. The future cost of compliance with these regulations may be substantial and will depend on how they are ultimately implemented by the states in which TE operates affected facilities.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. On March 14, 2005, the EPA finalized the “Clean Air Mercury Rule,” which provides for a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases. Initially, mercury emissions will be capped nationally at 38 tons by 2010 as a "co-benefit" from implementation of SO_2 and NO_x emission caps under the EPA's CAIR program. Phase II of the mercury cap-and-trade program will cap nationwide mercury emissions from coal-fired power plants at 15 tons per year by 2018. However, the final rules give states substantial discretion in developing rules to implement these programs. In addition, both the CAIR and the Clean Air Mercury rule have been challenged in the United States Court of Appeals for the District of Columbia. Future cost of compliance with these regulations may be substantial.

Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol (Protocol), to address global warming by reducing the amount of man-made GHG emitted by developed countries by 5.2% from 1990 levels between 2008 and 2012. The United States signed the Protocol in 1998 but it failed to receive the two-thirds vote of the United States Senate required for ratification. However, the Bush administration has committed the United States to a voluntary climate change strategy to reduce domestic GHG intensity - the ratio of emissions to economic output - by 18 percent through 2012. The Energy Policy Act of 2005 established a Committee on Climate Change Technology to coordinate federal climate change activities and promote the development and deployment of GHG reducing technologies.

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

Regulation of Hazardous Waste

TE has been named a 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 are liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of September 30, 2005, 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. Included in Other Noncurrent Liabilities are accrued liabilities aggregating approximately $0.2 million as of September 30, 2005.

See Note 13(B) to the consolidated financial statements for further details and a complete discussion of environmental matters.

Other Legal Proceedings

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to TE's normal business operations pending against TE and its subsidiaries. The other material items not otherwise discussed above are described below.

On August 14, 2003, various states and parts of southern Canada experienced widespread power outages. The outages affected approximately 1.4 million customers in FirstEnergy's service area. The U.S. - Canada Power System Outage Task Force's final report in April 2004 on the outages concludes, among other things, that the problems leading to the outages began in FirstEnergy's Ohio service area. Specifically, the final report concluded, among other things, that the initiation of the August 14, 2003 power outages resulted from an alleged failure of both FirstEnergy and ECAR to assess and understand perceived inadequacies within the FirstEnergy system; inadequate situational awareness of the developing conditions; and a perceived failure to adequately manage tree growth in certain transmission rights of way. The Task Force also concluded that there was a failure of the interconnected grid's reliability organizations (MISO and PJM) to provide effective real-time diagnostic support. The final report is publicly available through the Department of Energy's website (www.doe.gov). FirstEnergy believes that the final report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14, 2003 power outages and that it does not adequately address the underlying causes of the outages. FirstEnergy remains convinced that the outages cannot be explained by events on any one utility's system. The final report contained 46 "recommendations to prevent or minimize the scope of future blackouts." Forty-five of those recommendations related to broad industry or policy matters while one, including subparts, related to activities the Task Force recommended be undertaken by FirstEnergy, MISO, PJM, ECAR, and other parties to correct the causes of the August 14, 2003 power outages. FirstEnergy implemented several initiatives, both prior to and since the August 14, 2003 power outages, which were independently verified by NERC as complete in 2004 and were consistent with these and other recommendations and collectively enhance the reliability of its electric system. FirstEnergy's implementation of these recommendations in 2004 included completion of the Task Force recommendations that were directed toward FirstEnergy. FirstEnergy also is proceeding with the implementation of the recommendations regarding enhancements to regional reliability that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new, or material upgrades, to existing equipment, and therefore FirstEnergy has not accrued a liability as of September 30, 2005 for any expenditures in excess of those actually incurred through that date. FirstEnergy notes, however, that FERC or other applicable government agencies and reliability coordinators may take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures. Finally, the PUCO is continuing to review FirstEnergy's filing that addressed upgrades to control room computer hardware and software and enhancements to the training of control room operators, before determining the next steps, if any, in the proceeding.

FirstEnergy companies also are defending six separate complaint cases before the PUCO relating to the August 14, 2003 power outage. Two such cases were originally filed in Ohio State courts but subsequently dismissed for lack of subject matter jurisdiction and further appeals were unsuccessful. In both such cases the individual complainants—three in one case and four in the other—sought to represent others as part of a class action. The PUCO dismissed the class allegations, stating that its rules of practice do not provide for class action complaints. Of the four other pending PUCO complaint cases, three were filed by various insurance carriers either in their own name as subrogees or in the name of their insured. In each such case, the carriers seek reimbursement against various FirstEnergy companies (and, in one case, against PJM, MISO and American Electric Power Co. as well) for claims they paid to their insureds allegedly due to the loss of power on August 14, 2003. The listed insureds in these cases, in many instances, are not customers of any FirstEnergy company. The fourth case involves the claim of a non-customer seeking reimbursement for losses incurred when its store was burglarized on August 14, 2003. In addition to these six cases, the Ohio

Companies were named as respondents in a regulatory proceeding that was initiated at the PUCO in response to complaints alleging failure to provide reasonable and adequate service stemming primarily from the August 14, 2003 power outages. No estimate of potential liability has been undertaken for any of these cases.

One complaint was filed on August 25, 2004 against FirstEnergy in the New York State Supreme Court. In this case, several plaintiffs in the New York City metropolitan area allege that they suffered damages as a result of the August 14, 2003 power outages. None of the plaintiffs are customers of any FirstEnergy affiliate. FirstEnergy's motion to dismiss the case was granted on September 26, 2005. Additionally, FirstEnergy Corp. was named in a complaint filed in Michigan State Court by an individual who is not a customer of any FirstEnergy company. A responsive pleading to this matter is not due until on or about December 1, 2005. No estimate of potential liability has been undertaken in this matter.

FirstEnergy is vigorously defending these actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be initiated against the Companies. In particular, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

FENOC received a subpoena in late 2003 from a grand jury sitting in the United States District Court for the Northern District of Ohio, Eastern Division requesting the production of certain documents and records relating to the inspection and maintenance of the reactor vessel head at the Davis-Besse Nuclear Power Station, in which TE has a 48.62% interest. On December 10, 2004, FirstEnergy received a letter from the United States Attorney's Office stating that FENOC is a target of the federal grand jury investigation into alleged false statements made to the NRC in the Fall of 2001 in response to NRC Bulletin 2001-01. The letter also said that the designation of FENOC as a target indicates that, in the view of the prosecutors assigned to the matter, it is likely that federal charges will be returned against FENOC by the grand jury. On February 10, 2005, FENOC received an additional subpoena for documents related to root cause reports regarding reactor head degradation and the assessment of reactor head management issues at Davis-Besse. On May 11, 2005, FENOC received a subpoena for documents related to outside meetings attended by Davis-Besse personnel on corrosion and cracking of control rod drive mechanisms and additional root cause evaluations.

On April 21, 2005, the NRC issued a NOV and proposed a $5.45 million civil penalty related to the degradation of the Davis-Besse reactor vessel head issue described above. TE accrued $1.0 million for a potential fine prior to 2005 and accrued the remaining liability for its share of the proposed fine of $1.65 million during the first quarter of 2005. On September 14, 2005, FENOC filed its response to the NOV with the NRC. FENOC accepted full responsibility for the past failure to properly implement its boric acid corrosion control and corrective action programs. The NRC NOV indicated that the violations do not represent current licensee performance. FirstEnergy paid the penalty in the third quarter of 2005.

If it were ultimately determined that FirstEnergy or its subsidiaries has legal liability based on events surrounding Davis-Besse, it could have a material adverse effect on FirstEnergy's or any of its subsidiaries' financial condition, results of operations and cash flows.

Effective July 1, 2005 the NRC oversight panel for Davis-Besse was terminated and Davis-Besse returned to the standard NRC reactor oversight process. At that time, NRC inspections were augmented to include inspections to support the NRC's Confirmatory Order dated March 8, 2004 that was issued at the time of startup and to address an NRC White Finding related to the performance of the emergency sirens.

On August 12, 2004, the NRC notified FENOC that it would increase its regulatory oversight of the Perry Nuclear Power Plant as a result of problems with safety system equipment over the preceding two years and the licensee's failure to take prompt and effective corrective action. FENOC operates the Perry Nuclear Power Plant, in which TE has a 19.91% interest (however, see Note 17 regarding FirstEnergy’s pending intra-system generation asset transfers, which include owned portions of the plant).

On April 4, 2005, the NRC held a public meeting to discuss FENOC’s performance at the Perry Nuclear Power Plant as identified in the NRC's annual assessment letter to FENOC. Similar public meetings are held with all nuclear power plant licensees following issuance by the NRC of their annual assessments. According to the NRC, overall the Perry Plant operated "in a manner that preserved public health and safety" even though it remained under heightened NRC oversight. During the public meeting and in the annual assessment, the NRC indicated that additional inspections will continue and that the plant must improve performance to be removed from the Multiple/Repetitive Degraded Cornerstone Column of the Action Matrix.

On May 26, 2005, the NRC held a public meeting to discuss its oversight of the Perry Plant. While the NRC stated that the plant continued to operate safely, the NRC also stated that the overall performance had not substantially improved since the heightened inspection was initiated. The NRC reiterated this conclusion in its mid-year assessment letter dated August 30, 2005. On September 28, 2005, the NRC sent a CAL to FENOC describing commitments that FENOC had made to improve the performance of Perry and stated that the CAL would remain open until substantial improvement was demonstrated. The CAL was anticipated as part of the NRC's Reactor Oversight Process. If performance does not improve, the NRC has a range of options under the Reactor Oversight Process from increased oversight to possible impact to the plant’s operating authority. As a result, these matters could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

On October 20, 2004, FirstEnergy was notified by the SEC that the previously disclosed informal inquiry initiated by the SEC's Division of Enforcement in September 2003 relating to the restatements in August 2003 of previously reported results by FirstEnergy and TE, and the Davis-Besse extended outage, have become the subject of a formal order of investigation. The SEC's formal order of investigation also encompasses issues raised during the SEC's examination of FirstEnergy and the Companies under the PUHCA. Concurrent with this notification, FirstEnergy received a subpoena asking for background documents and documents related to the restatements and Davis-Besse issues. On December 30, 2004, FirstEnergy received a subpoena asking for documents relating to issues raised during the SEC's PUHCA examination. On August 24, 2005, additional information was requested regarding Davis-Besse. FirstEnergy has cooperated fully with the informal inquiry and will continue to do so with the formal investigation.

The City of Huron filed a complaint against OE with the PUCO challenging the ability of electric distribution utilities to collect transition charges from a customer of a newly formed municipal electric utility. The complaint was filed on May 28, 2003, and OE timely filed its response on June 30, 2003. In a related filing, the Ohio Companies filed for approval with the PUCO of a tariff that would specifically allow the collection of transition charges from customers of municipal electric utilities formed after 1998. An adverse ruling could negatively affect full recovery of transition charges by TE. Hearings on the matter were held in August 2005. Initial briefs from all parties were filed on September 22, 2005 and reply briefs were filed on October 14, 2005. It is unknown when the PUCO will rule on this case.

If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on the above matters, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

See Note 13(C) to the consolidated financial statements for further details and a complete discussion of other legal proceedings.

New Accounting Standards and Interpretations

EITF Issue 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty"

In September 2005, the EITF reached a final consensus on Issue 04-13 concluding that two or more legally separate exchange transactions with the same counterparty should be combined and considered as a single arrangement for purposes of applying APB 29, when the transactions were entered into "in contemplation" of one another. If two transactions are combined and considered a single arrangement, the EITF reached a consensus that an exchange of inventory should be accounted for at fair value. Although electric power is not capable of being held in inventory, there is no substantive conceptual distinction between exchanges involving power and other storable inventory. Therefore, TE will adopt this EITF effective for new arrangements entered into, or modifications or renewals of existing arrangements, in interim or annual periods beginning after March 15, 2006.

EITF Issue No. 05-6, "Determining the Amortization Period for Leasehold Improvements Purchased after Lease Inception or Acquired in a Business Combination"

In June 2005, the EITF reached a consensus on the application guidance for Issue 05-6. EITF 05-6 addresses the amortization period for leasehold improvements that were either acquired in a business combination or placed in service significantly after and not contemplated at or near the beginning of the initial lease term. For leasehold improvements acquired in a business combination, the amortization period is the shorter of the useful life of the assets or a term that includes required lease periods and renewals that are deemed to be reasonably assured at the date of acquisition. Leasehold improvements that are placed in service significantly after and not contemplated at or near the beginning of the lease term should be amortized over the shorter of the useful life of the assets or a term that includes required lease periods and renewals that are deemed to be reasonably assured at the date the leasehold improvements are purchased. This EITF was effective July 1, 2005 and is consistent with TE's current accounting.

FIN 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143"

On March 30, 2005, the FASB issued FIN 47 to clarify the scope and timing of liability recognition for conditional asset retirement obligations. Under this interpretation, companies are required to recognize a liability for the fair value of an asset retirement obligation that is conditional on a future event, if the fair value of the liability can be reasonably estimated. In instances where there is insufficient information to estimate the liability, the obligation is to be recognized in the first period in which sufficient information becomes available to estimate its fair value. If the fair value cannot be reasonably estimated, that fact and the reasons why must be disclosed. This Interpretation is effective for TE in the fourth quarter of 2005. TE is currently evaluating the effect this Interpretation will have on its financial statements.

SFAS 154 - "Accounting Changes and Error Corrections - a replacement of APB Opinion No. 20 and FASB Statement No. 3"

In May 2005, the FASB issued SFAS 154 to change the requirements for accounting and reporting a change in accounting principle. It applies to all voluntary changes in accounting principle and to changes required by an accounting pronouncement when that pronouncement does not include specific transition provisions. This Statement requires retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. In those instances, this Statement requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that period rather than being reported in the Consolidated Statements of Income. This Statement also requires that a change in depreciation, amortization, or depletion method for long-lived, nonfinancial assets be accounted for as a change in accounting estimate affected by a change in accounting principle. The provisions of this Statement are effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. TE will adopt this Statement effective January 1, 2006.

SFAS 153, "Exchanges of Nonmonetary Assets - an amendment of APB Opinion No. 29"

In December 2004, the FASB issued SFAS 153 amending APB 29, which was based on the principle that nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance in APB 29 included certain exceptions to that principle. SFAS 153 eliminates the exception from fair value measurement for nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges that do not have commercial substance. This Statement specifies that a nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of this Statement are effective January 1, 2006 for TE. This FSP is not expected to have a material impact on TE's financial statements.

SFAS 151, "Inventory Costs - an amendment of ARB No. 43, Chapter 4"

In November 2004, the FASB issued SFAS 151 to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage). Previous guidance stated that in some circumstances these costs may be "so abnormal" that they would require treatment as current period costs. SFAS 151 requires abnormal amounts for these items to always be recorded as current period costs. In addition, this Statement requires that allocation of fixed production overheads to the cost of conversion be based on the normal capacity of the production facilities. The provisions of this statement are effective for inventory costs incurred by TE beginning January 1, 2006. TE is currently evaluating this Standard and does not expect it to have a material impact on its financial statements.

FSP FAS 115-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"

In September 2005, the FASB finalized and renamed EITF 03-1 and 03-1-a to FSP FAS 115-1. FSP FAS 115-1 will (1) supersede Issue 03-1 and EITF topic No. D-44, "Recognition of Other Than Temporary Impairment upon the Planned Sale of a Security Whose Cost Exceeds Fair Value," (2) clarify that an investor should recognize an impairment loss no later than when the impairment is deemed other than temporary, even if a decision to sell has not been made, and (3) be effective for other-than-temporary impairment and analyses conducted in periods beginning after September 15, 2005. The FASB expects to issue this FSP in the fourth quarter of 2005, which would require prospective application with an effective date for reporting periods beginning after December 15, 2005. TE is currently evaluating this FSP and any impact on its investments.

PENNSYLVANIA POWER COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In thousands)			
STATEMENTS OF INCOME				
OPERATING REVENUES	$ 145,540	$ 143,340	$ 414,306	$ 420,578
OPERATING EXPENSES AND TAXES:				
Fuel	6,205	6,347	17,351	18,408
Purchased power	42,242	44,096	131,948	136,699
Nuclear operating costs	16,997	19,934	56,710	55,737
Other operating costs	19,030	16,212	48,541	45,371
Provision for depreciation	3,847	3,556	11,351	10,390
Amortization of regulatory assets	9,784	9,979	29,499	30,082
General taxes	6,836	6,416	19,752	17,538
Income taxes	17,402	16,541	43,055	46,425
Total operating expenses and taxes	122,343	123,081	358,207	360,650
OPERATING INCOME	23,197	20,259	56,099	59,928
OTHER INCOME (net of income taxes)	549	745	623	2,287
NET INTEREST CHARGES:				
Interest expense	2,371	1,911	7,477	7,434
Allowance for borrowed funds used during construction	(1,665)	(1,271)	(4,508)	(3,197)
Net interest charges	706	640	2,969	4,237
NET INCOME	23,040	20,364	53,753	57,978
PREFERRED STOCK DIVIDEND REQUIREMENTS	156	639	1,534	1,919
EARNINGS ON COMMON STOCK	$ 22,884	$ 19,725	$ 52,219	$ 56,059
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$ 23,040	$ 20,364	$ 53,753	$ 57,978

OTHER COMPREHENSIVE INCOME		-		-		-		-
TOTAL COMPREHENSIVE INCOME	$	23,040	$	20,364	$	53,753	$	57,978

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

PENNSYLVANIA POWER COMPANY

CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2005	December 31, 2004
	(In thousands)	
ASSETS		
UTILITY PLANT:		
In service	$ 907,382	$ 866,303
Less - Accumulated provision for depreciation	378,707	356,020
	528,675	510,283
Construction work in progress -		
Electric plant	133,790	104,366
Nuclear fuel	10,428	3,362
	144,218	107,728
	672,893	618,011
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	146,706	143,062
Long-term notes receivable from associated companies	32,864	32,985
Other	502	722
	180,072	176,769
CURRENT ASSETS:		
Cash and cash equivalents	24	38
Notes receivable from associated companies	566	431
Receivables -		
Customers (less accumulated provisions of $1,066,000 and $888,000, respectively, for uncollectible accounts)	44,990	44,282
Associated companies	6,206	23,016
Other	2,617	1,656
Materials and supplies, at average cost	37,974	37,923
Prepayments and other	12,110	8,924
	104,487	116,270
DEFERRED CHARGES	10,721	10,106
	$ 968,173	$ 921,156
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	$ 188,700
Other paid-in capital	65,035	64,690
Accumulated other comprehensive loss	(13,706)	(13,706)
Retained earnings	131,914	87,695
Total common stockholder's equity	371,943	327,379
Preferred stock	14,105	39,105

Long-term debt and other long-term obligations		121,170		133,887
		507,218		500,371
CURRENT LIABILITIES:				
Currently payable long-term debt		25,774		26,524
Short-term borrowings -				
Associated companies		34,821		11,852
Accounts payable -				
Associated companies		16,864		46,368
Other		1,884		1,436
Accrued taxes		26,163		14,055
Accrued interest		1,635		1,872
Other		8,491		8,802
		115,632		110,909
NONCURRENT LIABILITIES:				
Accumulated deferred income taxes		79,801		93,418
Asset retirement obligation		155,959		138,284
Retirement benefits		51,389		49,834
Regulatory liabilities		47,809		18,454
Other		10,365		9,886
		345,323		309,876
COMMITMENTS AND CONTINGENCIES (Note 13)				
	$	968,173	$	921,156

