FIRSTENERGY CORP
Form 10-Q
November 02, 2006

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 10-Q
(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2006

OR

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

For the transition period from to

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
333-21011	FIRSTENERGY CORP.	34-1843785
	(An Ohio Corporation)	
	76 South Main Street	
	Akron, OH 44308	
	Telephone (800)736-3402	
1-2578	OHIO EDISON COMPANY	34-0437786
	(An Ohio Corporation)	
	c/o FirstEnergy Corp.	
	76 South Main Street	
	Akron, OH 44308	
	Telephone (800)736-3402	
1-2323	THE CLEVELAND ELECTRIC ILLUMINATING COMPANY	34-0150020
	(An Ohio Corporation)	
	c/o FirstEnergy Corp.	
	76 South Main Street	

	Akron, OH 44308	
	Telephone (800)736-3402	
1-3583	THE TOLEDO EDISON COMPANY	34-4375005
	(An Ohio Corporation)	
	c/o FirstEnergy Corp.	
	76 South Main Street	
	Akron, OH 44308	
	Telephone (800)736-3402	
1-3491	PENNSYLVANIA POWER COMPANY	25-0718810
	(A Pennsylvania Corporation)	
	c/o FirstEnergy Corp.	
	76 South Main Street	
	Akron, OH 44308	
	Telephone (800)736-3402	
1-3141	JERSEY CENTRAL POWER & LIGHT COMPANY	21-0485010
	(A New Jersey Corporation)	
	c/o FirstEnergy Corp.	
	76 South Main Street	
	Akron, OH 44308	
	Telephone (800)736-3402	
1-446	METROPOLITAN EDISON COMPANY	23-0870160
	(A Pennsylvania Corporation)	
	c/o FirstEnergy Corp.	
	76 South Main Street	
	Akron, OH 44308	
	Telephone (800)736-3402	
1-3522	PENNSYLVANIA ELECTRIC COMPANY	25-0718085
	(A Pennsylvania Corporation)	
	c/o FirstEnergy Corp.	
	76 South Main Street	
	Akron, OH 44308	
	Telephone (800)736-3402	

Indicate by check mark whether each of the registrants (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes (X) No ( )

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer (X)	FirstEnergy Corp.
Accelerated Filer ( )	N/A
Non-accelerated Filer (X)	Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Pennsylvania Power Company, Jersey Central Power & Light Company, Metropolitan Edison Company, and Pennsylvania Electric Company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Yes ( ) No (X)

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

CLASS	OUTSTANDING AS OF OCTOBER 31, 2006
FirstEnergy Corp., $.10 par value	319,205,517
Ohio Edison Company, no par value	80
The Cleveland Electric Illuminating Company, no par value	79,590,689
The Toledo Edison Company, $5 par value	39,133,887
Pennsylvania Power Company, $30 par value	6,290,000
Jersey Central Power & Light Company, $10 par value	15,371,270
Metropolitan Edison Company, no par value	859,500
Pennsylvania Electric Company, $20 par value	5,290,596

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

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

This Form 10-Q includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words. Actual results may differ materially due to the speed and nature of increased competition and deregulation in the electric utility industry, economic or weather conditions affecting future sales and margins, changes in markets for energy services, changing energy and commodity market prices, replacement power costs being higher than anticipated or inadequately hedged, the continued ability of FirstEnergy Corp.'s regulated utilities to collect transition and other charges or to recover increased transmission costs, maintenance costs being higher than anticipated, legislative and regulatory changes (including revised environmental requirements), and the legal and regulatory changes resulting from the implementation of the Energy Policy Act of 2005 (including, but not limited to, the repeal of the Public Utility Holding Company Act of 1935), the uncertainty of the timing and amounts of the capital expenditures needed to, among other things, implement the Air Quality Compliance Plan (including that such amounts could be higher than anticipated) or levels of emission reductions related to the Consent Decree resolving the New Source Review litigation, adverse regulatory or legal decisions and outcomes (including, but not limited to, the revocation of necessary licenses or operating permits, fines or other enforcement actions and remedies) of governmental investigations and oversight, including by the Securities and Exchange Commission, the United States Attorney's Office, the Nuclear Regulatory Commission and the various state public utility commissions as disclosed in the registrants' Securities and Exchange Commission filings, generally, and with respect to the Davis-Besse Nuclear Power Station outage and heightened scrutiny at the Perry Nuclear Power Plant in particular, the timing and outcome of various proceedings before the Public Utilities Commission of Ohio (including, but not limited to, the successful resolution of the issues remanded to the Public Utilities Commissioni of Ohio by the Ohio Supreme Court regarding the Rate Stabilization Plan) and the Pennsylvania Public Utility Commission, including the transition rate plan filings for Met-Ed and Penelec, the continuing availability and operation of generating units, the ability of generating units to continue to operate at, or near full capacity, the inability to accomplish or realize anticipated benefits from strategic goals (including employee workforce initiatives), the anticipated benefits from voluntary pension plan contributions, the ability to improve electric commodity margins and to experience growth in the distribution business, the ability to access the public securities and other capital markets and the cost of such capital, the outcome, cost and other effects of present and potential legal and administrative proceedings and claims related to the August 14, 2003 regional power outages, the successful completion of the share repurchase program announced on August 10, 2006, the risks and other factors discussed from time to time in the registrants' Securities and Exchange Commission filings, including their annual report on Form 10-K for the year ended December 31, 2005, and other similar factors. A security rating is not a recommendation to buy, sell or hold securities and it may be subject to revision or withdrawal at any time by the credit rating agency. The registrants expressly disclaim any current intention to update any forward-looking statements contained herein as a result of new information, future events, or otherwise.

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GLOSSARY OF TERMS

The following abbreviations and acronyms are used in this report to identify FirstEnergy Corp. and its current and former subsidiaries:

ATSI	American Transmission Systems, Inc., owns and operates transmission facilities
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
Centerior	Centerior Energy Corporation, former parent of CEI and TE, which merged with OE to form FirstEnergy on November 8, 1997
CFC	Centerior Funding Corporation, a wholly owned finance subsidiary of CEI
Companies	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec
FENOC	FirstEnergy Nuclear Operating Company, operates nuclear generating facilities
FES	FirstEnergy Solutions Corp., provides energy-related products and services
FESC	FirstEnergy Service Company, provides legal, financial, and other corporate support services
FGCO	FirstEnergy Generation Corp., owns and operates non-nuclear generating facilities
FirstCom	First Communications, LLC, provides local and long-distance telephone service
FirstEnergy	FirstEnergy Corp., a public utility holding company
FSG	FirstEnergy Facilities Services Group, LLC, the parent company of several heating, ventilation, air conditioning and energy management companies
GPU	GPU, Inc., former parent of JCP&L, Met-Ed and Penelec, which merged with FirstEnergy on November 7, 2001
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
JCP&L Transition Funding	JCP&L Transition Funding LLC, a Delaware limited liability company and issuer of transition bonds
JCP&L Transition Funding II	JCP&L Transition Funding II LLC, a Delaware limited liability company and issuer of transition bonds
Met-Ed	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MYR	MYR Group, Inc., a utility infrastructure construction service company
NGC	FirstEnergy Nuclear Generation Corp., owns nuclear generating facilities
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
OE Companies	OE and Penn
Ohio Companies	CEI, OE and TE

Penelec	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
Shippingport	Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
TEBSA	Termobarranquilla S.A., Empresa de Servicios Publicos

The following abbreviations and acronyms are used to identify frequently used terms in this report:

ALJ	Administrative Law Judge
AOCL	Accumulated Other Comprehensive Loss
APB	Accounting Principles Board
APB 25	APB Opinion No. 25, "Accounting for Stock Issued to Employees"
APB 29	APB Opinion No. 29, "Accounting for Nonmonetary Transactions"
ARB	Accounting Research Bulletin
ARB 43	ARB No. 43, "Restatement and Revision of Accounting Research Bulletins"
ARO	Asset Retirement Obligation
B&W	Babcock & Wilcox Company
Bechtel	Bechtel Power Corporation
BGS	Basic Generation Service
BTU	British Thermal Unit
CAIDI	Customer Average Interruption Duration Index
CAIR	Clean Air Interstate Rule
CAL	Confirmatory Action Letter
CAMR	Clean Air Mercury Rule
CBP	Competitive Bid Process
CIEP	Commercial Industrial Energy Price
CO_2	Carbon Dioxide
CTC	Competitive Transition Charge
DCPD	Deferred Compensation Plan for Outside Directors
DIG C20	Derivatives Implementation Group Issue No. C20, “Scope Exceptions: Interpretations of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature”

GLOSSARY OF TERMS Cont'd.

DOJ	U.S. Department of Justice
DRA	Division of the Ratepayer Advocate
ECAR	East Central Area Reliability Coordination Agreement
EDCP	Executive Deferred Compensation Plan
EITF	Emerging Issues Task Force
EPA	U.S. Environmental Protection Agency
EPACT	Energy Policy Act of 2005
ERO	Electric Reliability Organization
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	U.S. Federal Energy Regulatory Commission
FIN	FASB Interpretation
FIN 46(R)	FIN 46 (revised December 2003), "Consolidation of Variable Interest Entities"
FIN 46(R)-6	FIN 46(R)-6, "Determining the Variability to be Considered in Applying FASB interpretation No. 46(R)"
FIN 47	FIN 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143"
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No.109"
FMB	First Mortgage Bonds
FSP	FASB Staff Position
FSP FIN 13-2	FSP FIN 13-2, "Accounting for a Change or Projected Change in the Timing of Cash Flows Relating to Income Taxes Generated by a Leveraged Lease Transaction"
GAAP	Accounting Principles Generally Accepted in the United States
GCAF	Generation Charge Adjustment Factor
GHG	Greenhouse Gases
KWH	Kilowatt-hours
LOC	Letter of Credit
LTIP	Long-Term Incentive Program
MEIUG	Met-Ed Industrial Users Group
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service
MOU	Memorandum of Understanding
MSG	Market Support Generation
MTC	Market Transition Charge
MW	Megawatts
MWH	Megawatt-hours
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Council
NJBPU	New Jersey Board of Public Utilities
NOAC	Northwest Ohio Aggregation Coalition

NOPR	Notice of Proposed Rulemaking
NOV	Notices of Violation
NO_X	Nitrogen Oxide
NRC	U.S. Nuclear Regulatory Commission
NUG	Non-Utility Generation
NUGC	Non-Utility Generation Charge
OCA	Office of Consumer Advocate
OCC	Office of the Ohio Consumers' Counsel
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OSBA	Office of Small Business Advocate
OTS	Office of Trial Staff
PaDEP	Pennsylvania Department of Environmental Protection
PCAOB	Public Company Accounting Oversight Board
PICA	Penelec Industrial Customer Association
PJM	PJM Interconnection L. L. C.
PLR	Provider of Last Resort
PPUC	Pennsylvania Public Utility Commission
PRP	Potentially Responsible Party
PUCO	Public Utilities Commission of Ohio
PUHCA	Public Utility Holding Company Act of 1935
RCP	Rate Certainty Plan
RFP	Request for Proposal
RSP	Rate Stabilization Plan

GLOSSARY OF TERMS Cont'd.

RTC	Regulatory Transition Charge
RTO	Regional Transmission Organization
RTOR	Regional Through and Out Rates
S&P	Standard & Poor's Ratings Service
SAB 108	SEC Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements"
SAIFI	System Average Interruption Frequency Index
SBC	Societal Benefits Charge
SEC	U.S. Securities and Exchange Commission
SECA	Seams Elimination Cost Adjustment
SFAS	Statement of Financial Accounting Standards
SFAS 123	SFAS No. 123, "Accounting for Stock-Based Compensation"
SFAS 123(R)	SFAS No. 123(R), "Share-Based Payment"
SFAS 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS 142	SFAS No. 142, "Goodwill and Other Intangible Assets"
SFAS 143	SFAS No. 143, "Accounting for Asset Retirement Obligations"
SFAS 144	SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets"
SFAS 157	SFAS No. 157, "Fair Value Measurements"
SFAS 158	SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)"
SIP	State Implementation Plan(s) Under the Clean Air Act
SO_2	Sulfur Dioxide
SRM	Special Reliability Master
TBC	Transition Bond Charge
TMI-2	Three Mile Island Unit 2
VIE	Variable Interest Entity
VMEP	Vegetation Management Enhancement Project

PART I. FINANCIAL INFORMATION

FIRSTENERGY CORP. AND SUBSIDIARIES
OHIO EDISON COMPANY AND SUBSIDIARIES
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY AND SUBSIDIARIES
THE TOLEDO EDISON COMPANY AND SUBSIDIARY
PENNSYLVANIA POWER COMPANY AND SUBSIDIARY
JERSEY CENTRAL POWER & LIGHT COMPANY AND SUBSIDIARIES
METROPOLITAN EDISON COMPANY AND SUBSIDIARIES
PENNSYLVANIA ELECTRIC COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. - ORGANIZATION AND BASIS OF PRESENTATION

FirstEnergy’s principal business is the holding, directly or indirectly, of all of the outstanding common stock of its eight principal electric utility operating subsidiaries: OE, CEI, TE, Penn, ATSI, JCP&L, Met-Ed and Penelec. Penn is a wholly owned subsidiary of OE. FirstEnergy's consolidated financial statements also include its other principal subsidiaries: FENOC, FES and its subsidiary FGCO, NGC, FESC and FSG.

FirstEnergy and its subsidiaries follow GAAP and comply with the regulations, orders, policies and practices prescribed by the SEC, FERC and, as applicable, PUCO, PPUC and NJBPU. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates. The reported results of operations are not indicative of results of operations for any future period.

These statements should be read in conjunction with the financial statements and notes included in the combined Annual Report on Form 10-K for the year ended December 31, 2005 for FirstEnergy and the Companies. The consolidated unaudited financial statements of FirstEnergy and each of the Companies reflect all normal recurring adjustments that, in the opinion of management, are necessary to fairly present results of operations for the interim periods. Certain businesses divested in the nine months ended September 30, 2005 have been classified as discontinued operations on the Consolidated Statements of Income (see Note 4). As discussed in Note 13, interim period segment reporting in 2005 was reclassified to conform with the current year business segment organizations and operations.

FirstEnergy and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation. FirstEnergy consolidates a VIE (see Note 9) when it is determined to be the VIE's primary beneficiary. Investments in nonconsolidated affiliates over which FirstEnergy and its subsidiaries have the ability to exercise significant influence, but not control, (20-50 percent owned companies, joint ventures and partnerships) are accounted for under the equity method. Under the equity method, the interest in the entity is reported as an investment in the Consolidated Balance Sheet and the percentage share of the entity’s earnings is reported in the Consolidated Statement of Income. Certain prior year amounts have been reclassified to conform to the current presentation.

FirstEnergy's and the Companies' independent registered public accounting firm has performed reviews of, and issued reports on, these consolidated interim financial statements in accordance with standards established by the PCAOB. Pursuant to Rule 436(c) under the Securities Act of 1933, their reports of those reviews should not be considered a report within the meaning of Section 7 and 11 of that Act, and the independent registered public accounting firm’s liability under Section 11 does not extend to them.

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2. - EARNINGS PER SHARE

Basic earnings per share are computed using the weighted average of actual common shares outstanding during the respective period as the denominator. The denominator for diluted earnings per share reflects the weighted average of common shares outstanding plus the potential additional common shares that could result if dilutive securities and other agreements to issue common stock were exercised. On August 10, 2006, FirstEnergy repurchased 10.6 million shares, approximately 3.2%, of its outstanding common stock through an accelerated share repurchase program (see Note 10(D)). The initial purchase price was $600 million, or $56.44 per share. The final purchase price will be adjusted to reflect the ultimate cost to acquire the shares over a period of up to seven months. The 2006 basic and diluted earnings per share results reflect the impact associated with the August 2006 accelerated share repurchase program. FirstEnergy intends to settle, in shares or cash, any obligation on its part to pay the difference between the average of the daily volume-weighted average price of the shares as calculated under the program and the initial price of the shares. Since the effect of any potential settlement in shares is currently unknown and therefore not expected to be dilutive, there is no impact on reported diluted earnings per share. The following table reconciles the computation of basic and diluted earnings per share of common stock before discontinued operations:

Reconciliation of Basic and Diluted Earnings per Share	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(In millions, except per share amounts)			
Income Before Discontinued Operations	$ 454	$ 332	$ 979	$ 652
Less: Redemption premium on subsidiary preferred stock	-	-	(3)	-
Earnings on Common Stock Before Discontinued Operations	$ 454	$ 332	$ 976	$ 652
Weighted Average Shares of Common Stock Outstanding:				
Denominator for basic earnings per share	322	328	326	328
Assumed exercise of dilutive stock options and awards	3	2	3	2
Denominator for diluted earnings per share	325	330	329	330
Earnings Before Discontinued Operations per Common Share:				
Basic	$1.41	$1.01	$2.99	$1.99
Diluted	$1.40	$1.01	$2.97	$1.98

3. - GOODWILL

In a business combination, the excess of the purchase price over the estimated fair values of assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by SFAS 142, FirstEnergy evaluates its goodwill for impairment at least annually and more frequently as indicators of impairment arise. In accordance with the accounting standard, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. If impairment is indicated, FirstEnergy recognizes a loss - calculated as the difference between the implied fair value of a reporting unit's goodwill and the carrying value of the goodwill.

FirstEnergy's 2006 annual review was completed in the third quarter of 2006 with no impairment indicated. As discussed in Note 11 to the consolidated financial statements, Met-Ed and Penelec have rate increase requests pending before the PPUC. The annual goodwill impairment analysis assumed management's best estimate of the rate increases that are expected to be granted in January 2007. If the PPUC authorizes less than the amounts assumed, an additional impairment analysis would be performed at that time and this could result in a future goodwill impairment loss that could be material. If rate relief were completely denied, it is estimated that approximately $604 million of Met-Ed’s goodwill would be impaired and approximately $374 million of Penelec’s goodwill would be impaired, and those amounts would be written off by those companies. However, no adjustment to FirstEnergy’s goodwill on a consolidated basis would be recognized in that circumstance because the fair value of its regulated segment (which represents FirstEnergy's reporting unit to evaluate goodwill) would continue to exceed the carrying value of its investment in the segment.

FirstEnergy's goodwill primarily relates to its regulated services segment. In the nine months ended September 30, 2006, FirstEnergy adjusted goodwill related to the divestiture of a non-core asset (62% interest in MYR), a successful tax claim relating to the former Centerior companies, and adjustments to the former GPU companies due to the realization of tax benefits that had been reserved in purchase accounting. The following tables reconcile changes to goodwill for the three months and nine months ended September 30, 2006.

Three Months Ended	**FirstEnergy**	**CEI**	**TE**	**JCP&L**	**Met-Ed**	**Penelec**
			(In millions)			
Balance as of July 1, 2006	$ 5,940	$ 1,688	$ 501	$ 1,978	$ 860	$ 878
Adjustments related to GPU acquisition	(5)			(1)		(4)
Balance as of September 30, 2006	$ 5,935	$ 1,688	$ 501	$ 1,977	$ 860	$ 874

Nine Months Ended	**FirstEnergy**	**CEI**	**TE**	**JCP&L**	**Met-Ed**	**Penelec**
			(In millions)			
Balance as of January 1, 2006	$ 6,010	$ 1,689	$ 501	$ 1,986	$ 864	$ 882
Non-core assets sale	(53)					
Adjustments related to Centerior acquisition	(1)	(1)				
Adjustments related to GPU acquisition	(21)			(9)	(4)	(8)
Balance as of September 30, 2006	$ 5,935	$ 1,688	$ 501	$ 1,977	$ 860	$ 874

4. - DIVESTITURES AND DISCONTINUED OPERATIONS

In August 2006, FirstEnergy sold two FSG subsidiaries (Roth Bros. and Hattenbach) for a net after-tax gain of $1.9 million. The remaining FSG subsidiaries continue to be actively marketed and qualify as assets held for sale in accordance with SFAS 144 because FirstEnergy anticipates that the transfer of these assets, with a net carrying value of $30.6 million as of September 30, 2006, will qualify for recognition as completed sales within one year. As of September 30, 2006, the remaining FSG subsidiaries classified as held for sale did not meet the criteria for discontinued operations. The carrying amounts of FSG's assets and liabilities are not material and have not been presented separately as assets held for sale on FirstEnergy's Consolidated Balance Sheets. See Note 13 for FSG's segment financial information.

In March 2006, FirstEnergy sold 60% of its interest in MYR for an after-tax gain of $0.2 million. In June 2006, FirstEnergy sold an additional 1.67% interest. As a result of the March sale, FirstEnergy deconsolidated MYR in the first quarter of 2006 and accounts for its remaining 38.33% interest under the equity method.

In March 2005, FirstEnergy sold 51% of its interest in FirstCom for an after-tax gain of $4 million. FirstEnergy accounts for its remaining 31.85% interest in FirstCom under the equity method.

During the first nine months of 2005, FirstEnergy sold three FSG subsidiaries (Cranston, Elliott-Lewis and Spectrum), an MYR subsidiary (Power Piping) and FES' retail natural gas business, resulting in aggregate after-tax gains of $17 million.

Net results (including the gains on sales of assets discussed above) for Cranston, Elliott-Lewis, Power Piping and FES' retail natural gas business of $18 million for the nine months ended September 30, 2005 are reported as discontinued operations on FirstEnergy's Consolidated Statements of Income. Pre-tax operating results for these entities were $2 million for the nine months ended September 30, 2005. Revenues associated with discontinued operations for the nine months ended September 30, 2005 were $207 million. The following table summarizes the sources of income from discontinued operations (in millions) for the nine months ended September 30, 2005:

Discontinued Operations (Net of tax)	
Gain on sale:	
Natural gas business	$ 5
FSG and MYR subsidiaries	12
Reclassification of operating income	1
Total	$ 18

5. - DERIVATIVE INSTRUMENTS

FirstEnergy is exposed to financial risks resulting from the fluctuation of interest rates and commodity prices, including prices for electricity, natural gas, coal and energy transmission. To manage the volatility relating to these exposures, FirstEnergy uses a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes. FirstEnergy's Risk Policy Committee, comprised of members of senior management, provides general management oversight to risk management activities. The Committee is responsible for promoting the effective design and implementation of sound risk management programs and oversees compliance with corporate risk management policies and established risk management practices.

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheet at their fair value unless they meet the normal purchase and normal sales exception criterion. Derivatives that meet that criterion are accounted for on the accrual basis. The changes in the fair value of derivative instruments that do not meet the normal purchase and sales criterion are recorded in current earnings, in AOCL, or as part of the value of the hedged item, depending on whether or not it is designated as part of a hedge transaction, the nature of the hedge transaction and hedge effectiveness.

FirstEnergy hedges anticipated transactions using cash flow hedges. Such transactions include hedges of anticipated electricity and natural gas purchases and anticipated interest payments associated with future debt issues. The effective portion of such hedges are initially recorded in equity as other comprehensive income or loss and are subsequently included in net income as the underlying hedged commodities are delivered or interest payments are made. Gains and losses from any ineffective portion of cash flow hedges are included directly in earnings.

The net deferred losses of $48 million included in AOCL as of September 30, 2006, for derivative hedging activity, as compared to the December 31, 2005 balance of $78 million of net deferred losses, resulted from a net $13 million decrease related to current hedging activity and a $17 million decrease due to net hedge losses reclassified into earnings during the nine months ended September 30, 2006. Based on current estimates, approximately $15 million (after tax) of the net deferred losses on derivative instruments in AOCL as of September 30, 2006 is expected to be reclassified to earnings during the next twelve months as hedged transactions occur. The fair value of these derivative instruments fluctuate from period to period based on various market factors.

FirstEnergy has entered into swaps that have been designated as fair value hedges of fixed-rate, long-term debt issues to protect 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 received, and interest payment dates match those of the underlying debt obligations. During the nine months ended September 30, 2006, FirstEnergy unwound swaps with a total notional amount of $350 million for which it paid $1 million in cash. The losses will be recognized in earnings over the remaining maturity of each respective hedged security as increased interest expense. As of September 30, 2006, FirstEnergy had interest rate swaps with an aggregate notional value of $750 million and a fair value of ($29) million.

During 2005 and the first nine months of 2006, FirstEnergy entered into several forward starting swap agreements (forward swaps) in order to hedge a portion of the consolidated interest rate risk associated with the anticipated issuances of fixed-rate, long-term debt securities for one or more of its subsidiaries during 2006 - 2008 as outstanding debt matures. 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. FirstEnergy revised the tenor and timing of its financing plan during the first nine months of 2006. FirstEnergy terminated and revised forward swaps with an aggregate notional value of $600 million during the second quarter of 2006, ultimately terminating the swaps as its subsidiaries issued long-term debt. In the third quarter of 2006, FirstEnergy revised the timing of swaps with an aggregate notional value of $100 million. As required by SFAS 133, FirstEnergy assessed the amount of ineffectiveness of the hedges at each termination. FirstEnergy received cash gains of $43 million, of which approximately $6 million ($4 million net of tax) was deemed ineffective and recognized in earnings in the first nine months of 2006. The remaining gain deemed effective in the amount of approximately $38 million ($23 million net of tax) was recorded in other comprehensive income and will subsequently be recognized in earnings over the terms of the associated future debt. As of September 30, 2006, FirstEnergy had forward swaps with an aggregate notional amount of $725 million and a long-term debt securities fair value of ($2) million.

6. - STOCK BASED COMPENSATION

Effective January 1, 2006, FirstEnergy adopted SFAS 123(R), which requires the expensing of stock-based compensation. Under SFAS 123(R), all share-based compensation cost is measured at the grant date based on the fair value of the award, and is recognized as an expense over the employee's requisite service period. FirstEnergy adopted the modified prospective method, under which compensation expense recognized in the three months and nine months ended September 30, 2006 included the expense for all share-based payments granted prior to but not yet vested as of January 1, 2006. Results for prior periods were not restated.

Prior to the adoption of SFAS 123(R) on January, 1, 2006, FirstEnergy's LTIP, EDCP, ESOP, and DCPD stock-based compensation programs were accounted for under the recognition and measurement principles of APB 25 and related interpretations. The LTIP includes four stock-based compensation programs - restricted stock, restricted stock units, stock options and performance shares.

Under APB 25, no compensation expense was reflected in net income for stock options as all options granted under those plans have exercise prices equal to the market value of the underlying common stock on the respective grant dates, resulting in substantially no intrinsic value. The pro forma effects on net income for stock options were instead disclosed in a footnote to the financial statements. Under APB 25 and SFAS 123(R), compensation expense was recorded in the income statement for restricted stock, restricted stock units, performance shares and the EDCP and DCPD programs. No stock options have been granted since the third quarter of 2004. Consequently, the impact of adopting SFAS 123(R) was not material to FirstEnergy's net income and earnings per share in the three months and nine months ended September 30, 2006. In the year of adoption, all disclosures prescribed by SFAS 123(R) are required to be included in both the quarterly Form 10-Q filings as well as the annual Form 10-K filing. However, due to the immaterial impact of the adoption of SFAS 123(R) on FirstEnergy's financial results, only condensed disclosure has been provided. Reference is made to FirstEnergy's annual report on Form 10-K for the year ended December 31, 2005 for expanded annual disclosure.

The following table illustrates the effect on net income and earnings per share for the three months and nine months ended September 30, 2005, as if FirstEnergy had adopted SFAS 123(R) as of January 1, 2005:

	Three Months	Nine Months
	(In millions, except per share amounts)	
Net Income, as reported	$ 332	$ 670
Add back compensation expense reported in net income, net of tax (based on APB 25)*	17	40
Deduct compensation expense based upon estimated fair value, net of tax*	(19)	(47)
Pro forma net income	$ 330	$ 663
Earnings Per Share of Common Stock -		
Basic		
As Reported	$1.01	$2.04
Pro Forma	$1.01	$2.02
Diluted		
As Reported	$1.01	$2.03
Pro Forma	$1.00	$2.01

* Includes restricted stock, restricted stock units, stock options, performance shares, ESOP, EDCP and DCPD.

7. - ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations under SFAS 143 for nuclear power plant decommissioning, reclamation of a sludge disposal pond and closure of two coal ash disposal sites. In addition, FirstEnergy has recognized conditional retirement obligations (primarily for asbestos remediation) in accordance with FIN 47, which was implemented on December 31, 2005. Had FIN 47 been applied in the nine months ended September 30, 2005, the impact on earnings would have been immaterial.

The ARO liability of $1.2 billion as of September 30, 2006 primarily relates to the nuclear decommissioning of the Beaver Valley, Davis-Besse, Perry and TMI-2 nuclear generating facilities. The obligation to decommission these units was developed based on site specific studies performed by an independent engineer. FirstEnergy uses an expected cash flow approach to measure the fair value of the nuclear decommissioning ARO.

FirstEnergy maintains nuclear decommissioning trust funds that are legally restricted for purposes of settling the nuclear decommissioning ARO. As of September 30, 2006, the fair value of the decommissioning trust assets was $1.9 billion.

The following tables analyze changes to the ARO balances during the three months and nine months ended September 30, 2006 and 2005, respectively.

Three Months Ended	**FirstEnergy**	**OE**	**CEI**	**TE**	**Penn**	**JCP&L**	**Met-Ed**	**Penelec**
				(In millions)				
ARO Reconciliation								
Balance, July 1, 2006	$ 1,160	$ 85	$ 2	$ 26	$ -	$ 82	$ 146	$ 74
Liabilities incurred	-	-	-	-	-	-	-	-
Liabilities settled	-	-	-	-	-	-	-	-
Accretion	19	2	-	-	-	1	3	2
Revisions in estimated cashflows	-	-	-	-	-	-	-	-
Balance, September 30, 2006	$ 1,179	$ 87	$ 2	$ 26	$ -	$ 83	$ 149	$ 76
Balance, July 1, 2005	$ 1,113	$ 208	$ 281	$ 201	$ 143	$ 75	$ 137	$ 68
Liabilities incurred	-	-	-	-	-	-	-	-
Liabilities settled	-	-	-	-	-	-	-	-
Accretion	18	3	5	4	2	1	2	1
Revisions in estimated cashflows	(1)	(2)	(5)	(5)	11	-	-	-
Balance, September 30, 2005	$ 1,130	$ 209	$ 281	$ 200	$ 156	$ 76	$ 139	$ 69

Nine Months Ended	**FirstEnergy**	**OE**	**CEI**	**TE**	**Penn**	**JCP&L**	**Met-Ed**	**Penelec**
				(In millions)				
ARO Reconciliation								
Balance, January 1, 2006	$ 1,126	$ 83	$ 8	$ 25	$ -	$ 80	$ 142	$ 72
Liabilities incurred	-	-	-	-	-	-	-	-
Liabilities settled	(6)	-	(6)	-	-	-	-	-
Accretion	55	4	-	1	-	3	7	4
Revisions in estimated cashflows	4	-	-	-	-	-	-	-
	$ 1,179	$ 87	$ 2	$ 26	$ -	$ 83	$ 149	$ 76

Balance, September 30, 2006																
Balance, January 1, 2005	$	1,078	$	201	$	272	$	195	$	138	$	72	$	133	$	67
Liabilities incurred		-		-		-		-		-		-		-		-
Liabilities settled		-		-		-		-		-		-		-		-
Accretion		53		10		14		10		7		4		6		2
Revisions in estimated cashflows		(1)		(2)		(5)		(5)		11		-		-		-
Balance, September 30, 2005	$	1,130	$	209	$	281	$	200	$	156	$	76	$	139	$	69

8. - PENSION AND OTHER POSTRETIREMENT BENEFITS

FirstEnergy provides noncontributory defined benefit pension plans that cover substantially all of its employees. The trusteed plans provide defined benefits based on years of service and compensation levels. FirstEnergy also provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are available upon retirement to employees hired prior to January 1, 2005, their dependents and, under certain circumstances, their survivors. FirstEnergy recognizes the expected cost of providing pension benefits and other postretirement benefits from the time employees are hired until they become eligible to receive those benefits.

The components of FirstEnergy's net periodic pension and other postretirement benefit costs (including amounts capitalized) for the three months and nine months ended September 30, 2006 and 2005 consisted of the following:

Pension Benefits	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
	(In millions)			
Service cost	$ 21	$ 19	$ 63	$ 58
Interest cost	66	64	199	191
Expected return on plan assets	(99)	(86)	(297)	(259)
Amortization of prior service cost	2	2	7	6
Recognized net actuarial loss	15	9	44	27
Net periodic cost	$ 5	$ 8	$ 16	$ 23

Other Postretirement Benefits	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
	(In millions)			
Service cost	$ 9	$ 10	$ 26	$ 30
Interest cost	26	27	79	83
Expected return on plan assets	(12)	(11)	(35)	(34)
Amortization of prior service cost	(19)	(11)	(57)	(33)
Recognized net actuarial loss	14	10	42	30
Net periodic cost	$ 18	$ 25	$ 55	$ 76

Pension and postretirement benefit obligations are allocated to FirstEnergy’s subsidiaries employing the plan participants. FirstEnergy’s subsidiaries capitalize employee benefits related to construction projects. The net periodic pension costs (credits) and net periodic postretirement benefit costs (including amounts capitalized) recognized by each of the Companies for the three months and nine months ended September 30, 2006 and 2005 were as follows:

Pension Benefit Cost (Credit)	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
	(In millions)			
OE	$ (1.1)	$ 0.2	$ (3.3)	$ 0.7
Penn	(0.4)	(0.2)	(1.2)	(0.7)
CEI	1.0	0.3	2.9	1.0

TE	0.2	0.3	0.7	1.0
JCP&L	(1.4)	(0.3)	(4.1)	(0.8)
Met-Ed	(1.7)	(1.1)	(5.2)	(3.2)
Penelec	(1.3)	(1.3)	(4.0)	(4.0)
Other FirstEnergy subsidiaries	9.9	9.6	29.9	28.6
	$ 5.2	$ 7.5	$ 15.7	$ 22.6

Other Postretirement Benefit Cost	**Three Months Ended September 30,**		**Nine Months Ended September 30,**	
	2006	**2005**	**2006**	**2005**
		(In millions)		
OE	$ 3.4	$ 5.8	$ 10.2	$ 17.3
Penn	0.8	1.2	2.4	3.5
CEI	2.8	3.8	8.3	11.4
TE	2.0	2.2	6.1	6.5
JCP&L	0.6	1.5	1.8	5.7
Met-Ed	0.7	0.4	2.2	1.2
Penelec	1.8	2.0	5.4	5.9
Other FirstEnergy subsidiaries	6.1	8.0	18.1	24.5
	$ 18.2	$ 24.9	$ 54.5	$ 76.0

9. - VARIABLE INTEREST ENTITIES

FIN 46R addresses the consolidation of VIEs, including special-purpose entities, that are not controlled through voting interests or in which the equity investors do not bear the entity's residual economic risks and rewards. FirstEnergy and its subsidiaries consolidate VIEs when they are determined to be the VIE's primary beneficiary as defined by FIN 46R.

Leases

FirstEnergy’s consolidated financial statements include PNBV and Shippingport, VIEs created in 1996 and 1997, respectively, to refinance debt originally issued in connection with sale and leaseback transactions. PNBV and Shippingport financial data are included in the consolidated financial statements of OE and CEI, respectively.

PNBV was established to purchase a portion of the lease obligation bonds issued in connection with OE’s 1987 sale and leaseback of its interests in the Perry Plant and Beaver Valley Unit 2. OE used debt and available funds to purchase the notes issued by PNBV. Ownership of PNBV includes a 3% equity interest by an unaffiliated third party and a 3% equity interest held by OES Ventures, a wholly owned subsidiary of OE. Shippingport was established to purchase all of the lease obligation bonds issued in connection with CEI’s and TE’s Bruce Mansfield Plant sale and leaseback transaction in 1987. CEI and TE used debt and available funds to purchase the notes issued by Shippingport.

OE, CEI and TE are exposed to losses under the applicable sale-leaseback agreements upon the occurrence of certain contingent events that each company considers unlikely to occur. OE, CEI and TE each have a maximum exposure to loss under these provisions of approximately $1 billion, which represents the net amount of casualty value payments upon the occurrence of specified casualty events that render the applicable plant worthless. Under the applicable sale-leaseback agreements, OE, CEI and TE have net minimum discounted lease payments of $655 million, $95 million and $506 million, respectively, that would not be payable if the casualty value payments are made.

Power Purchase Agreements

In accordance with FIN 46R, FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities may be VIEs to the extent they own a plant that sells substantially all of its output to the Companies and the contract price for power is correlated with the plant’s variable costs of production. FirstEnergy, through its subsidiaries JCP&L, Met-Ed and Penelec, maintains approximately 30 long-term power purchase agreements with NUG entities. The agreements were entered into pursuant to the Public Utility Regulatory Policies Act of 1978. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, these entities.

FirstEnergy has determined that for all but eight of these entities, neither JCP&L, Met-Ed nor Penelec have variable interests in the entities or the entities are governmental or not-for-profit organizations not within the scope of FIN 46R. JCP&L, Met-Ed or Penelec may hold variable interests in the remaining eight entities, which sell their output at variable prices that correlate to some extent with the operating costs of the plants. As required by FIN 46R, FirstEnergy periodically requests from these eight entities the information necessary to determine whether they are VIEs or whether JCP&L, Met-Ed or Penelec is the primary beneficiary. FirstEnergy has been unable to obtain the requested information, which in most cases was deemed by the requested entity to be proprietary. As such, FirstEnergy applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities under FIN 46R.

Since FirstEnergy has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs it incurs for power. FirstEnergy expects any above-market costs it incurs to be recovered from customers. As of September 30, 2006, the net above-market loss liability projected for these eight NUG agreements was $239 million. Purchased power costs from these entities during the three months and nine months ended September 30, 2006 and 2005 are shown in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
		(In millions)		
JCP&L	$ 29	$ 33	$ 63	$ 74
Met-Ed	12	10	45	40
Penelec	8	7	22	21
Total	$ 49	$ 50	$ 130	$ 135

Securitized Transition Bonds

The consolidated financial statements of FirstEnergy and JCP&L include the results of JCP&L Transition Funding and JCP&L Transition Funding II, wholly owned limited liability companies of JCP&L. In June 2002, JCP&L Transition Funding sold $320 million of transition bonds to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station. In August 2006, JCP&L Transition Funding II sold $182 million of transition bonds to securitize the recovery of deferred costs associated with JCP&L’s supply of BGS.

JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on FirstEnergy's and JCP&L's Consolidated Balance Sheets. The transition bonds are the sole obligations of JCP&L Transition Funding and JCP&L Transition Funding II and are collateralized by each company’s equity and assets, which consists primarily of bondable transition property.

Bondable transition property represents the irrevocable right under New Jersey law of a utility company to charge, collect and receive from its customers, through a non-bypassable TBC, the principal amount and interest on transition bonds and other fees and expenses associated with their issuance. JCP&L sold its bondable transition property to JCP&L Transition Funding and JCP&L Transition Funding II and, as servicer, manages and administers the bondable transition property, including the billing, collection and remittance of the TBC, pursuant to separate servicing agreements with JCP&L Transition Funding and JCP&L Transition Funding II. For the two series of transition bonds, JCP&L is entitled to aggregate quarterly servicing fees of $157,000 that is payable from TBC collections.

10. - COMMITMENTS, GUARANTEES AND CONTINGENCIES

(A) 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. These agreements include contract guarantees, surety bonds and LOCs. As of September 30, 2006, outstanding guarantees and other assurances totaled approximately $3.6 billion consisting of contract guarantees $2.0 billion, surety bonds $0.2 billion and LOCs $1.4 billion.

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy commodity activities principally to facilitate normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of credit support for subsidiary financings or refinancings of costs related to the acquisition of, or improvements to, property, plant and equipment. These agreements legally obligate FirstEnergy to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financing where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, FirstEnergy's guarantee enables the counterparty's legal claim to be satisfied by other FirstEnergy assets. The likelihood is remote that such parental guarantees of $0.9 billion (included in the $2.0 billion discussed above) as of September 30, 2006 would increase amounts otherwise payable by FirstEnergy to meet its obligations incurred in connection with financings and ongoing energy and energy-related activities.

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. As of September 30, 2006, FirstEnergy's maximum exposure under these collateral provisions was $487 million.

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related FirstEnergy guarantees of $147 million provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction jobs, environmental commitments and various retail transactions.

The Companies, with the exception of TE and JCP&L, each have a wholly owned subsidiary whose borrowings are secured by customer accounts receivable purchased from its respective parent company. The CEI subsidiary's borrowings are also secured by customer accounts receivable purchased from TE. Each subsidiary company has its own receivables financing arrangement and, as a separate legal entity with separate creditors, would have to satisfy its obligations to creditors before any of its remaining assets could be available to its parent company.

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Subsidiary Company	Parent Company	Borrowing Capacity (In millions)	
OES Capital, Incorporated	OE	$	170
Centerior Funding Corp.	CEI		200
Penn Power Funding LLC	Penn		25
Met-Ed Funding LLC	Met-Ed		80
Penelec Funding LLC	Penelec		75
		$	550

FirstEnergy has also guaranteed the obligations of the operators of the TEBSA project up to a maximum of $6 million (subject to escalation) under the project's operations and maintenance agreement. In connection with the sale of TEBSA in January 2004, the purchaser indemnified FirstEnergy against any loss under this guarantee. FirstEnergy has also provided an LOC ($36 million as of September 30, 2006), which is renewable and declines yearly based upon the senior outstanding debt of TEBSA. The LOC was reduced to $27 million on October 15, 2006.

(B) ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. The effects of compliance on the Companies with regard to environmental matters could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that it competes with companies that are not subject to such regulations and therefore do not bear the risk of costs associated with compliance, or failure to comply, with such regulations. Overall, FirstEnergy believes it is in compliance with existing regulations but is unable to predict future changes in regulatory policies and what, if any, the effects of such changes would be. FirstEnergy estimates additional capital expenditures for environmental compliance of approximately $1.8 billion for 2006 through 2010.

FirstEnergy 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 FirstEnergy’s determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

On December 1, 2005, FirstEnergy issued a comprehensive report to shareholders regarding air emissions regulations and an assessment of its future risks and mitigation efforts.

Clean Air Act Compliance

FirstEnergy is required to meet federally-approved SO_2 emissions regulations. Violations of such regulations can result in shutdown of the generating unit involved and/or civil or criminal penalties of up to $32,500 for each day the unit is in violation. The EPA has an interim enforcement policy for SO_2 regulations in Ohio that allows for compliance based on a 30-day averaging period. FirstEnergy believes it is currently in compliance with this policy, but cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The EPA Region 5 issued a Finding of Violation and NOV to the Bay Shore Power Plant dated June 15, 2006 alleging violations to various sections of the Clean Air Act. A meeting was held on August 8, 2006 to discuss the alleged violations with the EPA. FirstEnergy has disputed those alleged violations based on its Clean Air Act permit, the Ohio SIP and other information provided at the August 2006 meeting with the EPA. The EPA has several enforcement options (administrative compliance order, administrative penalty order, and/or judicial, civil or criminal action) and has indicated that such option may depend on the time needed to achieve and demonstrate compliance with the rules alleged to have been violated.

FirstEnergy complies with SO_2 reduction requirements under the Clean Air Act Amendments of 1990 by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NO_X reductions required by the 1990 Amendments are being achieved through combustion controls and the generation of more electricity at lower-emitting plants. In September 1998, the EPA finalized regulations requiring additional NO_X reductions at FirstEnergy's facilities. The EPA's NO_X Transport Rule imposes uniform reductions of NO_X emissions (an approximate 85% reduction in utility plant NO_X emissions from projected 2007 emissions) across a region of nineteen states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on a conclusion that such NO_X emissions are contributing significantly to ozone levels in the eastern United States. FirstEnergy believes its facilities are also complying with the NO_X budgets established under SIPs through combustion controls and post-combustion controls, including Selective Catalytic Reduction and Selective Non-Catalytic Reduction systems, and/or using emission allowances.

National Ambient Air Quality Standards

In July 1997, the EPA promulgated changes in the NAAQS for ozone and fine particulate matter. In March 2005, the EPA finalized the CAIR 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 non-attainment 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). FirstEnergy's Michigan, Ohio and Pennsylvania fossil-fired generation facilities will be subject to caps on SO_2 and NO_X emissions, whereas its New Jersey fossil-fired generation facility will be subject to only a cap on 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 FirstEnergy 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. In March 2005, the EPA finalized the CAMR, 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 CAMR 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 and will depend on how they are ultimately implemented by the states in which FirstEnergy operates affected facilities.

The model rules for both CAIR and CAMR contemplate an input-based methodology to allocate allowances to affected facilities. Under this approach, allowances would be allocated based on the amount of fuel consumed by the affected sources. FirstEnergy would prefer an output-based generation-neutral methodology in which allowances are allocated based on megawatts of power produced, since then, new and non-emitting generating facilities, including renewables and nuclear, would be entitled to their proportionate share of the allowances. Consequently, FirstEnergy will be disadvantaged if these model rules were implemented as proposed because FirstEnergy’s substantial reliance on non-emitting (largely nuclear) generation is not recognized under the input-based allocation.

Pennsylvania has proposed a new rule to regulate mercury emissions from coal-fired power plants that does not provide a cap and trade approach as in CAMR, but rather follows a command and control approach imposing emission limits on individual sources. If adopted as proposed, Pennsylvania’s mercury regulation would deprive FirstEnergy of mercury emission allowances that were to be allocated to the Bruce Mansfield Plant under CAMR and that would otherwise be available for achieving FirstEnergy system-wide compliance. The future cost of compliance with these regulations, if adopted and implemented as proposed, 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 was approved by the Court on July 11, 2005, and requires reductions of NO_X and SO_2 emissions at the W. H. Sammis Plant and other coal-fired plants through the installation of pollution control devices and provides for stipulated penalties for failure to install and operate such pollution controls in accordance with that agreement. Consequently, if FirstEnergy fails to install such pollution control devices, for any reason, including, but not limited to, the failure of any third-party contractor to timely meet its delivery obligations for such devices, FirstEnergy could be exposed to penalties under the settlement agreement. Capital expenditures necessary to meet those requirements are currently estimated to be $1.5 billion ($400 million of which is expected to be spent in 2007 with the primary portion of the remaining $1.1 billion expected to be spent in 2008 and 2009). On August 26, 2005, FGCO entered into an agreement with Bechtel Power Corporation under which Bechtel will engineer, procure, and construct air quality control systems for the reduction of SO_2 emissions. FGCO also entered into an agreement with B&W on August 25, 2006 to supply flue gas desulfurization systems for the reduction of SO_2 emissions. Selective Catalytic Reduction (SCR) systems for the reduction of NOx emissions also are being installed at the W.H. Sammis Plant under a 1999 agreement with B&W.

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 paid by OE and Penn of $7.8 million and $0.7 million, respectively. OE and Penn also recognized liabilities in the first quarter of 2005 of $9.2 million and $0.8 million, respectively, 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, 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 Kyoto Protocol in 1998 but it failed to receive the two-thirds vote required for ratification by the United States Senate. 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% through 2012. The EPACT established a Committee on Climate Change Technology to coordinate federal climate change activities and promote the development and deployment of GHG reducing technologies.

FirstEnergy 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. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

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

On September 7, 2004, the EPA established new performance standards under Section 316(b) of the Clean Water Act for reducing impacts on fish and shellfish from cooling water intake structures at certain existing large electric generating plants. The regulations call for reductions in impingement mortality, when aquatic organisms are pinned against screens or other parts of a cooling water intake system, and entrainment, which occurs when aquatic species are drawn into a facility's cooling water system. FirstEnergy is conducting comprehensive demonstration studies, due in 2008, to determine the operational measures, equipment or restoration activities, if any, necessary for compliance by its facilities with the performance standards. FirstEnergy is unable to predict the outcome of such studies. Depending on the outcome of such studies, the future cost of compliance with these standards may require material capital expenditures.

Regulation of Hazardous Waste

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

The Companies have been named as 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, 2006, based on estimates of the total costs of cleanup, the Companies' proportionate responsibility for such costs and the financial ability of other unaffiliated 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 $73 million (JCP&L - $55 million, CEI - $1 million, and other subsidiaries- $17 million) have been accrued through September 30, 2006.

(C) OTHER LEGAL PROCEEDINGS

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. In 2005, JCP&L renewed its motion to decertify the class based on a very limited number of class members who incurred damages and also filed a motion for summary judgment on the remaining plaintiffs’ claims for negligence, breach of contract and punitive damages. In July 2006, the New Jersey Superior Court dismissed the punitive damage claim and again decertified the class based on the fact that a vast majority of the class members did not suffer damages and those that did would be more appropriately addressed in individual actions. Plaintiffs appealed this ruling to the New Jersey Appellate Division because it effectively terminates this class action. Briefs are being prepared and filed, and legal argument is scheduled for late November 2006. FirstEnergy is unable to predict the outcome of these matters and no liability has been accrued as of September 30, 2006.

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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 Web site (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 is also proceeding with the implementation of the recommendations 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 may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future as a result of adoption of mandatory reliability standards pursuant to the EPACT that could require additional material expenditures.

FirstEnergy companies also are defending six separate complaint cases before the PUCO relating to the August 14, 2003 power outages. Two cases were originally filed in Ohio State courts but were subsequently dismissed for lack of subject matter jurisdiction and further appeals were unsuccessful. In these 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. Three other pending PUCO complaint cases were filed by various insurance carriers either in their own name as subrogees or in the name of their insured. In each of these three cases, the carrier seeks reimbursement from various FirstEnergy companies (and, in one case, from PJM, MISO and American Electric Power Company, Inc., as well) for claims paid to insureds for damages allegedly arising as a result of 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 sixth case involves the claim of a non-customer seeking reimbursement for losses incurred when its store was burglarized on August 14, 2003. That case has been dismissed. On March 7, 2006, the PUCO issued a ruling, based on motions filed by the parties, applicable to all pending cases. Among its various rulings, the PUCO consolidated all of the pending outage cases for hearing; limited the litigation to service-related claims by customers of the Ohio operating companies; dismissed FirstEnergy as a defendant; ruled that the U.S.-Canada Power System Outage Task Force Report was not admissible into evidence; and gave the plaintiffs additional time to amend their complaints to otherwise comply with the PUCO's underlying order. Also, most complainants, along with the FirstEnergy companies, filed applications for rehearing with the PUCO over various rulings contained in the March 7, 2006 order. On April 26, 2006, the PUCO granted rehearing to allow the insurance company claimants, as insurers, to prosecute their claims in their name so long as they also identify the underlying insured entities and the Ohio utilities that provide their service. The PUCO denied all other motions for rehearing. The plaintiffs in each case have since filed an amended complaint and the named FirstEnergy companies have answered and also have filed a motion to dismiss each action. On September 27, 2006, the PUCO dismissed certain parties and claims and otherwise ordered the complaints to go forward to hearing. The cases have been set for hearing on October 16, 2007.

On October 10, 2006, various insurance carriers refiled a complaint in Cuyahoga County Common Pleas Court seeking reimbursement for claims paid to numerous insureds who allegedly suffered losses as a result of the August 14, 2003 outages. All of the insureds appear to be non-customers. The plaintiff insurance companies are the same claimants in one of the pending PUCO cases. FirstEnergy, the Ohio Companies and Penn were served on October 27, 2006, and expect to seek summary dismissal of these cases based on the prior court rulings noted above. No estimate of potential liability is available for any of these cases.

FirstEnergy was also named, along with several other entities, in a complaint in New Jersey State Court. The allegations against FirstEnergy were based, in part, on an alleged failure to protect the citizens of Jersey City from an electrical power outage. None of FirstEnergy's subsidiaries serve customers in Jersey City. A responsive pleading has been filed. On April 28, 2006, the Court granted FirstEnergy's motion to dismiss. The plaintiff has not appealed.

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. Although unable to predict the impact of these proceedings, 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.

Nuclear Plant Matters

On January 20, 2006, FENOC announced that it had entered into a deferred prosecution agreement with the U.S. Attorney's Office for the Northern District of Ohio and the Environmental Crimes Section of the Environment and Natural Resources Division of the DOJ related to FENOC's communications with the NRC during the fall of 2001 in connection with the reactor head issue at the Davis-Besse Nuclear Power Station. Under the agreement, which expires on December 31, 2006, the United States acknowledged FENOC's extensive corrective actions at Davis-Besse, FENOC's cooperation during investigations by the DOJ and the NRC, FENOC's pledge of continued cooperation in any related criminal and administrative investigations and proceedings, FENOC's acknowledgement of responsibility for the behavior of its employees, and its agreement to pay a monetary penalty. The DOJ will refrain from seeking an indictment or otherwise initiating criminal prosecution of FENOC for all conduct related to the statement of facts attached to the deferred prosecution agreement, as long as FENOC remains in compliance with the agreement, which FENOC fully intends to do. FENOC paid a monetary penalty of $28 million (not deductible for income tax purposes) which reduced FirstEnergy's earnings by $0.09 per common share in the fourth quarter of 2005.

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 discussed above. FirstEnergy accrued $2 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. On January 23, 2006, FENOC supplemented its response to the NRC's NOV on the Davis-Besse head degradation to reflect the deferred prosecution agreement that FENOC had reached with the DOJ.

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 corrective action. FENOC operates the Perry Nuclear Power 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 Nuclear Power 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 September 28, 2005, the NRC sent a CAL to FENOC describing commitments that FENOC had made to improve the performance at the Perry Nuclear Power Plant 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.

In the NRC's 2005 annual assessment letter dated March 2, 2006 and associated meetings to discuss the performance of the Perry Nuclear Power Plant on March 14, 2006, the NRC again stated that the Perry Nuclear Power Plant continued to operate in a manner that "preserved public health and safety." However, the NRC also stated that increased levels of regulatory oversight would continue until sustained improvement in the performance of the facility was realized. 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. Although FirstEnergy is unable to predict the impact of the ultimate disposition of this matter, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

Other Legal Matters

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 potentially material items not otherwise discussed above are described below.

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 now repealed 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-related disclosures, which has been provided. FirstEnergy has cooperated fully with the informal inquiry and continues 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 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. On October 18, 2006, the Ohio Supreme Court transferred this case to a Tuscarawas County Common Pleas Court judge due to concerns over potential class membership by the Jefferson County Common Pleas Court.

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 arbitration panel decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the arbitration panel issued an opinion to award approximately $16 million to the bargaining unit employees. On February 6, 2006, a federal district court granted a union motion to dismiss as premature a JCP&L appeal of the award filed on October 18, 2005. JCP&L intends to re-file an appeal again in federal district court once the damages associated with this case are identified at an individual employee level. JCP&L recognized a liability for the potential $16 million award in 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 of a tariff that would specifically allow the collection of transition charges from customers of municipal electric utilities formed after 1998. Both filings were consolidated for hearing and decision. 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. On May 10, 2006, the PUCO issued its Opinion and Order dismissing the City's complaint and approving the related tariffs, thus affirming OE's entitlement to recovery of its transition charges. The City of Huron filed an application for rehearing of the PUCO's decision on June 9, 2006 and OE filed a memorandum in opposition to that application on June 19, 2006. The PUCO denied the City's application for rehearing on June 28, 2006. The City of Huron has taken no further action and the period for filing an appeal has expired.

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.

(D) ACCELERATED SHARE REPURCHASE PROGRAM

On August 9, 2006, FirstEnergy entered into an accelerated share repurchase agreement with a financial institution counterparty under which FirstEnergy repurchased 10.6 million shares, or approximately 3.2%, of its outstanding common stock on August 10, 2006 at an initial price of $56.44 per share, or a total initial purchase price of $600 million. This forward sale contract is being accounted for as an equity instrument. The final purchase price is subject to a contingent purchase price adjustment based on the average of the daily volume-weighted average prices over a subsequent purchase period of up to seven months, as well as other purchase price adjustments in the event of an extraordinary cash dividend or other dilution events. The price adjustment can be settled, at FirstEnergy’s option, in cash or in shares of its common stock. The size of any settlement amount and whether it is to be paid or received by FirstEnergy will depend upon the average of the daily volume-weighted average prices of the shares as calculated by the counterparty under the program. The settlement is expected to occur in the first quarter of 2007.

The accelerated share repurchase was completed under a program authorized by the Board of Directors on June 20, 2006 to repurchase up to 12 million shares of common stock. At management's discretion, additional shares may be acquired under the program on the open market or through privately negotiated transactions, subject to market conditions and other factors. The Board's authorization of the repurchase program does not require FirstEnergy to make any further repurchases of shares and the program may be terminated at any time.

11. - REGULATORY MATTERS

RELIABILITY INITIATIVES

In late 2003 and early 2004, a series of letters, reports and recommendations were issued from various entities, including governmental, industry and ad hoc reliability entities (PUCO, FERC, NERC and the U.S. - Canada Power System Outage Task Force) regarding enhancements to regional reliability. In 2004, FirstEnergy completed implementation of all actions and initiatives related to enhancing area reliability, improving voltage and reactive management, operator readiness and training and emergency response preparedness recommended for completion in 2004. On July 14, 2004, NERC independently verified that FirstEnergy had implemented the various initiatives to be completed by June 30 or summer 2004, with minor exceptions noted by FirstEnergy, which exceptions are now essentially complete. FirstEnergy is proceeding with the implementation of the recommendations 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 equipment or material upgrades to existing equipment. 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 as the result of adoption of mandatory reliability standards pursuant to the EPACT, all of which could require additional, material expenditures.

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. In 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 an SRM 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 DRA to discuss reliability improvements. The SRM completed his work and issued his final report to the NJBPU on June 1, 2006. A meeting was held between JCP&L and the NJBPU on June 29, 2006 to discuss the SRM's final report. JCP&L filed a comprehensive response to the NJBPU on July 14, 2006. JCP&L continues to file compliance reports reflecting activities associated with the MOU and Stipulation.

The EPACT provides for the creation of an ERO to establish and enforce reliability standards for the bulk power system, subject to FERC's review. On February 3, 2006, the FERC adopted a rule establishing certification requirements for the ERO, as well as regional entities envisioned to assume monitoring responsibility for the new reliability standards. The FERC issued an order on rehearing on March 30, 2006, providing certain clarifications and essentially affirming the rule.

The NERC has been preparing the implementation aspects of reorganizing its structure to meet the FERC's certification requirements for the ERO. The NERC made a filing with the FERC on April 4, 2006 to obtain certification as the ERO and to obtain FERC approval of delegation agreements with regional reliability organizations (regional entities). The new FERC rule referred to above, further provides for reorganizing regional entities that would replace the current regional councils and for rearranging their relationship with the ERO. 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 ERO filing was noticed on April 7, 2006 and comments and reply comments were filed in May, June and July 2006. On July 20, 2006, the FERC certified the NERC as the ERO to implement the provisions of Section 215 of the Federal Power Act and directed the NERC to make a compliance filing within 90 days addressing such issues as the regional delegation agreements. The NERC made its compliance filing in October 2006. This filing is pending before the FERC.

On April 4, 2006, NERC also submitted a filing with the FERC seeking approval of mandatory reliability standards. These reliability standards are based, with some modifications and additions, on the current NERC Version O reliability standards. The reliability standards filing was noticed by the FERC on April 18, 2006. In that notice, the FERC announced its intent to issue a Notice of Proposed Rulemaking on the proposed reliability standards at a future date. On May 11, 2006, the FERC staff released a preliminary assessment that cited many deficiencies in the proposed reliability standards. The NERC and industry participants filed comments in response to the Staff's preliminary assessment. The FERC held a technical conference on the proposed reliability standards on July 6, 2006. The FERC issued a Notice of Proposed Rulemaking on the proposed reliability standards on October 20, 2006. The FERC voted to adopt 83 of the proposed 107 reliability standards. The FERC asked the NERC to make technical improvements to 62 of the 83 standards approved. The 24 standards that were not adopted remain pending at the FERC awaiting further clarification and filings by the NERC and regional entities. The FERC also provided additional clarification on the proposed application of final standards in the NOPR. Interested parties will be given the opportunity to comment on the NOPR within 60 days of its publication in the Federal Register. Mandatory reliability standards are expected to be in place by the summer of 2007. In a separate order issued October 24, 2006, the FERC approved NERC's 2007 budget and business plan subject to certain compliance filings.

The ECAR, Mid-Atlantic Area Council, and Mid-American Interconnected Network reliability councils have completed the consolidation of these regions into a single new regional reliability organization known as ReliabilityFirst Corporation. ReliabilityFirst began operations as a regional reliability council under NERC on January 1, 2006 and intends to file and obtain certification consistent with the final rule as a "regional entity" under the ERO during 2006. All of FirstEnergy's facilities are located within the ReliabilityFirst region.

On May 2, 2006, the NERC Board of Trustees adopted eight new cyber security standards that replaced interim standards put in place in the wake of the September 11, 2001 terrorist attacks, and thirteen additional reliability standards. The security standards became effective on June 1, 2006, and the remaining standards will become effective throughout 2006 and 2007. NERC intends to file the standards with the FERC and relevant Canadian authorities for approval, but the cyber security standards were not included in the October 20, 2006 NOPR.

FirstEnergy believes it is in compliance with all current NERC reliability standards. However, based upon a review of the October 20, 2006 NOPR, it appears that the FERC will adopt stricter reliability standards than those contained in the current NERC standards. The financial impact of complying with the new standards cannot be determined at this time. However, the EPACT required that all prudent costs incurred to comply with the new reliability standards be recovered in rates. If FirstEnergy is unable to meet the reliability standards for the bulk power system in the future, it could have a material adverse effect on the Company's and its subsidiaries' financial condition, results of operations and cash flows.

OHIO

On October 21, 2003, the Ohio Companies filed their RSP case with the PUCO. 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 CBP. The RSP was intended to establish generation service rates beginning January 1, 2006, in response to the PUCO's 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 the proceeding as well as the associated entries on rehearing. On May 3, 2006, the Supreme Court of Ohio issued an opinion affirming the PUCO's order with respect to the approval of the rate stabilization charge, approval of the shopping credits, the granting of interest on shopping credit incentive deferral amounts, and approval of the Ohio Companies' financial separation plan. It remanded back to the PUCO the matter of ensuring the availability of sufficient means for customer participation in the competitive marketplace. The RSP contained a provision that permitted the Ohio Companies to withdraw and terminate the RSP in the event that the PUCO, or the Supreme Court of Ohio, rejected all or part of the RSP. In such event, the Ohio Companies have 30 days from the final order or decision to provide notice of termination. On July 20, 2006 the Ohio Companies filed with the PUCO a Request to Initiate a Proceeding on Remand. In their Request, the Ohio Companies provided notice of termination to those provisions of the RSP subject to termination, subject to being withdrawn, and also set forth a framework for addressing the Supreme Court of Ohio's findings on customer participation, requesting the PUCO to initiate a proceeding to consider the Ohio Companies' proposal. If the PUCO approves a resolution to the issues raised by the Supreme Court of Ohio that is acceptable to the Ohio Companies, the Ohio Companies' termination will be withdrawn and considered to be null and void. Separately, the OCC and NOAC also submitted to the PUCO on July 20, 2006 a conceptual proposal dealing with the issue raised by the Supreme Court of Ohio. On July 26, 2006, the PUCO issued an Entry acknowledging the July 20, 2006 filings of the Ohio Companies and the OCC and NOAC, and giving the Ohio Companies 45 days to file a plan in a new docket to address the Court's concern. On September 19, 2006, the PUCO issued an Entry granting the Ohio Companies' motion for extension of time to file the remand proposal. The Ohio Companies filed their RSP Remand CBP on September 29, 2006. No further proceedings have been scheduled at this time.

The Ohio Companies filed an application and stipulation with the PUCO on September 9, 2005 seeking approval of the RCP, a supplement to the RSP. On November 4, 2005, the Ohio Companies filed a supplemental stipulation with the PUCO, which constituted an additional component of the RCP filed on September 9, 2005. Major provisions of the RCP include:

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

Deferring and capitalizing for future recovery (over a 25-year period) with carrying charges 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;

Adjusting 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;

Reducing 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

Recovering increased fuel costs (compared to a 2002 baseline) 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, TE, and CEI may defer and capitalize (for recovery over a 25-year period) increased fuel costs above the amount collected through the fuel recovery mechanism.

On January 4, 2006, the PUCO approved, with modifications, the Ohio Companies’ RCP to supplement the RSP to provide customers with more certain rate levels than otherwise available under the RSP during the plan period. On January 10, 2006, the Ohio Companies filed a Motion for Clarification of the PUCO order approving the RCP. The Ohio Companies sought clarity on issues related to distribution deferrals, including requirements of the review process, timing for recognizing certain deferrals and definitions of the types of qualified expenditures. The Ohio Companies also sought confirmation that the list of deferrable distribution expenditures originally included in the revised stipulation fall within the PUCO order definition of qualified expenditures. On January 25, 2006, the PUCO issued an Entry on Rehearing granting in part, and denying in part, the Ohio Companies’ previous requests and clarifying issues referred to above. The PUCO granted the Ohio Companies’ requests to:

Recognize fuel and distribution deferrals commencing January 1, 2006;

Recognize distribution deferrals on a monthly basis prior to review by the PUCO Staff;

Clarify that the types of distribution expenditures included in the Supplemental Stipulation may be deferred; and

Clarify that distribution expenditures do not have to be “accelerated” in order to be deferred.

The PUCO approved the Ohio Companies' methodology for determining distribution deferral amounts, but denied the Motion in that the PUCO Staff must verify the level of distribution expenditures contained in current rates, as opposed to simply accepting the amounts contained in the Ohio Companies' Motion. On February 3, 2006, several other parties filed applications for rehearing on the PUCO's January 4, 2006 Order. The Ohio Companies responded to the applications for rehearing on February 8, 2006. In an Entry on Rehearing issued by the PUCO on March 1, 2006, all motions for rehearing were denied. Certain of these parties have subsequently filed notices of appeal with the Supreme Court of Ohio alleging various errors made by the PUCO in its order approving the RCP. The Ohio Companies' Motion to Intervene in the appeals was granted by the Supreme Court on June 8, 2006. The Appellants' Merit Briefs were filed at the Supreme Court on July 5, 2006. The Appellees include the PUCO and the Ohio Companies. The Appellees' Merit Briefs were filed on August 24, 2006 and the Appellants' Reply Briefs were filed on September 21, 2006. The OCC filed an amicus brief on August 4, 2006, which the Ohio Companies moved to strike as improperly filed. The Supreme Court denied the Ohio Companies' motion on October 18, 2006.

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 sought recovery of these costs beginning January 1, 2006. 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 parties reached a settlement agreement that was approved by the PUCO on August 31, 2005. The incremental transmission and ancillary service revenues recovered from January 1 through June 30, 2006 were approximately $61 million. That amount included the recovery of a portion of the 2005 deferred MISO expenses as described below. On April 27, 2006, the Ohio Companies filed the annual update rider to determine revenues ($139 million) from July 2006 through June 2007. The filed rider went into effect on July 1, 2006.