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

PENNSYLVANIA POWER COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 23,040	$ 20,364	$ 53,753	$ 57,978
Adjustments to reconcile net income to net cash from operating activities -				
Provision for depreciation	3,847	3,556	11,351	10,390
Amortization of regulatory assets	9,784	9,979	29,499	30,082
Nuclear fuel and other amortization	4,634	4,550	12,912	13,546
Deferred income taxes and investment tax credits, net	(2,612)	(501)	(7,567)	(2,852)
Pension trust contribution	-	(12,934)	-	(12,934)
Decrease (increase) in operating assets -				
Receivables	4,303	(30,285)	15,141	(10,551)
Materials and supplies	755	(1,078)	(51)	(3,374)
Prepayments and other current assets	5,074	4,164	(3,186)	(3,977)
Increase (decrease) in operating liabilities -				
Accounts payable	(9,161)	40,306	(29,056)	21,678
Accrued taxes	5	(2,485)	12,108	2,301
Accrued interest	(353)	(986)	(237)	(2,415)
Other	564	1,353	1,027	5,294
Net cash provided from operating activities	39,880	36,003	95,694	105,166
CASH FLOWS FROM FINANCING ACTIVITIES:				
New Financing -				
Short-term borrowings, net	-	-	22,969	10,789
Equity contribution from parent	-	25,000	-	25,000
Redemptions and Repayments -				
Preferred stock	-	-	(37,750)	-
Long-term debt	(39)	(20,508)	(849)	(63,297)
Short-term borrowings, net	(10,776)	(11,414)	-	-
Dividend Payments -				
Common stock	-	-	(8,000)	(23,000)

Preferred stock	(156)	(639)	(1,534)	(1,919)
Net cash used for financing activities	(10,971)	(7,561)	(25,164)	(52,427)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions	(28,537)	(24,670)	(69,630)	(56,080)
Contributions to nuclear decommissioning trusts	(399)	(399)	(1,196)	(1,196)
Loan repayments from (loans to) associated companies	(187)	(36)	(14)	5,975
Other	214	(3,337)	296	(1,440)
Net cash used for investing activities	(28,909)	(28,442)	(70,544)	(52,741)
Net change in cash and cash equivalents	-	-	(14)	(2)
Cash and cash equivalents at beginning of period	24	38	38	40
Cash and cash equivalents at end of period	$ 24	$ 38	$ 24	$ 38

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

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Report of Independent Registered Public Accounting Firm

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

We have reviewed the accompanying consolidated balance sheet of Pennsylvania Power Company and its subsidiary as of September 30, 2005, and the related consolidated statements of income and comprehensive income and cash flows for each of the three-month and nine-month periods ended September 30, 2005 and 2004. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 the standards of the Public Company Accounting Oversight Board, 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 the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2004, and the related consolidated statements of income, capitalization, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended, management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004 and the effectiveness of the Company's internal control over financial reporting as of December 31, 2004; and in our report (which contained references to the Company's change in its method of accounting for asset retirement obligations as of January 1, 2003 as discussed in Note 2(G) to those consolidated financial statements) dated March 7, 2005, we expressed unqualified opinions thereon. The consolidated financial statements and management's assessment of the effectiveness of internal control over financial reporting referred to above are not presented herein. In our opinion, the information set forth in the accompanying consolidated balance sheet information as of December 31, 2004, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio
November 1, 2005

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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 Penn 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 third quarter of 2005 increased to $23 million from $20 million in the third quarter of 2004. The increased earnings resulted primarily from higher operating revenues and lower operating expenses and taxes. Earnings on common stock for the first nine months of 2005 decreased to $52 million from $56 million for the same period of 2004. The lower earnings resulted primarily from a decrease in operating revenues and other income, partially offset by lower operating expenses and taxes and lower net interest charges.

Operating revenues increased by $2 million, or 1.5%, in the third quarter of 2005 compared with the third quarter of 2004. Higher revenues in the third quarter of 2005 primarily resulted from increased retail generation sales revenues of $6 million and a $2 million increase in rental revenues, partially offset by a $6 million decrease in wholesale sales to FES. Retail generation sales increased as a result of increased KWH sales to residential (7.6%) and commercial (4.0%) customers, due to warmer weather in Penn's service area, and a 19.8% KWH sales increase to industrial customers, primarily within the steel sector.

Revenues from distribution deliveries in the third quarter of 2005 increased slightly from the third quarter of 2004, as lower unit prices partially offset a 10.2% increase in KWH sales. The lower unit prices were primarily attributable to changes in Penn's CTC rate schedules in April 2005 as a result of the annual CTC reconciliation. Increased revenues from distribution deliveries to residential ($0.3 million) and industrial ($0.8 million) customers were offset by a $1 million decrease in revenues from commercial customers.

Operating revenues decreased by $6 million in the first nine months of 2005 compared with the same period of 2004. The lower operating revenues reflected a $24 million decrease in wholesale sales to FES, partially offset by higher retail sales of $14 million. Higher retail electric generation revenues of $14 million resulted from increased KWH sales to all sectors (Residential - 8.0%, Commercial - 5.6% and Industrial - 1.5%) and higher unit prices for commercial and industrial customers.

In the first nine months of 2005, revenues from distribution deliveries increased by $0.3 million compared to the same period of 2004. An increase in total KWH deliveries of 5.0% was offset by lower unit prices, reflecting the changes in Penn's CTC rates discussed above. Increased revenues from distribution deliveries to residential customers of $4 million were partially offset by lower revenues from commercial ($1 million) and industrial ($2 million) customers.

Changes in kilowatt-hour sales by customer class in the three months and nine months ended September 30, 2005 from the corresponding periods of 2004 are summarized in the following table:

Changes in KWH Sales Increase (Decrease)	Three Months	Nine Months
Electric Generation:		
Retail	10.2%	5.0%
Wholesale	(1.4)%	(5.5)%
Total Electric Generation Sales	3.1%	(1.4)%
Distribution Deliveries:		
Residential	7.6%	8.0%
Commercial	4.0%	5.6%
Industrial	19.8%	1.5%
Total Distribution Deliveries	10.2%	5.0%

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Operating Expenses and Taxes

Total operating expenses and taxes decreased by $1 million in the third quarter and $2 million in the first nine months of 2005 from the same periods of 2004. The following table presents changes from the prior year by expense category.

Operating Expenses and Taxes - Changes	Three Months	Nine Months
	(In millions)	
Increase (Decrease)		
Fuel costs	$ -	$ (1)
Purchased power costs	(2)	(4)
Nuclear operating costs	(3)	1
Other operating costs	3	3
General taxes	-	2
Income taxes	1	(3)
Net decrease in operating expenses and taxes	$ (1)	$ (2)

The decrease in purchased power costs in the three months and nine months ended September 30, 2005 resulted from lower unit prices for power. Nuclear operating costs were lower in the third quarter of 2005, reflecting a decrease in labor and postretirement benefit expenses from the third quarter of 2004. Other operating costs were higher in the three months and nine months ended September 30, 2005 as the result of increased transmission related expenses associated with MISO's energy market that began on April 1, 2005.

Other Income

Other income (net of income taxes) decreased slightly in the third quarter and by $2 million in the first nine months of 2005, compared with the same periods in 2004. The decrease in the nine month period reflects liabilities recognized in the first quarter of 2005 related to the W. H. Sammis Plant settlement (see Outlook - Environmental Matters).

Net Interest Charges

Net interest charges decreased by $1 million in the nine months ended September 30, 2005 from the corresponding period last year, reflecting redemptions of $40 million principal amount of debt securities since October 1, 2004.

Capital Resources and Liquidity

Penn’s cash requirements for operating expenses, construction expenditures, scheduled debt maturities and preferred stock redemptions are expected to be met with a combination of cash from operations and funds from the capital markets. Borrowing capacity under credit facilities is available to manage working capital requirements.

Changes in Cash Position

As of September 30, 2005, Penn had $24,000 of cash and cash equivalents, compared with $38,000 as of December 31, 2004. The major changes in these balances are summarized below.

Cash Flows From Operating Activities

Net cash provided from operating activities in the three months and nine months ended September 30, 2005, compared with the corresponding 2004 periods, was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Operating Cash Flows	**2005**	**2004**	**2005**	**2004**
		(In millions)		
Cash earnings [1]	$ 40	$ 34	$ 101	$ 108
Pension trust contribution[2]	-	(8)	-	(8)
Working capital and other	-	10	(5)	5
Total cash flows from operating activities	$ 40	$ 36	$ 96	$ 105

[1] Cash earnings is a non-GAAP measure (see reconciliation below).
[2] Pension trust contribution net of $5 million of income tax benefits.

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Cash earnings (in the table above) are not a measure of performance calculated in accordance with GAAP. Penn believes that cash earnings is a useful financial measure because it provides investors and management with an additional means of evaluating its cash-based operating performance. The following table reconciles cash earnings with net income.

Reconciliation of Cash Earnings	**Three Months Ended September 30, 2005**	**2004**	**Nine Months Ended September 30, 2005**	**2004**
	(In millions)			
Net income (GAAP)	$ 23	$ 20	$ 54	$ 58
Non-cash charges (credits):				
Provision for depreciation	4	4	11	10
Amortization of regulatory assets	10	10	29	30
Nuclear fuel and other amortization	5	4	13	14
Deferred income taxes and investment tax credits, net	(3)	(5)	(8)	(8)
Other non-cash items	1	1	2	4
Cash earnings (Non-GAAP)	$ 40	$ 34	$ 101	$ 108

The $6 million increase in cash earnings in the third quarter of 2005 and the $7 million decrease in cash earnings for the first nine months of 2005, as compared to the corresponding periods of 2004, are described under "Results of Operations." The $10 million change in working capital and other in the three-month period was primarily due to a $49 million change in accounts payable, partially offset by changes of $35 million in receivables, $2 million in materials and supplies, and $2 million in accrued taxes. The $10 million change in working capital and other in the nine-month period was primarily due to a $51 million change in accounts payable, partially offset by changes of $26 million in receivables, $3 million in materials and supplies, and $10 million in accrued taxes.

Cash Flows From Financing Activities

Net cash used for financing activities totaled $11 million in the third quarter of 2005, compared with $8 million in the same period last year. The $3 million increase resulted primarily from the absence of a $25 million equity contribution from OE in the third quarter of 2004, partially offset by a $21 million decrease in debt redemptions and repayments in the third quarter of 2005.

Net cash used for financing activities totaled $25 million in the nine months ended September 30, 2005, compared with $52 million in the same period last year. The $27 million decrease resulted primarily from reduced long-term debt redemptions and common stock dividend payments in the first nine months of 2005, offset by reduced short-term borrowings and OE's $25 million equity contribution in 2004.

On May 16, 2005, Penn redeemed all 127,500 outstanding shares of 7.625% preferred stock at $102.29 per share and all 250,000 outstanding shares of 7.75% preferred stock at $100 per share, both plus accrued dividends to the date of redemption. The total par value of the preferred stock redeemed was $37.8 million.

Penn had $590,000 of cash and temporary investments (which included short-term notes receivable from associated companies) and $35 million of short-term indebtedness as of September 30, 2005. Penn has authorization from the SEC to incur short-term debt up to its charter limit of $51 million. As of October 24, 2005, Penn had the capability to issue approximately $520 million of additional FMB on the basis of property additions and retired bonds following the recently completed intra-system transfer of fossil generating plants (See Note 17) . Based upon applicable earnings coverage tests, Penn could issue up to $383 million of preferred stock (assuming no additional debt was issued) as of September 30, 2005. It is estimated that the annualized impact of the intra-system transfer of fossil generating plants will reduce the capability of Penn to issue preferred stock by approximately 14%. The above financing capabilities do not take into consideration changes related to the intercompany transfer of generating assets (see Note 17).

On June 14, 2005, FirstEnergy, OE, Penn, CEI, TE, JCP&L, Met-Ed, Penelec, FES and ATSI, as Borrowers, entered into a syndicated $2 billion five-year revolving credit facility. Borrowings under the facility are available to each Borrower separately and will mature on the earlier of 364 days from the date of borrowing and the commitment termination date, as the same may be extended. Penn's borrowing limit under the facility is $51 million.

Penn has the ability to borrow from its regulated affiliates and FirstEnergy to meet its short-term working capital requirements. FESC administers this money pool and tracks surplus funds of FirstEnergy and its regulated subsidiaries. Companies receiving a loan under the money pool agreements must repay the principal amount of such a loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from the pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings under these arrangements in the third quarter of 2005 was 3.50%.

Penn Power Funding LLC (Penn Funding), a wholly owned subsidiary of Penn, is a limited liability company whose borrowings are secured by customer accounts receivable purchased from Penn. Penn Funding can borrow up to $25 million under a receivables financing arrangement. As a separate legal entity with separate creditors, Penn Funding would have to satisfy its obligations to creditors before any of its remaining assets could be made available to Penn. The facility was not drawn as of September 30, 2005. On July 15, 2005, the facility was renewed until June 29, 2006. The annual facility fee is 0.25% on the entire finance limit.

Penn's access to capital markets and costs of financing are dependent on the ratings of its securities and the securities of OE and FirstEnergy.

On July 18, 2005, Moody's revised its rating outlook on FirstEnergy and its subsidiaries to positive from stable. Moody's stated that the revision to FirstEnergy's outlook resulted from steady financial improvement and steps taken by management to improve operations, including the stabilization of its nuclear operations. Moody's further stated that the revision in their outlook recognized management's regional strategy of focusing on its core utility businesses and the improvement in FirstEnergy's credit profile stemming from the application of free cash flow toward debt reduction. Moody's noted that a ratings upgrade could be considered if FirstEnergy continues to achieve planned improvements in its operations and balance sheet.

On October 3, 2005, S&P raised its corporate credit rating on FirstEnergy and the EUOC to 'BBB' from 'BBB-'. At the same time, S&P raised the senior unsecured ratings at the holding company to 'BBB-' from 'BB+' and each of the EUOC by one notch above the previous rating. S&P noted that the upgrade followed the continuation of a good operating track record, specifically for the nuclear fleet through the third quarter 2005. S&P also stated that FirstEnergy's rating reflects the benefits of supportive regulation, low-cost base load generation fleet, low-risk transmission and distribution operations and rate certainty in Ohio. FirstEnergy's ability to consistently generate free cash flow, good liquidity, and an improving financial profile were also noted as strengths.

Cash Flows From Investing Activities

Net cash used in investing activities totaled $29 million in the third quarter of 2005, compared with $28 million in the third quarter of 2004. For the nine months ended September 30, 2005, net cash used in investing activities totaled $71 million, compared with $53 million in the same period last year. The $18 million increase was primarily the result of higher expenditures for property additions in 2005 and reduced loan repayments from associated companies.

In the last quarter of 2005, capital requirements for property additions are expected to be about $32 million. Penn also expects to contribute up to $63 million (unfunded liability recognized as of September 30, 2005) for nuclear decommissioning in connection with the generation asset transfers described below, and has additional requirements of $0.5 million to meet sinking fund requirements for long-term debt during the remainder of 2005. These cash requirements are expected to be satisfied from internal cash and short-term credit arrangements. Penn's capital spending for the period 2005-2007 is expected to be about $227 million, of which approximately $87 million applies to 2005. Penn had no other material obligations as of September 30, 2005 that have not been recognized on its Consolidated Balance Sheet.

On July 22, 2005, the Philadelphia Stock Exchange (Exchange) filed an application with the SEC for termination of the listing of the following three series of Penn's cumulative preferred stock, $100 par value, as such series no longer met the Exchange's technical listing requirements regarding the number of outstanding shares and the number of holders: 4.24% Series, 4.25% Series and 4.64% Series. On August 17, 2005, the SEC granted the Exchange's application for delisting effective August 18, 2005.

Equity Price Risk

Included in Penn's nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $60 million and $57 million as of September 30, 2005 and December 31, 2004, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $6 million reduction in fair value as of September 30, 2005.

FirstEnergy Intra-System Generation Asset Transfers

On May 13, 2005, Penn entered into an agreement to transfer its ownership interests in its nuclear and fossil generating facilities to NGC and FGCO, respectively.

On October 24, 2005, Penn completed the transfer of fossil generation assets to FGCO. Penn currently expects to complete the transfer of nuclear generation assets to NGC through a spin-off by way of dividend before the end of 2005. Consummation of the nuclear transfer remains subject to necessary regulatory approvals.

These transactions are being undertaken in connection with Penn's restructuring plan that was approved by the PPUC under applicable Pennsylvania electric utility restructuring legislation. Consistent with the restructuring plan, Penn's generation assets were required to be separated from the regulated delivery business through transfers to a separate corporate entity. FENOC currently operates and maintains the nuclear generation assets to be transferred. FGCO, as lessee under a Master Facility Lease, leased, operated and maintained the non-nuclear generation assets that it now owns. The transactions will essentially complete the divestitures contemplated by the restructuring plan by transferring the ownership interests to NGC and FGCO, respectively, without impacting the operation of the plants.

See Note 17 to the consolidated financial statements for disclosure of Penn's assets held for sale as of September 30, 2005.

Regulatory Matters

Regulatory assets and liabilities are costs which have been authorized by the PPUC and the FERC for recovery from or credit to customers in future periods and, without such authorization, would have been charged or credited to income when incurred. Penn's net regulatory liabilities were approximately $48 million and $18 million as of September 30, 2005 and December 31, 2004, respectively, and are included in Noncurrent Liabilities on the Consolidated Balance Sheets.

In October 11, 2005, Penn filed a plan with the PPUC to secure electricity supply for its customers at set rates following the end of its transition period on December 31, 2006. Penn is recommending that the Request for Proposal process cover the period of January 1, 2007 through May 31, 2008. Under Pennsylvania's electric competition law, Penn is required to secure generation supply for customers who do not choose alternative suppliers for their electricity.

See Note 14 to the consolidated financial statements for further details and a complete discussion of regulatory matters in Pennsylvania, including a more detailed discussion of reliability initiatives.

Environmental Matters

Penn accrues environmental liabilities when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. Unasserted claims are reflected in Penn's determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

FirstEnergy plans to issue a report regarding its response to air emission requirements. FirstEnergy expects to complete the report by December 1, 2005.

National Ambient Air Quality Standards

In July 1997, the EPA promulgated changes in the NAAQS for ozone and proposed a new NAAQS for fine particulate matter. On March 10, 2005, the EPA finalized the "Clean Air Interstate Rule" covering a total of 28 states (including Ohio and Pennsylvania) and the District of Columbia based on proposed findings that air emissions from 28 eastern states and the District of Columbia significantly contribute to nonattainment of the NAAQS for fine particles and/or the "8-hour" ozone NAAQS in other states. CAIR provides each affected state until 2006 to develop implementing regulations to achieve additional reductions of NO_x and SO_2 emissions in two phases (Phase I in 2009 for NO_x, 2010 for SO_2 and Phase II in 2015 for both NO_x and SO_2), in all cases from the 2003 levels. Penn's Ohio and Pennsylvania fossil-fired generation facilities will be subject to the caps on SO_2 and NO_x emissions. According to the EPA, SO_2 emissions will be reduced by 45% (from 2003 levels) by 2010 across the states covered by the rule, with reductions reaching 73% (from 2003 levels) by 2015, capping SO_2 emissions in affected states to just 2.5 million tons annually. NO_x emissions will be reduced by 53% (from 2003 levels) by 2009 across the states covered by the rule, with reductions reaching 61% (from 2003 levels) by 2015, achieving a regional NO_x cap of 1.3 million tons annually. The future cost of compliance with these regulations may be substantial and will depend on how they are ultimately implemented by the states in which Penn operates affected facilities.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. On March 14, 2005, the EPA finalized the "Clean Air Mercury Rule," which provides a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases. Initially, mercury emissions will be capped nationally at 38 tons by 2010 as a "co-benefit" from implementation of SO_2 and NO_x emission caps under the EPA's CAIR program. Phase II of the mercury cap-and-trade program will cap nationwide mercury emissions from coal-fired power plants at 15 tons per year by 2018. However, the final rules give states substantial discretion in developing rules to implement these programs. In addition, both the CAIR and the Clean Air Mercury rule have been challenged in the United States Court of Appeals for the District of Columbia. Future cost of compliance with these regulations may be substantial.