The second application sought authority to defer costs associated with transmission and ancillary service related costs incurred during the period 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 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 the Ohio Companies to accrue carrying charges on the deferred balances. On August 31, 2005, the OCC appealed the PUCO's decision. On January 20, 2006, the OCC sought rehearing of the PUCO’s approval of the recovery of deferred costs through the rider during the period January 1, 2006 through June 30, 2006. The PUCO denied the OCC's application on February 6, 2006. On March 23, 2006, the OCC appealed the PUCO's order to the Ohio Supreme Court. On March 27, 2006, the OCC filed a motion to consolidate this appeal with the deferral appeals discussed above and to postpone oral arguments in the deferral appeal until after all briefs are filed in this most recent appeal of the rider recovery mechanism. On March 20, 2006, the Ohio Supreme Court, on its own motion, consolidated the OCC's appeal of the Ohio Companies' case with a similar case involving Dayton Power & Light Company. Oral arguments were heard on May 10, 2006. The Ohio Companies are awaiting a final ruling from the Ohio Supreme Court, which is expected before the end of 2006.

PENNSYLVANIA

A February 2002 Commonwealth Court of Pennsylvania decision affirmed the June 2001 PPUC decision regarding approval of the FirstEnergy/GPU merger, remanded the issues of quantification and allocation of merger savings to the PPUC and denied Met-Ed and Penelec the rate relief initially approved in the PPUC decision. On October 2, 2003, the PPUC issued an order concluding that the Commonwealth Court reversed the PPUC’s June 2001 order in its entirety. In accordance with the PPUC's direction, Met-Ed and Penelec filed supplements to their tariffs that became effective in October 2003 and that reflected the CTC rates and shopping credits in effect prior to the June 2001 order. Met-Ed’s and Penelec’s combined portion of total net merger savings during 2001 - 2004 is estimated to be approximately $51 million. A procedural schedule was established by the ALJ on January 17, 2006 and the companies filed initial testimony on March 1, 2006. On May 4, 2006, the PPUC consolidated this proceeding with the April 10, 2006 comprehensive rate filing proceeding discussed below. Met-Ed and Penelec are unable to predict the outcome of this matter.

In an October 16, 2003 order, the PPUC approved June 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 Commonwealth Court, 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. Oral arguments were held on June 8, 2006. On July 19, 2006, the Commonwealth Court issued its decision affirming the PPUC’s prior orders. Although the decision denied the appeal of Met-Ed and Penelec, they had previously accounted for the treatment of costs required by the PPUC’s October 2003 orders.

Met-Ed and Penelec purchase a portion of their PLR requirements from FES through a wholesale power sales agreement. Under this 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 contracts with NUGs and other unaffiliated suppliers. The FES 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. The wholesale power sales agreement with FES could automatically be extended for each successive calendar year unless any party elects to cancel the agreement by November 1 of the preceding year. On November 1, 2005, FES and the other parties thereto amended the agreement to provide FES the right in 2006 to terminate the agreement at any time upon 60 days notice. On April 7, 2006, the parties to the wholesale power sales agreement entered into a Tolling Agreement that arises out of FES’ notice to Met-Ed and Penelec that FES elected to exercise its right to terminate the wholesale power sales agreement effective midnight December 31, 2006, because that agreement is not economically sustainable to FES.

In lieu of allowing such termination to become effective as of December 31, 2006, the parties agreed, pursuant to the Tolling Agreement, to amend the wholesale power sales agreement to provide as follows:

1. The termination provisions of the wholesale power sales agreement will be tolled for one year until December 31, 2007, provided that during such tolling period:
a. FES will be permitted to terminate the wholesale power sales agreement at any time with sixty days written notice;
b. Met-Ed and Penelec will procure through arrangements other than the wholesale power sales agreement beginning December 1, 2006 and ending December 31, 2007, approximately 33% of the amounts of capacity and energy necessary to satisfy their PLR obligations for which Committed Resources (i.e., non-utility generation under contract to Met-Ed and Penelec, Met-Ed- and Penelec-owned generating facilities, purchased power contracts and distributed generation) have not been obtained; and
c. FES will not be obligated to supply additional quantities of capacity and energy in the event that a supplier of Committed Resources defaults on its supply agreement;

2. During the tolling period, FES will not act as an agent for Met-Ed or Penelec in procuring the services under 1.(b) above; and

3. The pricing provision of the wholesale power sales agreement shall remain unchanged provided Met-Ed and Penelec comply with the provisions of the Tolling Agreement and any applicable provision of the wholesale power sales agreement.

In the event that FES elects not to terminate the wholesale power sales agreement effective midnight December 31, 2007, similar tolling agreements effective after December 31, 2007 are expected to be considered by FES for subsequent years if Met-Ed and Penelec procure through arrangements other than the wholesale power sales agreement approximately 64%, 83% and 95% of the additional amounts of capacity and energy necessary to satisfy their PLR obligations for 2008, 2009 and 2010, respectively, for which Committed Resources have not been obtained from the market. On September 26, 2006, Met-Ed and Penelec successfully conducted a competitive RFP for 33% of their PLR obligation for which Committed Resources have not been obtained for the period December 1, 2006 through December 31, 2008.

The wholesale power sales agreement, as modified by the Tolling Agreement, requires Met-Ed and Penelec to satisfy the portion of their PLR obligations currently supplied by FES from unaffiliated suppliers at prevailing prices, which are likely to be higher than the current price charged by FES under the current agreement and, as a result, Met-Ed’s and Penelec’s purchased power costs could materially increase. If Met-Ed and Penelec were to replace the entire FES supply at current market power prices without corresponding regulatory authorization to increase their generation prices to customers, each company would likely incur a significant increase in operating expenses and experience a material deterioration in credit quality metrics. Under such a scenario, each company's credit profile would no longer be expected to support an investment grade rating for its fixed income securities. There can be no assurance, however, that if FES ultimately determines to terminate, further reduce, or significantly modify the agreement, timely regulatory relief will be granted by the PPUC pursuant to the April 10, 2006 comprehensive rate filing discussed below, or, to the extent granted, adequate to mitigate such adverse consequences.

Met-Ed and Penelec made a comprehensive rate filing with the PPUC on April 10, 2006 that addresses a number of transmission, distribution and supply issues. If Met-Ed's and Penelec's preferred approach involving accounting deferrals is approved, the filing would increase annual revenues by $216 million and $157 million, respectively. That filing includes, among other things, a request to charge customers for an increasing amount of market priced power procured through a CBP as the amount of supply provided under the existing FES agreement is phased out in accordance with the April 7, 2006 Tolling Agreement described above. Met-Ed and Penelec also requested approval of the January 12, 2005 petition for the deferral of transmission-related costs discussed above, but only for those costs incurred during 2006. In this rate filing, Met-Ed and Penelec also requested recovery of annual transmission and related costs incurred on or after January 1, 2007, plus the amortized portion of 2006 costs over a ten-year period, along with applicable carrying charges, through an adjustable rider similar to that implemented in Ohio. Changes in the recovery of NUG expenses and the recovery of Met-Ed's non-NUG stranded costs are also included in the filing. The filing contemplates a reduction in distribution rates for Met-Ed of $37 million annually and an increase in distribution rates for Penelec of $20 million annually. The PPUC suspended the effective date (June 10, 2006) of these rate changes for seven months after the filing as permitted under Pennsylvania law. If the PPUC adopts the overall positions taken in the intervenors' testimony as filed, this would have a material adverse effect on the financial statements of FirstEnergy, Met-Ed and Penelec. Hearings were held in late August 2006 and all reply briefs were filed by October 6, 2006. The ALJ's recommended decision is due by November 8, 2006 and the PPUC decision is expected by January 12, 2007.

As of September 30, 2006, Met-Ed's and Penelec's regulatory deferrals pursuant to the 1998 Restructuring Settlement (including the Phase 2 Proceedings) and the FirstEnergy/GPU Merger Settlement Stipulation were $297 million and $56 million, respectively. Penelec's $56 million is subject to the pending resolution of taxable income issues associated with NUG trust fund proceeds. The PPUC recently conducted a review and audit of a modification to the NUG purchased power stranded cost accounting methodology for Met-Ed and Penelec. On August 18, 2006, a PPUC Order was entered requiring Met-Ed and Penelec to reflect the deferred NUG cost balances as if the stranded cost accounting methodology modification had not been implemented. As a result of the PPUC's Order, Met-Ed recognized a pre-tax charge of approximately $10.3 million in the third quarter of 2006, representing incremental costs deferred under the revised methodology in 2005. Met-Ed and Penelec continue to believe that the stranded cost accounting methodology modification is appropriate and filed a petition with the PPUC pursuant to its Order for authorization to reflect the stranded cost accounting methodology modification effective January 1, 1999.

On January 12, 2005, Met-Ed and Penelec filed, before the PPUC, a request for deferral of transmission-related costs beginning January 1, 2005. The OCA, OSBA, OTS, MEIUG, PICA, Allegheny Electric Cooperative and Pennsylvania Rural Electric Association all intervened in the case. Met-Ed and Penelec sought to consolidate this proceeding (and modified their request to provide deferral of 2006 transmission-related costs only) with the comprehensive rate filing they made on April 10, 2006 as described above. On May 4, 2006, the PPUC approved the modified request. Accordingly, Met-Ed and Penelec have deferred approximately $90 million and $21 million, respectively, representing transmission costs that were incurred from January 1, 2006 through September 30, 2006. On June 5, 2006, the OCA filed before the Commonwealth Court a petition for review of the PPUC's approval of the deferral. On July 12, 2006, the Commonwealth Court granted the PPUC's motion to quash the OCA's appeal. The ratemaking treatment of the deferrals will be determined in the comprehensive rate filing proceeding discussed further above.

Under Pennsylvania's electric competition law, Penn is required to secure generation supply for customers who do not choose alternative suppliers for their electricity. 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 recommended that the RFP process cover the period January 1, 2007 through May 31, 2008. Hearings before the PPUC were held on January 10, 2006 with main briefs filed on January 27, 2006 and reply briefs filed on February 3, 2006. On February 16, 2006, the ALJ issued a Recommended Decision to adopt Penn's RFP process with modifications. On April 20, 2006, the PPUC approved the Recommended Decision with additional modifications to use an RFP process with two separate solicitations. An initial solicitation was held for Penn in May 2006 with all tranches fully subscribed, which was approved by the PPUC on June 2, 2006. On July 18, 2006, the second PLR solicitation was held for Penn. The tranches for the Residential Group and Small Commercial Group were fully subscribed. However, supply was not acquired for two tranches for the Large Commercial Group. On July 20, 2006, the PPUC approved the submissions for the second bid. A contingency solicitation was held on August 15, 2006 for the two remaining Large Commercial Group tranches. The PPUC rejected the bids from the contingency solicitation and directed Penn's independent auction manager to offer the two unfilled Large Commercial tranches to the companies which had won tranches in the prior solicitations. This resulted in the acquisition of a supplier for the two remaining tranches, which were filed and accepted by the PPUC in a secretarial letter that was entered on September 22, 2006. On August 24, 2006, Penn made a compliance filing. OCA and OSBA filed exceptions to the compliance filing. Penn filed reply exceptions on September 5, 2006. On September 21, 2006, Penn submitted a revised compliance filing to the PPUC for the Residential Group and Small Commercial Group as a result of an agreement between Penn, OCA and OSBA. The PPUC approved proposed rates for the large commercial and industrial customers at the PPUC Public meeting on October 19, 2006, and found that the results of the competitive solicitation process were consistent with prevailing market prices.

On May 25, 2006, Penn filed a Petition for Review of the PPUC's Orders of April 28, 2006 and May 4, 2006, which together decided the issues associated with Penn's proposed Interim PLR Supply Plan. Penn has asked the

Commonwealth Court to review the PPUC's decision to deny Penn's recovery of certain PLR costs through a reconciliation mechanism and the PPUC's decision to impose a geographic limitation on the sources of alternative energy credits. On June 7, 2006, the PaDEP filed a Petition for Review appealing the PPUC's ruling on the method by which alternative energy credits may be acquired and traded. Penn is unable to predict the outcome of this appeal.

NEW JERSEY

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 NUGC rates and market sales of NUG energy and capacity. As of September 30, 2006, the accumulated deferred cost balance totaled approximately $340 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 to securitize the July 31, 2003 deferred balance. On June 8, 2006, the NJBPU approved JCP&L's request to issue securitization bonds associated with BGS stranded cost deferrals. On August 10, 2006, JCP&L Transition Funding II, a wholly owned subsidiary of JCP&L, issued $182 million of transition bonds with a weighted average interest rate of 5.5%.

On December 2, 2005, JCP&L filed its request for recovery of $165 million of actual above-market NUG costs incurred from August 1, 2003 through October 31, 2005 and forecasted above-market NUG costs for November and December 2005. On February 23, 2006, JCP&L filed updated data reflecting actual amounts through December 31, 2005 of $154 million of costs incurred since July 31, 2003. On March 29, 2006, a pre-hearing conference was held with the presiding ALJ. On July 18, 2006, JCP&L filed rebuttal testimony that included a request for an additional $14 million of costs that had been eliminated from the securitized amount. Evidentiary hearings were held during September 2006 and the briefing schedule has been postponed pending settlement discussions.

An NJBPU Decision and Order approving a Phase II Stipulation of Settlement and resolving the Motion for Reconsideration of the Phase I Order was issued on May 31, 2005. The Phase II Settlement includes a performance standard pilot program with potential penalties of up to 0.25% of allowable equity return. The Order requires that JCP&L file quarterly reliability reports (CAIDI and SAIFI information related to the performance pilot program) through December 2006 and updates to reliability related project expenditures until all projects are completed. The latest quarterly reliability reports were submitted on September 12, 2006. As of September 30, 2006, there were no performance penalties issued by the NJBPU.

Reacting to the higher closing prices of the 2006 BGS fixed rate auction, the NJBPU, on March 16, 2006, initiated a generic proceeding to evaluate the auction process and potential options for the future. On April 6, 2006, initial comments were submitted. A public meeting was held on April 21, 2006 and a legislative-type hearing was held on April 28, 2006. On June 21, 2006, the NJBPU approved the continued use of a descending block auction for the Fixed Price Residential Class. JCP&L filed its 2007 BGS company specific addendum on July 10, 2006. On October 27, 2006, the NJBPU approved the auction format to procure the 2007 Commercial Industrial Energy Price as well as the specific rules for both the Fixed Price and Commercial Industrial Energy Price auctions. These rules were essentially unchanged from the prior auctions.

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 DRA filed comments on February 28, 2005 requesting that decommissioning funding be suspended. On March 18, 2005, JCP&L filed a response to the Ratepayer Advocate's comments. A schedule for further NJBPU proceedings has not yet been set.

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of PUHCA pursuant to the EPACT. An NJBPU proposed rulemaking to address the issues was published in the NJ Register on December 19, 2005. The proposal would prevent a holding company that owns a gas or electric public utility from investing more than 25% of the combined assets of its utility and utility-related subsidiaries into businesses unrelated to the utility industry. A public hearing was held on February 7, 2006 and comments were submitted to the NJBPU. On August 16, 2006, the NJBPU approved the regulations with an effective date of October 2, 2006. These regulations are not expected to materially impact FirstEnergy or JCP&L. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. Comments on the alternative proposal were submitted on June 15, 2006.

On December 21, 2005, the NJBPU initiated a generic proceeding and requested comments in order to formulate an appropriate regulatory treatment for investment tax credits related to generation assets divested by New Jersey's four electric utility companies. Comments were filed by the utilities and by the DRA. JCP&L filed a request with the IRS for a ruling on the issue. JCP&L was advised by the IRS on April 10, 2006 that the ruling was tentatively adverse. On April 28, 2006, the NJBPU directed JCP&L to withdraw its request for a private letter ruling on this issue, which had been previously filed with the IRS as ordered by the NJBPU. On May 11, 2006, after a JCP&L Motion for Reconsideration was denied by the NJBPU, JCP&L filed to withdraw the request for a private letter ruling. On July 19, 2006, the IRS acknowledged that the JCP&L ruling request was withdrawn.

FERC MATTERS

On November 1, 2004, ATSI filed with the FERC a request to defer approximately $54 million of costs to be incurred from 2004 through 2007 in connection with ATSI's VMEP, which represents ATSI's adoption of newly identified industry "best practices" for vegetation management. On March 4, 2005, the FERC approved ATSI's request to defer the VMEP costs (approximately $34 million has been deferred as of September 30, 2006). On March 28, 2006, ATSI and MISO filed with the FERC a request to modify ATSI's Attachment O formula rate to include revenue requirements associated with recovery of deferred VMEP costs over a five-year period. The requested effective date to begin recovery was June 1, 2006. Various parties filed comments responsive to the March 28, 2006 submission. The FERC conditionally approved the filing on May 22, 2006, subject to a compliance filing that ATSI made on June 13, 2006. A request for rehearing of the FERC's May 22, 2006 Order was filed by a party, which ATSI answered. On July 14, 2006, the FERC accepted ATSI's June 13, 2006 compliance filing. The estimated annual revenues to ATSI from the VMEP cost recovery is $12 million for each of the five years beginning June 1, 2006. On October 25, 2006, the FERC denied the request for rehearing.

On January 24, 2006, ATSI and MISO filed a request with the FERC to correct ATSI's Attachment O formula rate to reverse revenue credits associated with termination of revenue streams from transitional rates stemming from FERC's elimination of RTOR. Revenues formerly collected under these rates were included in, and served to reduce, ATSI's zonal transmission rate under the Attachment O formula. Absent the requested correction, elimination of these revenue streams would not be fully reflected in ATSI's formula rate until June 1, 2008. On March 16, 2006, the FERC approved the revenue credit correction without suspension, effective April 1, 2006. One party sought rehearing of the FERC's order. The request for rehearing of this order was denied on June 27, 2006. The FERC accepted MISO's and ATSI's revised tariff sheets for filing on June 7, 2006. The estimated annual revenue impact of the correction mechanism is approximately $40 million effective on June 1, 2006.

On November 18, 2004, the FERC issued an order eliminating the RTOR for transmission service between the MISO and PJM regions. The FERC also ordered the MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a SECA mechanism to recover lost RTOR revenues during a 16-month transition period from load serving entities. The FERC issued orders in 2005 setting the SECA for hearing. ATSI, JCP&L, Met-Ed, Penelec, and FES continue to be involved in the FERC hearings concerning the calculation and imposition of the SECA charges. The hearing was held in May 2006. Initial briefs were submitted on June 9, 2006, and reply briefs were filed on June 27, 2006. The Presiding Judge issued an Initial Decision on August 10, 2006, rejecting the compliance filings made by the RTOs and transmission owners, ruling on various issues and directing new compliance filings. This decision is subject to review and approval by the FERC. Briefs addressing the Initial Decision were filed on September 11, 2006 and October 20, 2006. A final order could be issued by the FERC by the end of 2006.

On January 31, 2005, certain PJM transmission owners made three filings with the FERC 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. American Electric Power Company, Inc. filed in opposition proposing to create a "postage stamp" rate for high voltage transmission facilities across PJM. Second, the FERC approved the proposed Schedule 12 rate harmonization. Third, the FERC accepted the proposed formula rate, subject to refund and hearing procedures. On June 30, 2005, the settling PJM transmission owners filed a request for rehearing of the May 31, 2005 order. On March 20, 2006, a settlement was filed with FERC in the formula rate proceeding that generally accepts the companies' formula rate proposal. The FERC issued an order approving this settlement on April 19, 2006. Hearings in the PJM rate design case concluded in April 2006. On July 13, 2006, an Initial Decision was issued by the ALJ. The ALJ adopted the Trial Staff's position that the cost of all PJM transmission facilities should be recovered through a postage stamp rate. The ALJ recommended an April 1, 2006 effective date for this change in rate design. If the FERC accepts this recommendation, the transmission rate applicable to many load zones in PJM would increase. FirstEnergy believes that significant additional transmission revenues would have to be recovered from the JCP&L, Met-Ed and Penelec transmission zones within PJM. JCP&L, Met-Ed and Penelec as part of the Responsible Pricing Alliance, filed a brief addressing the Initial Decision on August 14, 2006 and September 5, 2006. The case will be reviewed by the FERC with a decision anticipated in the fourth quarter of 2006.

On November 1, 2005, FES filed two power sales agreements for approval with the FERC. One power sales agreement provided for FES to provide the PLR requirements of the Ohio Companies at a price equal to the retail generation rates approved by the PUCO for a period of three years beginning January 1, 2006. The Ohio Companies will be relieved of their obligation to obtain PLR power requirements from FES if the Ohio CBP results in a lower price for retail customers. A similar power sales agreement between FES and Penn permits Penn to obtain its PLR power requirements from FES at a fixed price equal to the retail generation price during 2006.

On December 29, 2005, the FERC issued an order setting the two power sales agreements for hearing. The order criticized the Ohio CBP, and required FES to submit additional evidence in support of the reasonableness of the prices charged in the power sales agreements. A pre-hearing conference was held on January 18, 2006 to determine the hearing schedule in this case. Under the procedural schedule approved in this case, FES expected an initial decision to be issued in late January 2007. However, on July 14, 2006, the Chief Judge granted the joint motion of FES and the Trial Staff to appoint a settlement judge in this proceeding and the procedural schedule was suspended pending settlement discussions among the parties. A settlement conference was held on September 5, 2006. FES and the Ohio Companies, Penn, and the PUCO, along with other parties, reached an agreement to settle the case. The settlement was filed with the FERC on October 17, 2006, and was unopposed by the remaining parties, including the FERC Trial Staff. Initial comments to the settlement are due by November 6, 2006.

The terms of the settlement provide for modification of both the Ohio and Penn power supply agreements with FES. Under the Ohio power supply agreement, separate rates are established for the Ohio Companies' PLR requirements, special retail contracts requirements, wholesale contract requirements, and interruptible buy-through retail load requirements. For their PLR and special retail contract requirements, the Ohio Companies will pay FES no more than the lower of (i) the sum of the retail generation charge, the rate stabilization charge, the fuel recovery mechanism charge, and FES' actual incremental fuel costs for such sales; or (ii) the wholesale price cap. Different wholesale price caps are imposed for PLR sales, special retail contracts, and wholesale contracts. The wholesale price for interruptible buy-through retail load requirements is limited to the actual spot price of power obtained by FES to provide this power. The Ohio Companies have recognized the estimated additional amount payable to FES for power supplied during the nine months ended September 30, 2006. The wholesale rate charged by FES under the Penn power supply agreement will be no greater than the generation component of charges for retail PLR load in Pennsylvania. The FERC is expected to act on this case by the end of the fourth quarter of 2006.

As a result of Penn's PLR competitive solicitation process approved by the PPUC, FES was selected as the winning bidder for a number of the tranches for individual customer classes. The balance of the tranches will be supplied by unaffiliated power suppliers. On October 2, 2006, FES filed an application with FERC under Section 205 of the Federal Power Act for authorization to make these affiliate sales to Penn. Interventions or protests were due on this filing on October 23, 2006. Penn was the only party to file an intervention in this proceeding. The FERC is expected to act on this filing on or before December 1, 2006.

On October 19, 2006, the FERC issued two final rules in connection with the Public Utility Holding Company Act of 2005 (PUHCA 2005). The final rules impose certain accounting, reporting and record-retention requirements for applicable holding companies and service companies, which includes FirstEnergy and certain of its subsidiaries.

12. - NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

SAB 108 - "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements"

In September 2006, the SEC issued SAB 108, which provides interpretive guidance on how registrants should quantify financial statement misstatements. There is currently diversity in practice, with the two commonly used methods to quantify misstatements being the “rollover” method (which primarily focuses on the income statement impact of misstatements) and the “iron curtain” method (which focuses on the balance sheet impact). SAB 108 requires registrants to use a dual approach whereby both of these methods are considered in evaluating the materiality of financial statement errors. Prior materiality assessments will need to be reconsidered using both the rollover and iron curtain methods. This guidance will be effective for FirstEnergy in the fourth quarter of 2006. FE does not expect this Statement to have a material impact on its financial statements.

EITF 06-5 - "Accounting for Purchases of Life Insurance-Determining the Amount That Could Be Realized in Accordance with FASB Technical Bulletin No. 85-4, Accounting for Purchases of Life Insurance"

In September 2006, the EITF reached a consensus on Issue 06-5 concluding that a policyholder should consider any additional amounts included in the contractual terms of the policy in determining the amount that could be realized under the insurance contract. Contractual limitations should be considered when determining the realizable amounts. Amounts that are recoverable by the policyholder at the discretion of the insurance company should be excluded from the amount that could be realized. Recoverable amounts in periods beyond one year from the surrender of the policy should be discounted in accordance with APB Opinion No. 21, "Interest on Receivables and Payables." Consensus was also reached that a policyholder should determine the amount that could be realized under the insurance contract assuming the surrender of an individual-life by individual-life policy (or certificate by certificate in a group policy). Any amount that would ultimately be realized by the policyholder upon the assumed surrender of the final policy (or final certificate) should be included in the amount that could be realized under the insurance contract. The EITF also concluded that a policyholder should not discount the cash surrender value component of the amount that could be realized when contractual restrictions on the ability to surrender a policy exist. However, if the contractual limitations prescribe that the cash surrender value component of the amount that could be realized is a fixed amount, then the amount that could be realized should be discounted in accordance with APB Opinion No. 21. This Issue is effective for fiscal years beginning after December 15, 2006. FirstEnergy does not expect this EITF to have a material impact on its financial statements.

SFAS 157 - "Fair Value Measurements"

In September 2006, the FASB issued SFAS 157, that establishes how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under GAAP. This Statement addresses the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. The key changes to current practice are: (1) the definition of fair value which focuses on an exit price rather than entry price; (2) the methods used to measure fair value such as emphasis that fair value is a market-based measurement, not an entity-specific measurement, as well as the inclusion of an adjustment for risk, restrictions and credit standing; and (3) the expanded disclosures about fair value measurements.

This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. FirstEnergy is currently evaluating the impact of this Statement on its financial statements.

SFAS 158 - "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)"

In September 2006, the FASB issued SFAS 158, which requires companies to recognize a net liability or asset to report the overfunded or underfunded status of their defined benefit pension and other postretirement benefit plans on their balance sheets and recognize changes in funded status in the year in which the changes occur through other comprehensive income. The funded status to be measured is the difference between plan assets at fair value and the benefit obligation. This Statement requires that gains and losses and prior service costs or credits, net of tax, that arise during the period be recognized as a component of other comprehensive income and not as components of net periodic benefit cost. Additional information should also be disclosed in the notes to the financial statements about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and transition asset or obligation. Upon the initial application of this Statement and subsequently, an employer should continue to apply the provisions in Statements 87, 88 and 106 in measuring plan assets and benefit obligations as of the date of its statement of financial position and in determining the amount of net periodic benefit cost. This Statement is effective for FirstEnergy as of December 31, 2006. Based upon the

December 31, 2005 measurement date, the estimated balance sheet impacts of adopting this Statement are a reduction in total assets of $0.4 billion, an increase in liabilities of $0.6 billion and a decrease in equity of $1 billion, before recognition of any related regulatory assets that may be appropriate under the circumstances.

FSP FIN 46(R)-6 - "Determining the Variability to Be Considered in Applying FASB interpretation No. 46(R)"

In April 2006, the FASB issued FSP FIN 46(R)-6 that addresses how a reporting enterprise should determine the variability to be considered in applying FASB interpretation No. 46 (revised December 2003). FirstEnergy adopted FIN 46(R) in the first quarter of 2004, consolidating VIE's when FirstEnergy or one of its subsidiaries is determined to be the VIE's primary beneficiary. The variability that is considered in applying interpretation 46(R) affects the determination of (a) whether the entity is a VIE; (b) which interests are variable interests in the entity; and (c) which party, if any, is the primary beneficiary of the VIE. This FSP states that the variability to be considered shall be based on an analysis of the design of the entity, involving two steps:

Step 1:	Analyze the nature of the risks in the entity
Step 2:	Determine the purpose(s) for which the entity was created and determine the variability the entity is designed to create and pass along to its interest holders.

After determining the variability to consider, the reporting enterprise can determine which interests are designed to absorb that variability. The guidance in this FSP is applied prospectively to all entities (including newly created entities) with which that enterprise first becomes involved and to all entities previously required to be analyzed under interpretation 46(R) when a reconsideration event has occurred after July 1, 2006. FirstEnergy does not expect this Statement to have a material impact on its financial statements.

FIN 48 - "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109."

In June 2006, the FASB issued FIN 48 which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, "Accounting for Income Taxes." This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken on a tax return. This interpretation also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation will be a two-step process. The first step will determine if it is more likely than not that a tax position will be sustained upon examination and should therefore be recognized. The second step will measure a tax position that meets the more likely than not recognition threshold to determine the amount of benefit to recognize in the financial statements. This interpretation is effective for fiscal years beginning after December 15, 2006. FirstEnergy is currently evaluating the impact of this Statement.

13. - SEGMENT INFORMATION

FirstEnergy has two reportable segments: regulated services and power supply management services. The aggregate “Other” segments do not individually meet the criteria to be considered a reportable segment. The regulated services segment's operations include the regulated sale of electricity and distribution and transmission services by its eight utility subsidiaries in Ohio, Pennsylvania and New Jersey. The power supply management services segment primarily consists of the subsidiaries (FES, FGCO, NGC and FENOC) that sell electricity in deregulated markets and operate and now own the generation facilities of OE, CEI, TE and Penn resulting from the deregulation of the Companies' electric generation business. “Other” consists of telecommunications services, the recently sold MYR (a construction service company) and retail natural gas operations (see Note 4). The assets and revenues for the other business operations are below the quantifiable threshold for operating segments for separate disclosure as “reportable segments.”

The regulated services segment designs, constructs, operates and maintains FirstEnergy's regulated transmission and distribution systems. Its revenues are primarily derived from electricity delivery and transition cost recovery. Assets of the regulated services segment as of September 30, 2005 included generating units that were leased or whose output had been sold to the power supply management services segment. The regulated services segment’s 2005 internal revenues represented the rental revenues for the generating unit leases which ceased in the fourth quarter of 2005 as a result of the intra-system generation asset transfers (see Note 14).

The power supply management services segment supplies the electric power needs of FirstEnergy’s end-use customers through retail and wholesale arrangements, including regulated retail sales to meet all or a portion of the PLR requirements of FirstEnergy's Ohio and Pennsylvania companies and competitive retail sales to customers primarily in Ohio, Pennsylvania, Maryland and Michigan. This business segment owns and operates FirstEnergy's generating facilities and purchases electricity to meet sales obligations. The segment's net income is primarily derived from all electric generation sales revenues less the related costs of electricity generation, including purchased power and net transmission, congestion and ancillary costs charged by PJM and MISO to deliver energy to retail customers.

Segment reporting for interim periods in 2005 was revised to conform to the current year business segment organization and operations and the reclassification of discontinued operations (see Note 4). Changes in the current year operations reporting reflected in the revised 2005 segment reporting primarily includes the transfer of retail transmission revenues and PJM/MISO transmission revenues and expenses associated with serving electricity load previously included in the regulated services segment to the power supply management services segment. In addition, as a result of the 2005 Ohio tax legislation reducing the effective state income tax rate, the calculated composite income tax rates used in the two reportable segments’ results for 2005 and 2006 have been changed to 40% from the 41% previously reported in their 2005 segment results. The net amounts of the changes in the 2005 reportable segments' income taxes reclassifications have been correspondingly offset in the 2005 "Reconciling Adjustments." FSG is being disclosed as a reportable segment due to its subsidiaries qualifying as held for sale. Interest expense on holding company debt and corporate support services revenues and expenses are included in "Reconciling Adjustments."

Segment Financial Information

Three Months Ended	Regulated Services	Power Supply Management Services	Facilities Services	Other	Reconciling Adjustments	Consolidated
				(In millions)		
September 30, 2006						
External revenues	$ 1,290	$ 2,066	$ 47	$ 14	$ (16)	$ 3,401
Internal revenues	-	-	-	-	-	-
Total revenues	1,290	2,066	47	14	(16)	3,401
Depreciation and amortization	280	(44)	-	1	6	243
Investment Income	67	19	-	-	(40)	46
Net interest charges	102	56	-	1	21	180
Income taxes	200	119	-	(15)	(32)	272
Income before discontinued operations	297	180	1	27	(51)	454
Discontinued operations	-	-	-	-	-	-
Net income	297	180	1	27	(51)	454
Total assets	24,181	6,822	30	290	839	32,162
Total goodwill	5,911	24	-	-	-	5,935
Property additions	123	126	-	-	3	252
September 30, 2005						
External revenues	$ 1,481	$ 1,824	$ 59	$ 138	$ 2	$ 3,504
Internal revenues	79	-	-	-	(79)	-
Total revenues	1,560	1,824	59	138	(77)	3,504
Depreciation and amortization	409	(22)	-	1	5	393
Investment income	83	-	-	-	-	83
Net interest charges	88	11	-	1	57	157
Income taxes	264	(9)	-	3	(21)	237
Income before discontinued operations	395	(13)	-	6	(56)	332
Discontinued operations	-	-	-	-	-	-
Net income	395	(13)	-	6	(56)	332
Total assets	28,385	1,741	82	522	644	31,374
Total goodwill	5,938	24	-	62	-	6,024
Property additions	207	79	-	1	7	294

Nine Months Ended						
September 30, 2006						
External revenues	$ 3,417	$ 5,364	$ 150	$ 149	$ (49)	$ 9,031
Internal revenues	-	-	-	-	-	-

Total revenues	3,417	5,364	150	149	(49)	9,031
Depreciation and amortization	765	(54)	-	3	17	731
Investment Income	204	36	-	1	(121)	120
Net interest charges	291	160	-	5	57	513
Income taxes	499	236	2	(21)	(93)	623
Income before discontinued operations	736	355	(11)	37	(138)	979
Discontinued operations	-	-	-	-	-	-
Net income	736	355	(11)	37	(138)	979
Total assets	24,181	6,822	30	290	839	32,162
Total goodwill	5,911	24	-	-	-	5,935
Property additions	492	473	-	2	23	990
<u>September 30, 2005</u>						
External revenues	$ 3,923	$ 4,617	$ 162	$ 385	$ 10	$ 9,097
Internal revenues	238	-	-	-	(238)	-
Total revenues	4,161	4,617	162	385	(228)	9,097
Depreciation and amortization	1,128	(26)	-	2	18	1,122
Investment income	171	-	-	-	-	171
Net interest charges	285	29	1	4	170	489
Income taxes	613	(43)	4	13	12	599
Income before discontinued operations	920	(64)	(6)	18	(216)	652
Discontinued operations	-	-	13	5	-	18
Net income	920	(64)	7	23	(216)	670
Total assets	28,385	1,741	82	522	644	31,374
Total goodwill	5,938	24	-	62	-	6,024
Property additions	506	226	1	5	18	756

Reconciling adjustments to segment operating results from internal management reporting to consolidated external financial reporting primarily consist of interest expense related to holding company debt, corporate support services revenues and expenses, fuel marketing revenues (which are reflected as reductions to expenses for internal management reporting purposes) and elimination of intersegment transactions.

14. - 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 that were completed in the fourth quarter of 2005. The asset transfers resulted in the respective undivided ownership interests of the Ohio Companies and Penn in FirstEnergy's nuclear and non-nuclear generation assets being owned by NGC and FGCO, respectively. The generating plant interests 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 FGCO's purchase option under the Master Facility Lease.

On December 16, 2005, the Ohio Companies and Penn completed the intra-system transfer of their respective ownership in the nuclear generation assets to NGC through, in the case of OE and Penn, an asset spin-off by way of dividend and, in the case of CEI and TE, a sale at net book value. FENOC continues to operate and maintain the nuclear generation assets.

These transactions were 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 essentially completed the divestitures contemplated by the restructuring plans by transferring the ownership interests to NGC and FGCO without impacting the operation of the plants.

15. - JCP&L RESTATEMENT

JCP&L's earnings for the three months and nine months ended September 30, 2005 have been restated to reflect the results of a tax audit by the State of New Jersey, in which JCP&L became aware that the New Jersey Transitional Energy Facilities Assessment (TEFA) is not an allowable deduction for state income tax purposes. JCP&L had incorrectly claimed a state income tax deduction for TEFA payments and as a result, income taxes and interest expense were understated by $0.7 million and $0.6 million, respectively, in the third quarter of 2005 and understated by $1.6 million and $1.8 million, respectively, in the nine months ended September 30, 2005. The effects of these adjustments on JCP&L's Consolidated Statements of Income for the three months and nine months ended September 30, 2005 are as follows:

	Three Months		Nine Months	
	As Previously Reported	As Restated	As Previously Reported	As Restated
	(In millions)			
Operating Revenues	$ 900.3	$ 900.3	$ 2,024.7	$ 2,024.7
Operating Expenses and Taxes	809.2	809.9	1,825.1	1,826.7
	91.1	90.4	199.6	198.0

Operating Income								
Other Income		3.0		3.0		3.3		3.3
Net Interest Charges		18.9		19.5		57.9		59.7
Net Income	$	75.2	$	73.9	$	145.0	$	141.6
Earnings Applicable to Common Stock	$	75.0	$	73.8	$	144.6	$	141.3

These adjustments were not material to FirstEnergy's consolidated financial statements, nor JCP&L's Consolidated Balance Sheets or Consolidated Statements of Cash Flows.

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(In millions, except per share amounts)			
REVENUES:				
Electric utilities	$ 2,996	$ 2,853	$ 7,677	$ 7,403
Unregulated businesses	405	651	1,354	1,694
Total revenues	3,401	3,504	9,031	9,097
EXPENSES:				
Fuel and purchased power	1,317	1,287	3,306	3,115
Other operating expenses	794	993	2,446	2,750
Provision for depreciation	153	152	445	444
Amortization of regulatory assets	243	366	665	983
Deferral of new regulatory assets	(153)	(125)	(379)	(305)
General taxes	187	188	553	541
Total expenses	2,541	2,861	7,036	7,528
OPERATING INCOME	860	643	1,995	1,569
OTHER INCOME (EXPENSE):				
Investment income	46	83	120	171
Interest expense	(185)	(162)	(528)	(488)
Capitalized interest	7	8	21	12
Subsidiaries' preferred stock dividends	(2)	(3)	(6)	(13)
Total other expense	(134)	(74)	(393)	(318)
INCOME BEFORE INCOME TAXES AND DISCONTINUED OPERATIONS	726	569	1,602	1,251
INCOME TAXES	272	237	623	599
INCOME BEFORE DISCONTINUED OPERATIONS	454	332	979	652
Discontinued operations (net of income tax benefit of $9 million) (Note 4)	-	-	-	18
NET INCOME	$ 454	$ 332	$ 979	$ 670

BASIC EARNINGS PER SHARE OF COMMON STOCK:								
Earnings before discontinued operations (Note 2)	$	1.41	$	1.01	$	2.99	$	1.99
Discontinued operations (Note 4)		-		-		-		0.05
Net earnings per basic share	$	1.41	$	1.01	$	2.99	$	2.04
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING		322		328		326		328
DILUTED EARNINGS PER SHARE OF COMMON STOCK:								
Earnings before discontinued operations (Note 2)	$	1.40	$	1.01	$	2.97	$	1.98
Discontinued operations (Note 4)		-		-		-		0.05
Net earnings per diluted share	$	1.40	$	1.01	$	2.97	$	2.03
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING		325		330		329		330
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$	0.45	$	0.43	$	1.35	$	1.255

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

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
		(In millions)		
NET INCOME	$ 454	$ 332	$ 979	$ 670
OTHER COMPREHENSIVE INCOME (LOSS):				
Unrealized gain (loss) on derivative hedges	(28)	18	45	19
Unrealized gain (loss) on available for sale securities	26	(13)	39	(37)
Other comprehensive income (loss)	(2)	5	84	(18)
Income tax expense (benefit) related to other comprehensive income	(1)	(2)	30	(8)
Other comprehensive income (loss), net of tax	(1)	7	54	(10)
COMPREHENSIVE INCOME	$ 453	$ 339	$ 1,033	$ 660

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

FIRSTENERGY CORP.

CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2006	December 31, 2005
	(In millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 41	$ 64
Receivables -		
Customers (less accumulated provisions of $44 million and $38 million, respectively, for uncollectible accounts)	1,226	1,293
Other (less accumulated provisions of $26 million and $27 million, respectively, for uncollectible accounts)	194	205
Materials and supplies, at average cost	585	518
Prepayments and other	168	237
	2,214	2,317
PROPERTY, PLANT AND EQUIPMENT:		
In service	23,823	22,893
Less - Accumulated provision for depreciation	9,986	9,792
	13,837	13,101
Construction work in progress	673	897
	14,510	13,998
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,874	1,752
Investments in lease obligation bonds	830	890
Other	770	709
	3,474	3,351
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	5,935	6,010
Regulatory assets	4,434	4,486
Prepaid pension costs	1,008	1,023
Other	587	656
	11,964	12,175
	$ 32,162	$ 31,841
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 1,667	$ 2,043
Short-term borrowings	1,213	731
Accounts payable	611	727

Accrued taxes	752	800
Other	1,021	1,152
	5,264	5,453
CAPITALIZATION:		
Common stockholders’ equity -		
Common stock, $.10 par value, authorized 375,000,000 shares -		
319,205,517 and 329,836,276 shares outstanding, respectively	32	33
Other paid-in capital	6,460	7,043
Accumulated other comprehensive income (loss)	34	(20)
Retained earnings	2,695	2,159
Unallocated employee stock ownership plan common stock -		
718,671 and 1,444,796 shares, respectively	(13)	(27)
Total common stockholders' equity	9,208	9,188
Preferred stock of consolidated subsidiaries	80	184
Long-term debt and other long-term obligations	8,760	8,155
	18,048	17,527
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	2,778	2,726
Asset retirement obligations	1,179	1,126
Power purchase contract loss liability	1,205	1,226
Retirement benefits	1,372	1,316
Lease market valuation liability	788	851
Other	1,528	1,616
	8,850	8,861
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)		
	$ 32,162	$ 31,841

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

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2006	2005
	(In millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 979	$ 670
Adjustments to reconcile net income to net cash from operating activities -		
Provision for depreciation	445	444
Amortization of regulatory assets	665	983
Deferral of new regulatory assets	(379)	(305)
Nuclear fuel and lease amortization	67	63
Deferred purchased power and other costs	(323)	(258)
Deferred income taxes and investment tax credits, net	36	24
Deferred rents and lease market valuation liability	(54)	(71)
Accrued compensation and retirement benefits	78	72
Commodity derivative transactions, net	28	(8)
Gain on asset sales	(38)	-
Income from discontinued operations	-	(18)
Cash collateral	(98)	49
Decrease (increase) in operating assets -		
Receivables	(7)	(226)
Materials and supplies	(30)	(40)
Prepayments and other current assets	(49)	(57)
Increase (decrease) in operating liabilities -		
Accounts payable	(93)	60
Accrued taxes	(35)	207
Accrued interest	104	92
Electric service prepayment programs	(45)	218
Other	(8)	17
Net cash provided from operating activities	1,243	1,916
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing -		
Long-term debt	1,235	334
Short-term borrowings, net	482	77
Redemptions and Repayments -		
Common stock	(600)	-
Preferred stock	(107)	(170)

Long-term debt		(993)		(852)
Net controlled disbursement activity		(22)		(27)
Common stock dividend payments		(439)		(411)
Net cash used for financing activities		(444)		(1,049)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions		(990)		(756)
Proceeds from asset sales		83		61
Proceeds from nuclear decommissioning trust fund sales		1,325		1,140
Investments in nuclear decommissioning trust funds		(1,336)		(1,216)
Cash investments		109		21
Other		(13)		(30)
Net cash used for investing activities		(822)		(780)
Net increase (decrease) in cash and cash equivalents		(23)		87
Cash and cash equivalents at beginning of period		64		53
Cash and cash equivalents at end of period	$	41	$	140

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

Report of Independent Registered Public Accounting Firm

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, 2006, and the related consolidated statements of income and comprehensive income for each of the three-month and nine-month periods ended September 30, 2006 and 2005 and the consolidated statements of cash flows for the nine-month periods ended September 30, 2006 and 2005. 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 have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2005, 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, 2005 and the effectiveness of the Company's internal control over financial reporting as of December 31, 2005; 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 and conditional asset retirement obligations as of December 31, 2005 as discussed in Note 2(K) and Note 12 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 February 27, 2006, 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 as of December 31, 2005, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers
LLP
Cleveland, Ohio
October 31, 2006

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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 2006 was $454 million, or basic earnings of $1.41 per share of common stock ($1.40 diluted), compared with net income of $332 million, or basic and diluted earnings of $1.01 per share of common stock in the third quarter of 2005. Net income in the first nine months of 2006 was $979 million, or basic earnings of $2.99 per share of common stock ($2.97 diluted) compared to $670 million in the first nine months of 2005, or basic earnings of $2.04 per share of common stock ($2.03 diluted). The increase in FirstEnergy's earnings in both periods was driven primarily by reduced transition cost amortization for the Ohio Companies, cost deferrals authorized by the PUCO and PPUC, and reduced operating expenses. Earnings in the first nine months of 2006 also reflected increased electric sales revenues. Net income in the third quarter and first nine months of 2006 included unusual charges resulting from the PPUC's NUG costs accounting order for prior year deferred costs of $10 million (or $6 million after-tax --$.02 per share) and the impact from the sale and impairment of non-core assets (or $1 million after-tax--$0.01 per share). Earnings in the first nine months of 2005 were reduced by $0.22 per share of common stock due to additional income tax expense of $71 million from the enactment of tax legislation in Ohio. The following Non-GAAP Reconciliation displays the unusual items resulting in the difference between GAAP and Non-GAAP earnings.

Non-GAAP to GAAP Reconciliation	**2006**		**2005**	
Three Months Ended September 30,	**After-tax Amount (Millions)**	**Basic Earnings Per Share**	**After-tax Amount (Millions)**	**Basic Earnings Per Share**
Earnings Before Unusual Items (Non-GAAP)	$ 459	$ 1.42	$ 342	$ 1.04
Unusual Items:				
PPUC NUG adjustment applicable to prior years	(6)	(0.02)	-	-
Non-core asset sales/impairments	1	0.01	-	-
JCP&L arbitration decision	-	-	(10)	(0.03)
Net Income (GAAP)	$ 454	$ 1.41	$ 332	$ 1.01
Nine Months Ended September 30,				
Earnings Before Unusual Items (Non-GAAP)	$ 995	$ 3.04	$ 730	$ 2.22
Unusual Items:				
PPUC NUG adjustment applicable to prior years	(6)	(0.02)	-	-

Non-core asset sales/impairments		(10)		(0.03)		22	0.07
Sammis plant New Source Review settlement		-		-		(14)	(0.04)
Davis-Besse NRC fine		-		-		(3)	(0.01)
New regulatory assets - JCP&L rate settlement						16	0.05
JCP&L arbitration decision		-		-		(10)	(0.03)
Ohio tax write-off		-		-		(71)	(0.22)
Net Income (GAAP)	$	979	$	2.99	$	670	$ 2.04

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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 FirstEnergy 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 impairments items refer to a finite set of energy-related assets that had been previously disclosed as held for sale, a substantial portion of which have already been sold. Similarly, the NRC fine in 2005 and further litigation settlements similar to the New Source Review settlement in 2005 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 FirstEnergy's businesses over the longer term and assists investors in comparing FirstEnergy's operating performance to the operating performance of others in the energy sector. Generally, a Non-GAAP financial measure is a numerical measure of a company's historical or future financial performance, financial position, or cash flows that either excludes or includes amounts, or is subject to adjustment that has the effect of excluding or including amounts, that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with GAAP. Earnings per share before unusual items on a Non-GAAP basis (normalized earnings per share) are not calculated in accordance with GAAP because it excludes the impact of "unusual items." Unusual items reflect the impact on earnings of material events that are not routine, including those that may be related to discontinued businesses or the cumulative effect of an accounting change. Management believes presenting normalized earnings calculated in this manner provides useful information to investors in evaluating the ongoing results of FirstEnergy's businesses and assists investors in comparing FirstEnergy's operating performance to the operating performance of other companies in the energy sector. FirstEnergy's management frequently references Non-GAAP financial measures in its decision-making, using them to facilitate historical and ongoing performance comparisons as well as comparisons to the performance of peer companies. Non-GAAP measures should be considered in addition to, and not as a substitute for, their most directly comparable financial measures prepared in accordance with GAAP.

Total electric generation sales were down 1.3% in the third quarter of 2006 compared to last year's third quarter. The decrease resulted from a 32.9% reduction in wholesale sales, which more than offset a 7.7% increase in retail sales. For the nine months ended September 30, 2006, electric generation sales increased 1.4% over the same period last year. The year-to-date increase was primarily due to the return of customers to the Ohio Companies from third-party suppliers that exited the northern Ohio marketplace. Electric distribution deliveries were down 2.3% and 2.2% for the quarter and year-to-date periods ending September 30, 2006, compared with the respective periods of 2005, reflecting milder weather conditions in 2006.

FirstEnergy's generating fleet produced a record 61.9 billion KWH during the first nine months of 2006 compared to 59.5 billion KWH in the same period of 2005. FirstEnergy's non-nuclear fleet produced a record 40.1 billion KWH, while its nuclear facilities produced 21.8 billion KWH.

Share Repurchase Program - On August 10, 2006, FirstEnergy repurchased 10.6 million shares, or approximately 3.2%, of its outstanding common stock through an accelerated share repurchase program with an affiliate of J.P. Morgan Securities. The initial purchase price was $600 million, or $56.44 per share. The final purchase price will be adjusted to reflect the average of the daily volume-weighted prices of the shares over a period of up to seven months. The share repurchase was initially funded with short-term debt. The share repurchase was executed under a June 20, 2006 Board of Directors' authorization to repurchase up to 12 million shares of common stock.

Renewed and Upsized Credit Facility - On August 24, 2006, FirstEnergy and certain of its subsidiaries, including all of its operating utility subsidiaries, entered into a new five-year syndicated credit facility totaling $2.75 billion. The new facility replaces FirstEnergy's previous $2 billion credit facility and provides an average annual savings of 10 basis points on facility-related borrowing costs. Borrowings under the new credit facility were used to pay off the outstanding borrowings under the previous facility. FirstEnergy can request an increase in the total commitments available under the new facility up to a maximum of $3.25 billion. Commitments under the new facility are available until August 24, 2011, unless the lenders agree, at the request of the Borrowers, to two additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each Borrower are subject to a specified sub-limit, as well as applicable regulatory and other limitations.

Pennsylvania Rate Matters - Evidentiary hearings in the Met-Ed and Penelec rate transition plan filings were held from August 24 through August 30, 2006. Parties to the proceedings filed their Main Briefs on September 22, 2006 and Reply Briefs on October 6, 2006. Met-Ed and Penelec anticipate an ALJ recommended decision in these proceedings by November 8, 2006 and a PPUC decision by January 12, 2007. As part of the transition of customers' generation service toward market-based supply, Met-Ed and Penelec secured approximately 950 MW of their PLR supply under a competitive RFP for the period December 1, 2006 through December 31, 2008. Recovery of the incremental costs under the RFP is one component of the transition plan cases.

Met-Ed and Penelec NUG Accounting Methodology - On August 18, 2006, following a review and audit of FirstEnergy's modification to its NUG purchased power stranded cost accounting methodology, the PPUC issued an order requiring Met-Ed and Penelec to revert to the original accounting methodology under which NUG regulatory asset balances are reduced when market prices exceed NUG costs during the month. As a result of the order, FirstEnergy and Met-Ed recognized a pre-tax charge of $10 million in the third quarter of 2006, relating to incremental NUG costs deferred in 2005 under the revised methodology.

Penn RFP - On October 19, 2006, the PPUC certified the RFP results for all customer classes reflecting the successful completion of the RFP bidding process. The RFP was conducted to secure Penn's PLR supply for the period January 1, 2007 through May 31, 2008 for those customers that do not choose alternative suppliers.

JCP&L NUG Proceeding - An evidentiary hearing was held on September 20, 2006 and settlement conferences were held in October 2006 in the proceeding involving JCP&L's request to recover $165 million of actual above-market NUG costs incurred from August 1, 2003 through December 31, 2005. If approved, this request would increase cash flow, but would have no impact on earnings. Main briefs were filed October 30, 2006 and reply briefs are due by November 20, 2006. An order by the NJBPU is expected in 2007.

Beaver Valley Power Station Uprates - In August 2006, Beaver Valley Unit 1 increased its net output capability from 821 MW to 846 MW. This three-percent increase in capability is the first phase of its overall eight-percent power uprate recently approved by the NRC. The uprate was made possible by improvements to plant equipment and systems completed during the Unit's spring refueling outage. The remainder of the eight-percent power uprate is expected to be implemented by early 2007. Similar work is planned for Beaver Valley Unit 2. During the Unit's current refueling outage, which began October 2, 2006, several modifications will be completed to prepare Beaver Valley Unit 2 for its eight-percent increase in generating capacity. After Beaver Valley Unit 2 returns to service, three percent of the uprate is expected to take effect. The balance of the eight-percent power output increase is anticipated to be implemented during the next refueling outage in 2008. Beaver Valley Unit 2 is expected to return to service from its current refueling outage in early to mid-November 2006.

FIRSTENERGY'S BUSINESS

FirstEnergy is a public utility holding company headquartered in Akron, Ohio, that operates primarily through two core business segments (see Results of Operations).

- **Regulated Services** transmits and distributes electricity through FirstEnergy's 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 derives its revenue principally from the delivery of electricity generated or purchased by the Power Supply Management Services segment or, in some cases, purchased from independent suppliers in the states where the utility subsidiaries operate.

- **Power Supply Management Services** supplies the electric power needs of end-use customers through retail and wholesale arrangements, including regulated retail sales to meet all or a portion of the PLR requirements of FirstEnergy's Ohio and Pennsylvania utility subsidiaries and competitive retail sales to customers primarily in Ohio, Pennsylvania, Maryland and Michigan. This business segment owns and operates FirstEnergy's generating facilities and purchases electricity to meet sales obligations. The segment's net income is primarily derived from electric generation sales revenues less the related costs of electricity generation, including purchased power, and net transmission, congestion and ancillary costs charged by PJM and MISO to deliver energy to retail customers.

Other operating segments provide related 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 its remaining non-core businesses (see Note 4). The assets and revenues for the other business operations are below the quantifiable threshold for separate disclosure as “reportable operating segments.”

FIRSTENERGY INTRA-SYSTEM GENERATION ASSET TRANSFERS

In 2005, the Ohio Companies and Penn entered into certain agreements implementing a series of intra-system generation asset transfers that were completed in the fourth quarter of 2005. The asset transfers resulted in the respective undivided ownership interests of the Ohio Companies and Penn in FirstEnergy’s nuclear and non-nuclear generation assets being owned by NGC and FGCO, respectively. The generating plant interests 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.

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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 FGCO's purchase option under the Master Facility Lease.

On December 16, 2005, the Ohio Companies and Penn completed the intra-system transfer of their respective ownership in the nuclear generation assets to NGC through, in the case of OE and Penn, an asset spin-off by way of dividend and, in the case of CEI and TE, a sale at net book value. FENOC continues to operate and maintain the nuclear generation assets.

These transactions were 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 essentially completed the divestitures contemplated by the restructuring plans by transferring the ownership interests to NGC and FGCO without impacting the operation of the plants. The transfers were intercompany transactions and, therefore, had no impact on FirstEnergy's consolidated results.

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 13 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 13 to the consolidated financial statements. Net income (loss) by major business segment was as follows:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2006	2005	Increase (Decrease)	2006	2005	Increase (Decrease)
	(In millions, except per share amounts)					
Net Income (Loss) By Business Segment:						
Regulated Services	$ 297	$ 395	$ (98)	$ 736	$ 920	$ (184)
Power supply management services	180	(13)	193	355	(64)	419
Other and reconciling adjustments*	(23)	(50)	27	(112)	(186)	74
Total	$ 454	$ 332	$ 122	$ 979	$ 670	$ 309
Basic Earnings Per Share:						
Earnings before discontinued operations	$ 1.41	$ 1.01	$ 0.40	$ 2.99	$ 1.99	$ 1.00

Discontinued operations	-	-	-	-	0.05	(0.05)
Net earnings per basic share	$ 1.41	$ 1.01	$ 0.40	$ 2.99	$ 2.04	$ 0.95
Diluted Earnings Per Share:						
Earnings before discontinued operations	$ 1.40	$ 1.01	$ 0.39	$ 2.97	$ 1.98	$ 0.99
Discontinued operations	-	-	-	-	0.05	(0.05)
Net earnings per diluted share	$ 1.40	$ 1.01	$ 0.39	$ 2.97	$ 2.03	$ 0.94

* 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 third quarter and the first nine months of 2006 included a $10 million ($6 million after-tax) charge (or $0.02 per share) applicable to prior year NUG costs resulting from an August 2006 PPUC accounting order. Net income in the first nine months of 2006 was also reduced by the net charges associated with the sale and impairment of non-core assets of $10 million (or $0.03 per share).

Net income in the third quarter of 2005 included a $16 million ($10 million after-tax) charge (or $0.03 per share) resulting from a JCP&L arbitration decision. In the first nine months of 2005, net income was further reduced by additional income tax expense of $71 million (or $0.22 per share) from the enactment of tax legislation in Ohio, $0.04 per share of expense associated with the W.H. Sammis Plant New Source Review settlement and $0.01 per share of expense related to the fine by the NRC regarding the Davis-Besse Nuclear Power Station. These reductions were partially offset by the combined impact of $0.07 per share of gains from the sale of non-core assets and a net benefit resulting from the JCP&L rate settlement of $16 million (or $0.05 per share).

Summary of Results of Operations - Third Quarter of 2006 Compared with the Third Quarter of 2005

Financial results for FirstEnergy's major business segments in the third quarter of 2006 and 2005 were as follows:

3rd Quarter 2006 Financial Results	**Regulated Services**	**Power Supply Management Services**	**Other and Reconciling Adjustments**	**FirstEnergy Consolidated**
			(In millions)	
Revenues:				
External				
Electric	$ 1,124	$ 1,991	$ -	$ 3,115
Other	166	75	45	286
Internal	-	-	-	-
Total Revenues	1,290	2,066	45	3,401
Expenses:				
Fuel and purchased power	-	1,317	-	1,317
Other operating expenses	338	414	42	794
Provision for depreciation	96	50	7	153
Amortization of regulatory assets	238	5	-	243
Deferral of new regulatory assets	(54)	(99)	-	(153)
General taxes	140	43	4	187
Total Expenses	758	1,730	53	2,541
Operating Income (Loss)	532	336	(8)	860
Other Income (Expense):				
Investment income	67	19	(40)	46
Interest expense	(104)	(58)	(23)	(185)
Capitalized interest	4	2	1	7
Subsidiaries' preferred stock dividends	(2)	-	-	(2)
Total Other Income (Expense)	(35)	(37)	(62)	(134)
Income before income taxes	497	299	(70)	726
Income tax expense (benefit)	200	119	(47)	272
Net Income (Loss)	$ 297	$ 180	$ (23)	$ 454

3rd Quarter 2005 Financial Results	**Regulated Services**	**Power Supply Management Services**	**Other and Reconciling Adjustments**	**FirstEnergy Consolidated**
			(In millions)	

Revenues:				
External				
Electric	$ 1,340	$ 1,777	$ -	$ 3,117
Other	141	47	199	387
Internal	79	-	(79)	-
Total Revenues	1,560	1,824	120	3,504
Expenses:				
Fuel and purchased power	-	1,287	-	1,287
Other operating expenses	337	537	119	993
Provision for depreciation	137	9	6	152
Amortization of regulatory assets	366	-	-	366
Deferral of new regulatory assets	(94)	(31)	-	(125)
General taxes	150	33	5	188
Total Expenses	896	1,835	130	2,861
Operating Income (Loss)	664	(11)	(10)	643
Other Income (Expense):				
Investment income	83	-	-	83
Interest expense	(91)	(12)	(58)	(161)
Capitalized interest	6	1	-	7
Subsidiaries' preferred stock dividends	(3)	-	-	(3)
Total Other Income (Expense)	(5)	(11)	(58)	(74)
Income before income taxes	659	(22)	(68)	569
Income tax expense (benefit)	264	(9)	(18)	237
Net Income (Loss)	$ 395	$ (13)	$ (50)	$ 332

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Change Between 3rd Quarter 2006 and 3rd Quarter 2005 Financial Results Increase (Decrease)	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$ (216)	$ 214	$ -	$ (2)
Other	25	28	(154)	(101)
Internal	(79)	-	79	-
Total Revenues	(270)	242	(75)	(103)
Expenses:				
Fuel and purchased power	-	30	-	30
Other operating expenses	1	(123)	(77)	(199)
Provision for depreciation	(41)	41	1	1
Amortization of regulatory assets	(128)	5	-	(123)
Deferral of new regulatory assets	40	(68)	-	(28)
General taxes	(10)	10	(1)	(1)
Total Expenses	(138)	(105)	(77)	(320)
Operating Income	(132)	347	2	217
Other Income (Expense):				
Investment income	(16)	19	(40)	(37)
Interest expense	(13)	(46)	35	(24)
Capitalized interest	(2)	1	1	-
Subsidiaries' preferred stock dividends	1	-	-	1
Total Other Income (Expense)	(30)	(26)	(4)	(60)
Income before income taxes	(162)	321	(2)	157
Income taxes	(64)	128	(29)	35
Net Income	$ (98)	$ 193	$ 27	$ 122

Regulated Services - Third Quarter 2006 Compared to Third Quarter 2005

Net income decreased $98 million (24.8%) to $297 million in the third quarter of 2006 compared to $395 million in the third quarter of 2005, primarily due to decreased operating revenues partially offset by lower operating expenses.

Revenues -

The decrease in total revenues by service type is summarized below:

Revenues By Type of Service	Three Months Ended September 30, 2006	2005	Increase (Decrease)
	(In millions)		
Distribution services	$ 1,124	$ 1,340	$ (216)
Transmission services	109	117	(8)
Internal lease revenues	-	79	(79)
Other	57	24	33
Total Revenues	$ 1,290	$ 1,560	$ (270)

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

Electric Distribution Deliveries	
Residential	(4.9)%
Commercial	(1.0)%
Industrial	(0.6)%
Total Distribution Deliveries	(2.3)%

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The completion of the Ohio Companies' generation transition cost recovery under their respective transition plans and Penn's transition plan in 2005 were the primary reasons for lower distribution unit prices, which, in conjunction with lower KWH deliveries, resulted in lower distribution delivery revenues. The decrease in deliveries to customers was primarily due to milder weather during the third quarter of 2006 as compared to the same period in 2005. The following table summarizes major factors contributing to the $216 million decrease in distribution service revenues in the third quarter of 2006:

Sources of Change in Distribution Revenues	**Increase (Decrease)**
	(In millions)
Changes in customer usage	$ (70)
Ohio shopping incentives	77
Reduced Ohio transition rates	(244)
Other	21
Net Decrease in Distribution Revenues	$ (216)

The decrease in internal lease revenues resulted from the generation asset transfers discussed above. The 2005 generation assets lease revenue from affiliates ceased as a result of the transfers.

Expenses-

The decrease in revenues discussed above was partially offset by the following decreases in total expenses:

- Lower depreciation expense of $41 million that resulted from the generation asset transfers;
- Reduced amortization of regulatory assets of $128 million principally due to the completion of Ohio generation transition cost recovery and Penn's transition plan in 2005; and
- Decreased general taxes of $10 million primarily due to lower property taxes as a result of the generation asset transfers.

Those decreases in expenses were partially offset by the following:

- Other operating expenses were $1 million higher in 2006 due, in part, to the following factors:

- The absence in 2006 of expenses for ancillary service refunds to third-parties of $9 million in 2005 due to the RCP, which provides that alternate suppliers of ancillary services now bill customers directly for those services;
- A $10 million decrease in employee and contractor costs resulting from reduced employee benefits (principally postretirement benefits) and the decreased use of outside contractors for tree trimming, reliability work, legal services and jobbing and contracting; and

- An $18 million increase due, in part, to regulatory fees, costs for jobbing and contracting and the absence in 2006 of an insurance settlement.

· The deferral of new regulatory assets was lower as a result of the end of shopping incentive deferrals under the Ohio Companies' transition plan, partially offset by the distribution cost deferrals under the Ohio Companies' RCP.

Other Income -

Lower investment income reflects the impact of the generation asset transfers. The reduction in 2006 of the nuclear decommissioning trust income, the majority of which is now included in the power supply management services segment, was partially offset by interest income on the affiliated company notes receivable from the power supply management services segment in the third quarter of 2006.

The $13 million increase in interest expense in the third quarter of 2006, compared with the same period of 2005, represents an additional $10 million of interest expense from OE's June 2006 issuance of $600 million of unsecured senior notes. As discussed under Capital Resources and Liquidity, OE used the debt proceeds to repurchase $500 million of its common stock from FirstEnergy, who then redeemed $400 million of FirstEnergy notes in July 2006. This represents a part of FirstEnergy's 2006 refinancing strategy to obtain additional financing flexibility at the holding company (represented in the Other and Reconciling Adjustment segment) and to capitalize the regulated utilities more appropriately from a regulatory context.

Power Supply Management Services - Third Quarter 2006 Compared to Third Quarter 2005

Net income for this segment was $180 million in the third quarter of 2006 compared to a net loss of $13 million in the same period last year. An improvement in the gross generation margin and increased transmission and fuel cost deferrals was partially offset by higher depreciation, general taxes and interest expense resulting from the generation asset transfers.

Revenues -

Electric generation sales revenues increased $185 million in the third quarter of 2006 compared to the same period in 2005. This increase primarily resulted from a 7.7% increase in retail KWH sales, mostly due to the return of customers as a result of third-party suppliers leaving the northern Ohio marketplace and higher unit prices resulting from the 2006 rate stabilization and fuel recovery charges. The higher retail sales reduced energy available for sale to the wholesale market. Increased transmission revenues resulted primarily from new revenues of approximately $34 million under the MISO transmission rider that began in the first quarter of 2006 and revenue increases from auction revenue rights and financial transmission rights.