W. H. Sammis Plant

In 1999 and 2000, the EPA issued NOV or Compliance Orders to nine utilities alleging violations of the Clean Air Act based on operation and maintenance of 44 power plants, including the W. H. Sammis Plant, which was owned at that time by OE and Penn. In addition, the DOJ filed eight civil complaints against various investor-owned utilities, including a complaint against OE and Penn in the U.S. District Court for the Southern District of Ohio. These cases are referred to as New Source Review cases. On March 18, 2005, OE and Penn announced that they had reached a settlement with the EPA, the DOJ and three states (Connecticut, New Jersey, and New York) that resolved all issues related to the W. H. Sammis Plant New Source Review litigation. This settlement agreement, which is in the form of a Consent Decree, was approved by the Court on July 11, 2005, requires OE and Penn to reduce NO_x and SO_2 emission at W. H. Sammis Plant and other coal-fired plants through the installation of pollution control devices. Capital expenditures necessary to meet those requirements are currently estimated to be $1.5 billion (the primary portion of which is expected to be spent in the 2008 to 2011 time period). The settlement agreement also requires OE and Penn to spend up to $25 million toward environmentally beneficial projects, which include wind energy purchased power agreements over a 20-year term. OE and Penn agreed to pay a civil penalty of $8.5 million, of which Penn's share was $0.7 million. Results for the first quarter of 2005 included the $0.7 million penalty payable by Penn and a $0.8 million liability for probable future cash contributions toward environmentally beneficial projects.

Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol (Protocol), to address global warming by reducing the amount of man-made greenhouse gases emitted by developed countries by 5.2% from 1990 levels between 2008 and 2012. The United States signed the Protocol in 1998 but it failed to receive the two-thirds vote of the United States Senate required for ratification. However, the Bush administration has committed the United States to a voluntary climate change strategy to reduce domestic greenhouse gas intensity - the ratio of emissions to economic output - by 18 percent through 2012. The Energy Policy Act of 2005 established a Committee on Climate Change Technology to coordinate federal climate change activities and promote the development and deployment of GHG reducing technologies.

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

See Note 13(B) to the consolidated financial statements for further details and a complete discussion of environmental matters.

Other Legal Proceedings

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to Penn's normal business operations pending against Penn. The other material items not otherwise discussed above are described below.

On August 14, 2003, various states and parts of southern Canada experienced widespread power outages. The outages affected approximately 1.4 million customers in FirstEnergy's service area. The U.S. - Canada Power System Outage Task Force's final report in April 2004 on the outages concluded, among other things, that the problems leading to the outages began in FirstEnergy's Ohio service area. Specifically, the final report concluded, among other things, that the initiation of the August 14, 2003 power outages resulted from an alleged failure of both FirstEnergy and ECAR to assess and understand perceived inadequacies within the FirstEnergy system; inadequate situational awareness of the developing conditions; and a perceived failure to adequately manage tree growth in certain transmission rights of way. The Task Force also concluded that there was a failure of the interconnected grid's reliability organizations (MISO and PJM) to provide effective real-time diagnostic support. The final report is publicly available through the Department of Energy's website (www.doe.gov). FirstEnergy believes that the final report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14, 2003 power outages and that it does not adequately address the underlying causes of the outages. FirstEnergy remains convinced that the outages cannot be explained by events on any one utility's system. The final report contained 46 "recommendations to prevent or minimize the scope of future blackouts." Forty-five of those recommendations related to broad industry or policy matters while one, including subparts, related to activities the Task Force recommended be undertaken by FirstEnergy, MISO, PJM, ECAR, and other parties to correct the causes of the August 14, 2003 power outages. FirstEnergy implemented several initiatives, both prior to and since the August 14, 2003 power outages, which were independently verified by NERC as complete in 2004 and were consistent with these and other recommendations and collectively enhance the reliability of its electric system. FirstEnergy's implementation of these recommendations in 2004 included completion of the Task Force recommendations that were directed toward FirstEnergy. FirstEnergy also is proceeding with the implementation of the recommendations regarding enhancements to regional reliability that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new or material upgrades to existing equipment, and therefore FirstEnergy has not accrued a liability as of September 30, 2005 for any expenditures in excess of those actually incurred through that date. The FERC or other applicable government agencies and reliability coordinators may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures. Finally, the PUCO is continuing to review FirstEnergy's filing that addressed upgrades to control room computer hardware and software and enhancements to the training of control room operators, before determining the next steps, if any, in the proceeding.

One complaint was filed on August 25, 2004 against FirstEnergy in the New York State Supreme Court. In this case, several plaintiffs in the New York City metropolitan area allege that they suffered damages as a result of the August 14, 2003 power outages. None of the plaintiffs are customers of any FirstEnergy affiliate. FirstEnergy's motion to dismiss the case was granted on September 26, 2005. Additionally, FirstEnergy Corp. was named in a complaint filed in Michigan State Court by an individual who is not a customer of any FirstEnergy company. A responsive pleading to this matter is not due until on or about December 1, 2005. No estimate of potential liability has been undertaken in this matter.

FirstEnergy is vigorously defending these actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be initiated against the Companies. In particular, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

On August 12, 2004, the NRC notified FENOC that it would increase its regulatory oversight of the Perry Nuclear Power Plant as a result of problems with safety system equipment over the preceding two years and the licensee's failure to take prompt and effective corrective action. FENOC operates the Perry Nuclear Power Plant, in which Penn currently has a 5.24% interest (however, see Note 17 regarding FirstEnergy's pending intra-system generation asset transfers, which will include owned portions of the plant).

On April 4, 2005, the NRC held a public meeting to discuss FENOC’s performance at the Perry Nuclear Power Plant as identified in the NRC's annual assessment letter to FENOC. Similar public meetings are held with all nuclear power plant licensees following issuance by the NRC of their annual assessments. According to the NRC, overall the Perry Plant operated "in a manner that preserved public health and safety" even though it remained under heightened NRC oversight. During the public meeting and in the annual assessment, the NRC indicated that additional inspections will continue and that the plant must improve performance to be removed from the Multiple/Repetitive Degraded Cornerstone Column of the Action Matrix.

On May 26, 2005, the NRC held a public meeting to discuss its oversight of the Perry Plant. While the NRC stated that the plant continued to operate safely, the NRC also stated that the overall performance had not substantially improved since the heightened inspection was initiated. The NRC reiterated this conclusion in its mid-year assessment letter dated August 30, 2005. On September 28, 2005, the NRC sent a CAL to FENOC describing commitments that FENOC had made to improve the performance of Perry and stated that the CAL would remain open until substantial improvement was demonstrated. The CAL was anticipated as part of the NRC's Reactor Oversight Process. If performance does not improve, the NRC has a range of options under the Reactor Oversight Process, from increased oversight to possible impact to the plant’s operating authority. As a result, these matters could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

See Note 13(C) to the consolidated financial statements for further details and a complete discussion of other legal proceedings.

New Accounting Standards and Interpretations

EITF Issue 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty"

In September 2005, the EITF reached a final consensus on Issue 04-13 concluding that two or more legally separate exchange transactions with the same counterparty should be combined and considered as a single arrangement for purposes of applying APB 29, when the transactions were entered into "in contemplation" of one another. If two transactions are combined and considered a single arrangement, the EITF reached a consensus that an exchange of inventory should be accounted for at fair value. Although electric power is not capable of being held in inventory, there is no substantive conceptual distinction between exchanges involving power and other storable inventory. Therefore, Penn will adopt this EITF effective for new arrangements entered into, or modifications or renewals of existing arrangements, in interim or annual periods beginning after March 15, 2006.

FIN 47, “Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143”

On March 30, 2005, the FASB issued FIN 47 to clarify the scope and timing of liability recognition for conditional asset retirement obligations. Under this interpretation, companies are required to recognize a liability for the fair value of an asset retirement obligation that is conditional on a future event, if the fair value of the liability can be reasonably estimated. In instances where there is insufficient information to estimate the liability, the obligation is to be recognized in the first period in which sufficient information becomes available to estimate its fair value. If the fair value cannot be reasonably estimated, that fact and the reasons why must be disclosed. This Interpretation is effective for Penn in the fourth quarter of 2005. Penn is currently evaluating the effect this Interpretation will have on its financial statements.

SFAS 154 - “Accounting Changes and Error Corrections - a replacement of APB Opinion No. 20 and FASB Statement No. 3”

In May 2005, the FASB issued SFAS 154 to change the requirements for accounting and reporting a change in accounting principle. It applies to all voluntary changes in accounting principle and to changes required by an accounting pronouncement when that pronouncement does not include specific transition provisions. This Statement requires retrospective application to prior periods’ financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. In those instances, this Statement requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that period rather than being reported in the Consolidated Statements of Income. This Statement also requires that a change in depreciation, amortization, or depletion method for long-lived, nonfinancial assets be accounted for as a change in accounting estimate affected by a change in accounting principle. The provisions of this Statement are effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. Penn will adopt this Statement effective January 1, 2006.

SFAS 153, "Exchanges of Nonmonetary Assets - an amendment of APB Opinion No. 29"

In December 2004, the FASB issued SFAS 153 amending APB 29, which was based on the principle that nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance in APB 29 included certain exceptions to that principle. SFAS 153 eliminates the exception from fair value measurement for nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges that do not have commercial substance. This Statement specifies that a nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of this Statement are effective January 1, 2006 for Penn. This FSP is not expected to have a material impact on Penn's financial statements.

SFAS 151, "Inventory Costs - an amendment of ARB No. 43, Chapter 4"

In November 2004, the FASB issued SFAS 151 to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage). Previous guidance stated that in some circumstances these costs may be "so abnormal" that they would require treatment as current period costs. SFAS 151 requires abnormal amounts for these items to always be recorded as current period costs. In addition, this Statement requires that allocation of fixed production overheads to the cost of conversion be based on the normal capacity of the production facilities. The provisions of this statement are effective for inventory costs incurred by Penn beginning January 1, 2006. Penn is currently evaluating this Standard and does not expect it to have a material impact on the financial statements.

FSP FAS 115-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"

In September 2005, the FASB finalized and renamed EITF 03-1 and 03-1-a to FSP FAS 115-1. FSP FAS 115-1 will (1) supersede Issue 03-1 and EITF topic No. D-44, "Recognition of Other Than Temporary Impairment upon the Planned Sale of a Security Whose Cost Exceeds Fair Value," (2) clarify that an investor should recognize an impairment loss no later than when the impairment is deemed other than temporary, even if a decision to sell has not been made, and (3) be effective for other-than-temporary impairment and analyses conducted in periods beginning after September 15, 2005. The FASB expects to issue this FSP in the fourth quarter of 2005, which would require prospective application with an effective date for reporting periods beginning after December 15, 2005. Penn is currently evaluating this FSP and any impact on its investments.

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	**2004**	**2005**	**2004**
		(In thousands)		
STATEMENTS OF INCOME				
OPERATING REVENUES	$ 900,247	$ 706,613	$ 2,024,630	$ 1,754,402
OPERATING EXPENSES AND TAXES:				
Purchased power	517,212	387,282	1,115,737	943,757
Other operating costs	112,690	91,516	293,996	259,176
Provision for depreciation	19,659	18,435	59,721	56,603
Amortization of regulatory assets	84,388	84,271	223,012	216,705
Deferral of new regulatory assets	-	-	(27,765)	-
General taxes	19,538	17,901	49,802	48,571
Income taxes	55,729	35,099	110,578	70,555
Total operating expenses and taxes	809,216	634,504	1,825,081	1,595,367
OPERATING INCOME	91,031	72,109	199,549	159,035
OTHER INCOME (net of income taxes)	3,014	1,996	3,331	4,603
NET INTEREST CHARGES:				
Interest on long-term debt	18,162	21,709	56,843	62,240
Allowance for borrowed funds used during construction	(497)	(169)	(1,337)	(440)
Deferred interest	(1,069)	(871)	(2,896)	(2,685)
Other interest expense	2,283	1,105	5,262	1,958
Net interest charges	18,879	21,774	57,872	61,073
NET INCOME	75,166	52,331	145,008	102,565
PREFERRED STOCK DIVIDEND REQUIREMENTS	125	125	375	375
EARNINGS ON COMMON STOCK	$ 75,041	$ 52,206	$ 144,633	$ 102,190
STATEMENTS OF COMPREHENSIVE INCOME				

NET INCOME	$ 75,166	$ 52,331	$ 145,008	$ 102,565
OTHER COMPREHENSIVE INCOME:				
Unrealized gain on derivative hedges	102	173	208	217
Unrealized loss on available for sale securities	-	-	-	(8)
Other comprehensive income	102	173	208	209
Income tax expense (benefit) related to other comprehensive income	42	(1,542)	85	(1,546)
Other comprehensive income, net of tax	60	1,715	123	1,755
TOTAL COMPREHENSIVE INCOME	$ 75,226	$ 54,046	$ 145,131	$ 104,320

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

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2005	December 31, 2004
	(In thousands)	
ASSETS		
UTILITY PLANT:		
In service	$ 3,840,213	$ 3,730,767
Less - Accumulated provision for depreciation	1,424,801	1,380,775
	2,415,412	2,349,992
Construction work in progress	85,335	75,012
	2,500,747	2,425,004
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	143,937	138,205
Nuclear fuel disposal trust	164,070	159,696
Long-term notes receivable from associated companies	19,751	20,436
Other	16,597	19,379
	344,355	337,716
CURRENT ASSETS:		
Cash and cash equivalents	571	162
Receivables -		
Customers (less accumulated provisions of $4,264,000 and $3,881,000, respectively, for uncollectible accounts)	313,730	201,415
Associated companies	1,171	86,531
Other (less accumulated provisions of $239,000 and $162,000, respectively, for uncollectible accounts)	38,569	39,898
Materials and supplies, at average cost	1,863	2,435
Prepayments and other	33,254	31,489
	389,158	361,930
DEFERRED CHARGES:		
Regulatory assets	2,310,532	2,176,520
Goodwill	1,983,699	1,985,036
Other	2,850	4,978
	4,297,081	4,166,534
	$ 7,531,341	$ 7,291,184
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	$ 153,713
Other paid-in capital	3,014,600	3,013,912

Accumulated other comprehensive loss	(55,411)	(55,534)
Retained earnings	104,904	43,271
Total common stockholder's equity	3,217,806	3,155,362
Preferred stock	12,649	12,649
Long-term debt and other long-term obligations	1,017,478	1,238,984
	4,247,933	4,406,995
CURRENT LIABILITIES:		
Currently payable long-term debt	167,045	16,866
Notes payable -		
Associated companies	114,932	248,532
Accounts payable -		
Associated companies	8,968	20,605
Other	162,583	124,733
Accrued taxes	78,342	2,626
Accrued interest	23,535	10,359
Other	152,638	65,130
	708,043	488,851
NONCURRENT LIABILITIES:		
Power purchase contract loss liability	1,410,659	1,268,478
Accumulated deferred income taxes	670,514	645,741
Nuclear fuel disposal costs	173,591	169,884
Asset retirement obligation	76,002	72,655
Retirement benefits	100,567	103,036
Other	144,032	135,544
	2,575,365	2,395,338
COMMITMENTS AND CONTINGENCIES (Note 13)		
	$ 7,531,341	$ 7,291,184

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

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 75,166	$ 52,331	$ 145,008	$ 102,565
Adjustments to reconcile net income to net cash from operating activities -				
Provision for depreciation	19,659	18,436	59,721	56,603
Amortization of regulatory assets	84,388	84,269	223,012	216,704
Deferral of new regulatory assets	-	-	(27,765)	-
Deferred purchased power and other costs	(42,381)	(77,162)	(168,646)	(155,552)
Deferred income taxes and investment tax credits, net	(11,222)	6,165	5,204	(13,582)
Accrued retirement benefit obligation	813	2,888	(2,468)	(5,880)
Accrued compensation, net	671	1,547	(4,077)	731
NUG power contract restructuring	-	-	-	52,800
Cash collateral from suppliers	76,978	-	76,978	-
Pension trust contribution	-	(62,499)	-	(62,499)
Decrease (increase) in operating assets -				
Receivables	(39,897)	(34,749)	(25,626)	(26,906)
Materials and supplies	395	64	572	411
Prepayments and other current assets	64,761	34,664	(1,764)	(5,040)
Increase (decrease) in operating liabilities -				
Accounts payable	(5,873)	57,485	26,214	58,430
Accrued taxes	18,498	(27,924)	75,716	35,844
Accrued interest	13,765	16,709	13,176	11,481
Other	6,928	27,603	23,982	8,539
Net cash provided from operating activities	262,649	99,827	419,237	274,649
CASH FLOWS FROM FINANCING ACTIVITIES:				

New Financing-				
Long-term debt	-	-	-	300,000
Redemptions and Repayments-				
Long-term debt	(4,321)	(7,082)	(67,648)	(304,150)
Short-term borrowings, net	(164,172)	(456)	(133,600)	(72,648)
Dividend Payments-				
Common stock	(43,000)	(40,000)	(83,000)	(60,000)
Preferred stock	(125)	(125)	(375)	(375)
Net cash used for financing activities	(211,618)	(47,663)	(284,623)	(137,173)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions	(50,837)	(52,507)	(133,498)	(135,932)
Loan repayments from (loans to) associated companies, net	15	(711)	685	(1,122)
Other	(50)	1,049	(1,392)	(416)
Net cash used for investing activities	(50,872)	(52,169)	(134,205)	(137,470)
Net increase (decrease) in cash and cash equivalents	159	(5)	409	6
Cash and cash equivalents at beginning of period	412	282	162	271
Cash and cash equivalents at end of period	$ 571	$ 277	$ 571	$ 277

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

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Report of Independent Registered Public Accounting Firm

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 September 30, 2005, and the related consolidated statements of income and comprehensive income and cash flows for each of the three-month and nine-month periods ended September 30, 2005 and 2004. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 the standards of the Public Company Accounting Oversight Board, 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 the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2004, and the related consolidated statements of income, capitalization, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended, management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004 and the effectiveness of the Company's internal control over financial reporting as of December 31, 2004; and in our report (which contained references to the Company's change in its method of accounting for asset retirement obligations as of January 1, 2003 as discussed in Note 9 to those consolidated financial statements and the Company's change in its method of accounting for the consolidation of variable interest entities as of December 31, 2003 as discussed in Note 6 to those consolidated financial statements) dated March 7, 2005, we expressed unqualified opinions thereon. The consolidated financial statements and management's assessment of the effectiveness of internal control over financial reporting referred to above are not presented herein. In our opinion, the information set forth in the accompanying consolidated balance sheet information as of December 31, 2004, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio
November 1, 2005

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JERSEY CENTRAL POWER & LIGHT COMPANY

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

JCP&L is a wholly owned, electric utility subsidiary of FirstEnergy. JCP&L conducts business in New Jersey, providing regulated electric transmission and distribution services. JCP&L also provides generation services to those customers electing to retain JCP&L as their power supplier. JCP&L has restructured its electric rates into unbundled service charges and transition cost recovery charges. JCP&L continues to deliver power to homes and businesses through its existing distribution system.

Results of Operations

Earnings on common stock in the third quarter of 2005 increased to $75 million from $52 million in the third quarter of 2004. During the first nine months of 2005, earnings on common stock increased to $145 million compared to $102 million for the same period of 2004. The increase in earnings for both periods was primarily due to higher operating revenues partially offset by increases in purchased power costs, other operating costs and income taxes. Other operating costs in both periods of 2005 included a charge of $16 million for potential awards related to a labor arbitration decision (see note 13 - Other Legal Matters).