An increase in reported segment revenues resulted from the following sources:

	Three Months Ended September 30,		
Revenues By Type of Service	**2006**	**2005**	**Increase (Decrease)**
		(In millions)	
Electric Generation Sales:			
Retail	$ 1,640	$ 1,254	$ 386
Wholesale	229	430	(201)
Total Electric Generation Sales	1,869	1,684	185
Transmission	182	110	72
Other	15	30	(15)
Total Revenues	$ 2,066	$ 1,824	$ 242

The following table summarizes the price and volume factors contributing to changes in sales revenues from retail and wholesale customers:

Source of Change in Electric Generation Sales	**Increase (Decrease)**
	(In millions)
Retail:	
Effect of 7.7% increase in	$ 97

customer usage		
Increased prices		289
		386
Wholesale:		
Effect of 32.9% decrease in KWH sales		(141)
Lower prices		(60)
		(201)
Net Increase in Electric Generation Sales	$	185

Expenses -

Total operating expenses decreased by $105 million. The decrease was due to the following factors:

· Lower non-fuel operating expenses of $123 million reflect the absence in 2006 of generating lease rents ($79 million paid in 2005) due to the generation asset transfers and decreases in fossil production and transmission expenses of $20 million and $21 million, respectively, partially offset by higher nuclear operating expenses of $9 million. The lower fossil production expenses reflected higher credits of $24 million in 2006 from emission allowance sales compared to the same period of 2005. Decreased transmission expenses reflected lower congestion costs. Nuclear operating costs were higher principally due to preparation costs related to the Beaver Valley Unit 2 outage that began on October 2, 2006 and increased labor and benefit costs; and

- A $68 million increase in the deferral of new regulatory assets primarily related to the Ohio RCP fuel deferral of $43 million in 2006. The increase also reflected PJM/MISO costs incurred that are expected to be recovered from customers through future rates. The recognition of these amounts under the Power Supply Management Services segment reflects a change in the current year operations reporting as discussed in Note 13 - Segment Information. Retail transmission revenues and PJM/MISO transmission revenues and expenses associated with serving electricity load are now included in the power supply management services segment results.

The above expense decreases were partially offset by the following:

- Higher fuel costs of $8 million, primarily coal cost increases resulting from higher coal commodity prices and increased transportation costs for western coal. The increased coal costs were partially offset by decreased generation output and lower natural gas and emission allowance costs of $20 million. Purchased power costs increased $22 million due to higher prices and were partially offset by lower volumes. Factors producing 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	$ 12
Change due to volume consumed	(4)
	8
Purchased Power:	
Change due to increased unit costs	68
Change due to volume purchased	(32)
PPUC NUG adjustment applicable to prior year	10
Increase in NUG costs deferred	(24)
	22

Net Increase in Fuel and Purchased Power Costs	$	30

- Increased depreciation expenses of $41 million resulted principally from the generation asset transfers; and

- Higher general taxes of $10 million due to additional property taxes resulting from the generation asset transfers.

Other Income and Expense -

- Investment income in the third quarter of 2006 increased by $19 million over the prior year primarily due to nuclear decommissioning trust investments acquired through the generation asset transfers; and

- Interest expense increased by $46 million in the third quarter of 2006 primarily due to the interest expense on associated company notes payable that financed the generation asset transfers.

Other - Third Quarter 2006 Compared to Third Quarter 2005

FirstEnergy’s financial results from other operating segments and reconciling items, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a $27 million increase to FirstEnergy’s net income in the third quarter of 2006 compared to the same quarter of 2005. The increase was primarily due to a $5 million improvement in gas commodity transactions, a $3 million increase in insurance investment income and $15 million of income tax benefits, primarily reflecting the 2005 federal income tax return filed in the third quarter of 2006.

Summary of Results of Operations - First Nine Months of 2006 Compared with the First Nine Months of 2005

Financial results for FirstEnergy's major business segments in the first nine months of 2006 and 2005 were as follows:

First Nine Months of 2006 Financial Results	**Regulated Services**	**Power Supply Management Services**	**Other and Reconciling Adjustments**	**FirstEnergy Consolidated**
		(In millions)		
Revenues:				
External				
Electric	$ 2,972	$ 5,207	$ -	$ 8,179
Other	445	157	250	852
Internal	-	-	-	-
Total Revenues	3,417	5,364	250	9,031
Expenses:				
Fuel and purchased power	-	3,306	-	3,306
Other operating expenses	921	1,270	255	2,446
Provision for depreciation	279	146	20	445
Amortization of regulatory assets	650	15	-	665
Deferral of new regulatory assets	(164)	(215)	-	(379)
General taxes	409	127	17	553
Total Expenses	2,095	4,649	292	7,036
Operating Income (Loss)	1,322	715	(42)	1,995
Other Income (Expense):				
Investment income	204	36	(120)	120
Interest expense	(293)	(168)	(67)	(528)
Capitalized interest	12	8	1	21
Subsidiaries' preferred stock dividends	(10)	-	4	(6)
Total Other Income (Expense)	(87)	(124)	(182)	(393)
Income before income taxes and discontinued operations	1,235	591	) (224	1,602
Income tax expense (benefit)	499	236	(112)	623
Income before discontinued operations	736	355	(112)	979
Discontinued operations	-	-	-	-
Net Income (Loss)	$ 736	$ 355	$ (112)	$ 979

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First Nine Months of 2005 Financial Results	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)	
Revenues:				
External				
Electric	$ 3,509	$ 4,523	$ -	$ 8,032
Other	414	94	557	1,065
Internal	238	-	(238)	-
Total Revenues	4,161	4,617	319	9,097
Expenses:				
Fuel and purchased power	-	3,115	-	3,115
Other operating expenses	963	1,505	282	2,750
Provision for depreciation	398	26	20	444
Amortization of regulatory assets	983	-	-	983
Deferral of new regulatory assets	(253)	(52)	-	(305)
General taxes	423	101	17	541
Total Expenses	2,514	4,695	319	7,528
Operating Income (Loss)	1,647	(78)	-	1,569
Other Income (Expense):				
Investment income	171	-	-	171
Interest expense	(285)	(28)	(175)	(488)
Capitalized interest	13	(1)	-	12
Subsidiaries' preferred stock dividends	(13)	-	-	(13)
Total Other Income (Expense)	(114)	(29)	(175)	(318)
Income before income taxes and discontinued operations	1,533	(107)	(175)	1,251
Income tax expense (benefit)	613	(43)	29	599
Income before discontinued operations	920	(64)	(204)	652
Discontinued operations	-	-	18	18
Net Income (Loss)	$ 920	$ (64)	$ (186)	$ 670

Change Between First Nine Months of 2006 and First Nine Months of 2005	Regulated	Power Supply Management	Other and Reconciling	FirstEnergy

Financial Results - Increase (Decrease)	Services	Services	Adjustments	Consolidated
		(In millions)		
Revenues:				
External				
Electric	$ (537)	$ 684	$ -	$ 147
Other	31	63	(307)	(213)
Internal	(238)	-	238	-
Total Revenues	(744)	747	(69)	(66)
Expenses:				
Fuel and purchased power	-	191	-	191
Other operating expenses	(42)	(235)	(27)	(304)
Provision for depreciation	(119)	120	-	1
Amortization of regulatory assets	(333)	15	-	(318)
Deferral of new regulatory assets	89	(163)	-	(74)
General taxes	(14)	26	-	12
Total Expenses	(419)	(46)	(27)	(492)
Operating Income	(325)	793	(42)	426
Other Income (Expense):				
Investment income	33	36	(120)	(51)
Interest expense	(8)	(140)	108	(40)
Capitalized interest	(1)	9	1	9
Subsidiaries' preferred stock dividends	3	-	4	7
Total Other Income (Expense)	27	(95)	(7)	(75)
Income before income taxes and discontinued operations	(298)	698	(49)	351
Income taxes	(114)	279	(141)	24
Income before discontinued operations	(184)	419	92	327
Discontinued operations	-	-	(18)	(18)
Net Income	$ (184)	$ 419	$ 74	$ 309

Regulated Services - First Nine Months of 2006 Compared to First Nine Months of 2005

Net income decreased $184 million (20.0%) to $736 million in the first nine months of 2006 compared to $920 million in the first nine months of 2005, primarily due to decreased operating revenues partially offset by lower operating expenses.

Revenues -

The decrease in total revenues by service type is summarized below:

Revenues By Type of Service	Nine Months Ended September 30, 2006	2005	Increase (Decrease)
		(In millions)	
Distribution services	$ 2,972	$ 3,509	$ (537)
Transmission services	290	314	(24)
Internal lease revenues	-	238	(238)
Other	155	100	55
Total Revenues	$ 3,417	$ 4,161	$ (744)

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

Electric Distribution Deliveries	
Residential	(4.1)%
Commercial	(1.4)%
Industrial	(1.0)%
Total Distribution Deliveries	(2.2)%

The completion of the Ohio Companies' generation transition cost recovery under their respective transition plans and Penn's transition plan in 2005 were the primary reasons for lower distribution unit prices, which, in conjunction with lower KWH deliveries, resulted in lower distribution delivery revenues. The decreases in deliveries to customers were primarily due to milder weather during the first nine months of 2006 as compared to the same period in 2005. The following table summarizes major factors contributing to the $537 million decrease in distribution service revenues in the first nine months of 2006:

Sources of Change in Distribution Revenues	Increase (Decrease)
	(In millions)

Changes in customer usage	$	(173)
Ohio shopping incentives		178
Reduced Ohio transition rates		(614)
Other		72
Net Decrease in Distribution Revenues	$	(537)

The decrease in internal lease revenues reflected the effect of the generation asset transfers discussed above. The 2005 generation assets lease revenue from affiliates ceased as a result of the transfers. The increase in other revenues is due to higher payments received during the first quarter of 2006 under a contract provision associated with the prior sale of TMI, a 2006 uranium enrichment settlement and increased income on life insurance investments.

Expenses-

The decrease in revenues discussed above was partially offset by the following decreases in total expenses:

- Other operating expenses were $42 million lower in 2006 due, in part, to the following factors:

- The absence in 2006 of expenses for ancillary service refunds to third parties of $22 million in 2005 due to the RCP, which provides that alternate suppliers of ancillary services now bill customers directly for those services;

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- A $43 million decrease in employee and contractor costs resulting from lower storm-related expenses, reduced employee benefits and the decreased use of outside contractors for tree trimming, reliability work, legal services and jobbing and contracting; and

- A $22 million increase in other expenses due, in part, to the absence in 2006 of a $6 million insurance premium credit and a $3.4 million insurance settlement received in 2005.

· Lower depreciation expense of $119 million resulted from the generation asset transfers;

· Reduced amortization of regulatory assets of $333 million resulted principally from the completion of Ohio generation transition cost recovery and Penn's transition plan in 2005; and

· General taxes decreased by $14 million primarily due to lower property taxes as a result of the generation asset transfers.

The reduction in the deferral of new regulatory assets resulted from last year’s JCP&L rate decision and the end of shopping incentive deferrals under the Ohio Companies’ transition plan, partially offset by the distribution cost deferrals under the Ohio Companies’ RCP.

Other Income and Expense -

· Higher investment income reflects the impact of the generation asset transfers. Interest income on the affiliated company notes receivable from the power supply management services segment in the first nine months of 2006 is partially offset by the absence of nuclear decommissioning trust investments, the majority of which is now included in the power supply management services segment; and

· Interest expense increased by $8 million due to the June 2006 issuance of $600 million of OE long-term debt, which reflects FirstEnergy’s financing strategy as discussed in the third quarter results analysis. Subsidiaries' preferred stock dividends decreased by $3 million in 2006 due to redemption activity since the third quarter of 2005.

Power Supply Management Services - First Nine Months of 2006 Compared to First Nine Months of 2005

Net income for this segment was $355 million in the first nine months of 2006 compared to a net loss of $64 million in the same period last year. An improvement in the gross generation margin and increased transmission and fuel costs deferrals was partially offset by higher depreciation, general taxes and interest expense resulting from the generation asset transfers.

Revenues -

Electric generation sales revenues increased $608 million in the first nine months of 2006 compared to the same period in 2005. This increase primarily resulted from a 7.4% increase in retail KWH sales, mostly due to the return of customers as a result of third-party suppliers leaving the northern Ohio marketplace and higher unit prices resulting from the 2006 rate stabilization and fuel recovery charges. The higher retail sales reduced energy available for sale to the wholesale market. Increased transmission revenues reflected new revenues of approximately $88 million under the MISO transmission rider that began in the first quarter of 2006. These increases were partially offset by a reduction in wholesale sales revenue as a result of both lower KWH sales and lower unit prices.

The increase in reported segment revenues resulted from the following sources:

Revenues By Type of Service	Nine Months Ended September 30, 2006	2005	Increase (Decrease)
	(In millions)		
Electric Generation Sales:			
Retail	$ 4,164	$ 3,223	$ 941
Wholesale	717	1,050	(333)
Total Electric Generation Sales	4,881	4,273	608
Transmission	444	292	152
Other	39	52	(13)
Total Revenues	$ 5,364	$ 4,617	$ 747

The following table summarizes the price and volume factors contributing to changes in sales revenues from retail and wholesale customers:

Source of Change in Electric Generation Sales		Increase (Decrease)
		(In millions)
Retail:		
Effect of 7.4% increase in customer usage	$	238
Change in prices		703
		941
Wholesale:		
Effect of 19.6% decrease in KWH sales		(205)
Change in prices		(128)
		(333)
Net Increase in Electric Generation Sales	$	608

Expenses -

Total operating expenses decreased by $46 million. The decrease was due to the following factors:

· Lower non-fuel operating expenses of $235 million, which reflect the absence in 2006 of generating asset lease rents of $238 million charged in 2005 due to the generation asset transfers and the emission allowance sales credits discussed above in the third quarter results analysis. Also absent in 2006 were the 2005 accrual of an $8.5 million civil penalty payable to the DOJ and $10 million for obligations to fund environmentally beneficial projects in connection with the Sammis Plant New Source Review settlement, and a $3.5 million penalty related to the Davis-Besse outage. These decreases were partially offset by increases in nuclear operating expenses of $9 million as discussed in the third quarter results analysis above and transmission expenses of $19 million; and

· An increase of $163 million in the deferral of new regulatory assets, which consisted of PJM/MISO costs incurred that are expected to be recovered from customers through future rates and the Ohio RCP fuel deferral and related interest of $94 million.

The above decreases in expenses were partially offset by:

- Higher fuel and purchased power costs of $191 million, including increased fuel costs of $80 million. In particular, coal costs increased $107 million as a result of increased generation output, higher coal commodity prices and increased transportation costs for western coal. The increased coal costs were partially offset by lower natural gas and emission allowance costs of $36 million. Purchased power costs increased $111 million due to higher prices partially offset by lower volumes. 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	$ 46
Change due to volume consumed	34
	80
Purchased Power:	
Change due to increased unit costs	197
Change due to volume purchased	(62)
PPUC NUG adjustment applicable to prior year	10
Increase in NUG costs deferred	(34)
	111
Net Increase in Fuel and Purchased Power Costs	$ 191

- Increased depreciation expenses of $120 million, resulting principally from the generation asset transfers; and

- Higher general taxes of $26 million due to additional property taxes resulting from the generation asset transfers.

Other Income and Expense -

- Investment income in the first nine months of 2006 was $36 million higher primarily due to nuclear decommissioning trust investments acquired through the generation asset transfers; and

- Interest expense increased by $140 million, primarily due to interest on the associated company notes payable that financed the generation asset transfers. This increase was partially offset by an additional $9 million of capitalized interest.

Other - First Nine Months of 2006 Compared to First Nine Months of 2005

FirstEnergy's financial results from other operating segments and reconciling items, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a $74 million increase to FirstEnergy's net income in the first nine months of 2006 compared to the same period of 2005. The increase was primarily due to the absence of last year's write-off of income tax benefits of $71 million due to the 2005 change in Ohio tax legislation, the 2006 income taxes benefits described in the Other - Third Quarter 2006 compared to Third Quarter 2005 results analysis above, a $3 million gain related to interest rate swap financing arrangements and a $6 million increase in insurance investment income in the first nine months of 2006. These increases were partially offset by the 2006 non-core assets sale and impairment charges of $10 million and the absence of the after-tax gains of $17 million from discontinued operations in 2005 (see Note 4). The following table summarizes the sources of income from discontinued operations (in millions) for the nine months ended September 30, 2005:

Discontinued Operations (Net of tax)	
Gain on sale:	
Natural gas business	$ 5
Elliot-Lewis, Spectrum and Power Piping	12
Reclassification of operating income	1
Total	$ 18

CAPITAL RESOURCES AND LIQUIDITY

FirstEnergy expects to meet its future contractual obligations primarily 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

FirstEnergy's primary source of cash required for continuing operations as a holding company is cash from the operations of its subsidiaries. FirstEnergy also has access to $2.75 billion of short-term financing under a revolving credit facility which expires in 2011, subject to short-term debt limitations under current regulatory approvals of

$1.5 billion and to outstanding borrowings by subsidiaries of FirstEnergy that are also parties to the facility.

In July 2006, FirstEnergy redeemed $400 million of its outstanding senior notes that were due to mature in November 2006 using cash proceeds from OE's repurchase of $500 million of common stock.

In August 2006, FirstEnergy repurchased 10.6 million shares, or approximately 3.2%, of its outstanding common stock at an initial purchase price of $600 million, pursuant to an accelerated share repurchase program. The repurchase was funded with borrowings from FirstEnergy's revolving credit facility.

As of September 30, 2006, FirstEnergy had $41 million of cash and cash equivalents compared with $64 million as of December 31, 2005. The major sources of changes in cash and cash equivalent balances are summarized below.

Cash Flows From Operating Activities

FirstEnergy's consolidated net cash from operating activities is provided primarily by its regulated services and power supply management services businesses (see Results of Operations above). Net cash provided from operating activities was $1.2 billion and $1.9 billion in the first nine months of 2006 and 2005, respectively, and is summarized as follows:

Operating Cash Flows	**Nine Months Ended September 30, 2006**	**2005**
	(In millions)	
Cash earnings *	$ 1,472	$ 1,572
Working capital and other	(229)	344
Net cash provided from operating activities	$ 1,243	$ 1,916

* Cash earnings are a Non-GAAP measure (see reconciliation below).

Cash earnings (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. Generally, a Non-GAAP financial measure is a numerical measure of a company's historical or future financial performance, financial position, or cash flows that either excludes or includes amounts, or is subject to adjustment that has the effect of excluding or including amounts, that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with GAAP. Earnings before unusual items on a Non-GAAP basis (normalized earnings) are not calculated in accordance with GAAP because they exclude the impact of "unusual items." Unusual items reflect the impact on earnings of material events that are not routine, including those that may be related to discontinued businesses or the cumulative effect of an accounting change. Management believes presenting normalized earnings calculated in this manner provides useful information to investors in evaluating the ongoing results of FirstEnergy's businesses and assists investors in comparing the company's operating performance to the operating performance of other companies in the energy sector. In addition, cash earnings (Non-GAAP) are not defined under GAAP. Management believes presenting this Non-GAAP measure provides useful information to investors in assessing FirstEnergy's operating performance from a cash perspective without the effects of material unusual economic events. FirstEnergy's management frequently references these Non-GAAP financial measures in its decision-making, using them to facilitate historical and ongoing performance comparisons as well as comparisons to the performance of peer companies. These Non-GAAP measures should be considered in addition to, and not as a substitute for, their most directly comparable financial measures prepared in accordance with GAAP.

Reconciliation of Cash Earnings	Nine Months Ended September 30, 2006	2005
	(In millions)	
Net income (GAAP)	$ 979	$ 670
Non-cash charges (credits):		
Provision for depreciation	445	444
Amortization of regulatory assets	665	983
Deferral of new regulatory assets	(379)	(305)
Nuclear fuel and lease amortization	67	63
Deferred purchased power and other costs	(323)	(258)
Deferred income taxes and investment tax credits	36	24
Deferred rents and lease market valuation liability	(54)	(71)
Accrued compensation and retirement benefits	78	72
Gain on asset sales	(38)	-
Income from discontinued operations	-	(18)
Other non-cash expenses	(4)	(32)
Cash earnings (Non-GAAP)	$ 1,472	$ 1,572

Net cash provided from operating activities decreased by $673 million in the first nine months of 2006 compared to the first nine months of 2005 primarily due to a $573 million decrease from working capital and a $100 million decrease in cash earnings described under "Results of Operations." The decrease from working capital changes primarily resulted from $242 million of funds received in 2005 for prepaid electric service (under a three-year Energy for Education Program with the Ohio Schools Council), increased outflows of $153 million for payables primarily caused by higher fuel and purchased power costs, increased tax payments of $242 million, and $147 million of cash collateral returned to suppliers. These decreases were partially offset by an increase in cash provided from the collection of receivables of $219 million, reflecting increased electric sales revenues.

Cash Flows From Financing Activities

In the nine months ended September 30, 2006, cash used for financing activities was $444 million compared to $1.0 billion in the same period of 2005. The following table summarizes security issuances and redemptions.

	Nine Months Ended September 30,	
Securities Issued or Redeemed	**2006**	**2005**
	(In millions)	
New issues		
Pollution control notes	$ 253	$ 334
Secured notes	382	-
Unsecured notes	600	-
	$ 1,235	$ 334
Redemptions		
First mortgage bonds	$ -	$ 178
Pollution control notes	311	377
Secured notes	182	74
Unsecured notes	500	8
Long-term revolving credit	-	215
Common stock	600	-
Preferred stock	107	170
	$ 1,700	$ 1,022
	$ 482	$ 77

Short-term borrowings, net

FirstEnergy had approximately $1.2 billion of short-term indebtedness as of September 30, 2006 compared to approximately $731 million as of December 31, 2005. This increase primarily reflects FirstEnergy’s use of short-term debt to fund its $600 million common share repurchase in August 2006. Available bank borrowing capability (in millions) as of September 30, 2006 included the following:

Borrowing Capability	
Short-term credit facilities[1]	$ 2,870
Accounts receivable financing facilities	550
Utilized	(1,207)
LOCs	(85)
Net	$ 2,128

[1] A $2.75 billion revolving credit facility that expires in 2011 is available in various amounts to FirstEnergy and certain of its subsidiaries, as described further below. A $100 million revolving credit facility that expires in December 2006 and a $20 million uncommitted line of credit facility are both available to FirstEnergy only.

As of September 30, 2006, the Ohio Companies and Penn had the aggregate capability to issue approximately $1.5 billion of additional FMB on the basis of property additions and retired bonds under the terms of their respective mortgage indentures. 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 $655 million and $579 million, respectively, as of September 30, 2006. Under the provisions of its senior note indenture, JCP&L may issue additional FMB only as collateral for senior notes. As of September 30, 2006, JCP&L had the capability to issue $626 million of additional senior notes upon the basis of FMB collateral.

Based upon applicable earnings coverage tests in their respective charters, Penn, TE and JCP&L could issue a total of $2.5 billion of preferred stock (assuming no additional debt was issued) as of September 30, 2006. CEI, Met-Ed and Penelec do not have similar restrictions and could issue up to the number of preferred shares authorized under their respective charters. As a result of OE redeeming all of its outstanding preferred stock in July 2006, the applicable earnings coverage test in its charter is inoperative. In the event that OE issues preferred stock in the future, the applicable earnings coverage test will govern the amount of preferred stock that OE may issue.

As of September 30, 2006, approximately $1.0 billion of capacity remained unused under an existing shelf registration statement, filed by FirstEnergy with the SEC in 2003, to support future securities issuances. 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. As of September 30, 2006, OE had approximately $400 million of capacity remaining unused under its existing shelf registration for unsecured debt securities. Shelf registration statements for unsecured debt securities for CEI of $550 million and TE of $300 million were declared effective by the SEC on October 31, 2006 and remain unused.

On August 24, 2006, FirstEnergy and certain of its subsidiaries entered into a new $2.75 billion five-year revolving credit facility (included in the borrowing capability table above), which replaced FirstEnergy's prior $2 billion credit facility. FirstEnergy may request an increase in the total commitments available under the new facility up to a maximum of $3.25 billion. Commitments under the new facility are available until August 24, 2011, unless the lenders agree, at the request of the Borrowers, to two additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each Borrower are subject to a specified sub-limit, as well as applicable regulatory and other limitations.

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	$ 2,750	$ 1,500
OE	500	500
Penn	50	44
CEI	250(3)	600
TE	250(3)	500
JCP&L	425	429
Met-Ed	250	250(2)
Penelec	250	250(2)
FES	-(4)	n/a
ATSI	-(4)	50

(1) As of September 30, 2006.

(2) Excluding amounts which may be borrowed under the regulated money pool.

(3) Borrowing sub-limits for CEI and TE may be increased to up to $500 million by delivering notice to the administrative agent that such borrower has senior unsecured debt ratings of at least BBB by S&P and Baa2 by Moody's.

(4) Borrowing sub-limits 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 ($390 million unused as of September 30, 2006) of accounts receivable financing facilities for OE, CEI, TE, Met-Ed, Penelec and Penn, are intended to provide liquidity to meet working capital and other general corporate requirements for FirstEnergy and its subsidiaries.

Under the revolving credit facility, borrowers may request the issuance of LOCs expiring up to one year from the date of issuance. The stated amount of outstanding LOCs 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 was $2.1 billion as of September 30, 2006.

The revolving credit facility contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%, measured at the end of each fiscal quarter. As of September 30, 2006, FirstEnergy and its subsidiaries' debt to total capitalization ratios (as defined under the revolving credit facility) were as follows:

Borrower	
FirstEnergy	55%
OE	46%
Penn	33%
CEI	49%
TE	30%
JCP&L	23%
Met-Ed	38%
Penelec	35%

The revolving credit facility does not contain 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 first nine months of 2006 was approximately 5.09% for both the regulated companies’ money pool and the unregulated companies' money pool.

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 the Companies' securities ratings as of October 31, 2006. The ratings outlook from S&P on all securities is stable. The ratings outlook from Moody's and Fitch on all securities is positive.

Issuer	Securities	S&P	Moody’s	Fitch
FirstEnergy	Senior unsecured	BBB-	Baa3	BBB-
OE	Senior unsecured	BBB-	Baa2	BBB
CEI	Senior secured	BBB	Baa2	BBB-
	Senior unsecured	BBB-	Baa3	BB+
TE	Senior secured	BBB	Baa2	BBB-
		BB+	Ba2	BB

	Preferred stock			
Penn	Senior secured	BBB+	Baa1	BBB+
	Senior unsecured [(1)]	BBB-	Baa2	BBB
	Preferred stock	BB+	Ba1	BBB-
JCP&L	Senior secured	BBB+	Baa1	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 January 20, 2006, TE redeemed all 1.2 million of its outstanding shares of Adjustable Rate Series B preferred stock at $25.00 per share, plus accrued dividends to the date of redemption.

On April 3, 2006, $106.5 million of pollution control revenue refunding bonds were issued on behalf of NGC ($60 million at 3.07% and $46.5 million at 3.25%). The proceeds from the bonds were used to redeem the following Companies' pollution control notes: OE - $60 million at 7.05%, CEI - $27.7 million at 3.32%, TE - $18.8 million at 3.32%. Also, on April 3, 2006, $146.7 million of pollution control revenue refunding bonds were issued on behalf of FGCO ($90.1 million at 3.03% and $56.6 million at 3.10%) which were used to redeem, in April and May 2006, the following Companies' pollution control notes: OE - $14.8 million at 5.45%, Penn - $6.95 million at 5.45%, TE - $34.85 million at 3.18%, CEI - $47.5 million at 3.22%, $39.8 million at 3.20% and $2.8 million at 3.15%. These refinancings were undertaken in connection with FirstEnergy's intra-system generation asset transfers discussed above. The proceeds from NGC's and FGCO's refinancing issuances were used to repay a portion of their associated company notes payable to OE, Penn, CEI and TE, who then redeemed their respective pollution control notes.

On May 12, 2006, JCP&L issued $200 million of 6.40% secured senior notes due 2036. The proceeds of the offering were used to repay at maturity $150 million aggregate principal amount of JCP&L’s 6.45% senior notes due May 15, 2006 and for general corporate purposes.

On June 26, 2006, OE issued $600 million of unsecured senior notes, comprised of $250 million of 6.4% notes due 2016 and $350 million of 6.875% notes due 2036. The majority of the proceeds from this offering were used in July 2006 to repurchase $500 million of OE common stock from FirstEnergy, enabling FirstEnergy to accelerate repayment of $400 million of senior notes that were due to mature in November 2006. The remainder of the proceeds were used to redeem approximately $61 million of OE’s preferred stock on July 7, 2006 and to reduce short-term borrowings.

On August 10, 2006, JCP&L Transition Funding II, a wholly owned subsidiary of JCP&L, issued $182 million of transition bonds with a weighted average interest rate of 5.5% to securitize the recovery of deferred costs associated with JCP&L’s supply of BGS.

On August 10, 2006, FirstEnergy repurchased 10.6 million shares, approximately 3.2%, of its outstanding common stock through an accelerated share repurchase program. The initial purchase price was $600 million, or $56.44 per share. The final purchase price will be adjusted to reflect the ultimate cost to acquire the shares over a period of up to seven months. The share repurchase was completed under a program authorized by the Board of Directors on June 20, 2006 to repurchase up to 12 million shares of common stock. At management’s discretion, additional shares may be acquired under the program on the open market or through privately negotiated transactions, subject to market conditions and other factors. The Board’s authorization of the repurchase program does not require FirstEnergy to make any further purchases of shares and the program may be terminated at any time.

FirstEnergy continues to pursue its strategy of replacing holding company debt with debt at its utility operating subsidiaries in order to obtain additional financing flexibility at the holding company level and capitalize its regulated utilities in a way that positions them appropriately in a regulatory context.

Cash Flows From Investing Activities

Net cash flows used in investing activities resulted principally from property additions. Regulated services expenditures for property additions primarily include expenditures supporting the transmission and distribution of electricity. Capital expenditures by the power supply management services segment are principally generation-related. The following table summarizes investments for the nine months ended September 30, 2006 and 2005 by segment:

Summary of Cash Flows Used for Investing Activities	**Property Additions**	**Investments**	**Other**	**Total**

Sources (Uses)		*(In millions)*		
Nine Months Ended September 30, 2006				
Regulated services	$ (492)	$ 142	$ (8)	$ (358)
Power supply management services	(473)	(7)	(1)	(481)
Other	(1)	(2)	-	(3)
Reconciling items	(24)	24	20	20
Total	$ (990)	$ 157	$ 11	$ (822)
Nine Months Ended September 30, 2005				
Regulated services	$ (506)	$ (14)	$ (7)	$ (527)
Power supply management services	(226)	15	-	(211)
Other	(6)	3	(17)	(20)
Reconciling items	(18)	(9)	5	(22)
Total	$ (756)	$ (5)	$ (19)	$ (780)

Net cash used for investing activities in the first nine months of 2006 increased by $42 million compared to the first nine months of 2005. The increase was principally due to a $234 million increase in property additions which reflects the replacement of the steam generators and reactor head at Beaver Valley Unit 1, air quality control system expenditures and the distribution system Accelerated Reliability Improvement Program. The increase in property additions was partially offset by a $65 million decrease in net nuclear decommissioning trust activities due to the completion of the Ohio Companies' and Penn's transition cost recovery for decommissioning at the end of 2005 and $88 million from cash investments, primarily from the expiration of restrictions on an escrow fund and mortgage indenture deposit.

During the last quarter of 2006, capital requirements for property additions and capital leases are expected to be approximately $324 million. FirstEnergy and the Companies have additional requirements of approximately $648 million for maturing long-term debt during the remainder of 2006. These cash requirements are expected to be satisfied from a combination of internal cash, funds raised in the long-term debt capital markets and short-term credit arrangements.

FirstEnergy's capital spending for the period 2006-2010 is expected to be approximately $6.8 billion (excluding nuclear fuel), of which $1.2 billion applies to 2006. Investments for additional nuclear fuel during the 2006-2010 periods are estimated to be approximately $885 million, of which approximately $166 million applies to 2006. During the same period, FirstEnergy's nuclear fuel investments are expected to be reduced by approximately $598 million and $91 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. These agreements include contract guarantees, surety bonds, and LOCs. Some of the guaranteed contracts contain collateral provisions that are contingent upon FirstEnergy's credit ratings.

As of September 30, 2006, FirstEnergy's maximum exposure to potential future payments under outstanding guarantees and other assurances totaled approximately $3.6 billion, as summarized below:

Guarantees and Other Assurances	**Maximum Exposure** *(In millions)*
FirstEnergy Guarantees of Subsidiaries:	
Energy and Energy-Related Contracts(1)	$ 887
Other(2)	1,094
	1,981
Surety Bonds	147
LOC(3)(4)	1,434
	$ 3,562

Total Guarantees and Other Assurances

(1) Issued for open-ended terms, with a 10-day termination right by FirstEnergy.

(2) Issued for various terms.

(3) Includes $85 million issued for various terms under LOC capacity available under FirstEnergy's revolving credit agreement and $730 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 the Perry Nuclear Power Plant by OE.

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy commodity activities principally to facilitate normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of credit support for subsidiary financings or refinancings of costs related to the acquisition of, or improvements to, property, plant and equipment. These agreements legally obligate FirstEnergy to fulfill the obligations of its subsidiaries directly involved in these energy and energy-related transactions or financings where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, 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 and energy-related contracts is remote.

While these types of guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating downgrade or “material adverse event” the immediate posting of cash collateral or provision of an LOC may be required of the subsidiary. As of September 30, 2006, FirstEnergy's maximum exposure under these collateral provisions was $487 million.

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 also provided an LOC ($36 million as of September 30, 2006) which is renewable and declines yearly based upon the senior outstanding debt of TEBSA. The LOC was reduced to $27 million on October 15, 2006.

OFF-BALANCE SHEET ARRANGEMENTS

FirstEnergy has obligations that are not included on its Consolidated Balance Sheets related to the sale and leaseback arrangements involving Perry, 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, 2006.

FirstEnergy has equity ownership interests in certain businesses that are accounted for using 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 Guarantees and Other Assurances 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 oversight to risk management activities throughout FirstEnergy and its subsidiaries.

Commodity Price Risk

FirstEnergy is exposed to financial and market risks resulting from the fluctuation of interest rates and commodity prices primarily due to fluctuations in electricity, energy transmission, natural gas, coal, nuclear fuel and emission allowance prices. To manage the volatility relating to these exposures, FirstEnergy uses a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes. Derivatives that fall within the scope of SFAS 133 must be recorded at their fair value and marked to market. The majority of FirstEnergy's derivative hedging contracts qualify for the normal purchase and normal sale exception under SFAS 133 and are therefore excluded from the table below. Contracts that are not exempt from such treatment include the power purchase agreements with NUG entities that were structured pursuant to the Public Utility Regulatory Policies Act of 1978. These non-trading contracts had been adjusted to fair value at the end of each quarter, with a corresponding regulatory asset recognized for above-market costs. On April 1, 2006, FirstEnergy elected to apply the normal purchase and normal sale exception to certain NUG power purchase agreements having a fair value of $13 million (included in “Other” in the table below) in accordance with guidance in DIG C20. The change in the fair value of commodity derivative contracts related to energy production during the three months and nine months ended September 30, 2006 is summarized in the following table:

Increase (Decrease) in the Fair Value of Commodity Derivative Contracts	**Three Months Ended September 30, 2006**			**Nine Months Ended September 30, 2006**		
	Non-Hedge	**Hedge**	**Total**	**Non-Hedge**	**Hedge**	**Total**
			(In millions)			
Change in the Fair Value of Commodity Derivative Contracts:						
Outstanding net liability at beginning of period	$ (1,081)	$ (4)	$ (1,085)	$ (1,170)	$ (3)	$ (1,173)
New contract value when entered	-	-	-	-	-	-
Additions/change in value of existing contracts	(164)	(6)	(170)	(195)	(16)	(211)
Change in techniques/assumptions	-	-	-	-	-	-
Settled contracts	85	1	86	218	10	228
Other	-	-	-	(13)	-	(13)
Outstanding net liability at end of period [1]	(1,160)	(9)	(1,169)	(1,160)	(9)	(1,169)
Non-commodity Net Liabilities at End of Period:						
Interest rate swaps [2]	-	(32)	(32)	-	(32)	(32)
Net Liabilities - Derivative Contracts at End of Period	$ (1,160)	$ (41)	$ (1,201)	$ (1,160)	$ (41)	$ (1,201)
Impact of Changes in Commodity Derivative Contracts[3]						
Income Statement effects (pre-tax)	$ 3	$ -	$ 3	$ -	$ -	$ -
Balance Sheet effects:						
Other comprehensive income (pre-tax)	$ -	$ (5)	$ (5)	$ -	$ (6)	$ (6)
Regulatory assets (net)	$ 82	$ -	$ 82	$ (23)	$ -	$ (23)

[1] Includes $1,160 million in non-hedge commodity derivative contracts (primarily with NUGs), which are offset by a regulatory asset.
[2] Interest rate swaps are treated as cash flow or fair value hedges (see Interest Rate Swap Agreements below).
[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, 2006 as follows:

	Non-Hedge	**Hedge**	**Total**

Balance Sheet Classification			
		(In millions)	
Current-			
Other assets	$ -	$ 10	$ 10
Other liabilities	(1)	(20)	(21)
Non-Current-			
Other deferred charges	46	4	50
Other noncurrent liabilities	(1,205)	(35)	(1,240)
Net liabilities	$ (1,160)	$ (41)	$ (1,201)

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, FirstEnergy relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FirstEnergy uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making. Sources of information for the valuation of commodity derivative contracts as of September 30, 2006 are summarized by year in the following table:

Source of Information - Fair Value by Contract Year	2006[1]	2007	2008	2009	2010	Thereafter	Total
				(In millions)			
Prices actively quoted[2]	$ -	$ (2)	$ -	$ -	$ -	$ -	$ (2)
Other external sources[3]	(57)	(270)	(241)	(191)	-	-	(759)
Prices based on models	-	-	-	-	(175)	(233)	(408)
Total[4]	$ (57)	$ (272)	$ (241)	$ (191)	$ (175)	$ (233)	$ (1,169)

(1) For the last quarter of 2006.
(2) Exchange traded.
(3) Broker quote sheets.
(4) Includes $1,160 million in non-hedge commodity derivative contracts (primarily with NUGs), which are offset by a regulatory asset.

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 its 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, 2006. Based on derivative contracts held as of September 30, 2006, an adverse 10% change in commodity prices would decrease net income by approximately $1 million during the next 12 months.

Interest Rate Swap Agreements - Fair Value Hedges

FirstEnergy utilizes fixed-for-floating interest rate swap agreements as part of its ongoing effort to manage the interest rate risk associated with its debt portfolio. These derivatives are treated as fair value hedges of fixed-rate, long-term debt issues - designed to protect against the risk of changes in the fair value of fixed-rate debt instruments when interest rates decrease. Swap maturities, call options, fixed interest rates and interest payment dates match those of the underlying obligations. During the first nine months of 2006, FirstEnergy unwound swaps with a total notional amount of $350 million, for which FirstEnergy paid $1 million in cash. The loss will be recognized over the remaining term of each respective hedged security as increased interest expense. As of September 30, 2006, the debt underlying the $750 million outstanding notional amount of interest rate swaps had a weighted average fixed interest rate of 5.74%, which the swaps have converted to a current weighted average variable rate of 6.46%.

	September 30, 2006			December 31, 2005		
Interest Rate Swaps	**Notional Amount**	**Maturity Date**	**Fair Value**	**Notional Amount**	**Maturity Date**	**Fair Value**
			(In millions)			
(Fair value hedges)	$ 100	2008	$ (2)	$ 100	2008	$ (3)
	50	2010	(1)	50	2010	-
	-	2011	-	50	2011	-
	300	2013	(7)	450	2013	(4)
	150	2015	(10)	150	2015	(9)
	-	2016	-	150	2016	-
	50	2025	(2)	50	2025	(1)
	100	2031	(7)	100	2031	(5)
	$ 750		$ (29)	$ 1,100		$ (22)

Forward Starting Swap Agreements - Cash Flow Hedges

FirstEnergy utilizes forward starting swap agreements (forward swaps) in order to hedge a portion of the consolidated interest rate risk associated with the anticipated future issuances of fixed-rate, long-term debt securities for one or more of its consolidated subsidiaries in 2006 through 2008. 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. During the first nine months of 2006, FirstEnergy revised the tenor and timing of its financing plans. During the second quarter, FirstEnergy terminated forward swaps with an aggregate notional value of $600 million concurrent with its subsidiaries issuing long-term debt. FirstEnergy received $41 million in cash related to the termination. The gain associated with the ineffective portion of the terminated hedges ($6 million) was recognized in earnings, with the remainder to be recognized over the terms of the associated future debt. During the third quarter, FirstEnergy revised its financing plan related to swaps with $100 million notional value. FirstEnergy terminated and revised the forward swaps and performed an ineffectiveness assessment. FirstEnergy received cash of $2 million, all of which was effective and will be recognized in earnings over the terms of the associated future debt. As of September 30, 2006, FirstEnergy had outstanding forward swaps with an aggregate notional amount of $725 million and an aggregate fair value of ($2) million.

	September 30, 2006			December 31, 2005		
Forward Starting Swaps	**Notional Amount**	**Maturity Date**	**Fair Value**	**Notional Amount**	**Maturity Date**	**Fair Value**
			(In millions)			
(Cash flow hedges)	$ 25	2015	$ -	$ 25	2015	$ -
	300	2016	(1)	600	2016	2
	200	2017	(3)	25	2017	-
	150	2018	1	275	2018	1
	50	2020	1	50	2020	-
	$ 725		$ (2)	$ 975		$ 3

Equity Price Risk

Included in nuclear decommissioning trusts are marketable equity securities carried at their market value of approximately $1.2 billion as of September 30, 2006 and $1.1 billion as of December 31, 2005. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $117 million reduction in fair value as of September 30, 2006.

CREDIT RISK

Credit risk is the risk of an obligor’s failure to meet the terms of an 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, 2006, the largest credit concentration with one party (currently rated investment grade) represented 9.9% of FirstEnergy's total credit risk. Within FirstEnergy's unregulated energy subsidiaries, 99% of credit exposures, net of collateral and reserves, were with investment-grade counterparties as of September 30, 2006.

OUTLOOK

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 Companies and ATSI 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. Regulatory assets that do not earn a current return totaled approximately $225 million as of September 30, 2006. The following table discloses the regulatory assets by company and by source:

Regulatory Assets*	September 30, 2006	December 31, 2005	Increase (Decrease)
		(In millions)	
OE	$ 746	$ 775	$ (29)
CEI	855	862	(7)
TE	256	287	(31)
JCP&L	2,178	2,227	(49)
Met-Ed	365	310	55
ATSI	34	25	9
Total	$ 4,434	$ 4,486	$ (52)

· Penn had net regulatory liabilities of approximately $64 million as of September 30, 2006 and $59 million as of December 31, 2005. Penelec had net regulatory liabilities of approximately $127 million and $163 million as of September 30, 2006 and December 31, 2005, respectively. These net regulatory liabilities are included in Other Non-current Liabilities on the Consolidated Balance Sheets.

Regulatory assets by source are as follows:

Regulatory Assets By Source	September 30, 2006	December 31, 2005	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 3,339	$ 3,576	$ (237)
Customer shopping incentives	621	884	(263)
Customer receivables for future income taxes	214	217	(3)
Societal benefits charge	1	29	(28)
Loss on reacquired debt	40	41	(1)
Employee postretirement benefits costs	49	55	(6)
Nuclear decommissioning, decontamination and spent fuel disposal costs	(135)	(126)	(9)
Asset removal costs	(168)	(365)	197
Property losses and unrecovered plant costs	21	29	(8)
	177	91	86

MISO/PJM transmission costs						
Fuel costs - RCP		94		-		94
Distribution costs - RCP		121		-		121
JCP&L reliability costs		16		23		(7)
Other		44		32		12
Total	$	4,434	$	4,486	$	(52)

Reliability Initiatives

FirstEnergy is proceeding with the implementation of the recommendations that were issued from various entities, including governmental, industry and ad hoc reliability entities (PUCO, FERC, NERC and the U.S. - Canada Power System Outage Task Force) in late 2003 and early 2004, regarding enhancements to regional reliability that were to be completed subsequent to 2004. FirstEnergy 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 EPACT that could require additional, material expenditures.

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. In 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 an SRM 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 DRA to discuss reliability improvements. The SRM completed his work and issued his final report to the NJBPU on June 1, 2006. A meeting was held between JCP&L and the NJBPU on June 29, 2006 to discuss the SRM's final report. JCP&L filed a comprehensive response to the NJBPU on July 14, 2006. JCP&L continues to file compliance reports reflecting activities associated with the MOU and Stipulation.

EPACT provides for the creation of an ERO to establish and enforce reliability standards for the bulk power system, subject to FERC's review. On February 3, 2006, the FERC adopted a rule establishing certification requirements for the ERO, as well as regional entities envisioned to assume monitoring responsibility for the new reliability standards. The FERC issued an order on rehearing on March 30, 2006, providing certain clarifications and essentially affirming the rule.

The NERC has been preparing the implementation aspects of reorganizing its structure to meet the FERC's certification requirements for the ERO. The NERC made a filing with the FERC on April 4, 2006 to obtain certification as the ERO and to obtain FERC approval of delegation agreements with regional reliability organizations (regional entities). The new FERC rule referred to above, further provides for reorganizing regional entities that would replace the current regional councils and for rearranging their relationship with the ERO. 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 ERO filing was noticed on April 7, 2006 and comments and reply comments were filed in May, June and July 2006. On July 20, 2006, the FERC certified the NERC as the ERO to implement the provisions of Section 215 of the Federal Power Act and directed the NERC to make a compliance filing within 90 days addressing such issues as the regional delegation agreements. The NERC made its compliance filing in October 2006. This filing is pending before the FERC.

On April 4, 2006, NERC also submitted a filing with the FERC seeking approval of mandatory reliability standards. These reliability standards are based, with some modifications and additions, on the current NERC Version O reliability standards. The reliability standards filing was noticed by the FERC on April 18, 2006. In that notice, the FERC announced its intent to issue a Notice of Proposed Rulemaking on the proposed reliability standards at a future date. On May 11, 2006, the FERC staff released a preliminary assessment that cited many deficiencies in the proposed reliability standards. The NERC and industry participants filed comments in response to the Staff's preliminary assessment. The FERC held a technical conference on the proposed reliability standards on July 6, 2006. The FERC issued a Notice of Proposed Rulemaking on the proposed reliability standards on October 20, 2006. The FERC voted to adopt 83 of the proposed 107 reliability standards. The FERC asked the NERC to make technical improvements to 62 of the 83 standards approved. The 24 standards that were not adopted remain pending at the FERC awaiting further clarification and filings by the NERC and regional entities. The FERC also provided additional clarification on the proposed application of final standards in the NOPR. Interested parties will be given the opportunity to comment on the NOPR within 60 days of its publication in the Federal Register. Mandatory reliability standards are expected to be in place by the summer of 2007. In a separate order issued October 24, 2006, the FERC approved NERC's 2007 budget and business plan subject to certain compliance filings.

The ECAR, Mid-Atlantic Area Council, and Mid-American Interconnected Network reliability councils have completed the consolidation of these regions into a single new regional reliability organization known as ReliabilityFirst Corporation. ReliabilityFirst began operations as a regional reliability council under NERC on

January 1, 2006 and intends to file and obtain certification consistent with the final rule as a "regional entity" under the ERO during 2006. All of FirstEnergy's facilities are located within the ReliabilityFirst region.

On May 2, 2006, the NERC Board of Trustees adopted eight new cyber security standards that replaced interim standards put in place in the wake of the September 11, 2001 terrorist attacks, and thirteen additional reliability standards. The security standards became effective on June 1, 2006, and the remaining standards will become effective throughout 2006 and 2007. NERC intends to file the standards with the FERC and relevant Canadian authorities for approval, but the cyber security standards were not included in the October 20, 2006 NOPR.

FirstEnergy believes that it is in compliance with all current NERC reliability standards. However, based upon a review of the October 20, 2006 NOPR, it appears that the FERC will adopt stricter reliability standards than those contained in the current NERC standards. The financial impact of complying with the new standards cannot be determined at this time. However, EPACT requires that all prudent costs incurred to comply with the new reliability standards be recovered in rates. If FirstEnergy is unable to meet the reliability standards for the bulk power system in the future, it could have a material adverse effect on the Company's and its subsidiaries' financial condition, results of operations and cash flows.

See Note 11 to the consolidated financial statements for a more detailed discussion of reliability initiatives.

Ohio

On October 21, 2003, the Ohio Companies filed their RSP case with the PUCO. 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 CBP. The RSP was intended to establish generation service rates beginning January 1, 2006, in response to the PUCO's 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 the proceeding as well as the associated entries on rehearing. On May 3, 2006, the Supreme Court of Ohio issued an opinion affirming the PUCO's order with respect to the approval of the rate stabilization charge, approval of the shopping credits, the granting of interest on shopping credit incentive deferral amounts, and approval of the Ohio Companies' financial separation plan. It remanded back to the PUCO the matter of ensuring the availability of sufficient means for customer participation in the competitive marketplace. The RSP contained a provision that permitted the Ohio Companies to withdraw and terminate the RSP in the event that the PUCO, or the Supreme Court of Ohio, rejected all or part of the RSP. In such event, the Ohio Companies have 30 days from the final order or decision to provide notice of termination. On July 20, 2006 the Ohio Companies filed with the PUCO a Request to Initiate a Proceeding on Remand. In their Request, the Ohio Companies provided notice of termination to those provisions of the RSP subject to termination, subject to being withdrawn, and also set forth a framework for addressing the Supreme Court of Ohio's findings on customer participation, requesting the PUCO to initiate a proceeding to consider the Ohio Companies' proposal. If the PUCO approves a resolution to the issues raised by the Supreme Court of Ohio that is acceptable to the Ohio Companies, the Ohio Companies' termination will be withdrawn and considered to be null and void. Separately, the OCC and NOAC also submitted to the PUCO on July 20, 2006 a conceptual proposal dealing with the issue raised by the Supreme Court of Ohio. On July 26, 2006, the PUCO issued an Entry acknowledging the July 20, 2006 filings of the Ohio Companies and the OCC and NOAC, and giving the Ohio Companies 45 days to file a plan in a new docket to address the Court's concern. On September 19, 2006, the PUCO issued an Entry granting the Ohio Companies' motion for extension of time to file the remand proposal. The Ohio Companies filed their RSP Remand CBP on September 29, 2006. No further proceedings have been scheduled at this time.

The Ohio Companies filed an application and stipulation with the PUCO on September 9, 2005 seeking approval of the RCP, a supplement to the RSP. On November 4, 2005, the Ohio Companies filed a supplemental stipulation with the PUCO, which constituted an additional component of the RCP filed on September 9, 2005. Major provisions of the RCP include:

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

- Deferring and capitalizing for future recovery (over a 25-year period) with carrying charges 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;

Adjusting 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;

Reducing 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

Recovering increased fuel costs (compared to a 2002 baseline) 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, TE, and CEI may defer and capitalize (for recovery over a 25-year period) increased fuel costs above the amount collected through the fuel recovery mechanism.

The following table provides the estimated net amortization of regulatory transition costs and deferred shopping incentives (including associated carrying charges) under the RCP for the period 2006 through 2010:

Amortization Period	**OE**	**CEI**	**TE**	**Total Ohio**
		(In millions)		
2006	$ 173	$ 96	$ 87	$ 356
2007	180	113	90	383
2008	207	130	112	449
2009	-	211	-	211
2010	-	264	-	264
Total Amortization	**$ 560**	**$ 814**	**$ 289**	**$ 1,663**

On January 4, 2006, the PUCO approved, with modifications, the Ohio Companies' RCP to supplement the RSP to provide customers with more certain rate levels than otherwise available under the RSP during the plan period. On January 10, 2006, the Ohio Companies filed a Motion for Clarification of the PUCO order approving the RCP. The Ohio Companies sought clarity on issues related to distribution deferrals, including requirements of the review process, timing for recognizing certain deferrals and definitions of the types of qualified expenditures. The Ohio Companies also sought confirmation that the list of deferrable distribution expenditures originally included in the revised stipulation fall within the PUCO order definition of qualified expenditures. On January 25, 2006, the PUCO issued an Entry on Rehearing granting in part, and denying in part, the Ohio Companies' previous requests and clarifying issues referred to above. The PUCO granted the Ohio Companies' requests to:

· Recognize fuel and distribution deferrals commencing January 1, 2006;

· Recognize distribution deferrals on a monthly basis prior to review by the PUCO Staff;

· Clarify that the types of distribution expenditures included in the Supplemental Stipulation may be deferred; and

· Clarify that distribution expenditures do not have to be "accelerated" in order to be deferred.

The PUCO approved the Ohio Companies' methodology for determining distribution deferral amounts, but denied the Motion in that the PUCO Staff must verify the level of distribution expenditures contained in current rates, as opposed to simply accepting the amounts contained in the Ohio Companies' Motion. On February 3, 2006, several other parties filed applications for rehearing on the PUCO's January 4, 2006 Order. The Ohio Companies responded to the applications for rehearing on February 13, 2006. In an Entry on Rehearing issued by the PUCO on March 1, 2006, all motions for rehearing were denied. Certain of these parties have subsequently filed notices of appeal with the Supreme Court of Ohio alleging various errors made by the PUCO in its order approving the RCP. The Ohio Companies' Motion to Intervene in the appeals was granted by the Supreme Court on June 8, 2006. The Appellants' Merit Briefs were filed at the Supreme Court on July 5, 2006. The Appellees include the PUCO and the Ohio Companies. The Appellees' Merit Briefs were filed on August 24, 2006 and the Appellants' Reply Briefs were filed on September 21, 2006. The OCC filed an amicus brief on August 4, 2006, which the Ohio Companies moved to strike as improperly filed. The Supreme Court denied the Ohio Companies' motion on October 18, 2006.

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 sought recovery of these costs beginning January 1, 2006. 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 parties reached a settlement agreement that was approved by the PUCO on August 31, 2005. The incremental transmission and ancillary service revenues recovered from January 1 through June 30, 2006 were approximately $61 million. That amount included the recovery of a portion of the 2005 deferred MISO expenses as described below. On April 27, 2006, the Ohio Companies filed the annual update rider to determine revenues ($139 million) from July 2006 through June 2007. The filed rider went into effect on July 1, 2006.

The second application sought authority to defer costs associated with transmission and ancillary service related costs incurred during the period 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 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 the Ohio Companies to accrue carrying charges on the deferred balances. On August 31, 2005, the OCC appealed the PUCO's decision. On January 20, 2006, the OCC sought rehearing of the PUCO’s approval of the recovery of deferred costs through the rider during the period January 1, 2006 through June 30, 2006. The PUCO denied the OCC's application on February 6, 2006. On March 23, 2006, the OCC appealed the PUCO's order to the Ohio Supreme Court. On March 27, 2006, the OCC filed a motion to consolidate this appeal with the deferral appeals discussed above and to postpone oral arguments in the deferral appeal until after all briefs are filed in this most recent appeal of the rider recovery mechanism. On March 20, 2006, the Ohio Supreme Court, on its own motion, consolidated the OCC's appeal of the Ohio Companies' case with a similar case involving Dayton Power & Light Company. Oral arguments were heard on May 10, 2006. The Ohio Companies are awaiting a final ruling from the Ohio Supreme Court, which is expected before the end of 2006.

See Note 11 to the consolidated financial statements for further details and a complete discussion of regulatory matters in Ohio.

Pennsylvania

Met-Ed and Penelec purchase a portion of their PLR requirements from FES through a wholesale power sales agreement. Under this 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 contracts with NUGs and other unaffiliated suppliers. The FES 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. The wholesale power sales agreement with FES could automatically be extended for each successive calendar year unless any party elects to cancel the agreement by November 1 of the preceding year. On November 1, 2005, FES and the other parties thereto amended the agreement to provide FES the right in 2006 to terminate the agreement at any time upon 60 days notice. On April 7, 2006, the parties to the wholesale power sales agreement entered into a Tolling Agreement that arises out of FES’ notice to Met-Ed and Penelec that FES elected to exercise its right to terminate the wholesale power sales agreement effective midnight December 31, 2006, because that agreement is not economically sustainable to FES.

In lieu of allowing such termination to become effective as of December 31, 2006, the parties agreed, pursuant to the Tolling Agreement, to amend the wholesale power sales agreement to provide as follows:

1. The termination provisions of the wholesale power sales agreement will be tolled for one year until December 31, 2007, provided that during such tolling period:
a. FES will be permitted to terminate the wholesale power sales agreement at any time with sixty days written notice;
b. Met-Ed and Penelec will procure through arrangements other than the wholesale power sales agreement beginning December 1, 2006 and ending December 31, 2007, approximately 33% of the amounts of capacity and energy necessary to satisfy their PLR obligations for which Committed Resources (i.e., non-utility generation under contract to Met-Ed and Penelec, Met-Ed- and Penelec-owned generating facilities, purchased power contracts and distributed generation) have not been obtained; and
c. FES will not be obligated to supply additional quantities of capacity and energy in the event that a supplier of Committed Resources defaults on its supply agreement;

2. During the tolling period, FES will not act as an agent for Met-Ed or Penelec in procuring the services under 1.(b) above; and

3. The pricing provision of the wholesale power sales agreement shall remain unchanged provided Met-Ed and Penelec comply with the provisions of the Tolling Agreement and any applicable provision of the wholesale power sales agreement.

In the event that FES elects not to terminate the wholesale power sales agreement effective midnight December 31, 2007, similar tolling agreements effective after December 31, 2007 are expected to be considered by FES for subsequent years if Met-Ed and Penelec procure through arrangements other than the wholesale power sales agreement approximately 64%, 83% and 95% of the additional amounts of capacity and energy necessary to satisfy their PLR obligations for 2008, 2009 and 2010, respectively, for which Committed Resources have not been obtained from the market. On September 26, 2006, Met-Ed and Penelec successfully conducted a competitive RFP for 33% of their PLR obligation for which Committed Resources have not been obtained for the period December 1, 2006 through December 31, 2008.

The wholesale power sales agreement, as modified by the Tolling Agreement, requires Met-Ed and Penelec to satisfy the portion of their PLR obligations currently supplied by FES from unaffiliated suppliers at prevailing prices, which are likely to be higher than the current price charged by FES under the current agreement and, as a result, Met-Ed’s and Penelec’s purchased power costs could materially increase. If Met-Ed and Penelec were to replace the entire FES supply at current market power prices without corresponding regulatory authorization to increase their generation prices to customers, each company would likely incur a significant increase in operating expenses and experience a material deterioration in credit quality metrics. Under such a scenario, each company's credit profile would no longer be expected to support an investment grade rating for its fixed income securities. There can be no assurance, however, that if FES ultimately determines to terminate, further reduce, or significantly modify the agreement, timely regulatory relief will be granted by the PPUC pursuant to the April 10, 2006 comprehensive rate filing discussed below, or, to the extent granted, adequate to mitigate such adverse consequences.

Met-Ed and Penelec made a comprehensive rate filing with the PPUC on April 10, 2006 that addresses a number of transmission, distribution and supply issues. If Met-Ed's and Penelec's preferred approach involving accounting deferrals is approved, the filing would increase annual revenues by $216 million and $157 million, respectively. That filing includes, among other things, a request to charge customers for an increasing amount of market priced power procured through a CBP as the amount of supply provided under the existing FES agreement is phased out in accordance with the April 7, 2006 Tolling Agreement described above. Met-Ed and Penelec also requested approval of the January 12, 2005 petition for the deferral of transmission-related costs discussed above, but only for those costs incurred during 2006. In this rate filing, Met-Ed and Penelec also requested recovery of annual transmission and related costs incurred on or after January 1, 2007, plus the amortized portion of 2006 costs over a ten-year period, along with applicable carrying charges, through an adjustable rider similar to that implemented in Ohio. Changes in the recovery of NUG expenses and the recovery of Met-Ed's non-NUG stranded costs are also included in the filing. The filing contemplates a reduction in distribution rates for Met-Ed of $37 million annually and an increase in distribution rates for Penelec of $20 million annually. The PPUC suspended the effective date (June 10, 2006) of these rate changes for seven months after the filing as permitted under Pennsylvania law. If the PPUC adopts the overall positions taken in the intervenors’ testimony as filed, this would have a material adverse effect on the financial statements of FirstEnergy, Met-Ed and Penelec. Hearings were held in late August 2006 and all reply briefs were filed by October 6, 2006. The ALJ’s recommended decision is due by November 8, 2006 and the PPUC decision is expected by January 12, 2007.

As of September 30, 2006, Met-Ed's and Penelec's regulatory deferrals pursuant to the 1998 Restructuring Settlement (including the Phase 2 Proceedings) and the FirstEnergy/GPU Merger Settlement Stipulation were $297 million and $56 million, respectively. Penelec's $56 million is subject to the pending resolution of taxable income issues associated with NUG trust fund proceeds. The PPUC recently conducted a review and audit of a modification to the NUG purchased power stranded cost accounting methodology for Met-Ed and Penelec. On August 18, 2006, a PPUC Order was entered requiring Met-Ed and Penelec to reflect the deferred NUG cost balances as if the stranded cost accounting methodology modification had not been implemented. As a result of the PPUC’s Order, Met-Ed recognized a pre-tax charge of approximately $10.3 million in the third quarter of 2006, representing incremental costs deferred under the revised methodology in 2005. Met-Ed and Penelec continue to believe that the stranded cost accounting methodology modification is appropriate and filed a petition with the PPUC pursuant to its Order for authorization to reflect the stranded cost accounting methodology modification effective January 1, 1999.

On January 12, 2005, Met-Ed and Penelec filed, before the PPUC, a request for deferral of transmission-related costs beginning January 1, 2005. The OCA, OSBA, OTS, MEIUG, PICA, Allegheny Electric Cooperative and Pennsylvania Rural Electric Association all intervened in the case. Met-Ed and Penelec sought to consolidate this proceeding (and modified their request to provide deferral of 2006 transmission-related costs only) with the comprehensive rate filing they made on April 10, 2006 as described above. On May 4, 2006, the PPUC approved the modified request. Accordingly, Met-Ed and Penelec have deferred approximately $90 million and

$21 million, respectively, representing transmission costs that were incurred from January 1, 2006 through September 30, 2006. On June 5, 2006, the OCA filed before the Commonwealth Court a petition for review of the PPUC's approval of the deferral. On July 12, 2006, the Commonwealth Court granted the PPUC's motion to quash the OCA's appeal. The ratemaking treatment of the deferrals will be determined in the comprehensive rate filing proceeding discussed further above.

Under Pennsylvania's electric competition law, Penn is required to secure generation supply for customers who do not choose alternative suppliers for their electricity. 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 recommended that the RFP process cover the period January 1, 2007 through May 31, 2008. Hearings before the PPUC were held on January 10, 2006 with main briefs filed on January 27, 2006 and reply briefs filed on February 3, 2006. On February 16, 2006, the ALJ issued a Recommended Decision to adopt Penn's RFP process with modifications. On April 20, 2006, the PPUC approved the Recommended Decision with additional modifications to use an RFP process with two separate solicitations. An initial solicitation was held for Penn in May 2006 with all tranches fully subscribed, which was approved by the PPUC on June 2, 2006. On July 18, 2006, the second PLR solicitation was held for Penn. The tranches for the Residential Group and Small Commercial Group were fully subscribed. However, supply was not acquired for two tranches for the Large Commercial Group. On July 20, 2006, the PPUC approved the submissions for the second bid. A contingency solicitation was held on August 15, 2006 for the two remaining Large Commercial Group tranches. The PPUC rejected the bids from the contingency solicitation and directed Penn's independent auction manager to offer the two unfilled Large Commercial tranches to the companies which had won tranches in the prior solicitations. This resulted in the acquisition of a supplier for the two remaining tranches, which were filed and accepted by the PPUC in a secretarial letter that was entered on September 22, 2006. On August 24, 2006, Penn made a compliance filing. OCA and OSBA filed exceptions to the compliance filing. Penn filed reply exceptions on September 5, 2006. On September 21, 2006, Penn submitted a revised compliance filing to the PPUC for the Residential Group and Small Commercial Group as a result of an agreement between Penn, OCA and OSBA. The PPUC approved proposed rates for the large commercial and industrial customers at the PPUC Public meeting on October 19, 2006, and found that the results of the competitive solicitation process were consistent with prevailing market prices.

On May 25, 2006, Penn filed a Petition for Review of the PPUC's Orders of April 28, 2006 and May 4, 2006, which together decided the issues associated with Penn's proposed Interim PLR Supply Plan. Penn has asked the Commonwealth Court to review the PPUC's decision to deny Penn's recovery of certain PLR costs through a reconciliation mechanism and the PPUC's decision to impose a geographic limitation on the sources of alternative energy credits. On June 7, 2006, the PaDEP filed a Petition for Review appealing the PPUC's ruling on the method by which alternative energy credits may be acquired and traded. Penn is unable to predict the outcome of this appeal.

See Note 11 to the consolidated financial statements for further details and a complete discussion of regulatory matters in Pennsylvania.

New Jersey

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 NUGC rates and market sales of NUG energy and capacity. As of September 30, 2006, the accumulated deferred cost balance totaled approximately $340 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 to securitize the July 31, 2003 deferred balance. On June 8, 2006, the NJBPU approved JCP&L's request to issue securitization bonds associated with BGS stranded cost deferrals. On August 10, 2006, JCP&L Transition Funding II, a wholly owned subsidiary of JCP&L, issued $182 million of transition bonds with a weighted average interest rate of 5.5%.

On December 2, 2005, JCP&L filed its request for recovery of $165 million of actual above-market NUG costs incurred from August 1, 2003 through October 31, 2005 and forecasted above-market NUG costs for November and December 2005. On February 23, 2006, JCP&L filed updated data reflecting actual amounts through December 31, 2005 of $154 million of costs incurred since July 31, 2003. On March 29, 2006, a pre-hearing conference was held with the presiding ALJ. On July 18, 2006, JCP&L filed rebuttal testimony that included a request for an additional $14 million of costs that had been eliminated from the securitized amount. Evidentiary hearings were held during September 2006 and the briefing schedule has been postponed pending settlement discussions.

An NJBPU Decision and Order approving a Phase II Stipulation of Settlement and resolving the Motion for Reconsideration of the Phase I Order was issued on May 31, 2005. The Phase II Settlement includes a performance standard pilot program with potential penalties of up to 0.25% of allowable equity return. The Order requires that JCP&L file quarterly reliability reports (CAIDI and SAIFI information related to the performance pilot program) through December 2006 and updates to reliability related project expenditures until all projects are completed. The latest quarterly reliability reports were submitted on September 12, 2006. As of September 30, 2006, there were no performance penalties issued by the NJBPU.

Reacting to the higher closing prices of the 2006 BGS fixed rate auction, the NJBPU, on March 16, 2006, initiated a generic proceeding to evaluate the auction process and potential options for the future. On April 6, 2006, initial comments were submitted. A public meeting was held on April 21, 2006 and a legislative-type hearing was held on April 28, 2006. On June 21, 2006, the NJBPU approved the continued use of a descending block auction for the Fixed Price Residential Class. JCP&L filed its 2007 BGS company specific addendum on July 10, 2006. On October 27, 2006, the NJBPU approved the auction format to procure the 2007 Commercial Industrial Energy Price as well as the specific rules for both the Fixed Price and Commercial Industrial Energy Price auctions. These rules were essentially unchanged from the prior auctions.

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of PUHCA pursuant to the EPACT. An NJBPU proposed rulemaking to address the issues was published in the NJ Register on December 19, 2005. The proposal would prevent a holding company that owns a gas or electric public utility from investing more than 25% of the combined assets of its utility and utility-related subsidiaries into businesses unrelated to the utility industry. A public hearing was held on February 7, 2006 and comments were submitted to the NJBPU. On August 16, 2006, the NJBPU approved the regulations with an effective date of October 2, 2006. These regulations are not expected to materially impact FirstEnergy or JCP&L. Also in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. Comments on the alternative proposal were submitted on June 15, 2006.