Operating revenues increased $194 million or 27.4% in the third quarter and $270 million or 15.4% in the first nine months of 2005 compared with the same periods in 2004. Increases in both periods were due to higher retail electric generation, distribution and wholesale revenues.

Retail generation revenues increased by $82 million in the third quarter and $134 million in the first nine months of 2005 as compared to the previous year. Higher KWH sales to residential and commercial customers increased generation revenues by $45 million in the third quarter and $81 million in the first nine months of 2005. Commercial generation revenue increased for the same periods of 2005 by $33 million and $54 million, respectively. The increases were attributable to higher KWH sales (residential - 14.9% and commercial - 20.3% in the third quarter of 2005; residential - 15.3% and commercial - 13.4% for the first nine months of 2005) primarily due to warmer weather and reduced customer shopping. Generation provided by alternative suppliers to residential and commercial customers as a percent of total sales delivered in JCP&L's service area decreased by 6.9 and 4.6 percentage points, respectively, in the first nine months of 2005. Industrial generation revenue increased by $4 million in the third quarter, but declined $2 million in the first nine months of 2005 reflecting the effect of a 25.6% KWH sales increase in the third quarter and a 9.3% decline in the first nine months of 2005.

Revenues from wholesale sales increased by $49 million in the third quarter and $42 in the first nine months of 2005 as compared to the previous year, principally due to increased prices in 2005. KWH sales to the wholesale sector increased in the quarter (5.5%) but declined for the first nine months (8.5%).

Distribution revenues increased by $62 million in the third quarter and $96 million in the first nine months of 2005, as compared to the same periods of 2004, due to increased KWH deliveries to all customer sectors and higher composite unit prices, caused in part by the June 1, 2005 rate increase.

Changes in KWH sales by customer class in the three months and nine months ended September 30, 2005 compared to the same periods of 2004 are summarized in the following table:

Changes in KWH Sales Increase (Decrease)	Three Months	Nine Months
Electric Generation:		
Retail	17.2%	13.4%
Wholesale	5.5%	(8.5)%
Total Electric Generation Sales	14.8%	8.2%
Distribution Deliveries:		
Residential	15.6%	7.4%
Commercial	13.4%	6.7%
Industrial	5.4%	0.4%
Total Distribution Deliveries	13.4%	6.2%

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Operating Expenses and Taxes

Total operating expenses and taxes increased by $175 million in the third quarter and $230 million in the first nine months of 2005 compared with the same periods of 2004. The following table presents changes from the prior year by expense category.

Operating Expenses and Taxes - Changes	**Three Months**	**Nine Months**
	(In millions)	
Increase (Decrease)		
Purchased power costs	$ 130	$ 172
Other operating costs	21	35
Provision for depreciation	1	3
Amortization of regulatory assets	-	7
Deferral of new regulatory assets	-	(28)
General taxes	2	1
Income taxes	21	40
Net increase in operating expenses and taxes	$ 175	$ 230

Purchased power costs increased by $130 million in the third quarter and $172 million in the first nine months of 2005 as compared to the same periods in 2004 due to higher KWH purchases to meet increased retail generation sales and, to a lesser extent, higher unit costs. Other operating costs increased $21 million in the third quarter of 2005 and $35 million in the first nine months of 2005 compared to the same periods of 2004, reflecting $16 million of expenses resulting from a JCP&L arbitration decision.

Deferral of new regulatory assets decreased expenses by $28 million in the first nine months of 2005, reflecting the NJBPU's (see Regulatory Matters) approval for JCP&L to defer $28 million of previously incurred reliability expenses. Amortization of regulatory assets increased $7 million in the first nine months of 2005 due to an increase in the level of MTC revenue recovery.

<u>Capital Resources and Liquidity</u>

JCP&L's cash requirements for the remainder of 2005 for operating expenses, construction expenditures and scheduled debt maturities are expected to be met with cash from operations.

Changes in Cash Position

As of September 30, 2005, JCP&L had $571,000 of cash and cash equivalents compared with $162,000 as of December 31, 2004. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Cash provided from operating activities in the third quarter and in the first nine months of 2005 compared with the corresponding periods of 2004, were as follows:

Operating Cash Flows	**Three Months Ended September 30, 2005**	**Three Months Ended September 30, 2004**	**Nine Months Ended September 30, 2005**	**Nine Months Ended September 30, 2004**
	(In millions)			
Cash earnings [1]	$ 204	$ 64	$ 307	$ 177
Pension trust contribution [2]	-	(37)	-	(37)
Working capital and other	58	73	112	135
Total cash flows from operating activities	$ 262	$ 100	$ 419	$ 275

[1] Cash earnings is a non-GAAP measure (see reconciliation below).
[2] Pension trust contribution net of $25 million of income tax benefits.

Cash earnings, as disclosed in the table above, are not a measure of performance calculated in accordance with GAAP. JCP&L believes that cash earnings is a useful financial measure because it provides investors and management with an additional means of evaluating its cash-based operating performance. The following table reconciles cash earnings with net income.

Reconciliation of Cash Earnings	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In millions)			
Net income (GAAP)	$ 75	$ 52	$ 145	$ 103
Non-cash charges (credits):				
Provision for depreciation	20	18	60	57
Amortization of regulatory assets	84	84	223	217
Deferral of new regulatory assets	-	-	(28)	-
Deferred purchased power and other costs	(42)	(77)	(169)	(156)
Deferred income taxes & investment tax credits, net	(11)	(19)	5	(39)
Other non-cash items	78	6	71	(5)
Cash earnings (Non-GAAP)	$ 204	$ 64	$ 307	$ 177

The $140 million and $130 million increases in cash earnings for the third quarter and the first nine months of 2005, respectively, are described above under "Results of Operations". The $15 million and $23 million decrease for the third quarter and the first nine months of 2005 from working capital primarily resulted from a reduction in accounts payables partially offset by an increase in accrued taxes. In the first nine months of 2004, JCP&L received $52.8 million in connection with restructuring a NUG power contract.

Cash Flows From Financing Activities

Net cash used for financing activities was $212 million in the third quarter of 2005 compared to $48 million in the third quarter of 2004. The increase resulted from redemptions of short-term debt in the third quarter of 2005. Net cash used for financing activities was $285 million for the first nine months of 2005 and $137 million for the same period of 2004. The $148 million increase resulted from a $124 million increase in net debt redemptions and a $23 million increase in common stock dividends to FirstEnergy.

JCP&L had approximately $571,000 of cash and temporary investments and $115 million of short-term indebtedness as of September 30, 2005. JCP&L has authorization from the SEC to incur short-term debt up to its charter limit of $1.8 billion (including the utility money pool). JCP&L will not issue FMB other than as collateral for senior notes, since its senior note indentures prohibit (subject to certain exceptions) JCP&L from issuing any debt which is senior to the senior notes. As of September 30, 2005, JCP&L had the capability to issue $673 million of additional senior notes based upon FMB collateral. Based upon applicable earnings coverage tests and its charter, JCP&L could issue $976 million of preferred stock (assuming no additional debt was issued) as of September 30, 2005.

On June 14, 2005, FirstEnergy, OE, Penn, CEI, TE, JCP&L, Met-Ed, Penelec, FES and ATSI, as Borrowers, entered into a syndicated $2 billion five-year revolving credit facility. Borrowings under the facility are available to each Borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. JCP&L's borrowing limit under the facility is $425 million.

JCP&L has the ability to borrow from FirstEnergy and its regulated affiliates to meet its short-term working capital requirements. FESC administers this money pool and tracks surplus funds of FirstEnergy and its regulated subsidiaries. Companies receiving a loan under the money pool agreements must repay the principal, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from the pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings was 3.50% in the third quarter of 2005 and 3.03% in the first nine months of 2005.

JCP&L's access to capital markets and costs of financing are influenced by the ratings of its securities and the securities of FirstEnergy. The ratings outlook from S&P and Fitch on all securities is stable. Moody's outlook on all securities is positive.

On July 18, 2005, Moody's revised its rating outlook on FirstEnergy and its subsidiaries to positive from stable. Moody's stated that the revision to FirstEnergy's outlook resulted from steady financial improvement and steps taken by management to improve operations, including the stabilization of its nuclear operations. Moody's further stated that the revision in their outlook recognized management's regional strategy of focusing on its core utility businesses and the improvement in FirstEnergy's credit profile stemming from the application of free cash flow toward debt reduction. Moody's noted that a ratings upgrade could be considered if FirstEnergy continues to achieve planned improvements in its operations and balance sheet.

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On October 3, 2005, S&P raised its corporate credit rating on FirstEnergy and the EUOC to 'BBB' from 'BBB-'. At the same time, S&P raised the senior unsecured ratings at the holding company to 'BBB-' from 'BB+' and each of the EUOC by one notch above the previous rating. S&P noted that the upgrade followed the continuation of a good operating track record, specifically for the nuclear fleet through the third quarter 2005. S&P also stated that FirstEnergy’s rating reflects the benefits of supportive regulation, low-cost base load generation fleet, low-risk transmission and distribution operations and rate certainty in Ohio. FirstEnergy’s ability to consistently generate free cash flow, good liquidity, and an improving financial profile were also noted as strengths.

Cash Flows From Investing Activities

Net cash used for investing activities was $51 million in the third quarter and $134 million for the first nine months of 2005 compared to $52 million and $137 million for the same periods of 2004. JCP&L’s capital spending for the period 2005-2007 is expected to be about $511 million of which approximately $185 million applies to 2005. In the last quarter of 2005, capital requirements for property additions and improvements are expected to be about $52 million.

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 members of senior management, provides general management oversight to risk management activities.

Commodity Price Risk

JCP&L is exposed to price risk primarily due to fluctuating 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 futures contracts. The derivatives are used for hedging purposes. Most of its non-hedge derivative contracts represent non-trading positions that do not qualify for hedge treatment under SFAS 133. As of September 30, 2005, JCP&L had commodity derivative contracts with a fair value of $14 million. A decrease of $1 million in the value of this asset was recorded in the first nine months of 2005 as a decrease in a regulatory liability, and therefore, had no impact on net income.

The valuation of derivative commodity 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 valuation of derivative contracts as of September 30, 2005 are summarized by year in the following table:

Sources of Information - Fair Value by Contract Year	**2005[1]**	**2006**	**2007**	**2008**	**2009**	**Thereafter**	**Total**
Prices based on external sources[2]	$ 3	$ 2	$ 3	$ -	$ -	$ -	$ 8
	-	-	-	2	2	2	6

Prices based on models													
Total	$	3	$	2	$	3	$	2	$	2	$	2	$	14

(1) For the last quarter of 2005.
(2) Broker quote sheets.

JCP&L performs sensitivity analyses to estimate its exposure to the market risk of its commodity position. 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 September 30, 2005.

Equity Price Risk

Included in nuclear decommissioning trusts are marketable equity securities carried at their current market value of approximately $82 million and $80 million as of September 30, 2005 and December 31, 2004, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in an $8 million reduction in fair value as of September 30, 2005.

Regulatory Matters

Regulatory assets are costs which have been authorized by the NJBPU and the FERC for recovery from customers in future periods and, without such authorization, would have been charged to income when incurred. JCP&L's regulatory assets as of September 30, 2005 and December 31, 2004 were $2.3 billion and $2.2 billion, respectively.

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 NUG agreements exceed amounts collected through BGS and MTC rates. As of September 30, 2005, the accumulated deferred cost balance totaled approximately $508 million. New Jersey law allows for securitization of JCP&L's deferred balance upon application by JCP&L and a determination by the NJBPU that the conditions of the New Jersey restructuring legislation are met. On February 14, 2003, JCP&L filed for approval of the securitization of the July 31, 2003 deferred balance. JCP&L is in discussions with the NJBPU staff as a result of the stipulated settlement agreements (as further discussed below) which recommended that the NJBPU issue an order regarding JCP&L's application. On July 20, 2005, JCP&L requested the NJBPU to set a procedural schedule for this matter and is awaiting NJBPU action.

The 2003 NJBPU decision on JCP&L's base electric rate proceeding (the Phase I Order) disallowed certain regulatory assets and provided for an interim return on equity of 9.5% on JCP&L's rate base. The Phase I Order also provided for a Phase II proceeding in which the NJBPU would review whether JCP&L is in compliance with current service reliability and quality standards and determine whether the expenditures and projects undertaken by JCP&L to increase its system reliability are prudent and reasonable for rate recovery. Depending on its assessment of JCP&L's service reliability, the NJBPU could have increased JCP&L’s return on equity to 9.75% or decreased it to 9.25%. On August 15, 2003 and June 1, 2004, JCP&L filed with the NJBPU an interim motion and a supplemental and amended motion for rehearing and reconsideration of the Phase I Order, respectively. On July 7, 2004, the NJPBU granted limited reconsideration and rehearing on the following issues: (1) deferred cost disallowances; (2) the capital structure including the rate of return; (3) merger savings, including amortization of costs to achieve merger savings; and (4) decommissioning costs.

On July 16, 2004, JCP&L filed the Phase II petition and testimony with the NJBPU, requesting an increase in base rates of $36 million for the recovery of system reliability costs and a 9.75% return on equity. The filing also requested an increase to the MTC deferred balance recovery of approximately $20 million annually.

On May 25, 2005, the NJBPU approved two stipulated settlement agreements. The first stipulation between JCP&L and the NJBPU staff resolves all of the issues associated with JCP&L's motion for reconsideration of the Phase I Order. The second stipulation between JCP&L, the NJBPU staff and the Ratepayer Advocate resolves all of the issues associated with JCP&L's Phase II proceeding. The stipulated settlements provide for, among other things, the following:

- An annual increase in distribution revenues of $23 million effective June 1, 2005, associated with the Phase I Order reconsideration;

- An annual increase in distribution revenues of $36 million effective June 1, 2005, related to JCP&L's Phase II Petition;

- An annual reduction in both rates and amortization expense of $8 million, effective June 1, 2005, in anticipation of an NJBPU order regarding JCP&L's request to securitize up to $277 million of its deferred cost balance;

- An increase in JCP&L's authorized return on common equity from 9.5% to 9.75%; and

· A commitment by JCP&L to maintain a target level of customer service reliability with a reduction in JCP&L's authorized return on common equity from 9.75% to 9.5% if the target is not met for two consecutive quarters. The authorized return on common equity would then be restored to 9.75% if the target is met for two consecutive quarters.

The Phase II stipulation included an agreement that the distribution revenue increase also reflects a three-year amortization of JCP&L's one-time service reliability improvement costs incurred in 2003-2005. This resulted in the creation of a regulatory asset associated with accelerated tree trimming and other reliability costs which were expensed in 2003 and 2004. The establishment of the new regulatory asset of approximately $28 million resulted in an increase to net income of approximately $16 million ($0.05 per share of FirstEnergy common stock) in the second quarter of 2005.

JCP&L sells all self-supplied energy (NUGs and owned generation) to the wholesale market with offsetting credits to its deferred energy balance with the exception of 300 MW from JCP&L's NUG committed supply currently being used to serve BGS customers pursuant to NJBPU order for the period June 1, 2005 through May 31, 2006. New BGS tariffs reflecting the results of a February 2005 auction for the BGS supply became effective June 1, 2005. On July 1, 2005, JCP&L filed its BGS procurement proposals for post transition year four. The auction is scheduled to take place in February 2006 for the annual supply period beginning June 1, 2006.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004 supporting a continuation of the current level and duration of the funding of TMI-2 decommissioning costs by New Jersey customers without a reduction, termination or capping of the funding. On September 30, 2004, JCP&L filed an updated TMI-2 decommissioning study. This study resulted in an updated total decommissioning cost estimate of $729 million (in 2003 dollars) compared to the estimated $528 million (in 2003 dollars) from the prior 1995 decommissioning study. The Ratepayer Advocate filed comments on February 28, 2005. On March 18, 2005, JCP&L filed a response to those comments. A schedule for further proceedings has not yet been set.

As a result of outages experienced in JCP&L's service area in 2002 and 2003, the NJBPU had implemented reviews into JCP&L's service reliability. On March 29, 2004, the NJBPU adopted an MOU that set out specific tasks related to service reliability to be performed by JCP&L and a timetable for completion and endorsed JCP&L's ongoing actions to implement the MOU. On June 9, 2004, the NJBPU approved a Stipulation that incorporates the final report of a Special Reliability Master who made recommendations on appropriate courses of action necessary to ensure system-wide reliability. The Stipulation also incorporates the Executive Summary and Recommendation portions of the final report of a focused audit of JCP&L's Planning and Operations and Maintenance programs and practices (Focused Audit). A final order in the Focused Audit docket was issued by the NJBPU on July 23, 2004. On February 11, 2005, JCP&L met with the Ratepayer Advocate to discuss reliability improvements. JCP&L continues to file compliance reports reflecting activities associated with the MOU and Stipulation.

On January 31, 2005, certain PJM transmission owners made three filings pursuant to a settlement agreement previously approved by the FERC. JCP&L, Met-Ed and Penelec were parties to that proceeding and joined in two of the filings. In the first filing, the settling transmission owners submitted a filing justifying continuation of their existing rate design within the PJM RTO. In the second filing, the settling transmission owners proposed a revised Schedule 12 to the PJM tariff designed to harmonize the rate treatment of new and existing transmission facilities. Interventions and protests were filed on February 22, 2005. In the third filing, Baltimore Gas and Electric Company and Pepco Holdings, Inc. requested a formula rate for transmission service provided within their respective zones. On May 31, 2005, the FERC issued an order on these cases. First, it set for hearing the existing rate design and indicated that it will issue a final order within six months. Second, the FERC approved the proposed Schedule 12 rate harmonization. Third, the FERC accepted the proposed formula rate, subject to referral and hearing procedures. On September 30, 2005, the PJM transmission owners filed a request for rehearing of the May 31, 2005 order. The rate design and formula rate filings continue to be litigated before the FERC. The outcome of these two cases cannot be predicted.

See Note 14 to the consolidated financial statements for further details and a complete discussion of regulatory matters in New Jersey.

Environmental Matters

JCP&L accrues environmental liabilities when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. Unasserted claims are reflected in JCP&L’s determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

JCP&L has been named a 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 are liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of September 30, 2005, 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 by JCP&L through a non-bypassable SBC. Included in Other Noncurrent Liabilities are accrued liabilities aggregating approximately $46.8 million as of September 30, 2005.

FirstEnergy plans to issue a report regarding its response to air emission requirements. FirstEnergy expects to complete the report by December 1, 2005.

See Note 13(B) to the consolidated financial statements for further details and a complete discussion of environmental matters.

Other Legal Proceedings

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to normal business operations pending against JCP&L. The other material items not otherwise discussed above are described below.

Power Outages and Related Litigation

In July 1999, the Mid-Atlantic States experienced a severe heat wave, which resulted in power outages throughout the service territories of many electric utilities, including JCP&L's territory. In an investigation into the causes of the outages and the reliability of the transmission and distribution systems of all four of New Jersey’s electric utilities, the NJBPU concluded that there was not a prima facie case demonstrating that, overall, JCP&L provided unsafe, inadequate or improper service to its customers. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against JCP&L, GPU and other GPU companies, seeking compensatory and punitive damages arising from the July 1999 service interruptions in the JCP&L territory.

In August 2002, the trial court granted partial summary judgment to JCP&L and dismissed the plaintiffs' claims for consumer fraud, common law fraud, negligent misrepresentation, and strict product liability. In November 2003, the trial court granted JCP&L's motion to decertify the class and denied plaintiffs' motion to permit into evidence their class-wide damage model indicating damages in excess of $50 million. These class decertification and damage rulings were appealed to the Appellate Division. The Appellate Division issued a decision on July 8, 2004, affirming the decertification of the originally certified class, but remanding for certification of a class limited to those customers directly impacted by the outages of JCP&L transformers in Red Bank, New Jersey. On September 8, 2004, the New Jersey Supreme Court denied the motions filed by plaintiffs and JCP&L for leave to appeal the decision of the Appellate Division. JCP&L has filed a motion for summary judgment. FirstEnergy is unable to predict the outcome of these matters and no liability has been accrued as of September 30, 2005.