See Note 11 to the consolidated financial statements for further details and a complete discussion of regulatory matters in New Jersey.

FERC Matters

On November 1, 2004, ATSI filed with the FERC a request to defer approximately $54 million of costs to be incurred from 2004 through 2007 in connection with ATSI’s VMEP, which represents ATSI’s adoption of newly identified industry “best practices” for vegetation management. On March 4, 2005, the FERC approved ATSI’s request to defer the VMEP costs (approximately $34 million has been deferred as of September 30, 2006). On March 28, 2006, ATSI and MISO filed with the FERC a request to modify ATSI’s Attachment O formula rate to include revenue requirements associated with recovery of deferred VMEP costs over a five-year period. The requested effective date to begin recovery was June 1, 2006. Various parties filed comments responsive to the March 28, 2006 submission. The FERC conditionally approved the filing on May 22, 2006, subject to a compliance filing that ATSI made on June 13, 2006. A request for rehearing of the FERC’s May 22, 2006 Order was filed by a party, which ATSI answered. On July 14, 2006, the FERC accepted ATSI’s June 13, 2006 compliance filing. The estimated annual revenues to ATSI from the VMEP cost recovery is $12 million for each of the five years beginning June 1, 2006. On October 25, 2006, the FERC denied the request for rehearing.

On January 24, 2006, ATSI and MISO filed a request with the FERC to correct ATSI’s Attachment O formula rate to reverse revenue credits associated with termination of revenue streams from transitional rates stemming from FERC’s elimination of RTOR. Revenues formerly collected under these rates were included in, and served to reduce, ATSI’s zonal transmission rate under the Attachment O formula. Absent the requested correction, elimination of these revenue streams would not be fully reflected in ATSI’s formula rate until June 1, 2008. On March 16, 2006, the FERC approved the revenue credit correction without suspension, effective April 1, 2006. One party sought rehearing of the FERC's order. The request for rehearing of this order was denied on June 27, 2006. The FERC accepted MISO’s and ATSI’s revised tariff sheets for filing on June 7, 2006. The estimated annual revenue impact of the correction mechanism is approximately $40 million effective on June 1, 2006.

On November 18, 2004, the FERC issued an order eliminating the RTOR for transmission service between the MISO and PJM regions. The FERC also ordered the MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a SECA mechanism to recover lost RTOR revenues during a 16-month transition period from load serving entities. The FERC issued orders in 2005 setting the SECA for hearing. ATSI, JCP&L, Met-Ed, Penelec, and FES continue to be involved in the FERC hearings concerning the calculation and imposition of the SECA charges. The hearing was held in May 2006. Initial briefs were submitted on June 9, 2006, and reply briefs were filed on June 27, 2006. The Presiding Judge issued an Initial Decision on August 10, 2006, rejecting the compliance filings made by the RTOs and transmission owners, ruling on various issues and directing new compliance filings. This decision is subject to review and approval by the FERC. Briefs addressing the Initial Decision were filed on September 11, 2006 and October 20, 2006. A final order could be issued by the FERC by the end of 2006.

On January 31, 2005, certain PJM transmission owners made three filings with the FERC 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. American Electric Power Company, Inc. filed in opposition proposing to create a "postage stamp" rate for high voltage transmission facilities across PJM. Second, the FERC approved the proposed Schedule 12 rate harmonization. Third, the FERC accepted the proposed formula rate, subject to refund and hearing procedures. On June 30, 2005, the settling PJM transmission owners filed a request for rehearing of the May 31, 2005 order. On March 20, 2006, a settlement was filed with FERC in the formula rate proceeding that generally accepts the companies' formula rate proposal. The FERC issued an order approving this settlement on April 19, 2006. Hearings in the PJM rate design case concluded in April 2006. On July 13, 2006, an Initial Decision was issued by the ALJ. The ALJ adopted the Trial Staff's position that the cost of all PJM transmission facilities should be recovered through a postage stamp rate. The ALJ recommended an April 1, 2006 effective date for this change in rate design. If the FERC accepts this recommendation, the transmission rate applicable to many load zones in PJM would increase. FirstEnergy believes that significant additional transmission revenues would have to be recovered from the JCP&L, Met-Ed and Penelec transmission zones within PJM. JCP&L, Met-Ed and Penelec as part of the Responsible Pricing Alliance, filed a brief addressing the Initial Decision on August 14, 2006 and September 5, 2006. The case will be reviewed by the FERC with a decision anticipated in the fourth quarter of 2006.

On November 1, 2005, FES filed two power sales agreements for approval with the FERC. One power sales agreement provided for FES to provide the PLR requirements of the Ohio Companies at a price equal to the retail generation rates approved by the PUCO for a period of three years beginning January 1, 2006. The Ohio Companies will be relieved of their obligation to obtain PLR power requirements from FES if the Ohio CBP results in a lower price for retail customers. A similar power sales agreement between FES and Penn permits Penn to obtain its PLR power requirements from FES at a fixed price equal to the retail generation price during 2006.

On December 29, 2005, the FERC issued an order setting the two power sales agreements for hearing. The order criticized the Ohio CBP, and required FES to submit additional evidence in support of the reasonableness of the prices charged in the power sales agreements. A pre-hearing conference was held on January 18, 2006 to determine the hearing schedule in this case. Under the procedural schedule approved in this case, FES expected an initial decision to be issued in late January 2007. However, on July 14, 2006, the Chief Judge granted the joint motion of FES and the Trial Staff to appoint a settlement judge in this proceeding and the procedural schedule was suspended pending settlement discussions among the parties. A settlement conference was held on September 5, 2006. FES and the Ohio Companies, Penn, and the PUCO, along with other parties, reached an agreement to settle the case. The settlement was filed with the FERC on October 17, 2006, and was unopposed by the remaining parties, including the FERC Trial Staff. Initial comments to the settlement are due by November 6, 2006.

The terms of the settlement provide for modification of both the Ohio and Penn power supply agreements with FES. Under the Ohio power supply agreement, separate rates are established for the Ohio Companies' PLR requirements, special retail contracts requirements, wholesale contract requirements, and interruptible buy-through retail load requirements. For their PLR and special retail contract requirements, the Ohio Companies will pay FES no more than the lower of (i) the sum of the retail generation charge, the rate stabilization charge, the fuel recovery mechanism charge, and FES' actual incremental fuel costs for such sales; or (ii) the wholesale price cap. Different wholesale price caps are imposed for PLR sales, special retail contracts, and wholesale contracts. The wholesale price for interruptible buy-through retail load requirements is limited to the actual spot price of power obtained by FES to provide this power. The Ohio Companies have recognized the estimated additional amount payable to FES for power supplied during the nine months ended September 30, 2006. The wholesale rate charged by FES under the Penn power supply agreement will be no greater than the generation component of charges for retail PLR load in Pennsylvania. The FERC is expected to act on this case by the end of the fourth quarter of 2006.

As a result of Penn’s PLR competitive solicitation process approved by the PPUC, FES was selected as the winning bidder for a number of the tranches for individual customer classes. The balance of the tranches will be supplied by unaffiliated power suppliers. On October 2, 2006, FES filed an application with FERC under Section 205 of the Federal Power Act for authorization to make these affiliate sales to Penn. Interventions or protests were due on this filing on October 23, 2006. Penn was the only party to file an intervention in this proceeding. The FERC is expected to act on this filing on or before December 1, 2006.

On October 19, 2006, the FERC issued two final rules in connection with the Public Utility Holding Company Act of 2005 (PUHCA 2005). The final rules impose certain accounting, reporting and record-retention requirements for applicable holding companies and service companies, which includes FirstEnergy and certain of its subsidiaries.

Environmental Matters

FirstEnergy 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 FirstEnergy’s determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

On December 1, 2005, FirstEnergy issued a comprehensive report to shareholders regarding air emissions regulations and an assessment of future risks and mitigation efforts. The report is available on FirstEnergy's Web site at www.firstenergycorp.com/environmental.

Clean Air Act Compliance

FirstEnergy is required to meet federally-approved SO_2 emissions regulations. Violations of such regulations can result in shutdown of the generating unit involved and/or civil or criminal penalties of up to $32,500 for each day the unit is in violation. The EPA has an interim enforcement policy for SO_2 regulations in Ohio that allows for compliance based on a 30-day averaging period. FirstEnergy believes it is currently in compliance with this policy, but cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The EPA Region 5 issued a Finding of Violation and NOV to the Bay Shore Power Plant dated June 15, 2006 alleging violations to various sections of the Clean Air Act. A meeting was held on August 8, 2006 to discuss the alleged violations with the EPA. FirstEnergy has disputed those alleged violations based on its Clean Air Act permit, the Ohio SIP and other information provided at the August 2006 meeting with the EPA. The EPA has several enforcement options (administrative compliance order, administrative penalty order, and/or judicial, civil or criminal action) and has indicated that such option may depend on the time needed to achieve and demonstrate compliance with the rules alleged to have been violated.

FirstEnergy complies with SO_2 reduction requirements under the Clean Air Act Amendments of 1990 by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NO_X reductions required by the 1990 Amendments are being achieved through combustion controls and the generation of more electricity at lower-emitting plants. In September 1998, the EPA finalized regulations requiring additional NO_X reductions at FirstEnergy's facilities. The EPA's NO_X Transport Rule imposes uniform reductions of NO_X emissions (an approximate 85% reduction in utility plant NO_X emissions from projected 2007 emissions) across a region of nineteen states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on a conclusion that such NO_X emissions are contributing significantly to ozone levels in the eastern United States. FirstEnergy believes its facilities are also complying with the NO_X budgets established under SIPs through combustion controls and post-combustion controls, including Selective Catalytic Reduction and Selective Non-Catalytic Reduction systems, and/or using emission allowances.

National Ambient Air Quality Standards

In July 1997, the EPA promulgated changes in the NAAQS for ozone and fine particulate matter. In March 2005, the EPA finalized CAIR 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 non-attainment 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). FirstEnergy's Michigan, Ohio and Pennsylvania fossil-fired generation facilities will be subject to caps on SO_2 and NO_X emissions, whereas its New Jersey fossil-fired generation facility 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 FirstEnergy 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. In March 2005, the EPA finalized CAMR, 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 CAIR and CAMR 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 and will depend on how they are ultimately implemented by the states in which FirstEnergy operates affected facilities.

The model rules for both CAIR and CAMR contemplate an input-based methodology to allocate allowances to affected facilities. Under this approach, allowances would be allocated based on the amount of fuel consumed by the affected sources. FirstEnergy would prefer an output-based generation-neutral methodology in which allowances are allocated based on megawatts of power produced, since then, new and non-emitting generating facilities, including renewables and nuclear, would be entitled to their proportionate share of the allowances. Consequently, FirstEnergy will be disadvantaged if these model rules were implemented as proposed because FirstEnergy’s substantial reliance on non-emitting (largely nuclear) generation is not recognized under the input-based allocation.

Pennsylvania has proposed a new rule to regulate mercury emissions from coal-fired power plants that does not provide a cap and trade approach as in CAMR, but rather follows a command and control approach imposing emission limits on individual sources. If adopted as proposed, Pennsylvania’s mercury regulation would deprive FirstEnergy of mercury emission allowances that were to be allocated to the Mansfield Plant under CAMR and that would otherwise be available for achieving FirstEnergy system-wide compliance. The future cost of compliance with these regulations, if adopted and implemented as proposed, 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 was approved by the Court on July 11, 2005, and requires reductions of NO_X and SO_2 emissions at the W. H. Sammis Plant and other coal-fired plants through the installation of pollution control devices and provides for stipulated penalties for failure to install and operate such pollution controls in accordance with that agreement. Consequently, if FirstEnergy fails to install such pollution control devices, for any reason, including, but not limited to, the failure of any third-party contractor to timely meet its delivery obligations for such devices, FirstEnergy could be exposed to penalties under the settlement agreement. Capital expenditures necessary to meet those requirements are currently estimated to be $1.5 billion ($400 million of which is expected to be spent in 2007 with the primary portion of the remaining $1.1 billion expected to be spent in 2008 and 2009). On August 26, 2005, FGCO entered into an agreement with Bechtel Power Corporation under which Bechtel will engineer, procure, and construct air quality control systems for the reduction of SO_2 emissions. FGCO also entered into an agreement with B&W on August 25, 2006 to supply flue gas desulfurization systems for the reduction of SO_2 emissions. Selective Catalytic Reduction (SCR) systems for the reduction of NOx emissions also are being installed at the W.H. Sammis Plant under a 1999 agreement with B&W.

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 paid by OE and Penn of $7.8 million and $0.7 million, respectively. OE and Penn also recognized liabilities in the first quarter of 2005 of $9.2 million and $0.8 million, respectively, 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, 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 Kyoto 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% through 2012. The EPACT established a Committee on Climate Change Technology to coordinate federal climate change activities and promote the development and deployment of GHG reducing technologies.

FirstEnergy 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 FirstEnergy is lower than many regional competitors due to its 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, 2006, based on estimates of the total costs of cleanup, the Companies' proportionate responsibility for such costs and the financial ability of other unaffiliated 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 $73 million have been accrued through September 30, 2006.

See Note 10(B) to the consolidated financial statements for further details and a complete discussion of environmental matters.

Other Legal Proceedings

Power Outages and Related Litigation

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 Web site (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 is also proceeding with the implementation of the recommendations 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 may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future as a result of adoption of mandatory reliability standards pursuant to the EPACT that could require additional material expenditures.

FirstEnergy companies also are defending six separate complaint cases before the PUCO relating to the August 14, 2003 power outages. Two cases were originally filed in Ohio State courts but were subsequently dismissed for lack of subject matter jurisdiction and further appeals were unsuccessful. In these 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. Three other pending PUCO complaint cases were filed by various insurance carriers either in their own name as subrogees or in the name of their insured. In each of these three cases, the carrier seeks reimbursement from various FirstEnergy companies (and, in one case, from PJM, MISO and American Electric Power Company, Inc., as well) for claims paid to insureds for damages allegedly arising as a result of 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 sixth case involves the claim of a non-customer seeking reimbursement for losses incurred when its store was burglarized on August 14, 2003. That case has been dismissed. On March 7, 2006, the PUCO issued a ruling, based on motions filed by the parties, applicable to all pending cases. Among its various rulings, the PUCO consolidated all of the pending outage cases for hearing; limited the litigation to service-related claims by customers of the Ohio operating companies; dismissed FirstEnergy as a defendant; ruled that the U.S.-Canada Power System Outage Task Force Report was not admissible into evidence; and gave the plaintiffs additional time to amend their complaints to otherwise comply with the PUCO's underlying order. Also, most complainants, along with the FirstEnergy companies, filed applications for rehearing with the PUCO over various rulings contained in the March 7, 2006 order. On April 26, 2006, the PUCO granted rehearing to allow the insurance company claimants, as insurers, to prosecute their claims in their name so long as they also identify the underlying insured entities and the Ohio utilities that provide their service. The PUCO denied all other motions for rehearing. The plaintiffs in each case have since filed an amended complaint and the named FirstEnergy companies have answered and also have filed a motion to dismiss each action. On September 27, 2006, the PUCO dismissed certain parties and claims and otherwise ordered the complaints to go forward to hearing. The cases have been set for hearing on October 16, 2007.

On October 10, 2006, various insurance carriers refiled a complaint in Cuyahoga County Common Pleas Court seeking reimbursement for claims paid to numerous insureds who allegedly suffered losses as a result of the August 14, 2003 outage. All of the insureds appear to be non-customers. The plaintiff insurance companies are the same claimants in one of the pending PUCO cases. FirstEnergy, the Ohio Companies and Penn were served on October 27, 2006, and expect to seek summary dismissal of these cases based on the prior court rulings noted above. No estimate of potential liability is available for any of these cases.

FirstEnergy was also named, along with several other entities, in a complaint in New Jersey State Court. The allegations against FirstEnergy were based, in part, on an alleged failure to protect the citizens of Jersey City from an electrical power outage. None of FirstEnergy's subsidiaries serve customers in Jersey City. A responsive pleading has been filed. On April 28, 2006, the Court granted FirstEnergy's motion to dismiss. The plaintiff has not appealed.

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. Although unable to predict the impact of these proceedings, 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.

Nuclear Plant Matters

On January 20, 2006, FENOC announced that it had entered into a deferred prosecution agreement with the U.S. Attorney's Office for the Northern District of Ohio and the Environmental Crimes Section of the Environment and Natural Resources Division of the DOJ related to FENOC's communications with the NRC during the fall of 2001 in connection with the reactor head issue at the Davis-Besse Nuclear Power Station. Under the agreement, which expires on December 31, 2006, the United States acknowledged FENOC's extensive corrective actions at Davis-Besse, FENOC’s cooperation during investigations by the DOJ and the NRC, FENOC’s pledge of continued cooperation in any related criminal and administrative investigations and proceedings, FENOC’s acknowledgement of responsibility for the behavior of its employees, and its agreement to pay a monetary penalty. The DOJ will refrain from seeking an indictment or otherwise initiating criminal prosecution of FENOC for all conduct related to the statement of facts attached to the deferred prosecution agreement, as long as FENOC remains in compliance with the agreement, which FENOC fully intends to do. FENOC paid a monetary penalty of $28 million (not deductible for income tax purposes) which reduced FirstEnergy's earnings by $0.09 per common share in the fourth quarter of 2005.

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 discussed above. FirstEnergy accrued $2 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. On January 23, 2006, FENOC supplemented its response to the NRC's NOV on the Davis-Besse head degradation to reflect the deferred prosecution agreement that FENOC had reached with the DOJ.

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 corrective action. FENOC operates the Perry Nuclear Power 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 September 28, 2005, the NRC sent a CAL to FENOC describing commitments that FENOC had made to improve the performance at the Perry Plant 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. In the NRC's 2005 annual assessment letter dated March 2, 2006 and associated meetings to discuss the performance of Perry on March 14, 2006, the NRC again stated that the Perry Nuclear Power Plant continued to operate in a manner that "preserved public health and safety." However, the NRC also stated that increased levels of regulatory oversight would continue until sustained improvement in the performance of the facility was realized. 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. Although FirstEnergy is unable to predict the impact of the ultimate disposition of this matter, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

Other Legal Matters

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 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 now repealed 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 related disclosures, which FirstEnergy has provided. 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 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. On October 18, 2006, the Ohio Supreme Court transferred this case to a Tuscarawas County Common Pleas Court judge due to concerns over potential class membership by the Jefferson County Common Pleas Court.

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 arbitration panel decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the arbitration panel issued an opinion to award approximately $16 million to the bargaining unit employees. On February 6, 2006, a federal district court granted a union motion to dismiss as premature a JCP&L appeal of the award filed on October 18, 2005. JCP&L intends to re-file an appeal again in federal district court once the damages associated with this case are identified at an individual employee level. JCP&L recognized a liability for the potential $16 million award in 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 of a tariff that would specifically allow the collection of transition charges from customers of municipal electric utilities formed after 1998. Both filings were consolidated for hearing and decision. 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. On May 10, 2006, the PUCO issued its Opinion and Order dismissing the City's complaint and approving the related tariffs, thus affirming OE's entitlement to recovery of its transition charges. The City of Huron filed an application for rehearing of the PUCO's decision on June 9, 2006 and OE filed a memorandum in opposition to that application on June 19, 2006. The PUCO denied the City's application for rehearing on June 28, 2006. The City of Huron has taken no further action and the period for filing an appeal has expired.

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

NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

SAB 108 - "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements"

In September 2006, the SEC issued SAB 108, which provides interpretive guidance on how registrants should quantify financial statement misstatements. There is currently diversity in practice, with the two commonly used methods to quantify misstatements being the "rollover" method (which primarily focuses on the income statement impact of misstatements) and the "iron curtain" method (which focuses on the balance sheet impact). SAB 108 requires registrants to use a dual approach whereby both of these methods are considered in evaluating the materiality of financial statement errors. Prior materiality assessments will need to be reconsidered using both the rollover and iron curtain methods. This guidance will be effective for FirstEnergy in the fourth quarter of 2006. FirstEnergy does not expect this Statement to have a material impact on its financial statements.

EITF 06-5 - "Accounting for Purchases of Life Insurance-Determining the Amount That Could Be Realized in Accordance with FASB Technical Bulletin No. 85-4, Accounting for Purchases of Life Insurance"

In September 2006, the EITF reached a consensus on Issue 06-5 concluding that a policyholder should consider any additional amounts included in the contractual terms of the policy in determining the amount that could be realized under the insurance contract. Contractual limitations should be considered when determining the realizable amounts. Amounts that are recoverable by the policyholder at the discretion of the insurance company should be excluded from the amount that could be realized. Recoverable amounts in periods beyond one year from the surrender of the policy should be discounted in accordance with APB Opinion No. 21, "Interest on Receivables and Payables." Consensus was also reached that a policyholder should determine the amount that could be realized under the insurance contract assuming the surrender of an individual-life by individual-life policy (or certificate by certificate in a group policy). Any amount that would ultimately be realized by the policyholder upon the assumed surrender of the final policy (or final certificate) should be included in the amount that could be realized under the insurance contract. The EITF also concluded that a policyholder should not discount the cash surrender value component of the amount that could be realized when contractual restrictions on the ability to surrender a policy exist. However, if the contractual limitations prescribe that the cash surrender value component of the amount that could be realized is a fixed amount, then the amount that could be realized should be discounted in accordance with APB Opinion No. 21. This Issue is effective for fiscal years beginning after December 15, 2006. FirstEnergy does not expect this EITF to have a material impact on its financial statements.

SFAS 157 - "Fair Value Measurements"

In September 2006, the FASB issued SFAS 157 that establishes how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under GAAP. This Statement addresses the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. The key changes to current practice are: (1) the definition of fair value which focuses on an exit price rather than entry price; (2) the methods used to measure fair value such as emphasis that fair value is a market-based measurement, not an entity-specific measurement, as well as the inclusion of an adjustment for risk, restrictions and credit standing; and (3) the expanded disclosures about fair value measurements.

This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. FirstEnergy is currently evaluating the impact of this Statement on its financial statements.

SFAS 158 - "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)"

In September 2006, the FASB issued SFAS 158, which requires companies to recognize a net liability or asset to report the overfunded or underfunded status of their defined benefit pension and other postretirement benefit plans on their balance sheets and recognize changes in funded status in the year in which the changes occur through other comprehensive income. The funded status to be measured is the difference between plan assets at fair value and the benefit obligation. This Statement requires that gains and losses and prior service costs or credits, net of tax, that arise during the period be recognized as a component of other comprehensive income and not as components of net periodic benefit cost. Additional information should also be disclosed in the notes to the financial statements about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and transition asset or obligation. Upon the initial application of this Statement and subsequently, an employer should continue to apply the provisions in Statements 87, 88 and 106 in measuring plan assets and benefit obligations as of the date of its statement of financial position and in determining the amount of net periodic benefit cost. This Statement is effective for FirstEnergy as of December 31, 2006. Based upon the December 31, 2005 measurement date, the estimated balance sheet impacts of adopting this Statement are a reduction in total assets of $0.4 billion, an increase in liabilities of $0.6 billion and a decrease in equity of $1 billion, before recognition of any related regulatory assets that may be appropriate under the circumstances.

FSP FIN 46(R)-6 - "Determining the Variability to Be Considered in Applying FASB interpretation No. 46(R)"

In April 2006, the FASB issued FSP FIN 46(R)-6 that addresses how a reporting enterprise should determine the variability to be considered in applying FASB interpretation No. 46 (revised December 2003). FirstEnergy adopted FIN 46(R) in the first quarter of 2004, consolidating VIE's when FirstEnergy or one of its subsidiaries is determined to be the VIE's primary beneficiary. The variability that is considered in applying interpretation 46(R) affects the determination of (a) whether the entity is a VIE; (b) which interests are variable interests in the entity; and (c) which party, if any, is the primary beneficiary of the VIE. This FSP states that the variability to be considered shall be based on an analysis of the design of the entity, involving two steps:

Step 1:	Analyze the nature of the risks in the entity
Step 2:	Determine the purpose(s) for which the entity was created and determine the variability

the entity is designed to create and pass along to its interest holders.

After determining the variability to consider, the reporting enterprise can determine which interests are designed to absorb that variability. The guidance in this FSP is applied prospectively to all entities (including newly created entities) with which that enterprise first becomes involved and to all entities previously required to be analyzed under interpretation 46(R) when a reconsideration event has occurred after July 1, 2006. FirstEnergy does not expect this Statement to have a material impact on its financial statements.

FIN 48 - "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109."

In June 2006, the FASB issued FIN 48 which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, "Accounting for Income Taxes." This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken on a tax return. This interpretation also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation will be a two-step process. The first step will determine if it is more likely than not that a tax position will be sustained upon examination and should therefore be recognized. The second step will measure a tax position that meets the more likely than not recognition threshold to determine the amount of benefit to recognize in the financial statements. This interpretation is effective for fiscal years beginning after December 15, 2006. FirstEnergy is currently evaluating the impact of this Statement.

OHIO EDISON COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
STATEMENTS OF INCOME		*(In thousands)*		
REVENUES	$ 673,673	$ 825,790	$ 1,832,968	$ 2,268,760
EXPENSES:				
Fuel	2,954	15,158	8,726	39,080
Purchased power	395,560	229,561	971,613	703,658
Nuclear operating costs	44,995	76,254	129,585	264,514
Other operating costs	108,362	114,762	290,776	293,530
Provision for depreciation	18,399	30,169	53,962	87,875
Amortization of regulatory assets	49,717	126,439	147,022	347,880
Deferral of new regulatory assets	(44,962)	(43,929)	(123,285)	(107,750)
General taxes	47,826	51,945	137,652	146,066
Total expenses	622,851	600,359	1,616,051	1,774,853
OPERATING INCOME	50,822	225,431	216,917	493,907
OTHER INCOME (EXPENSE):				
Investment income	32,993	25,260	98,853	68,349
Miscellaneous income (expense)	1,639	368	835	(23,529)
Interest expense	(24,597)	(17,182)	(60,195)	(56,787)
Capitalized interest	698	3,014	1,832	8,255
Subsidiary's preferred stock dividend requirements	(156)	(156)	(467)	(1,534)
Total other income (expense)	10,577	11,304	40,858	(5,246)
INCOME BEFORE INCOME TAXES	61,399	236,735	257,775	488,661
INCOME TAXES	17,902	105,337	91,239	253,410
NET INCOME	43,497	131,398	166,536	235,251
PREFERRED STOCK DIVIDEND REQUIREMENTS				
	51	659	4,297	1,976

AND REDEMPTION PREMIUM								
EARNINGS ON COMMON STOCK	$	43,446	$	130,739	$	162,239	$	233,275
STATEMENTS OF COMPREHENSIVE INCOME								
NET INCOME	$	43,497	$	131,398	$	166,536	$	235,251
OTHER COMPREHENSIVE INCOME (LOSS):								
Unrealized gain (loss) on available for sale securities		3,795		(3,402)		5,467		(19,079)
Income tax expense (benefit) related to other comprehensive income		1,369		(2,043)		1,972		(7,713)
Other comprehensive income (loss), net of tax		2,426		(1,359)		3,495		(11,366)
TOTAL COMPREHENSIVE INCOME	$	45,923	$	130,039	$	170,031	$	223,885

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, 2006	December 31, 2005
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 703	$ 929
Receivables-		
Customers (less accumulated provisions of $15,017,000 and $7,619,000, respectively, for uncollectible accounts)	255,173	290,887
Associated companies	190,516	187,072
Other (less accumulated provisions of $1,058,000 and $4,000, respectively, for uncollectible accounts)	21,399	15,327
Notes receivable from associated companies	471,393	536,629
Prepayments and other	19,053	93,129
	958,237	1,123,973
UTILITY PLANT:		
In service	2,599,266	2,526,851
Less - Accumulated provision for depreciation	1,005,404	984,463
	1,593,862	1,542,388
Construction work in progress	48,397	58,785
	1,642,259	1,601,173
OTHER PROPERTY AND INVESTMENTS:		
Long-term notes receivable from associated companies	1,675,813	1,758,776
Investment in lease obligation bonds	310,077	325,729
Nuclear plant decommissioning trusts	111,325	103,854
Other	39,734	44,210
	2,136,949	2,232,569
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	746,001	774,983
Prepaid pension costs	229,316	224,813
Property taxes	52,897	52,875
Unamortized sale and leaseback costs	51,386	55,139
Other	27,463	31,752
	1,107,063	1,139,562
	$ 5,844,508	$ 6,097,277
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 226,191	$ 280,255
Short-term borrowings-		
Associated companies	1,608	57,715

Other	22,097	143,585
Accounts payable-		
Associated companies	146,370	172,511
Other	10,811	9,607
Accrued taxes	136,044	163,870
Accrued interest	21,172	8,333
Other	100,742	61,726
	665,035	897,602
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 175,000,000 shares -	1,796,560	2,297,253
80 and 100 shares outstanding, respectively		
Accumulated other comprehensive income	7,589	4,094
Retained earnings	290,880	200,844
Total common stockholder's equity	2,095,029	2,502,191
Preferred stock not subject to mandatory redemption	-	60,965
Preferred stock of consolidated subsidiary not subject to mandatory redemption	14,105	14,105
Long-term debt and other long-term obligations	1,526,833	1,019,642
	3,635,967	3,596,903
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	736,396	769,031
Accumulated deferred investment tax credits	21,419	24,081
Asset retirement obligations	86,893	82,527
Retirement benefits	296,634	291,051
Deferred revenues - electric service programs	96,718	121,693
Other	305,446	314,389
	1,543,506	1,602,772
COMMITMENTS AND CONTINGENCIES (Note 10)		
	$ 5,844,508	$ 6,097,277

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)

	Nine Months Ended September 30, 2006	2005
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 166,536	$ 235,251
Adjustments to reconcile net income to net cash from operating activities -		
Provision for depreciation	53,962	87,875
Amortization of regulatory assets	147,022	347,880
Deferral of new regulatory assets	(123,285)	(107,750)
Nuclear fuel and lease amortization	728	30,530
Amortization of lease costs	28,600	30,011
Deferred income taxes and investment tax credits, net	(27,850)	(22,929)
Accrued compensation and retirement benefits	2,985	10,261
Decrease (increase) in operating assets -		
Receivables	26,198	110,460
Materials and supplies	-	(2,538)
Prepayments and other current assets	(4,172)	(4,232)
Increase (decrease) in operating liabilities -		
Accounts payable	(24,937)	(105,234)
Accrued taxes	(27,826)	60,443
Accrued interest	12,839	1,667
Electric service prepayment programs	(24,975)	127,586
Other	1,842	1,372
Net cash provided from operating activities	207,667	800,653
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing -		
Long-term debt	592,763	146,450
Short-term borrowings, net	-	65,696
Redemptions and Repayments -		
Common stock	(500,000)	-
Preferred stock	(63,893)	(37,750)
Long-term debt	(138,085)	(278,327)
Short-term borrowings, net	(177,595)	-
Dividend Payments -		
Common stock	(73,000)	(241,000)
Preferred stock	(1,369)	(1,976)
Net cash used for financing activities	(361,179)	(346,907)

CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions		(94,278)		(190,804)
Proceeds from nuclear decommissioning trust fund sales		34,655		196,235
Investments in nuclear decommissioning trust funds		(36,038)		(219,890)
Loan repayments from (loans to) associated companies, net		148,199		(258,561)
Cash investments		93,900		13,372
Other		6,848		5,572
Net cash provided from (used for) investing activities		153,286		(454,076)
Net decrease in cash and cash equivalents		(226)		(330)
Cash and cash equivalents at beginning of period		929		1,230
Cash and cash equivalents at end of period	$	703	$	900

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

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Report of Independent Registered Public Accounting Firm

To the Stockholder 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, 2006, and the related consolidated statements of income and comprehensive income for each of the three-month and nine-month periods ended September 30, 2006 and 2005 and the consolidated statements of cash flows for the nine-month periods ended September 30, 2006 and 2005. 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 have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2005, and the related consolidated statements of income, capitalization, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report [which contained references to the Company's change in its method of accounting for asset retirement obligations as of January 1, 2003 and conditional asset retirement obligations as of December 31, 2005 as discussed in Note 2(G) and Note 11 to those consolidated financial statements] dated February 27, 2006, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2005, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers
LLP
Cleveland, Ohio
October 31, 2006

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. Penn's rate restructuring plan and its associated transition charge revenue recovery was completed in 2005. The OE Companies also provide generation services to those customers electing to retain the OE Companies as their power supplier. Power supply requirements of the OE Companies are provided by FES - an affiliated company.

FirstEnergy Intra-System Generation Asset Transfers

In 2005, the Ohio Companies and Penn entered into certain agreements implementing a series of intra-system generation asset transfers that were completed in the fourth quarter of 2005. The asset transfers resulted in the respective undivided ownership interests of the Ohio Companies and Penn in FirstEnergy's nuclear and non-nuclear generation assets being owned by NGC and FGCO, respectively. The generating plant interests transferred did 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 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 FGCO's purchase option under the Master Facility Lease.

On December 16, 2005, the OE Companies completed the intra-system transfer of their ownership interests in the nuclear generation assets to NGC through an asset spin-off in the form of a dividend. FENOC continues to operate and maintain the nuclear generation assets.

These transactions were undertaken 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 essentially completed the divestitures contemplated by the restructuring plans by transferring the ownership interests to NGC and FGCO without impacting the operation of the plants.