On August 14, 2003, various states and parts of southern Canada experienced widespread power outages. The outages affected approximately 1.4 million customers in FirstEnergy's service area. The U.S. - Canada Power System Outage Task Force’s final report in April 2004 on the outages concludes, among other things, that the problems leading to the outages began in FirstEnergy’s Ohio service area. Specifically, the final report concluded, among other things, that the initiation of the August 14, 2003 power outages resulted from an alleged failure of both FirstEnergy and ECAR to assess and understand perceived inadequacies within the FirstEnergy system; inadequate situational awareness of the developing conditions; and a perceived failure to adequately manage tree growth in certain transmission rights of way. The Task Force also concluded that there was a failure of the interconnected grid's reliability organizations (MISO and PJM) to provide effective real-time diagnostic support. The final report is publicly available through the Department of Energy’s website (www.doe.gov). FirstEnergy believes that the final report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14, 2003 power outages and that it does not adequately address the underlying causes of the outages. FirstEnergy remains convinced that the outages cannot be explained by events on any one utility's system. The final report contained 46 “recommendations to prevent or minimize the scope of future blackouts.” Forty-five of those recommendations related to broad industry or policy matters while one, including subparts, related to activities the Task Force recommended be undertaken by FirstEnergy, MISO, PJM, ECAR, and other parties to correct the causes of the August 14, 2003 power outages. FirstEnergy implemented several initiatives, both prior to and since the August 14, 2003 power outages, which were independently verified by NERC as complete in 2004 and were consistent with these and other recommendations and collectively enhance the reliability of its electric system. FirstEnergy’s implementation of these recommendations in

2004 included completion of the Task Force recommendations that were directed toward FirstEnergy. FirstEnergy also is proceeding with the implementation of the recommendations regarding enhancements to regional reliability that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new or material upgrades to existing equipment, and therefore FirstEnergy has not accrued a liability as of September 30, 2005 for any expenditures in excess of those actually incurred through that date. The FERC or other applicable government agencies and reliability coordinators may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures. Finally, the PUCO is continuing to review FirstEnergy's filing that addressed upgrades to control room computer hardware and software and enhancements to the training of control room operators, before determining the next steps, if any, in the proceeding.

One complaint was filed on August 25, 2004 against FirstEnergy in the New York State Supreme Court. In this case, several plaintiffs in the New York City metropolitan area allege that they suffered damages as a result of the August 14, 2003 power outages. None of the plaintiffs are customers of any FirstEnergy affiliate. FirstEnergy's motion to dismiss the case was granted on September 26, 2005. Additionally, FirstEnergy Corp. was named in a complaint filed in Michigan State Court by an individual who is not a customer of any FirstEnergy company. A responsive pleading to this matter is not due until on or about December 1, 2005. No estimate of potential liability has been undertaken in this matter.

FirstEnergy is vigorously defending these actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be initiated against the Companies. In particular, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

Other Legal Matters

JCP&L's bargaining unit employees filed a grievance challenging JCP&L's 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties’ collective bargaining agreement. At the conclusion of the June 1, 2005 hearing, the Arbitrator decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the Arbitrator issued an opinion to award approximately $16.1 million to the bargaining unit employees. JCP&L initiated an appeal of this award by filing a motion to vacate in Federal Court in New Jersey on October 18, 2005. JCP&L recognized a liability for the potential $16.1 million award during the three months ended September 30, 2005.

See Note 13(C) to the consolidated financial statements for further details and a complete discussion of other legal proceedings.

New Accounting Standards and Interpretations

EITF Issue 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty"

In September 2005, the EITF reached a final consensus on Issue 04-13 concluding that two or more legally separate exchange transactions with the same counterparty should be combined and considered as a single arrangement for purposes of applying APB 29, when the transactions were entered into "in contemplation" of one another. If two transactions are combined and considered a single arrangement, the EITF reached a consensus that an exchange of inventory should be accounted for at fair value. Although electric power is not capable of being held in inventory, there is no substantive conceptual distinction between exchanges involving power and other storable inventory. Therefore, JCP&L will adopt this EITF effective for new arrangements entered into, or modifications or renewals of existing arrangements, in interim or annual periods beginning after March 15, 2006.

EITF Issue No. 05-6, "Determining the Amortization Period for Leasehold Improvements Purchased after Lease Inception or Acquired in a Business Combination"

In June 2005, the EITF reached a consensus on the application guidance for Issue 05-6. EITF 05-6 addresses the amortization period for leasehold improvements that were either acquired in a business combination or placed in service significantly after and not contemplated at or near the beginning of the initial lease term. For leasehold improvements acquired in a business combination, the amortization period is the shorter of the useful life of the assets or a term that includes required lease periods and renewals that are deemed to be reasonably assured at the date of acquisition. Leasehold improvements that are placed in service significantly after and not contemplated at or near the beginning of the lease term should be amortized over the shorter of the useful life of the assets or a term that includes required lease periods and renewals that are deemed to be reasonably assured at the date the leasehold improvements are purchased. This EITF was effective July 1, 2005 and is consistent with JCP&L's current accounting.

FIN 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143"

On March 30, 2005, the FASB issued FIN 47 to clarify the scope and timing of liability recognition for conditional asset retirement obligations. Under this interpretation, companies are required to recognize a liability for the fair value of an asset retirement obligation that is conditional on a future event, if the fair value of the liability can be reasonably estimated. In instances where there is insufficient information to estimate the liability, the obligation is to be recognized in the first period in which sufficient information becomes available to estimate its fair value. If the fair value cannot be reasonably estimated, that fact and the reasons why must be disclosed. This Interpretation is effective for JCP&L in the fourth quarter of 2005. JCP&L is currently evaluating the effect this Interpretation will have on its financial statements.

SFAS 154 - "Accounting Changes and Error Corrections - a replacement of APB Opinion No. 20 and FASB Statement No. 3"

In May 2005, the FASB issued SFAS 154 to change the requirements for accounting and reporting a change in accounting principle. It applies to all voluntary changes in accounting principle and to changes required by an accounting pronouncement when that pronouncement does not include specific transition provisions. This Statement requires retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. In those instances, this Statement requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that period rather than being reported in the Consolidated Statements of Income. This Statement also requires that a change in depreciation, amortization, or depletion method for long-lived, nonfinancial assets be accounted for as a change in accounting estimate affected by a change in accounting principle. The provisions of this Statement are effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. JCP&L will adopt this Statement effective January 1, 2006.

SFAS 153, "Exchanges of Nonmonetary Assets - an amendment of APB Opinion No. 29"

In December 2004, the FASB issued SFAS 153 amending APB 29, which was based on the principle that nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance in APB 29 included certain exceptions to that principle. SFAS 153 eliminates the exception from fair value measurement for nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges that do not have commercial substance. This Statement specifies that a nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of this Statement are effective January 1, 2006 for FirstEnergy. This FSP is not expected to have a material impact on JCP&L's financial statements.

SFAS 151, "Inventory Costs - an amendment of ARB No. 43, Chapter 4"

In November 2004, the FASB issued SFAS 151 to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage). Previous guidance stated that in some circumstances these costs may be "so abnormal" that they would require treatment as current period costs. SFAS 151 requires abnormal amounts for these items to always be recorded as current period costs. In addition, this Statement requires that allocation of fixed production overheads to the cost of conversion be based on the normal capacity of the production facilities. The provisions of this statement are effective for inventory costs incurred by JCP&L beginning January 1, 2006. JCP&L is currently evaluating this Standard and does not expect it to have a material impact on the financial statements.

FSP FAS 115-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"

In September 2005, the FASB finalized and renamed EITF 03-1 and 03-1-a to FSP FAS 115-1. FSP FAS 115-1 will (1) supersede Issue 03-1 and EITF topic No. D-44, "Recognition of Other Than Temporary Impairment upon the Planned Sale of a Security Whose Cost Exceeds Fair Value," (2) clarify that an investor should recognize an impairment loss no later than when the impairment is deemed other than temporary, even if a decision to sell has not been made, and (3) be effective for other-than-temporary impairment and analyses conducted in periods beginning after September 15, 2005. The FASB expects to issue this FSP in the fourth quarter of 2005, which would require prospective application for reporting periods beginning after December 15, 2005. JCP&L is currently evaluating this FSP and any impact on its investments.

METROPOLITAN EDISON COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In thousands)			
OPERATING REVENUES	$ 333,180	$ 285,419	$ 892,097	$ 788,361
OPERATING EXPENSES AND TAXES:				
Purchased power	186,148	146,938	467,911	421,660
Other operating costs	81,774	50,141	192,892	130,210
Provision for depreciation	9,323	10,648	32,221	30,370
Amortization of regulatory assets	32,853	30,291	86,760	78,737
General taxes	19,906	18,680	56,201	53,103
Income taxes	(2,111)	8,448	9,754	17,179
Total operating expenses and taxes	327,893	265,146	845,739	731,259
OPERATING INCOME	5,287	20,273	46,358	57,102
OTHER INCOME (net of income taxes)	6,459	6,888	19,897	18,530
NET INTEREST CHARGES:				
Interest on long-term debt	8,941	8,823	27,886	31,208
Allowance for borrowed funds used during construction	(150)	(65)	(401)	(208)
Other interest expense	1,950	1,326	5,626	2,846
Net interest charges	10,741	10,084	33,111	33,846
NET INCOME	1,005	17,077	33,144	41,786
OTHER COMPREHENSIVE INCOME (LOSS):				
Unrealized gain (loss) on derivative hedges	84	84	252	(3,182)
Unrealized gain (loss) on available for sale securities	67	-	67	(53)
Other comprehensive income (loss)	151	84	319	(3,235)
Income tax expense (benefit) related to other comprehensive income	62	(1,314)	132	(1,342)
Other comprehensive income (loss), net of tax	89	1,398	187	(1,893)

TOTAL COMPREHENSIVE INCOME	$	1,094	$	18,475	$	33,331	$	39,893

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

METROPOLITAN EDISON COMPANY

CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2005	December 31, 2004
	(In thousands)	
ASSETS		
UTILITY PLANT:		
In service	$ 1,841,450	$ 1,800,569
Less - Accumulated provision for depreciation	712,549	709,895
	1,128,901	1,090,674
Construction work in progress	7,458	21,735
	1,136,359	1,112,409
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	229,437	216,951
Long-term notes receivable from associated companies	11,162	10,453
Other	29,355	34,767
	269,954	262,171
CURRENT ASSETS:		
Cash and cash equivalents	120	120
Notes receivable from associated companies	15,793	18,769
Receivables -		
Customers (less accumulated provisions of $4,320,000 and $4,578,000, respectively, for uncollectible accounts)	131,213	119,858
Associated companies	1,401	118,245
Other	7,684	15,493
Prepayments and other	13,285	11,057
	169,496	283,542
DEFERRED CHARGES:		
Goodwill	867,649	869,585
Regulatory assets	571,745	693,133
Other	24,055	24,438
	1,463,449	1,587,156
	$ 3,039,258	$ 3,245,278
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common stockholder's equity -		
Common stock, without par value, authorized 900,000 shares - 859,500 shares outstanding	$ 1,290,296	$ 1,289,943
Accumulated other comprehensive loss	(43,303)	(43,490)
Retained earnings	28,110	38,966
Total common stockholder's equity	1,275,103	1,285,419
	594,116	701,736

Long-term debt and other long-term obligations				
		1,869,219		1,987,155
CURRENT LIABILITIES:				
Currently payable long-term debt		100,000		30,435
Short-term borrowings -				
Associated companies		76,755		80,090
Other		-		-
Accounts payable -				
Associated companies		39,505		88,879
Other		30,966		26,097
Accrued taxes		2,247		11,957
Accrued interest		9,462		11,618
Other		20,008		23,076
		278,943		272,152
NONCURRENT LIABILITIES:				
Accumulated deferred income taxes		309,979		305,389
Accumulated deferred investment tax credits		10,250		10,868
Power purchase contract loss liability		250,024		349,980
Asset retirement obligation		139,216		132,887
Retirement benefits		77,501		82,218
Nuclear fuel disposal costs		39,213		38,408
Other		64,913		66,221
		891,096		985,971
COMMITMENTS AND CONTINGENCIES (Note 13)				
	$	3,039,258	$	3,245,278

The preceding Notes to Consolidated 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 September 30,		Nine Months Ended September 30,	
	2005	2004	2005	2004
		(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 1,005	$ 17,077	$ 33,144	$ 41,786
Adjustments to reconcile net income to net cash from operating activities -				
Provision for depreciation	9,323	10,648	32,221	30,370
Amortization of regulatory assets	32,853	30,291	86,760	78,737
Deferred costs recoverable as regulatory assets	8,521	(15,629)	(21,491)	(45,616)
Deferred income taxes and investment tax credits, net	(8,438)	666	(10,336)	(4,853)
Accrued retirement benefit obligation	(1,514)	(273)	(4,717)	492
Accrued compensation, net	1,527	649	211	201
Pension trust contribution	-	(38,823)	-	(38,823)
Decrease (increase) in operating assets -				
Receivables	3,088	(2,599)	113,298	29,943
Materials and supplies	(1)	5	(19)	41
Prepayments and other current assets	18,978	14,298	(2,209)	(15,027)
Increase (decrease) in operating liabilities -				
Accounts payable	6,088	(12,536)	(44,505)	(17,857)
Accrued taxes	(4,526)	(145)	(9,710)	(6,255)
Accrued interest	(1,269)	(3,006)	(2,156)	(127)
Other	(7,701)	(7,356)	(24,063)	(9,581)
Net cash provided from (used for) operating activities	57,934	(6,733)	146,428	43,431
CASH FLOWS FROM FINANCING ACTIVITIES:				
New Financing-				
Long-term debt	-	-	-	247,607
Short-term borrowings, net	-	70,000	-	4,665
Redemptions and Repayments-				
Long-term debt	-	(45,936)	(37,830)	(196,371)
Short-term borrowings, net	(24,266)	-	(3,335)	-

Dividend Payments-				
Common stock	(10,000)	(10,000)	(44,000)	(35,000)
Net cash provided from (used for) financing activities	(34,266)	14,064	(85,165)	20,901
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions	(21,680)	(12,390)	(56,075)	(33,733)
Contributions to nuclear decommissioning trusts	(2,370)	(2,371)	(7,112)	(7,113)
Loan repayments from (loans to) associated companies, net	(1,072)	17,989	2,267	(13,046)
Other	1,454	(10,559)	(343)	(10,441)
Net cash provided used for investing activities	(23,668)	(7,331)	(61,263)	(64,333)
Net change in cash and cash equivalents	-	-	-	(1)
Cash and cash equivalents at beginning of period	120	120	120	121
Cash and cash equivalents at end of period	$ 120	$ 120	$ 120	$ 120

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

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Report of Independent Registered Public Accounting Firm

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 September 30, 2005, and the related consolidated statements of income and comprehensive income and cash flows for each of the three-month and nine-month periods ended September 30, 2005 and 2004. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 the standards of the Public Company Accounting Oversight Board, 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 the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2004, and the related consolidated statements of income, capitalization, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended, management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004 and the effectiveness of the Company's internal control over financial reporting as of December 31, 2004; and in our report (which contained references to the Company's change in its method of accounting for asset retirement obligations as of January 1, 2003 as discussed in Note 2(G) to those consolidated financial statements and the Company's change in its method of accounting for the consolidation of variable interest entities as of December 31, 2003 as discussed in Note 6 to those consolidated financial statements) dated March 7, 2005, we expressed unqualified opinions thereon. The consolidated financial statements and management's assessment of the effectiveness of internal control over financial reporting referred to above are not presented herein. In our opinion, the information set forth in the accompanying consolidated balance sheet information as of December 31, 2004, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio
November 1, 2005

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METROPOLITAN EDISON COMPANY

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

Met-Ed is a wholly owned, electric utility subsidiary of FirstEnergy. Met-Ed conducts business in eastern Pennsylvania, providing regulated electric transmission and distribution services. Met-Ed also provides generation service to those customers electing to retain Met-Ed as their power supplier. Met-Ed has unbundled 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.

Results of Operations

Net income decreased to $1 million for the third quarter of 2005 from $17 million in the third quarter of 2004. The decrease in net income primarily resulted from higher purchased power costs, transmission expenses, and amortization of regulatory assets, partially offset by higher operating revenues and lower depreciation and income taxes. For the first nine months of 2005, net income decreased to $33 million from $42 million in the same period of 2004. The decrease in net income primarily resulted from higher purchased power costs, transmission expenses, and amortization of regulatory assets, partially offset by higher operating revenues and other income and lower income taxes as discussed below.

Operating revenues increased by $48 million, or 16.7%, in the third quarter of 2005 and $104 million, or 13.2%, in the first nine months of 2005, compared with the same periods of 2004. Increases in both periods were due, in part, to higher retail generation electric revenues from all customer sectors ($17 million for the third quarter and $41 million for the first nine months of 2005). The increases in retail generation KWH sales for both periods of 2005 were mainly attributable to warmer weather and reduced customer shopping - primarily in the industrial sector. Industrial customer shopping decreased by 4.9% and 11.2% percentage points in the third quarter and first nine months of 2005, respectively. While higher generation sales in the third quarter of 2005 were offset by slightly lower composite unit prices, overall higher composite unit prices during the nine-month period also contributed to the increase in generation revenues.

Revenues from distribution throughput increased by $13 million in the third quarter and by $23 million in the first nine months of 2005 compared with the same periods of 2004. Increases in both periods of 2005 were primarily due to higher KWH deliveries and slightly higher unit prices. Increased transmission revenues of $17 million in the third quarter and $32 million in the first nine months of 2005 also contributed to higher operating revenues. These increases were due to a change in the power supply agreement with FES in the second quarter of 2004. This change also resulted in higher transmission expenses as discussed further below. In the first nine months of 2005, operating revenues also included a $4 million payment received under a contract provision associated with the prior sale of TMI Unit 1. Under the contract, additional payments are received if subsequent energy prices rise above specific levels and are credited to Met-Ed's customers, resulting in no net impact to earnings.

Changes in KWH sales by customer class in the three months and nine months ended September 30, 2005 compared to the same periods of 2004 are summarized in the following table:

Changes in KWH Sales	Three Months	Nine Months

Increase (Decrease)		
Retail Electric Generation:		
Residential	15.5%	7.6%
Commercial	10.1%	7.6%
Industrial	9.1%	17.0%
Total Retail Electric Generation Sales	11.9%	9.9%
Distribution Deliveries:		
Residential	15.5%	7.5%
Commercial	10.0%	6.7%
Industrial	3.2%	1.9%
Total Distribution Deliveries	10.0%	5.6%

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Operating Expenses and Taxes

Total operating expenses and taxes increased by $63 million in the third quarter and by $114 million in the first nine months of 2005 compared with the same periods of 2004. The following table presents changes from the prior year by expense category:

Operating Expenses and Taxes - Changes	Three Months	Nine Months
	(In millions)	
Increase (Decrease)		
Purchased power costs	$ 39	$ 46
Other operating costs	32	62
Provision for depreciation	(1)	2
Amortization of regulatory assets	3	8
General taxes	1	3
Income taxes	(11)	(7)
Net increase in operating expenses and taxes	$ 63	$ 114

Purchased power costs increased by $39 million in the third quarter and $46 million in the first nine months of 2005 compared with the same periods of 2004. The increases in both periods were primarily due to increased third party power purchases ($47 million in the third quarter and $92 million in the first nine months of 2005) and NUG contract purchases ($21 million in the third quarter and $29 million in the first nine months of 2005) partially offset by reduced purchased power from FES ($30 million in the third quarter and $77 million in the first nine months of 2005). These changes, for both periods, were due to increased KWH purchased to meet increased retail generation sales requirements offset by slightly lower unit costs.

Other operating costs increased by $32 million in the third quarter and by $62 million in first nine months of 2005 compared with the same periods of 2004. The increases in both periods were primarily caused by higher PJM congestion charges and transmission expenses as a result of the change in the power supply agreement with FES discussed above.

In the first nine months of 2005, depreciation expense increased due to additions to the asset base and higher costs to decommission the Saxton nuclear plant as compared to the same period of 2004. For both periods of 2005, regulatory asset amortization reflected increases associated with the level of CTC revenue recovery, partially offset by lower amortization related to above market NUG costs as compared to the prior year periods.

General taxes increased in both periods primarily as a result of higher gross receipt taxes associated with the increase in KWH sales. Income taxes decreased in the third quarter and first nine months of 2005 due to lower taxable income.

Capital Resources and Liquidity

Met-Ed’s cash requirements for the remainder of 2005, for operating expenses, construction expenditures and scheduled debt maturities are expected to be met with cash from operations.

Changes in Cash Position

As of September 30, 2005, Met-Ed’s cash and cash equivalents of $120,000 remained unchanged from December 31, 2004.

Cash Flows From Operating Activities

Cash provided from (used for) operating activities during the third quarter and first nine months of 2005, compared with the corresponding periods of 2004 were as follows:

Operating Cash Flows	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
		(In millions)		
Cash earnings [1]	$ 43	$ 27	$ 116	$ 85
Pension trust contribution [2]	-	(23)	-	(23)
Working capital and other	15	(11)	30	(19)
Total cash flows from operating activities	$ 58	$ (7)	$ 146	$ 43

[1] Cash earnings is a non-GAAP measure (see reconciliation below).
[2] Pension trust contribution net of $16 million of income tax benefits.

Cash earnings, as disclosed in the table above, are not a measure of performance calculated in accordance with GAAP. Met-Ed believes that cash earnings is a useful financial measure because it provides investors and management with an additional means of evaluating its cash-based operating performance. The following table reconciles cash earnings with net income.

Reconciliation of Cash Earnings	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
		(In millions)		
Net income (GAAP)	$ 1	$ 17	$ 33	$ 42
Non-cash charges (credits):				
Provision for depreciation	9	11	32	30
Amortization of regulatory assets	33	30	87	79
Deferred costs recoverable as regulatory assets	8	(16)	(22)	(46)
Deferred income taxes and investment tax credits, net	(8)	(16)	(10)	(21)
Other non-cash charges	-	1	(4)	1
Cash earnings (Non-GAAP)	$ 43	$ 27	$ 116	$ 85

The $16 million and $31 million increases in cash earnings for the third quarter and first nine months of 2005, respectively, are described above under "Results of Operations". Net cash from operating activities increased in the third quarter and the first nine months due to the absence of a $23 million after-tax voluntary pension contribution made in the third quarter of 2004. The $26 million change in working capital in the third quarter of 2005 primarily resulted from changes of $6 million in accounts receivable, $19 million in accounts payable and $5 million in prepayments, offset by a change of $4 million in accrued taxes. The $49 million change in working capital for the first nine months of 2005 primarily resulted from net changes in accounts receivable and accounts payable from associated companies of $52 million and $13 million in prepayments, partially offset by changes of $11 million in customer deposits, $3 million in accrued taxes and $2 million in accrued interest.

Cash Flows From Financing Activities

For the third quarter of 2005, net cash used for financing activities was $34 million compared to $14 million of cash provided from financing activities in the third quarter of 2004. The $48 million decrease resulted primarily from a $70 million reduction in new debt financing compared to the third quarter of 2004 offset in part by a $22 million reduction in debt redemptions. For the first nine months of 2005, net cash used for financing activities was $85 million compared to $21 million of net cash provided from financing activities in the same period of 2004. The $106 million change reflected a $252 million reduction in new debt financing and a $9 million increase in common stock dividends to FirstEnergy, partially offset by a $155 million decrease in debt redemptions compared to the same period of 2004.

As of September 30, 2005, Met-Ed had approximately $16 million of cash and temporary investments (including short-term notes receivable from associated companies) and $77 million of short-term borrowings outstanding. Met-Ed has authorization from the SEC to incur short-term debt up to $250 million (including the utility money pool). Under the terms of Met-Ed's senior note indenture, no more first mortgage bonds can be issued as long as the senior bonds are outstanding. Met-Ed had no restrictions on the issuance of preferred stock.

Met-Ed Funding LLC (Met-Ed Funding), a wholly owned subsidiary of Met-Ed, is a limited liability company whose borrowings are secured by customer accounts receivable purchased from Met-Ed. Met-Ed Funding can borrow up to $80 million under a receivables financing arrangement. As a separate legal entity with separate creditors, Met-Ed Funding would have to satisfy its obligations to creditors before any of its remaining assets could be made available to Met-Ed. On July 15, 2005, the facility was renewed until June 29, 2006. As of September 30, 2005, the facility was undrawn. The annual facility fee is 0.25% on the entire finance limit.

Met-Ed has the ability to borrow from its regulated affiliates and FirstEnergy to meet its short-term working capital requirements. FESC administers this money pools and tracks surplus funds of FirstEnergy and the respective regulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from the pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in the third quarter of 2005 was 3.50%.

On June 14, 2005, FirstEnergy, OE, Penn, CEI, TE, JCP&L, Met-Ed, Penelec, FES and ATSI, as borrowers, entered into a syndicated $2 billion five-year revolving credit facility. Borrowings under the facility are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. Met-Ed's borrowing limit under the facility is $250 million.

Met-Ed's access to capital markets and costs of financing are dependent on the ratings of its securities and that of FirstEnergy. The ratings outlook from S&P and Fitch on all securities is stable. Moody's outlook on all securities is positive.

On July 18, 2005, Moody's revised its rating outlook on FirstEnergy and its subsidiaries to positive from stable. Moody's stated that the revision to FirstEnergy's outlook resulted from steady financial improvement and steps taken by management to improve operations, including the stabilization of its nuclear operations. Moody's further stated that the revision in their outlook recognized management's regional strategy of focusing on its core utility businesses and the improvement in FirstEnergy's credit profile stemming from the application of free cash flow toward debt reduction. Moody's noted that a ratings upgrade could be considered if FirstEnergy continues to achieve planned improvements in its operations and balance sheet.

On October 3, 2005, S&P raised its corporate credit rating on FirstEnergy and the EUOC to 'BBB' from 'BBB-'. At the same time, S&P raised the senior unsecured ratings at the holding company to 'BBB-' from 'BB+' and each of the EUOC by one notch above the previous rating. S&P noted that the upgrade followed the continuation of a good operating track record, specifically for the nuclear fleet through the third quarter 2005. S&P also stated that FirstEnergy's rating reflects the benefits of supportive regulation, low-cost base load generation fleet, low-risk transmission and distribution operations and rate certainty in Ohio. FirstEnergy's ability to consistently generate free cash flow, good liquidity, and an improving financial profile were also noted as strengths.

Cash Flows From Investing Activities

In the third quarter of 2005, net cash used for investing activities totaled $24 million, compared to $7 million in the third quarter of 2004. The change in the third quarter of 2005 primarily resulted from a $19 million increase in loan repayments to associated companies and a $9 million increase in property additions, partially offset by a $9 million capital transfer from FESC in the third quarter of 2004. In the first nine months of 2005, net cash used for investing activities totaled $61 million compared to $64 million in the same period of 2004. The change resulted from a $15 million increase in loan repayments from associated companies and the previously mentioned capital transfer, partially offset by a $22 million increase in property additions. Expenditures for property additions primarily support Met-Ed's energy delivery operations.

Met-Ed's capital spending for the period 2005 through 2007 is expected to be about $205 million, of which approximately $68 million applies to 2005. In the last quarter of 2005, capital requirements for property additions are expected to be about $14 million. These cash requirements are expected to be satisfied from internal cash and short-term credit arrangements. Met-Ed has no additional requirements for maturing long-term debt during the remainder of 2005.

Market Risk Information

Met-Ed 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 members of senior management, provides general management oversight to risk management activities.

Commodity Price Risk

Met-Ed is exposed to price risk primarily resulting from fluctuating 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 futures 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. As of September 30, 2005, Met-Ed’s commodity derivative contract was an embedded option with a fair value of $28 million. A $4 million net decrease in the value of this asset was recorded as a decrease in regulatory liabilities, and therefore, had no impact on net income.

The valuation of derivative commodity 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 as of September 30, 2005 are summarized by year in the following table:

Sources of Information - Fair Value by Contract Year	**2005[1]**	**2006**	**2007**	**2008**	**2009**	**Thereafter**	**Total**
Prices based on external sources[2]	$ 5	$ 5	$ 5	$ -	$ -	$ -	$ 15
Prices based on models	-	-	-	5	4	4	13
Total	$ 5	$ 5	$ 5	$ 5	$ 4	$ 4	$ 28

(1) For the last quarter of 2005.
(2) Broker quote sheets.

Met-Ed 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 derivative instruments would not have had a material effect on its consolidated financial position or cash flows as of September 30, 2005.

Equity Price Risk

Included in Met-Ed's nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $138 million as of September 30, 2005 and $134 million as of December 31, 2004. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $14 million reduction in fair value as of September 30, 2005.

Regulatory Matters

Regulatory assets are costs which have been authorized by the PPUC and the FERC for recovery from customers in future periods and, without such authorization, would have been charged to income when incurred. Met-Ed's regulatory assets as of September 30, 2005 and December 31, 2004 were $572 million and $693 million, respectively.

In accordance with PPUC directives, Met-Ed and Penelec have been negotiating with interested parties in an attempt to resolve the merger savings issues that are the subject of remand from the Commonwealth Court. Met-Ed’s and Penelec’s combined portion of total merger savings is estimated to be approximately $31.5 million. On April 13, 2005, the Commonwealth Court issued an interim order in the remand proceeding that the parties should report the status of the negotiations to the PPUC with a copy to the ALJ. The parties exchanged settlement proposals in May and June 2005 and continue to have settlement discussions.

In an October 16, 2003 order, the PPUC approved September 30, 2004 as the date for Met-Ed's and Penelec's NUG trust fund refunds. The PPUC order also denied their accounting treatment request regarding the CTC rate/shopping credit swap by requiring Met-Ed and Penelec to treat the stipulated CTC rates that were in effect from January 1, 2002 on a retroactive basis. On October 22, 2003, Met-Ed and Penelec filed an Objection with the Commonwealth Court asking that the Court reverse this PPUC finding; a Commonwealth Court judge subsequently denied their Objection on October 27, 2003 without explanation. On October 31, 2003, Met-Ed and Penelec filed an Application for Clarification of the Court order with the judge, a Petition for Review of the PPUC's October 2 and October 16, 2003 Orders, and an application for reargument, if the judge, in his clarification order, indicates that Met-Ed's and Penelec's Objection was intended to be denied on the merits. The Reargument Brief before the Commonwealth Court was filed on January 28, 2005.

Met-Ed purchases a portion of its PLR requirements from FES through a wholesale power sales agreement. The PLR sale is 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 retains the supply obligation and the supply profit and loss risk, for the portion of power supply requirements not self-supplied by Met-Ed under its NUG contracts and other power contracts with nonaffiliated third party suppliers. This arrangement reduces Met-Ed's exposure to high wholesale power prices by providing power at a fixed price for their uncommitted PLR energy costs during the term of the agreement with FES. Met-Ed is authorized to defer differences between NUG contract costs and current market prices. On November 1, 2005, FES and the other parties to the wholesale power agreement amended the agreement to provide FES the right over the next year to terminate the agreement at any time upon 60 days notice. If the wholesale power agreement were terminated, Met-Ed and Penelec would need to satisfy the applicable portion of their PLR obligations from other sources at prevailing prices, which are likely to be higher than the current price charged by FES under the agreement and, as a result, Met-Ed’s and Penelec’s purchased power costs could materially increase.

On January 12, 2005, Met-Ed filed a request with the PPUC for deferral of transmission-related costs beginning January 1, 2005, estimated to be approximately $4 million per month. The OCA, OSBA, OTS, MEIUG, PICA, Allegheny Electric Cooperative and Pennsylvania Rural Electric Association have all intervened in the case. To date no hearing schedule has been established, and Met-Ed has not yet implemented deferral accounting for these costs.

On January 31, 2005, certain PJM transmission owners made three filings pursuant to a settlement agreement previously approved by the FERC. JCP&L, Met-Ed and Penelec were parties to that proceeding and joined in two of the filings. In the first filing, the settling transmission owners submitted a filing justifying continuation of their existing rate design within the PJM RTO. In the second filing, the settling transmission owners proposed a revised Schedule 12 to the PJM tariff designed to harmonize the rate treatment of new and existing transmission facilities. Interventions and protests were filed on February 22, 2005. In the third filing, Baltimore Gas and Electric Company and Pepco Holdings, Inc. requested a formula rate for transmission service provided within their respective zones. On May 31, 2005, the FERC issued an order on these cases. First, it set for hearing the existing rate design and indicated that it will issue a final order within six months. Second, the FERC approved the proposed Schedule 12 rate harmonization. Third, the FERC accepted the proposed formula rate, subject to referral and hearing procedures. On June 30, 2005, the PJM transmission owners filed a request for rehearing of the May 31, 2005 order. The rate design and formula rate filings continue to be litigated before the FERC. The outcome of these two cases cannot be predicted.

See Note 14 to the consolidated financial statements for further details and a complete discussion of regulatory matters in Pennsylvania including a more detailed discussion of reliability initiatives, including actions by the PPUC, that impact Met-Ed.

Environmental Matters

Met-Ed accrues environmental liabilities only when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. Unasserted claims are reflected in Met-Ed’s determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

Met-Ed has been named as a 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 are liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of September 30, 2005, 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.

FirstEnergy plans to issue a report regarding its response to air emission requirements. FirstEnergy expects to complete the report by December 1, 2005.

See Note 13(B) to the consolidated financial statements for further details and a complete discussion of environmental matters.

Other Legal Proceedings

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to Met-Ed's normal business operations pending against Met-Ed. The other material items not otherwise discussed above are described below.

On August 14, 2003, various states and parts of southern Canada experienced widespread power outages. The outages affected approximately 1.4 million customers in FirstEnergy's service area. The U.S. - Canada Power System Outage Task Force’s final report in April 2004 on the outages concludes, among other things, that the problems leading to the outages began in FirstEnergy’s Ohio service area. Specifically, the final report concluded, among other things, that the initiation of the August 14, 2003 power outages resulted from an alleged failure of both FirstEnergy and ECAR to assess and understand perceived inadequacies within the FirstEnergy system; inadequate situational awareness of the developing conditions; and a perceived failure to adequately manage tree growth in certain transmission rights of way. The Task Force also concluded that there was a failure of the interconnected grid's reliability organizations (MISO and PJM) to provide effective real-time diagnostic support. The final report is publicly available through the Department of Energy’s website (www.doe.gov). FirstEnergy believes that the final report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14, 2003 power outages and that it does not adequately address the underlying causes of the outages. FirstEnergy remains convinced that the outages cannot be explained by events on any one utility's system. The final report contained 46 “recommendations to prevent or minimize the scope of future blackouts.” Forty-five of those recommendations related to broad industry or policy matters while one, including subparts, related to activities the Task Force recommended be undertaken by FirstEnergy, MISO, PJM, ECAR, and other parties to correct the causes of the August 14, 2003 power outages. FirstEnergy implemented several initiatives, both prior to and since the August 14, 2003 power outages, which were independently verified by NERC as complete in 2004 and were consistent with these and other recommendations and collectively enhance the reliability of its electric system. FirstEnergy’s implementation of these recommendations in 2004 included completion of the Task Force recommendations that were directed toward FirstEnergy. FirstEnergy also is proceeding with the implementation of the recommendations regarding enhancements to regional reliability that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new or material upgrades to existing equipment, and therefore FirstEnergy has not accrued a liability as of September 30, 2005 for any expenditures in excess of those actually incurred through that date. The FERC or other applicable government agencies and reliability coordinators may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures. Finally, the PUCO is continuing to review FirstEnergy’s filing that addressed upgrades to control room computer hardware and software and enhancements to the training of control room operators, before determining the next steps, if any, in the proceeding.

One complaint was filed on August 25, 2004 against FirstEnergy in the New York State Supreme Court. In this case, several plaintiffs in the New York City metropolitan area allege that they suffered damages as a result of the August 14, 2003 power outages. None of the plaintiffs are customers of any FirstEnergy affiliate. FirstEnergy's motion to dismiss the case was granted on September 26, 2005. Additionally, FirstEnergy Corp. was named in a complaint filed in Michigan State Court by an individual who is not a customer of any FirstEnergy company. A responsive pleading to this matter is not due until on or about December 1, 2005. No estimate of potential liability has been undertaken in this matter.

FirstEnergy is vigorously defending these actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be initiated against the Companies. In particular, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

See Note 13(C) to the consolidated financial statements for further details and a complete discussion of other legal proceedings.

New Accounting Standards and Interpretations

EITF Issue 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty"

In September 2005, the EITF reached a final consensus on Issue 04-13 concluding that two or more legally separate exchange transactions with the same counterparty should be combined and considered as a single arrangement for purposes of applying APB 29, when the transactions were entered into "in contemplation" of one another. If two transactions are combined and considered a single arrangement, the EITF reached a consensus that an exchange of inventory should be accounted for at fair value. Although electric power is not capable of being held in inventory, there is no substantive conceptual distinction between exchanges involving power and other storable inventory. Therefore, Met-Ed will adopt this EITF effective for new arrangements entered into, or modifications or renewals of existing arrangements, in interim or annual periods beginning after March 15, 2006.

EITF Issue No. 05-6, "Determining the Amortization Period for Leasehold Improvements Purchased after Lease Inception or Acquired in a Business Combination"

In June 2005, the EITF reached a consensus on the application guidance for Issue 05-6. EITF 05-6 addresses the amortization period for leasehold improvements that were either acquired in a business combination or placed in service significantly after and not contemplated at or near the beginning of the initial lease term. For leasehold improvements acquired in a business combination, the amortization period is the shorter of the useful life of the assets or a term that includes required lease periods and renewals that are deemed to be reasonably assured at the date of acquisition. Leasehold improvements that are placed in service significantly after and not contemplated at or near the beginning of the lease term should be amortized over the shorter of the useful life of the assets or a term that includes required lease periods and renewals that are deemed to be reasonably assured at the date the leasehold improvements are purchased. This EITF was effective July 1, 2005 and is consistent with Met-Ed's current accounting.

FIN 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143"

On March 30, 2005, the FASB issued FIN 47 to clarify the scope and timing of liability recognition for conditional asset retirement obligations. Under this interpretation, companies are required to recognize a liability for the fair value of an asset retirement obligation that is conditional on a future event, if the fair value of the liability can be reasonably estimated. In instances where there is insufficient information to estimate the liability, the obligation is to be recognized in the first period in which sufficient information becomes available to estimate its fair value. If the fair value cannot be reasonably estimated, that fact and the reasons why must be disclosed. This Interpretation is effective for Met-Ed in the fourth quarter of 2005. Met-Ed is currently evaluating the effect this Interpretation will have on its financial statements.

SFAS 154 - "Accounting Changes and Error Corrections - a replacement of APB Opinion No. 20 and FASB Statement No. 3"

In May 2005, the FASB issued SFAS 154 to change the requirements for accounting and reporting a change in accounting principle. It applies to all voluntary changes in accounting principle and to changes required by an accounting pronouncement when that pronouncement does not include specific transition provisions. This Statement requires retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. In those instances, this Statement requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that period rather than being reported in the Consolidated Statements of Income. This Statement also requires that a change in depreciation, amortization, or depletion method for long-lived, nonfinancial assets be accounted for as a change in accounting estimate affected by a change in accounting principle. The provisions of this Statement are effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. Met-Ed will adopt this Statement effective January 1, 2006.

SFAS 153, "Exchanges of Nonmonetary Assets - an amendment of APB Opinion No. 29"

In December 2004, the FASB issued SFAS 153 amending APB 29, which was based on the principle that nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance in APB 29 included certain exceptions to that principle. SFAS 153 eliminates the exception from fair value measurement for nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges that do not have commercial substance. This Statement specifies that a nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of this

Statement are effective January 1, 2006 for Met-Ed. This FSP is not expected to have a material impact on Met-Ed's financial statements.

SFAS 151, "Inventory Costs - an amendment of ARB No. 43, Chapter 4"

In November 2004, the FASB issued SFAS 151 to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage). Previous guidance stated that in some circumstances these costs may be "so abnormal" that they would require treatment as current period costs. SFAS 151 requires abnormal amounts for these items to always be recorded as current period costs. In addition, this Statement requires that allocation of fixed production overheads to the cost of conversion be based on the normal capacity of the production facilities. The provisions of this statement are effective for inventory costs incurred by Met-Ed beginning January 1, 2006. Met-Ed is currently evaluating this Standard and does not expect it to have a material impact on the financial statements.

FSP FAS 115-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"

In September 2005, the FASB finalized and renamed EITF 03-1 and 03-1-a to FSP FAS 115-1. FSP FAS 115-1 will (1) supersede Issue 03-1 and EITF topic No. D-44, "Recognition of Other Than Temporary Impairment upon the Planned Sale of a Security Whose Cost Exceeds Fair Value," (2) clarify that an investor should recognize an impairment loss no later than when the impairment is deemed other than temporary, even if a decision to sell has not been made, and (3) be effective for other-than-temporary impairment and analyses conducted in periods beginning after September 15, 2005. The FASB expects to issue this FSP in the fourth quarter of 2005, which would require prospective application with an effective date for reporting periods beginning after December 15, 2005. Met-Ed is currently evaluating this FSP and any impact on its investments.

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PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In thousands)			
OPERATING REVENUES	$ 290,451	$ 254,339	$ 846,477	$ 752,986
OPERATING EXPENSES AND TAXES:				
Purchased power	178,090	137,146	467,639	432,974
Other operating costs	66,417	37,100	183,024	122,988
Provision for depreciation	12,736	12,281	37,721	35,229
Amortization of regulatory assets	12,627	11,759	38,930	39,130
General taxes	17,552	16,913	51,892	50,795
Income taxes	(3,101)	11,693	14,991	16,000
Total operating expenses and taxes	284,321	226,892	794,197	697,116
OPERATING INCOME	6,130	27,447	52,280	55,870
OTHER INCOME (net of income taxes)	1,057	1,300	1,477	1,663
NET INTEREST CHARGES:				
Interest on long-term debt	7,305	7,513	22,187	22,528
Allowance for borrowed funds used during construction	(285)	(60)	(674)	(192)
Deferred interest	-	-	-	190
Other interest expense	2,536	3,058	7,392	8,063
Net interest charges	9,556	10,511	28,905	30,589
NET INCOME (LOSS)	(2,369)	18,236	24,852	26,944
OTHER COMPREHENSIVE INCOME (LOSS):				
Unrealized gain (loss) on derivative hedges	17	17	49	(618)
Unrealized gain (loss) on available for sale securities	18	7	(3)	(3)
Other comprehensive income (loss)	35	24	46	(621)
Income tax expense (benefit) related to other comprehensive income	20	(256)	20	(258)
Other comprehensive income (loss), net of tax	15	280	26	(363)

TOTAL COMPREHENSIVE INCOME (LOSS)	$	(2,354)	$	18,516	$	24,878	$	26,581

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

PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED BALANCE SHEETS
(Unaudited)

		September 30, 2005		December 31, 2004
		(In thousands)		
ASSETS				
UTILITY PLANT:				
In service	$	2,004,891	$	1,981,846
Less - Accumulated provision for depreciation		772,818		776,904
		1,232,073		1,204,942
Construction work in progress		23,622		22,816
		1,255,695		1,227,758
OTHER PROPERTY AND INVESTMENTS:				
Nuclear plant decommissioning trusts		111,826		109,620
Non-utility generation trusts		97,473		95,991
Long-term notes receivable from associated companies		15,629		14,001
Other		14,855		18,746
		239,783		238,358
CURRENT ASSETS:				
Cash and cash equivalents		35		36
Notes receivable from associated companies		-		7,352
Receivables -				
Customers (less accumulated provisions of $4,095,000 and $4,712,000, respectively, for uncollectible accounts)		120,580		121,112
Associated companies		6,339		97,528
Other		7,369		12,778
Prepayments and other		15,818		7,198
		150,141		246,004
DEFERRED CHARGES:				
Goodwill		886,559		888,011
Regulatory assets		99,491		200,173
Other		13,234		13,448
		999,284		1,101,632
	$	2,644,903	$	2,813,752
CAPITALIZATION AND LIABILITIES				
CAPITALIZATION:				
Common stockholder's equity-				
Common stock, $20 par value, authorized 5,400,000 shares - 5,290,596 shares outstanding	$	105,812	$	105,812
Other paid-in capital		1,206,358		1,205,948

Accumulated other comprehensive loss		(52,787)		(52,813)
Retained earnings		38,920		46,068
Total common stockholder's equity		1,298,303		1,305,015
Long-term debt and other long-term obligations		478,954		481,871
		1,777,257		1,786,886
CURRENT LIABILITIES:				
Currently payable long-term debt		4		8,248
Short-term borrowings -				
Associated companies		114,749		241,496
Other		75,000		-
Accounts payable -				
Associated companies		30,456		56,154
Other		35,987		25,960
Accrued taxes		19,234		7,999
Accrued interest		15,289		9,695
Other		19,264		23,750
		309,983		373,302
NONCURRENT LIABILITIES:				
Power purchase contract loss liability		259,675		382,548
Retirement benefits		121,251		118,247
Asset retirement obligation		69,608		66,443
Accumulated deferred income taxes		56,029		37,318
Other		51,100		49,008
		557,663		653,564
COMMITMENTS AND CONTINGENCIES (Note 13)				
	$	2,644,903	$	2,813,752

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

PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income (loss)	$ (2,369)	$ 18,236	$ 24,852	$ 26,944
Adjustments to reconcile net income (loss) to net cash from operating activities -				
Provision for depreciation	12,736	12,281	37,721	35,229
Amortization of regulatory assets	12,627	11,759	38,930	39,130
Deferred costs recoverable as regulatory assets	(5,355)	(25,618)	(41,301)	(62,122)
Deferred income taxes and investment tax credits, net	(5,412)	28,574	(2,765)	30,308
Accrued retirement benefit obligations	1,100	1,164	3,005	4,805
Accrued compensation, net	691	894	(1,695)	2,271
Pension trust contribution	-	(50,281)	-	(50,281)
Decrease (increase) in operating assets -				
Receivables	17,528	(17,689)	97,130	35,806
Prepayments and other current assets	13,487	9,703	(8,620)	(25,247)
Increase (decrease) in operating liabilities -				
Accounts payable	4,662	(23,255)	(15,671)	(38,015)
Accrued taxes	507	2	11,235	(7,572)
Accrued interest	5,628	5,605	5,594	2,856
Other	(1,460)	562	2,905	24,851
Net cash provided from (used for) operating activities	54,370	(28,063)	151,320	18,963
CASH FLOWS FROM FINANCING ACTIVITIES:				
New Financing -				
Long-term debt	-	-	-	150,000
Short-term borrowings, net	-	158,282	-	165,918
Redemptions and Repayments -				
Long-term debt	(8,013)	(103,241)	(11,534)	(228,453)
Short-term borrowings, net	(15,139)	-	(51,747)	-
Dividend Payments -				

Common stock		(2,000)		(3,000)		(32,000)		(8,000)
Net cash provided from (used for) financing activities		(25,152)		52,041		(95,281)		79,465
CASH FLOWS FROM INVESTING ACTIVITIES:								
Property additions		(27,997)		(10,192)		(61,680)		(33,428)
Non-utility generation trust contribution		-		-		-		(50,614)
Loan repayments from (loans to) associated companies, net		(1,287)		(3,124)		5,724		(3,144)
Other, net		66		(10,662)		(84)		(11,242)
Net cash used for investing activities		(29,218)		(23,978)		(56,040)		(98,428)
Net change in cash and cash equivalents		-		-		(1)		-
Cash and cash equivalents at beginning of period		35		36		36		36
Cash and cash equivalents at end of period	$	35	$	36	$	35	$	36

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

Report of Independent Registered Public Accounting Firm

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 September 30, 2005, and the related consolidated statements of income and comprehensive income and cash flows for each of the three-month and nine-month periods ended September 30, 2005 and 2004. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 the standards of the Public Company Accounting Oversight Board, 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 the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2004, and the related consolidated statements of income, capitalization, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended, management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004 and the effectiveness of the Company's internal control over financial reporting as of December 31, 2004; and in our report (which contained references to the Company's change in its method of accounting for asset retirement obligations as of January 1, 2003 as discussed in Note 2(G) to those consolidated financial statements and the Company's change in its method of accounting for the consolidation of variable interest entities as of December 31, 2003 as discussed in Note 6 to those consolidated financial statements) dated March 7, 2005, we expressed unqualified opinions thereon. The consolidated financial statements and management's assessment of the effectiveness of internal control over financial reporting referred to above are not presented herein. In our opinion, the information set forth in the accompanying consolidated balance sheet information as of December 31, 2004, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio

November 1, 2005

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PENNSYLVANIA ELECTRIC COMPANY

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

Penelec is a wholly owned electric utility subsidiary of FirstEnergy. Penelec conducts business in northern, western and south central Pennsylvania, providing regulated transmission and distribution services. Penelec also provides generation services to those customers electing to retain Penelec as their power supplier. Penelec has unbundled the price for electricity into its component elements - including generation, transmission, distribution and transition charges.

Results of Operations

Penelec recognized a net loss of $2 million in the third quarter of 2005, compared to $18 million in net income in the third quarter of 2004. During the first nine months of 2005, net income decreased to $25 million compared to $27 million in the first nine months of 2004. The decrease in both periods resulted from higher purchased power and other operating costs, partially offset by higher operating revenues and lower income taxes.

Operating revenues increased by $36 million in the third quarter and $93 million in the first nine months of 2005 compared to the same periods of 2004. Increases in both periods were due to higher retail generation revenues in all sectors ($14 million for the quarter and $23 million for the first nine months). The increases in retail generation KWH sales in both periods of 2005 were mainly due to the warmer weather in 2005 compared to 2004. While the higher generation sales in the third quarter were offset by slightly lower composite unit prices, overall higher composite unit prices - especially in the industrial sector - for the nine-month period further contributed to the increase in generation revenues.

Distribution revenues increased by $4 million in the third quarter and by $6 million in the first nine months of 2005 compared to the same periods of 2004. Increases in both periods were due to higher KWH deliveries partially offset by lower unit prices. Also contributing to higher operating revenues was an increase in transmission revenues of $18 million in the third quarter and $61 million in the first nine months of 2005. These increases were due to a change in the power supply agreement with FES in the second quarter of 2004. This change also resulted in higher transmission expenses as discussed further below.

Changes in KWH sales by customer class in the three months and nine months ended September 30, 2005 from the corresponding periods of 2004 are summarized in the following table:

Changes in KWH Sales	Three Months	Nine Months
Increase (Decrease)		
Retail Electric Generation:		
Residential	8.8%	4.2%
Commercial	7.0%	4.3%
Industrial	17.0%	7.3%
	10.2%	**5.1%**

Total Retail Electric Generation Sales		
Distribution Deliveries:		
Residential	8.7%	4.1%
Commercial	6.6%	4.1%
Industrial	8.3%	5.2%
Total Distribution Deliveries	**7.8%**	**4.5%**

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Operating Expenses and Taxes

Total operating expenses and taxes increased by $57 million in the third quarter and $97 million in the first nine months of 2005 compared with the same periods in 2004. The following table presents changes from the prior year by expense category:

Operating Expenses and Taxes - Changes	**Three Months**	**Nine Months**
	(In millions)	
Increase (Decrease)		
Purchased power costs	$ 41	$ 35
Other operating costs	29	60
Provision for depreciation	-	2
Amortization of regulatory assets	1	-
General taxes	1	1
Income taxes	(15)	(1)
Net increase in operating expenses and taxes	$ 57	$ 97

Purchased power costs increased by $41 million or 29.9% in the third quarter and $35 million or 8.0% in the first nine months of 2005 compared to the same periods of 2004. The increase in the third quarter of 2005 is due to increased KWH purchased to meet increased retail generation sales requirements, and higher unit costs. Third-party power purchases and NUG costs increased $48 million and $20 million, respectively, in the third quarter of 2005, partially offset by reduced purchased power from FES of $27 million. The increase in the first nine months is due to increased KWH purchased to meet sales requirements partially offset by lower unit costs. Increases from third-party power purchases and NUG costs of $81 million and $21 million, respectively, in the first nine months of 2005, were partially offset by reduced purchased power from FES of $67 million.

Other operating costs increased by $29 million in the third quarter and $60 million in the first nine months of 2005 compared to same periods in 2004. The increases in both periods were primarily due to increased transmission expenses in 2005 as a result of the change in the power supply agreement with FES referred to above. The increased transmission expenses were partially offset by reduced labor costs that were charged to capital projects. Income taxes decreased in the third quarter of 2005 due to lower pre-tax income compared to the third quarter of 2004.

Capital Resources and Liquidity

Penelec’s cash requirements for the remainder of 2005 for operating expenses, construction expenditures and scheduled debt maturities are expected to be met with cash from operations.

Changes in Cash Position

As of September 30, 2005, Penelec had $35,000 of cash and cash equivalents compared with $36,000 as of December 31, 2004. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Net cash provided from (used for) operating activities in the third quarter and first nine months of 2005, compared with the corresponding periods in 2004, are summarized as follows:

Operating Cash Flows	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In millions)			
Cash earnings [1]	$ 14	$ 27	$ 59	$ 56
Pension trust contribution [2]	-	(30)	-	(30)
Working capital and other	40	(25)	92	(7)
Total cash flows from operating activities	$ 54	$ (28)	$ 151	$ 19

[1] Cash earnings is a non-GAAP measure (see reconciliation below).
[2] Pension trust contribution net of $20 million of income tax benefits.

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Cash earnings, as disclosed in the table above, are not a measure of performance calculated in accordance with GAAP. Penelec believes that cash earnings is a useful financial measure because it provides investors and management with an additional means of evaluating its cash-based operating performance. The following table reconciles cash earnings with net income.

Reconciliation of Cash Earnings	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In millions)			
Net income (loss) (GAAP)	$ (2)	$ 18	$ 25	$ 27
Non-cash charges (credits):				
Provision for depreciation	13	12	38	35
Amortization of regulatory assets	12	12	39	39
Deferred costs recoverable as regulatory assets	(5)	(26)	(41)	(62)
Deferred income taxes and investment tax credits, net	(6)	9	(3)	10
Other non-cash items	2	2	1	7
Cash earnings (Non-GAAP)	$ 14	$ 27	$ 59	$ 56

Net cash from operating activities increased $82 million in the third quarter of 2005, compared with the third quarter of 2004, due to a $66 million increase from changes in working capital, an absence of a $30 million after-tax voluntary pension contribution made in the third quarter of 2004, and partially offset by a $13 million decrease in cash earnings as described above under “Results of Operations”. The increase in working capital primarily reflects net changes in accounts receivable and accounts payable to associated companies of $42 million and a $22 million increase in purchase power accounts payable.

Net cash from operating activities increased $132 million in the first nine months of 2005, compared with the same period of 2004, due to a $100 million increase from changes in working capital, an absence of the $30 million after-tax voluntary pension contribution, and a $3 million increase in cash earnings as described above under “Results of Operations”. The increase in working capital primarily reflects changes in accounts receivable to associated companies of $61 million, $30 million increase in purchase power and other accounts payable, and $19 million change in accrued taxes, partially offset by changes in customer deposits.

Cash Flows From Financing Activities

Net cash used for financing activities was $25 million in the third quarter of 2005 compared to net cash provided from financing activities of $52 million in the third quarter of 2004. The net change reflects a $1 million decrease in common stock dividends to FirstEnergy and a $173 million increase in repayments of short-term borrowings, offset by a $95 million decrease in debt redemptions.

Net cash used for financing activities was $95 million for the first nine months of 2005 compared to net cash provided from financing activities of $79 million in the first nine months of 2004. The net change of $174 million reflects $150 million of long-term debt financing in 2004, a $24 million increase in common stock dividends to FirstEnergy in 2005 and a $218 million increase in repayments of short-term borrowings, offset by a $217 million decrease in debt redemptions.

Penelec had approximately $35,000 of cash and temporary investments (which included short-term notes receivable from associated companies) and approximately $190 million of short-term indebtedness as of September 30, 2005. Penelec has authorization from the SEC to incur short-term debt of up to $250 million (including the utility money pool). Penelec will not issue FMB other than as collateral for senior notes, since its senior note indentures prohibit (subject to certain exceptions) Penelec from issuing any debt which is senior to the senior notes. As of September 30, 2005, Penelec had the capability to issue $18 million of additional senior notes based upon FMB collateral. Penelec has no restrictions on the issuance of preferred stock.

Penelec Funding LLC (Penelec Funding), a wholly owned subsidiary of Penelec, is a limited liability company whose borrowings are secured by customer accounts receivable purchased from Penelec. Penelec Funding can borrow up to $75 million under a receivables financing arrangement. As a separate legal entity with separate creditors, Penelec Funding would have to satisfy its obligations to creditors before any of its remaining assets could be made available to Penelec. On July 15, 2005, the facility was renewed until June 29, 2006. The facility was undrawn as of September 30, 2005. The annual facility fee is 0.25% on the entire finance limit.

On June 14, 2005, FirstEnergy, OE, Penn, CEI, TE, JCP&L, Met-Ed, Penelec, FES and ATSI, as Borrowers, entered into a syndicated $2 billion five-year revolving credit facility. Borrowings under the facility are available to each Borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. Penelec's borrowing limit under the facility is $250 million.

Penelec has the ability to borrow from its regulated affiliates and FirstEnergy to meet its short-term working capital requirements. FESC administers this money pool and tracks surplus funds of FirstEnergy and its regulated subsidiaries. Companies receiving a loan under the money pool agreements must repay the principal, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from the pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings under these arrangements in the third quarter of 2005 was 3.5%.

On July 18, 2005, Moody’s revised its rating outlook on FirstEnergy and its subsidiaries to positive from stable. Moody’s stated that the revision to FirstEnergy’s outlook resulted from steady financial improvement and steps taken by management to improve operations, including the stabilization of its nuclear operations. Moody’s further stated that the revision in their outlook recognized management’s regional strategy of focusing on its core utility businesses and the improvement in FirstEnergy’s credit profile stemming from the application of free cash flow toward debt reduction. Moody’s noted that a ratings upgrade could be considered if FirstEnergy continues to achieve planned improvements in its operations and balance sheet.

On October 3, 2005, S&P raised its corporate credit rating on FirstEnergy and the EUOC to 'BBB' from 'BBB-'. At the same time, S&P raised the senior unsecured ratings at the holding company to 'BBB-' from 'BB+' and each of the EUOC by one notch above the previous rating. S&P noted that the upgrade followed the continuation of a good operating track record, specifically for the nuclear fleet through the third quarter 2005. S&P also stated that FirstEnergy’s rating reflects the benefits of supportive regulation, low-cost base load generation fleet, low-risk transmission and distribution operations and rate certainty in Ohio. FirstEnergy’s ability to consistently generate free cash flow, good liquidity, and an improving financial profile were also noted as strengths.

Penelec’s access to capital markets and costs of financing are influenced by the ratings of its securities and the securities of FirstEnergy. The ratings outlook from S&P and Fitch on all securities is stable. Moody’s outlook on all securities is positive.

Cash Flows From Investing Activities

Cash used for investing activities was $29 million in the third quarter of 2005 compared to $24 million in the third quarter of 2004. The increase was primarily due to higher property additions, partially offset by lower loan repayments from associated companies and the absence in 2005 of an $11 million capital transfer from FESC that took place in September 2004. Cash used for investing activities was $56 million in the first nine months of 2005 compared to $98 million in the first nine months of 2004. The decrease was primarily due to a $51 million repayment to the NUG trust fund in 2004, increased loans from associated companies, and the $11 million capital transfer from above, partially offset by higher property additions in 2005. Capital expenditures for property additions primarily support Penelec’s energy delivery operations.

Penelec’s capital spending for the period 2005-2007 is expected to be about $272 million for property additions and improvements, of which about $91 million applies to 2005. In the last quarter of 2005, capital requirements for property additions are expected to be about $26 million. Penelec has no additional requirements for maturing long-term debt during the remainder of 2005. These cash requirements are expected to be satisfied from internal cash and short-term credit arrangements.

Market Risk Information

Penelec 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 members of senior management, provides general management oversight to risk management activities.

Commodity Price Risk

Penelec is exposed to price risk primarily due to fluctuating 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 futures contracts. The derivatives are used for hedging purposes. Penelec's non-hedge derivative contracts represent non-trading positions that do not qualify for hedge treatment under SFAS 133. As of September 30, 2005, Penelec's commodity derivatives contract was an embedded option with a fair value of $14 million. A decrease of $1 million in the value of this asset was recorded in the first nine months of 2005 as a decrease in regulatory liabilities, and therefore, had no impact on net income.

The valuation of derivative commodity 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 decision making. Sources of information for valuation of derivative contracts as of September 30, 2005 are summarized by year in the following table:

Sources of Information - Fair Value by Contract Year	2005[1]	2006	2007	2008	2009	Thereafter	Total
Prices based on external sources[2]	$ 3	$ 3	$ 2	$ -	$ -	$ -	$ 8
Prices based on models	-	-	-	2	2	2	6
Total	$ 3	$ 3	$ 2	$ 2	$ 2	$ 2	$ 14

(1) For the last quarter of 2005.
(2) Broker quote sheets.

Penelec 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 its trading and nontrading derivative instruments would not have had a material effect on its consolidated financial position or cash flows as of September 30, 2005.

Equity Price Risk

Included in nuclear decommissioning trusts are marketable equity securities carried at their current fair value of approximately $61 million and $60 million as of September 30, 2005 and December 31, 2004, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $6 million reduction in fair value as of September 30, 2005.

Regulatory Matters

Regulatory assets are costs which have been authorized by the PPUC and the FERC for recovery from customers in future periods and, without such authorization, would have been charged to income when incurred. Penelec's regulatory assets as of September 30, 2005 and December 31, 2004 were $99 million and $200 million, respectively.

In accordance with PPUC directives, Met-Ed and Penelec have been negotiating with interested parties in an attempt to resolve the merger savings issues that are the subject of remand from the Commonwealth Court. Met-Ed’s and Penelec’s combined portion of total merger savings is estimated to be approximately $31.5 million. On April 13, 2005, the Commonwealth Court issued an interim order in the remand proceeding that the parties should report the status of the negotiations to the PPUC with a copy to the ALJ. The parties exchanged settlement proposals in May and June 2005 and continue to have settlement discussions.

In an October 16, 2003 order, the PPUC approved September 30, 2004 as the date for Met-Ed's and Penelec's NUG trust fund refunds. The PPUC order also denied their accounting treatment request regarding the CTC rate/shopping credit swap by requiring Met-Ed and Penelec to treat the stipulated CTC rates that were in effect from January 1, 2002 on a retroactive basis. On October 22, 2003, Met-Ed and Penelec filed an Objection with the Commonwealth Court asking that the Court reverse this PPUC finding; a Commonwealth Court judge subsequently denied their Objection on October 27, 2003 without explanation. On October 31, 2003, Met-Ed and Penelec filed an Application for Clarification of the Court order with the judge, a Petition for Review of the PPUC's October 2 and October 16, 2003 Orders, and an application for reargument, if the judge, in his clarification order, indicates that Met-Ed's and Penelec's Objection was intended to be denied on the merits. The Reargument Brief before the Commonwealth Court was filed on January 28, 2005.

Penelec purchases a portion of its PLR requirements from FES through a wholesale power sales agreement. The PLR sale is automatically extended for each successive calendar year unless either party elects to cancel the agreement by November 1 of the preceding year. Under the terms of the wholesale agreement, FES retains the supply obligation and the supply profit and loss risk, for the portion of power supply requirements not self-supplied by Penelec under its NUG contracts and other power contracts with nonaffiliated third party suppliers. This arrangement reduces Penelec's exposure to high wholesale power prices by providing power at a fixed price for its uncommitted PLR energy costs during the term of the agreement with FES. Penelec is authorized to defer differences between NUG contract costs and current market prices. On November 1, 2005, FES and the other parties to the wholesale power agreement amended the agreement to provide FES the right over the next year to terminate the agreement at any time upon 60 days notice. If the wholesale power agreement were terminated, Met-Ed and Penelec would need to satisfy the applicable portion of their PLR obligations from other sources at prevailing prices, which are likely to be higher than the current price charged by FES under the agreement and, as a result, Met-Ed’s and Penelec’s purchased power costs could materially increase.

On January 12, 2005, Penelec filed a request with the PPUC to defer transmission-related costs beginning January 1, 2005, estimated to be approximately $4 million per month. The OCA, OSBA, OTS, MEIUG, PICA, Allegheny Electric Cooperative and Pennsylvania Rural Electric Association have all intervened in the case. To date no hearing schedule has been established, and Penelec has not yet implemented deferral accounting for these costs.

On January 31, 2005, certain PJM transmission owners made three filings pursuant to a settlement agreement previously approved by the FERC. Penelec was party to that proceeding and joined in two of the filings. In the first filing, the settling transmission owners submitted a filing justifying continuation of their existing rate design within the PJM RTO. In the second filing, the settling transmission owners proposed a revised Schedule 12 to the PJM tariff designed to harmonize the rate treatment of new and existing transmission facilities. Interventions and protests were filed on February 22, 2005. In the third filing, Baltimore Gas and Electric Company and Pepco Holdings, Inc. requested a formula rate for transmission service provided within their respective zones. On May 31, 2005, the FERC issued an order on these cases. First, it set for hearing the existing rate design and indicated that it will issue a final order within six months. Second, the FERC approved the proposed Schedule 12 rate harmonization. Third, the FERC accepted the proposed formula rate, subject to referral and hearing procedures. On June 30, 2005, the PJM transmission owners filed a request for rehearing of the May 31, 2005 order. The rate design and formula rate filings continue to be litigated before the FERC. The outcome of these two cases cannot be predicted.

See Note 14 to the consolidated financial statements for further details and a complete discussion of regulatory matters in Pennsylvania, including a more detailed discussion of reliability initiatives, including actions by the PPUC that impact Penelec.

Environmental Matters

Penelec accrues environmental liabilities when it concludes that it is probable that it has an obligation for such costs and can reasonably estimate the amount of such costs. Unasserted claims are reflected in Penelec's determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

Penelec has been named a 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 are liable on a joint and several basis.

FirstEnergy plans to issue a report regarding its response to air emission requirements. FirstEnergy expects to complete the report by December 1, 2005.

See Note 13(B) to the consolidated financial statements for further details and a complete discussion of environmental matters.

Other Legal Proceedings

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to Penelec's normal business operations pending against Penelec. The other material items not otherwise discussed above are described below.

On August 14, 2003, various states and parts of southern Canada experienced widespread power outages. The outages affected approximately 1.4 million customers in FirstEnergy's service area. The U.S. - Canada Power System Outage Task Force’s final report in April 2004 on the outages concludes, among other things, that the problems leading to the outages began in FirstEnergy’s Ohio service area. Specifically, the final report concluded, among other things, that the initiation of the August 14, 2003 power outages resulted from an alleged failure of both FirstEnergy and ECAR to assess and understand perceived inadequacies within the FirstEnergy system; inadequate situational awareness of the developing conditions; and a perceived failure to adequately manage tree growth in certain transmission rights of way. The Task Force also concluded that there was a failure of the interconnected grid's reliability organizations (MISO and PJM) to provide effective real-time diagnostic support. The final report is publicly available through the Department of Energy's website (www.doe.gov). FirstEnergy believes that the final report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14, 2003 power outages and that it does not adequately address the underlying causes of the outages. FirstEnergy remains convinced that the outages cannot be explained by events on any one utility's system. The final report contained 46 "recommendations to prevent or minimize the scope of future blackouts." Forty-five of those recommendations related to broad industry or policy matters while one, including subparts, related to activities the Task Force recommended be undertaken by FirstEnergy, MISO, PJM, ECAR, and other parties to correct the causes of the August 14, 2003 power outages. FirstEnergy implemented several initiatives, both prior to and since the August 14, 2003 power outages, which were independently verified by NERC as complete in 2004 and were consistent with these and other recommendations and collectively enhance the reliability of its electric system. FirstEnergy's implementation of these recommendations in 2004 included completion of the Task Force recommendations that were directed toward FirstEnergy. FirstEnergy also is proceeding with the implementation of the recommendations regarding enhancements to regional reliability that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new or material upgrades to existing equipment, and therefore FirstEnergy has not accrued a liability as of September 30, 2005 for any expenditures in excess of those actually incurred through that date. The FERC or other applicable government agencies and reliability coordinators may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures. Finally, the PUCO is continuing to review FirstEnergy's filing that addressed upgrades to control room computer hardware and software and enhancements to the training of control room operators, before determining the next steps, if any, in the proceeding.

One complaint was filed on August 25, 2004 against FirstEnergy in the New York State Supreme Court. In this case, several plaintiffs in the New York City metropolitan area allege that they suffered damages as a result of the August 14, 2003 power outages. None of the plaintiffs are customers of any FirstEnergy affiliate. FirstEnergy's motion to dismiss the case was granted on September 26, 2005. Additionally, FirstEnergy Corp. was named in a complaint filed in Michigan State Court by an individual who is not a customer of any FirstEnergy company. A responsive pleading to this matter is not due until on or about December 1, 2005. No estimate of potential liability has been undertaken in this matter.

FirstEnergy is vigorously defending these actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be initiated against the Companies. In particular, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

See Note 13(C) to the consolidated financial statements for further details and a complete discussion of other legal proceedings.

New Accounting Standards and Interpretations

EITF Issue 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty"

In September 2005, the EITF reached a final consensus on Issue 04-13 concluding that two or more legally separate exchange transactions with the same counterparty should be combined and considered as a single arrangement for purposes of applying APB 29, when the transactions were entered into "in contemplation" of one another. If two transactions are combined and considered a single arrangement, the EITF reached a consensus that an exchange of inventory should be accounted for at fair value. Although electric power is not capable of being held in inventory, there is no substantive conceptual distinction between exchanges involving power and other storable inventory. Therefore, Penelec will adopt this EITF effective for new arrangements entered into, or modifications or renewals of existing arrangements, in interim or annual periods beginning after March 15, 2006.

EITF Issue No. 05-6, "Determining the Amortization Period for Leasehold Improvements Purchased after Lease Inception or Acquired in a Business Combination"

In June 2005, the EITF reached a consensus on the application guidance for Issue 05-6. EITF 05-6 addresses the amortization period for leasehold improvements that were either acquired in a business combination or placed in service significantly after and not contemplated at or near the beginning of the initial lease term. For leasehold improvements acquired in a business combination, the amortization period is the shorter of the useful life of the assets or a term that includes required lease periods and renewals that are deemed to be reasonably assured at the date of acquisition. Leasehold improvements that are placed in service significantly after and not contemplated at or near the beginning of the lease term should be amortized over the shorter of the useful life of the assets or a term that includes required lease periods and renewals that are deemed to be reasonably assured at the date the leasehold improvements are purchased. This EITF was effective July 1, 2005 and is consistent with Penelec's current accounting.

FIN 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143"

On March 30, 2005, the FASB issued FIN 47 to clarify the scope and timing of liability recognition for conditional asset retirement obligations. Under this interpretation, companies are required to recognize a liability for the fair value of an asset retirement obligation that is conditional on a future event, if the fair value of the liability can be reasonably estimated. In instances where there is insufficient information to estimate the liability, the obligation is to be recognized in the first period in which sufficient information becomes available to estimate its fair value. If the fair value cannot be reasonably estimated, that fact and the reasons why must be disclosed. This Interpretation is effective for Penelec in the fourth quarter of 2005. Penelec is currently evaluating the effect this Interpretation will have on its financial statements.

SFAS 154 - "Accounting Changes and Error Corrections - a replacement of APB Opinion No. 20 and FASB Statement No. 3"

In May 2005, the FASB issued SFAS 154 to change the requirements for accounting and reporting a change in accounting principle. It applies to all voluntary changes in accounting principle and to changes required by an accounting pronouncement when that pronouncement does not include specific transition provisions. This Statement requires retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. In those instances, this Statement requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that period rather than being reported in the Consolidated Statements of Income. This Statement also requires that a change in depreciation, amortization, or depletion method for long-lived, nonfinancial assets be accounted for as a change in accounting estimate affected by a change in accounting principle. The provisions of this Statement are effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. Penelec will adopt this Statement effective January 1, 2006.

SFAS 153, "Exchanges of Nonmonetary Assets - an amendment of APB Opinion No. 29"

In December 2004, the FASB issued SFAS 153 amending APB 29, which was based on the principle that nonmonetary assets should be measured based on the fair value of the assets exchanged. The guidance in APB 29 included certain exceptions to that principle. SFAS 153 eliminates the exception from fair value measurement for nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges that do not have commercial substance. This Statement specifies that a nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of this Statement are effective January 1, 2006 for Penelec. This FSP is not expected to have a material impact on Penelec's financial statements.

SFAS 151, "Inventory Costs - an amendment of ARB No. 43, Chapter 4"

In November 2004, the FASB issued SFAS 151 to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage). Previous guidance stated that in some circumstances these costs may be "so abnormal" that they would require treatment as current period costs. SFAS 151 requires abnormal amounts for these items to always be recorded as current period costs. In addition, this Statement requires that allocation of fixed production overheads to the cost of conversion be based on the normal capacity of the production facilities. The provisions of this statement are effective for inventory costs incurred by Penelec beginning January 1, 2006. Penelec is currently evaluating this Standard and does not expect it to have a material impact on the financial statements.

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FSP FAS 115-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"

In September 2005, the FASB finalized and renamed EITF 03-1 and 03-1-a to FSP FAS 115-1. FSP FAS 115-1 will (1) supersede Issue 03-1 and EITF topic No. D-44, "Recognition of Other Than Temporary Impairment upon the Planned Sale of a Security Whose Cost Exceeds Fair Value," (2) clarify that an investor should recognize an impairment loss no later than when the impairment is deemed other than temporary, even if a decision to sell has not been made, and (3) be effective for other-than-temporary impairment and analyses conducted in periods beginning after September 15, 2005. The FASB expects to issue this FSP in the fourth quarter of 2005, which would require prospective application with an effective date for reporting periods beginning after December 15, 2005. Penelec is currently evaluating this FSP and any impact on its investments.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See “Management’s Discussion and Analysis of Results of Operation and Financial Condition - Market Risk Information” in Item 2 above.

ITEM 4. 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-15(e) and 15d-15(e), as of the end of the date covered by the report. Based on that evaluation, those officers have concluded that the registrant's disclosure controls and procedures are effective in timely alerting them to any information relating to the registrants and their consolidated subsidiaries that is required to be included in the registrants’ periodic reports and in ensuring that information required in the reports filed under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time period specified by the SEC's rules and forms.

(b) CHANGES IN INTERNAL CONTROLS

During the quarter ended September 30, 2005, there were no changes in the registrants' internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information required for Part II, Item 1 is incorporated by reference to the discussions in Notes 13 and 14 to the Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

ITEM 2. CHANGES IN SECURITIES, USE OF PROCEEDS AND ISSUER PURCHASES OF EQUITY SECURITIES

(e) FirstEnergy

The table below includes information on a monthly basis regarding purchases made by FirstEnergy of its common stock.

Period	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs (b)	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
July 1-31, 2005	219,344	$ 49.40	-	-
August 1-31, 2005	698,858	$ 49.46	-	-
September 1-30, 2005	489,705	$ 51.69	-	-
Third quarter 2005	1,407,907	$ 50.23	-	-

(a) Share amounts reflect purchases on the open market to satisfy FirstEnergy's obligations to deliver common stock under its Executive and Director Incentive Compensation Plan, Deferred Compensation Plan for Outside Directors, Executive Deferred Compensation Plan, Savings Plan and Stock Investment Plan. In addition, such amounts reflect shares tendered by employees to pay the exercise price or withholding taxes upon exercise of stock options granted under the Executive and Director Incentive Compensation Plan.

(b) FirstEnergy does not currently have any publicly announced plan or program for share purchases.

ITEM 5. OTHER INFORMATION

On November 1, 2005, the Restated Partial Requirements Agreement, dated as of January 1, 2003, as amended August 29, 2003 and June 8, 2004 (as so amended, the "Agreement"), among FES, Met-Ed, Penelec and Waverly was amended by the parties to provide FES the right over the next year to terminate the Agreement at any time upon 60 days written notice. Otherwise, the agreement remains automatically extended as to each operating company for each successive calendar year unless FES or such operating company elects to cancel the agreement by November 1 of the preceding year.

Under the Agreement, Met-Ed and Penelec currently purchase a portion of their PLR requirements from FES at fixed prices. The remainder of PLR requirements are currently sourced from existing NUG contracts or other power contracts with non-affiliated third party suppliers. If the Agreement were terminated, Met-Ed and Penelec would need to satisfy the applicable portion of their PLR obligations from other sources at prevailing prices, which are likely to be higher than the current price charged by FES under the Agreement, and as a result, Met-Ed's and Penelec's purchased power costs could materially increase.

Met-Ed, Penelec and FES are all wholly owned subsidiaries of FirstEnergy and Waverly is a wholly owned subsidiary of Penelec. A copy of the November 1, 2005 amendment is filed as Exhibit 10.1 to this Quarterly Report on Form 10-Q.

ITEM 6. EXHIBITS

(a) Exhibits

Exhibit Number	
JCP&L	
12	Fixed charge ratios
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
31.3	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
32.2	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350.
Met-Ed	
10.1	Notice of Termination Tolling Agreement, Restated Partial Requirements Agreement
12	Fixed charge ratios
31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
32.1	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350.

Penelec

10.1	Notice of Termination Tolling Agreement, Restated Partial Requirements Agreement
12	Fixed charge ratios
15	Letter from independent registered public accounting firm
31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
32.1	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350.

FirstEnergy

10.1	Notice of Termination Tolling Agreement, Restated Partial Requirements Agreement
10.2	Agreement by and between FirstEnergy Generation Corp. and Bechtel Power Corporation dated August 26, 2005.*
15	Letter from independent registered public accounting firm
31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
32.1	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350.

OE

15	Letter from independent registered public accounting firm
31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
32.1	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350.

Penn

15	Letter from independent registered public accounting firm.
31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
32.1	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350.

CEI

31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
32.1	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350.

TE

31.1	

	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
32.1	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350.

* Confidential Treatment has been requested with respect to certain portions of this exhibit. Omitted portions have been filed separately with the Securities and Exchange Commission.

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.

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.

November 2, 2005

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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