The transfers affect the OE Companies' comparative earnings results with reductions in both revenues and expenses. Revenues are reduced due to the termination of certain arrangements with FES, under which the OE Companies previously sold their nuclear-generated KWH to FES and leased their non-nuclear generation assets to FGCO, a subsidiary of FES. Their expenses are lower due to the nuclear fuel and operating costs assumed by NGC as well as depreciation and property tax expenses assumed by FGCO and NGC related to the transferred generating assets. With respect to OE's retained leasehold interests in the Perry Plant and Beaver Valley Unit 2, OE has continued the nuclear-generated KWH sales arrangement with FES for the associated output and continues to be obligated on the applicable portion of expenses related to those interests. In addition, the OE Companies receive interest income on associated company notes receivable from the transfer of their generation net assets. FES continues to provide OE's PLR requirements under revised purchased power arrangements covering the three-year period beginning January 1, 2006 and Penn's during the remainder of 2006 (see Outlook - Regulatory Matters).

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The effects on the OE Companies' results of operations in the third quarter and nine months ended September 30, 2006 as compared to the same periods of 2005 from the generation asset transfers (also reflecting OE's retained leasehold interests discussed above) are summarized in the following table:

Intra-System Generation Asset Transfers Income Statement Effects		**Three Months**	**Nine Months**
Increase (Decrease)		***(In millions)***	
Revenues:			
Non-nuclear generating units rent	(a)	$ (44)	$ (133)
Nuclear-generated KWH sales	(b)	(86)	(217)
Total - Revenues Effect		(130)	(350)
Expenses:			
Fuel costs - nuclear	(c)	(12)	(30)
Nuclear operating costs	(c)	(33)	(122)
Provision for depreciation	(d)	(15)	(43)
General taxes	(e)	(3)	(9)
Total - Expenses Effect		(63)	(204)
Operating Income Effect		(67)	(146)
Other Income:			
Interest income from notes receivable	(f)	14	44
Nuclear decommissioning trust earnings	(g)	(5)	(11)
Capitalized Interest	(h)	(3)	(7)
Total - Other Income Effect		6	26
Income taxes	(i)	(25)	(49)
Net Income Effect		$ (36)	$ (71)

(a) Elimination of non-nuclear generation assets lease to FGCO.
(b) Reduction of nuclear-generated wholesale KWH sales to FES.
(c) Reduction of nuclear fuel and operating costs.
(d) Reduction of depreciation expense and asset retirement obligation accretion related to generation assets.
(e) Reduction of property tax expense on generation assets.
(f) Interest income on associated company notes receivable from the transfer of generation net assets.
(g) Reduction of earnings on nuclear decommissioning trusts.

(h) Reduction of allowance for borrowed funds used during construction on nuclear capital expenditures.
(i) Income tax effect of the above adjustments.

Results of Operations

Earnings on common stock in the third quarter of 2006 decreased to $43 million from $131 million in the third quarter of 2005. In the first nine months of 2006, earnings on common stock decreased to $162 million from $233 million in the same period of 2005. The change in earnings in both periods reflected the effects of the generation asset transfer shown in the table above. Expenses during the third quarter of 2006 included $25 million of costs associated with the proposed FERC settlement (see Note 11) applicable to the first half of 2006. Earnings in the first nine months of 2005 were reduced by additional income taxes of $36 million from the implementation of Ohio tax legislation changes and charges related to an $8.5 million civil penalty payable to the DOJ and $10 million for environmental projects in connection with the Sammis Plant settlement (see Outlook — Environmental Matters).

Revenues

Revenues decreased by $152 million or 18.4% in the third quarter of 2006 compared with the same period in 2005, primarily due to the generation asset transfer impact summarized in the table above. Excluding the effects of the asset transfer, revenues in the third quarter of 2006 decreased $22 million, primarily due to decreases of $68 million and $127 million in wholesale sales and distribution revenues, respectively, partially offset by increases in retail generation revenues of $149 million and reduced customer shopping incentives of $24 million.

In the first nine months of 2006 compared with the same period in 2005, revenues decreased by $436 million or 19.2%, primarily from the generation asset transfer impact summarized in the table above. Excluding the effects of the asset transfer, revenues in the first nine months of 2006 decreased $86 million, primarily due to decreases of $198 million and $337 million in wholesale sales and distribution revenues, respectively, partially offset by increases in retail generation revenues of $381 million and reduced customer shopping incentives of $62 million.

The lower wholesale revenues in both periods of 2006 primarily resulted from the termination of a non-affiliated wholesale sales agreement and the December 2005 cessation of the MSG sales arrangements under OE’s transition plan. OE had been required to provide the MSG to non-affiliated alternative suppliers.

Changes in electric generation KWH sales and revenues in the third quarter and first nine months of 2006 from the corresponding periods of 2005 are summarized in the following table.

Changes in Generation KWH Sales Increase (Decrease)	**Three Months**	**Nine Months**
Electric Generation:		
Retail	14.9 %	13.3 %
Wholesale	(85.8)%	(83.9)%
Net Decrease in Generation Sales	**(32.7)%**	**(30.7)%**

Changes in Generation Revenues Increase (Decrease)	**Three Months**	**Nine Months**
	(In millions)	
Retail Generation:		
Residential	$ 59	$ 143
Commercial	46	116
Industrial	44	122
Total Retail Generation	149	381
Wholesale*	(68)	(198)
Net Increase in Generation Revenues	**$ 81**	$ 183

* Excludes impact of generation asset transfers related to nuclear-generated KWH sales.

Increased retail generation revenues for the third quarter of 2006 (as shown in the table above) resulted from higher KWH sales and higher unit prices. The increase in generation KWH sales primarily resulted from decreased customer shopping, as the percentage of generation services provided by alternative suppliers to total sales delivered in OE's service area decreased by: residential - 12.4 percentage points; commercial - 13.0 percentage points; and industrial - 10.9 percentage points. The decrease in shopping resulted from certain alternative energy suppliers terminating their supply arrangements with OE's shopping customers in the fourth quarter of 2005. Higher unit prices for generation reflected the rate stabilization charge and the fuel recovery rider that both became effective in the first quarter of 2006 under provisions of the RSP and RCP.

Retail generation revenues increased in the first nine months of 2006 compared to the same period of 2005 for the reasons described above. The increase in generation KWH sales primarily resulted from a decrease in customer shopping, as the percentage of generation services provided by alternative suppliers to total sales delivered in OE's service area decreased by: residential - 10.6 percentage points; commercial - 12.2 percentage points; and industrial - 10.5 percentage points. Higher unit prices for generation reflected the impact of the RSP and RCP described above.

Changes in distribution KWH deliveries and revenues in the third quarter and first nine months of 2006 from the corresponding periods of 2005 are summarized in the following table.

Changes in Distribution KWH Deliveries	**Three Months**	**Nine Months**
Increase (Decrease)		
Distribution Deliveries:		
Residential	(4.2)%	(3.9)%
Commercial	(1.4)%	(1.5)%
Industrial	0.3%	0.4%
Net Decrease in Distribution Deliveries	**(1.8)%**	**(1.7)%**

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Changes in Distribution Revenues	**Three Months**	**Nine Months**
Increase (Decrease)	***(In millions)***	
Residential	$ (60)	$ (148)
Commercial	(37)	(102)
Industrial	(30)	(87)
Net Decrease in Distribution Revenues	**(127)**	**$ (337)**

Lower distribution revenues shown in the table above for the third quarter and first nine months of 2006 reflect lower composite prices and reduced KWH deliveries to residential and commercial customers. The lower unit prices in both periods resulted from the completion of the generation-related transition cost recovery under the OE Companies' respective rate restructuring plans in 2005, partially offset by increased transmission rates to recover MISO costs beginning in 2006 (see Outlook - Regulatory Matters). Lower KWH deliveries to residential and commercial customers reflected the impact of milder weather conditions in the third quarter and first nine months of 2006, compared to the same periods of 2005. KWH deliveries to industrial customers increased slightly in both periods due to the recovering steel industry in the OE Companies' service territory.

Under the Ohio transition plan, OE provided incentives to customers to encourage switching to alternative energy providers, which reduced OE's revenues by $24 million in the third quarter of 2005 and $62 million in the first nine months of 2005. These revenue reductions, which were deferred for future recovery and did not affect earnings, ceased in 2006. The deferred shopping incentives (Extended RTC) are now being recovered under the RCP (see Outlook - Regulatory Matters).

Expenses

Total expenses increased by $22 million in the third quarter of 2006 and decreased by $159 million in the first nine months of 2006 from the same periods of 2005. The change in both periods was impacted by the effects of the generation asset transfers shown in the table above. Excluding the asset transfer effects, the following table presents changes from the prior year by expense category:

Expenses - Changes	**Three Months**	**Nine Months**
Increase (Decrease)	***(In millions)***	
Purchased power costs	$ 166	$ 268
Nuclear operating costs	2	(12)
Other operating costs	(7)	(3)
Provision for depreciation	3	9

Amortization of regulatory assets		(77)	(201)
Deferral of new regulatory assets		(1)	(16)
General taxes		(2)	-
Net increase in expenses	**$**	**84**	**45**

Increased purchased power costs in the third quarter and first nine months of 2006 reflected higher unit prices associated with the new power supply agreement with FES, partially offset by a decrease in KWH purchased to meet the lower net generation sales requirements. Excluding the effects of the generation asset transfers, the lower nuclear operating costs in the first nine months of 2006 for OE's nuclear leasehold interests were primarily due to the absence in 2006 of both the Beaver Valley Unit 2 refueling outage in 2005 and the Perry Nuclear Power Plant scheduled refueling outage (including an unplanned extension) that was completed on May 6, 2005. The decrease in other operating costs during the third quarter and the first nine months of 2006 was primarily due to lower associated company (FES) transmission expenses as a result of alternative energy suppliers terminating their supply arrangements with OE's shopping customers in the fourth quarter of 2005 and lower employee benefit expenses. These decreases in the first nine months of 2006 were partially offset by increases in transmission expenses related to MISO Day 2 operations that began on April 1, 2005.

Excluding the effects of the generation asset transfers, higher depreciation expense in the third quarter and first nine months of 2006 reflected capital additions subsequent to the third quarter of 2005. Lower amortization of regulatory assets in both periods was due to the completion of the generation-related transition cost amortization under the OE Companies' respective transition plans, partially offset by the amortization of deferred MISO costs being recovered in 2006. The higher deferrals of new regulatory assets in the third quarter and first nine months of 2006 primarily resulted from the deferral of fuel costs ($21 million and $45 million, respectively) and distribution costs ($18 million and $58 million, respectively) under the RCP, partially offset by lower MISO cost deferrals ($13 million and $23 million, respectively) and the decrease in shopping incentive deferrals ($25 million and $64 million, respectively) which ceased in 2006 under the Ohio transition plan. The deferral of interest on the unamortized shopping incentive balances continues under the RCP.

Other Income (Expense)

Other income decreased $1 million in the third quarter of 2006 as compared with the same period of 2005, reflecting the effects of the generation asset transfers. Excluding the effects of the generation asset transfers, the $8 million decrease in the third quarter of 2006 was primarily due to an additional $10 million of interest expense from OE's June 2006 issuance of $600 million of long-term debt. As discussed below under Capital Resources and Liquidity, OE primarily used the debt proceeds to repurchase $500 million of its common stock from FirstEnergy. This represents a part of FirstEnergy's 2006 refinancing strategy to obtain additional holding company financing flexibility by using the OE common stock repurchase proceeds to redeem holding company debt and to capitalize its regulated utility subsidiaries more appropriately from a regulatory context.

Other income increased $46 million in the first nine months of 2006 as compared with the same period of 2005, primarily due to the effects of the generation asset transfers. Excluding the effects of the generation asset transfers, the $20 million increase in the first nine months of 2006 is primarily due to the absence in 2006 of the 2005 charges of $8.5 million for a civil penalty payable to the DOJ and $10 million for environmental projects in connection with the Sammis New Source Review settlement (see Outlook - Environmental Matters) partially offset by a $3 million increase in interest expense. The interest expense increase reflected the effect of the June 2006 long-term debt issuance discussed above, and was partially offset by the impact of other debt redemptions subsequent to the third quarter of 2005.

Income Taxes

Income taxes decreased $87 million in the third quarter of 2006 and $162 million in the first nine months of 2006 compared with the same periods of 2005. Excluding the effects of the generation asset transfer, income taxes decreased $63 million in the third quarter of 2006 and $113 million in the first nine months of 2006. The decreases in both periods was mainly due to decreases in taxable income, partially offset by a reduction in the tax rates due to the continuing phase-out of the income-based Ohio franchise tax. The income taxes decrease in the first nine months of 2006 also reflected the absence in 2006 of a $36 million write-off of net deferred tax benefits in the second quarter of 2005, resulting from the new Ohio tax legislation in 2005.

Capital Resources and Liquidity

OE's cash requirements for the remainder of 2006 for operating expenses, construction expenditures and scheduled debt maturities are expected to be met with cash from operations and short-term credit arrangements. OE repurchased $500 million of common stock from FirstEnergy and redeemed $64 million of preferred stock (including redemption premiums) in July 2006 with proceeds of senior notes issued in June 2006. Available borrowing capacity under credit facilities will be used to manage working capital requirements.

Changes in Cash Position

OE had $703,000 of cash and cash equivalents as of September 30, 2006 compared with $929,000 as of December 31, 2005. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Cash provided from operating activities during the first nine months of 2006, compared with the corresponding period in 2005, was as follows:

Operating Cash Flows	Nine Months Ended September 30, 2006	2005
	(In millions)	
Cash earnings [1]	$ 224	$ 603
Working capital and other	(16)	198
Net cash provided from operating activities	$ 208	$ 801

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

Cash earnings (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. Generally, a non-GAAP financial measure is a numerical measure of a company's historical or future financial performance, financial position, or cash flows that either excludes or includes amounts, or is subject to adjustment that has the effect of excluding or including amounts, that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with GAAP. In addition, cash earnings (non-GAAP) are not defined under GAAP. Management believes presenting this non-GAAP measure provides useful information to investors in assessing OE's operating performance from a cash perspective without the effects of material unusual economic events. OE's management frequently references these non-GAAP financial measures in its decision-making, using them to facilitate historical and ongoing performance comparisons as well as comparisons to the performance of peer companies. These non-GAAP measures should be considered in addition to, and not as a substitute for, their most directly comparable financial measures prepared in accordance with GAAP.

	Nine Months Ended September 30,	
Reconciliation of Cash Earnings	**2006**	**2005**
	(In millions)	
Net income (GAAP)	$ 167	$ 235
Non-cash charges (credits):		
Provision for depreciation	54	88
Amortization of regulatory assets	147	348
Deferral of new regulatory assets	(123)	(108)
Nuclear fuel and capital lease amortization	1	31
Amortization of electric service obligation	(25)	(8)
Amortization of lease costs	28	30
Deferred income taxes and investment tax credits, net	(28)	(23)
Accrued compensation and retirement benefits	3	10
Cash earnings (Non-GAAP)	$ 224	$ 603

Net cash provided from operating activities decreased $593 million in the first nine months of 2006, compared with the same period in 2005, due to a $379 million decrease in cash earnings as described above under “Results of Operations” and a $214 million decrease from changes in working capital. The decrease in working capital primarily reflects the absence in 2006 of $136 million in funds received under the Energy for Education program in 2005 and changes in accrued taxes of $88 million and accounts receivable of $84 million, partially offset by changes in accounts payable of $80 million.

Cash Flows From Financing Activities

Net cash used for financing activities increased by $14 million in the first nine months of 2006 from the same period last year. The increase in funds used for financing activities primarily resulted from a $500 million repurchase of common stock, partially offset by a $317 million decrease in net preferred stock and debt redemptions and a $168 million decrease in common stock dividend payments to FirstEnergy.

OE had approximately $472 million of cash and temporary cash investments (which include short-term notes receivable from associated companies) and $24 million of short-term indebtedness as of September 30, 2006. OE has authorization from the PUCO to incur short-term debt of up to $500 million, which is available through the bank facility and the utility money pool described below. Penn has authorization from the FERC to incur short-term debt up to its charter limit of $44 million as of September 30, 2006, and also has access to the bank facility and 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, 2006, the facility was not drawn.

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 which expires July 28, 2007. 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, 2006, the facility was drawn for $19 million.

As of September 30, 2006, OE and Penn had the aggregate capability to issue approximately $592 million of additional FMB on the basis of property additions and retired bonds under the terms of their respective mortgage indentures. The issuance of FMB by OE is also subject to provisions 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, OE is permitted under the indenture to incur additional secured debt not otherwise permitted by a specified exception of up to $655 million as of September 30, 2006. Based upon applicable earnings coverage tests in its charter, Penn could issue a total of $136 million of preferred stock (assuming no additional debt was issued) as of September 30, 2006. As a result of OE redeeming all of its outstanding preferred stock on July 7, 2006, the applicable earnings coverage test is inoperable for OE. In the event that OE issues preferred stock in the future, the applicable earnings coverage test will govern the amount of additional preferred stock that OE may issue.

As of September 30, 2006, OE had approximately $400 million of capacity remaining unused under its existing shelf registration for unsecured debt securities.

On August 24, 2006, FirstEnergy, OE, Penn, CEI, TE, JCP&L, Met-Ed, Penelec, FES and ATSI, as Borrowers, entered into a new $2.75 billion five-year revolving credit facility which replaced the prior $2 billion credit facility. FirstEnergy may request an increase in the total commitments available under the new facility up to a maximum of $3.25 billion. Commitments under the new facility are available until August 24, 2011, unless the lenders agree, at the request of the Borrowers, to two additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each Borrower are subject to a specified sub-limit, as well as applicable regulatory and other limitations. OE's borrowing limit under the facility is $500 million and Penn’s is $50 million, subject in each case to applicable regulatory approvals.

Under the revolving credit facility, borrowers may request the issuance of LOCs expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under the facility and against the applicable borrower’s borrowing sub-limit. Total unused borrowing capability under the credit facility and accounts receivable financing facilities totaled $726 million as of September 30, 2006.

The revolving credit facility contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%, measured at the end of each fiscal quarter. As of September 30, 2006, debt to total capitalization as defined under the revolving credit facility was 46% for OE and 33% for Penn.

The revolving credit facility does not contain any provisions that either restricts the ability of OE and Penn 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 OE’s and Penn’s credit ratings.

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 first nine months of 2006 was 5.09%.

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

On April 3, 2006, pollution control notes that were formerly obligations of OE and Penn were refinanced and became obligations of FGCO and NGC. The proceeds from the refinancings were used to repay a portion of FGCO's and NGC's associated company notes payable to Penn and OE. With those repayments, OE redeemed $74.8 million and Penn redeemed $6.95 million of pollution control notes having variable interest rates.

On June 26, 2006, OE issued $600 million of unsecured senior notes, comprised of $250 million of 6.4% notes due 2016 and $350 million of 6.875% notes due 2036. The net proceeds from this offering were used in July 2006 to repurchase $500 million of OE common stock from FirstEnergy, redeem approximately $61 million of its preferred stock and to reduce short-term borrowings.

Cash Flows From Investing Activities

Net cash provided from investing activities was $153 million in the first nine months of 2006 compared to $454 million used for investing activities in the first nine months of 2005. The change resulted primarily from a $407 million increase in loan repayments from associated companies and a $97 million decrease in property additions, which reflects the impact of the generation asset transfers and $78 million from liquidating investments (restrictions on short-term investments expired for an escrow fund and a mortgage indenture deposit).

In the last quarter of 2006, capital requirements for property additions and capital leases are expected to be approximately $20 million. OE has additional requirements of approximately $2 million to meet requirements for maturing long-term debt during the remainder of 2006. These cash requirements are expected to be satisfied from a combination of internal cash and short-term credit arrangements. OE’s capital spending for the period 2006-2010 is expected to be approximately $630 million, of which approximately $114 million applies to 2006.

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 $655 million as of September 30, 2006.

Equity Price Risk

Included in OE’s nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $73 million and $67 million as of September 30, 2006 and December 31, 2005, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $7 million reduction in fair value as of September 30, 2006. 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

Regulatory assets and liabilities are costs which have been authorized by the PUCO, the PPUC and the FERC for recovery from, or credit to, customers in future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets and liabilities would have been charged or creditied to income as incurred. All regulatory assets are expected to be recovered under the provisions of OE’s transition plan. OE‘s regulatory assets were $746 million and $775 million as of September 30, 2006 and December 31, 2005, respectively. Penn had net regulatory liabilities of $64 million and $59 million as of September 30, 2006 and December 31, 2005, respectively, which are included in Other Noncurrent Liabilities on the Consolidated Balance Sheets as of September 30, 2006 and December 31, 2005.

On October 21, 2003, the Ohio Companies filed their RSP case with the PUCO. 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 CBP. The RSP was intended to establish generation service rates beginning January 1, 2006, in response to the PUCO’s 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 the proceeding as well as the associated entries on rehearing. On May 3, 2006, the Supreme Court of Ohio issued an opinion affirming the PUCO's order with respect to the approval of the rate stabilization charge, approval of the shopping credits, the granting of interest on shopping credit incentive deferral amounts, and approval of the Ohio Companies’ financial separation plan. It remanded back to the PUCO the matter of ensuring the availability of sufficient means for customer participation in the competitive marketplace. The RSP contained a provision that permitted the Ohio Companies to withdraw and terminate the RSP in the event that the PUCO, or the Supreme Court of Ohio, rejected all or part of the RSP. In such event, the Ohio Companies have 30 days from the final order or decision to provide notice of termination. On July 20, 2006 the Ohio Companies filed with the PUCO a Request to Initiate a Proceeding on Remand. In their Request, the Ohio Companies provided notice of termination to those provisions of the RSP subject to termination, subject to being withdrawn, and also set forth a framework for addressing the Supreme Court of Ohio’s findings on customer participation, requesting the PUCO to initiate a proceeding to consider the Ohio Companies’ proposal. If the PUCO approves a resolution to the issues raised by the Supreme Court of Ohio that is acceptable to the Ohio Companies, the Ohio Companies’ termination will be withdrawn and considered to be null and void. Separately, the OCC and NOAC also submitted to the PUCO on July 20, 2006 a conceptual proposal dealing with the issue raised by the Supreme Court of Ohio. On July 26, 2006, the PUCO issued an Entry acknowledging the July 20, 2006 filings of the Ohio Companies and the OCC and NOAC, and giving the Ohio Companies 45 days to file a plan in a new docket to address the Court’s concern. On September 19, 2006, the PUCO issued an Entry granting the Ohio Companies’ motion for extension of time to file the remand proposal. The Ohio Companies filed their RSP Remand CBP on September 29, 2006. No further proceedings have been scheduled at this time.

The Ohio Companies filed an application and stipulation with the PUCO on September 9, 2005 seeking approval of the RCP, a supplement to the RSP. On November 4, 2005, the Ohio Companies filed a supplemental stipulation with the PUCO, which constituted an additional component of the RCP filed on September 9, 2005. Major provisions of the RCP include:

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

Deferring and capitalizing for future recovery (over a 25-year period) with carrying charges 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;

Adjusting 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;

Reducing the deferred shopping incentive balances 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

Recovering increased fuel costs (compared to a 2002 baseline) 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. The Ohio Companies may defer and capitalize (for recovery over a 25-year period) increased fuel costs above the amount collected through the fuel recovery mechanism.

The following table provides OE’s estimated net amortization of regulatory transition costs and deferred shopping incentives (including associated carrying charges) under the RCP for the period 2006 through 2008:

Amortization Period	**Amortization**	
	(In millions)	
2006	$	173
2007		180
2008		207
Total Amortization	**$**	**560**

On January 4, 2006, the PUCO approved, with modifications, the Ohio Companies' RCP to supplement the RSP to provide customers with more certain rate levels than otherwise available under the RSP during the plan period. On January 10, 2006, the Ohio Companies filed a Motion for Clarification of the PUCO order approving the RCP. The Ohio Companies sought clarity on issues related to distribution deferrals, including requirements of the review process, timing for recognizing certain deferrals and definitions of the types of qualified expenditures. The Ohio Companies also sought confirmation that the list of deferrable distribution expenditures originally included in the revised stipulation fall within the PUCO order definition of qualified expenditures. On January 25, 2006, the PUCO issued an Entry on Rehearing granting in part, and denying in part, the Ohio Companies' previous requests and clarifying issues referred to above. The PUCO granted the Ohio Companies' requests to:

- Recognize fuel and distribution deferrals commencing January 1, 2006;
- Recognize distribution deferrals on a monthly basis prior to review by the PUCO Staff;
- Clarify that the types of distribution expenditures included in the Supplemental Stipulation may be deferred; and
- Clarify that distribution expenditures do not have to be "accelerated" in order to be deferred.

The PUCO approved the Ohio Companies' methodology for determining distribution deferral amounts, but denied the Motion in that the PUCO Staff must verify the level of distribution expenditures contained in current rates, as opposed to simply accepting the amounts contained in the Ohio Companies' Motion. On February 3, 2006, several other parties filed applications for rehearing on the PUCO's January 4, 2006 Order. The Ohio Companies responded to the applications for rehearing on February 13, 2006. In an Entry on Rehearing issued by the PUCO on March 1, 2006, all motions for rehearing were denied. Certain of these parties have subsequently filed notices of appeal with the Supreme Court of Ohio alleging various errors made by the PUCO in its order approving the RCP. The Ohio Companies' Motion to Intervene in the appeals was granted by the Supreme Court on June 8, 2006. The Appellants' Merit Briefs were filed at the Supreme Court on July 5, 2006. The Appellees include the PUCO and the Ohio Companies. The Appellees' Merit Briefs were filed on August 24, 2006 and the Appellants' Reply Briefs were filed on September 21, 2006. The OCC filed an amicus brief on August 4, 2006, which the Ohio Companies moved to strike as improperly filed. The Supreme Court denied the Ohio Companies' motion on October 18, 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 sought recovery of these costs beginning January 1, 2006. OE requested that these costs be recovered through a rider that would be effective on January 1, 2006 and adjusted each July 1 thereafter. The parties reached a settlement agreement that was approved by the PUCO on August 31, 2005. The incremental transmission and ancillary service revenues recovered from January 1 through June 30, 2006 were approximately $31 million. That amount included the recovery of a portion of the 2005 deferred MISO expenses as described below. On April 27, 2006, OE filed the annual update rider to determine revenues ($70 million) from July 2006 through June 2007. The filed rider went into effect on July 1, 2006.

The second application sought authority to defer costs associated with transmission and ancillary service related costs incurred during the period 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 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 the Ohio Companies to accrue carrying charges on the deferred balances. On August 31, 2005, the OCC appealed the PUCO's decision. On January 20, 2006, the OCC sought rehearing of the PUCO’s approval of the recovery of deferred costs through the rider during the period January 1, 2006 through June 30, 2006. The PUCO denied the OCC's application on February 6, 2006. On March 23, 2006, the OCC appealed the PUCO's order to the Ohio Supreme Court. On March 27, 2006, the OCC filed a motion to consolidate this appeal with the deferral appeals discussed above and to postpone oral arguments in the deferral appeal until after all briefs are filed in this most recent appeal of the rider recovery mechanism. On March 20, 2006, the Ohio Supreme Court, on its own motion, consolidated the OCC's appeal of the Ohio Companies' case with a similar case involving Dayton Power & Light Company. Oral arguments were heard on May 10, 2006. The Ohio Companies are awaiting a final ruling from the Ohio Supreme Court, which is expected before the end of 2006.

Under Pennsylvania's electric competition law, Penn is required to secure generation supply for customers who do not choose alternative suppliers for their electricity. 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 recommended that the RFP process cover the period January 1, 2007 through May 31, 2008. Hearings before the PPUC were held on January 10, 2006 with main briefs filed on January 27, 2006 and reply briefs filed on February 3, 2006. On February 16, 2006, the ALJ issued a Recommended Decision to adopt Penn's RFP process with modifications. On April 20, 2006, the PPUC approved the Recommended Decision with additional modifications to use an RFP process with two separate solicitations. An initial solicitation was held for Penn in May 2006 with all tranches fully subscribed, which was approved by the PPUC on June 2, 2006. On July 18, 2006, the second PLR solicitation was held for Penn. The tranches for the Residential Group and Small Commercial Group were fully subscribed. However, supply was not acquired for two tranches for the Large Commercial Group. On July 20, 2006, the PPUC approved the submissions for the second bid. A contingency solicitation was held on August 15, 2006 for the two remaining Large Commercial Group tranches. The PPUC rejected the bids from the contingency solicitation and directed Penn’s independent auction manager to offer the two unfilled Large Commercial tranches to the companies which had won tranches in the prior solicitations. This resulted in the acquisition of a supplier for the two remaining tranches, which were filed and accepted by the PPUC in a secretarial letter that was entered on September 22, 2006. On August 24, 2006, Penn made a compliance filing. OCA and OSBA filed exceptions to the compliance filing. Penn filed reply exceptions on September 5, 2006. On September 21, 2006, Penn submitted a revised compliance filing to the PPUC for the Residential Group and Small Commercial Group as a result of an agreement between Penn, OCA and OSBA. The PPUC approved proposed rates for the large commercial and industrial customers at the PPUC Public meeting on October 19, 2006, and found that the results of the competitive solicitation process were consistent with prevailing market prices.

On May 25, 2006, Penn filed a Petition for Review of the PPUC’s Orders of April 28, 2006 and May 4, 2006, which together decided the issues associated with Penn’s proposed Interim PLR Supply Plan. Penn has asked the Commonwealth Court to review the PPUC’s decision to deny Penn’s recovery of certain PLR costs through a reconciliation mechanism and the PPUC’s decision to impose a geographic limitation on the sources of alternative energy credits. On June 7, 2006, the PaDEP filed a Petition for Review appealing the PPUC’s ruling on the method by which alternative energy credits may be acquired and traded. Penn is unable to predict the outcome of this appeal.

On November 1, 2005, FES filed two power sales agreements for approval with the FERC. One power sales agreement provided for FES to provide the PLR requirements of the Ohio Companies at a price equal to the retail generation rates approved by the PUCO for a period of three years beginning January 1, 2006. The Ohio Companies will be relieved of their obligation to obtain PLR power requirements from FES if the Ohio CBP results in a lower price for retail customers. A similar power sales agreement between FES and Penn permits Penn to obtain its PLR power requirements from FES at a fixed price equal to the retail generation price during 2006.

On December 29, 2005, the FERC issued an order setting the two power sales agreements for hearing. The order criticized the Ohio CBP, and required FES to submit additional evidence in support of the reasonableness of the prices charged in the power sales agreements. A pre-hearing conference was held on January 18, 2006 to determine the hearing schedule in this case. Under the procedural schedule approved in this case, FES expected an initial decision to be issued in late January 2007. However, on July 14, 2006, the Chief Judge granted the joint motion of FES and the Trial Staff to appoint a settlement judge in this proceeding and the procedural schedule was suspended pending settlement discussions among the parties. A settlement conference was held on September 5, 2006. FES and the Ohio Companies, Penn, and the PUCO, along with other parties, reached an agreement to settle the case. The settlement was filed with the FERC on October 17, 2006, and was unopposed by the remaining parties, including the FERC Trial Staff. Initial comments to the settlement are due by November 6, 2006.

The terms of the settlement provide for modification of both the Ohio and Penn power supply agreements with FES. Under the Ohio power supply agreement, separate rates are established for the Ohio Companies' PLR requirements, special retail contracts requirements, wholesale contract requirements, and interruptible buy-through retail load requirements. For their PLR and special retail contract requirements, the Ohio Companies will pay FES no more than the lower of (i) the sum of the retail generation charge, the rate stabilization charge, the fuel recovery mechanism charge, and FES' actual incremental fuel costs for such sales; or (ii) the wholesale price cap. Different wholesale price caps are imposed for PLR sales, special retail contracts, and wholesale contracts. The wholesale price for interruptible buy-through retail load requirements is limited to the actual spot price of power obtained by FES to provide this power. The Ohio Companies have recognized the estimated additional amount payable to FES for power supplied during the nine months ended September 30, 2006. The wholesale rate charged by FES under the Penn power supply agreement will be no greater than the generation component of charges for retail PLR load in Pennsylvania. The FERC is expected to act on this case by the end of the fourth quarter of 2006.

As a result of Penn's PLR competitive solicitation process approved by the PPUC, FES was selected as the winning bidder for a number of the tranches for individual customer classes. The balance of the tranches will be supplied by unaffiliated power suppliers. On October 2, 2006, FES filed an application with FERC under Section 205 of the Federal Power Act for authorization to make these affiliate sales to Penn. Interventions or protests were due on this filing on October 23, 2006. Penn was the only party to file an intervention in this proceeding. The FERC is expected to act on this filing on or before December 1, 2006.

See Note 11 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 initiatives 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.

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 was approved by the Court on July 11, 2005, and requires reductions of NO_X and SO_2 emissions at the W. H. Sammis Plant and other coal-fired plants through the installation of pollution control devices and provides for stipulated penalties for failure to install and operate such pollution controls in accordance with that agreement. Consequently, if FirstEnergy fails to install such pollution control devices, for any reason, including, but not limited to, the failure of any third-party contractor to timely meet its delivery obligations for such devices, FirstEnergy could be exposed to penalties under the settlement agreement. Capital expenditures necessary to meet those requirements are currently estimated to be $1.5 billion ($400 million of which is expected to be spent in 2007 with the primary portion of the remaining $1.1 billion expected to be spent in 2008 and 2009). On August 26, 2005, FGCO entered into an agreement with Bechtel Power Corporation under which Bechtel will engineer, procure, and construct air quality control systems for the reduction of SO_2 emissions. FGCO also entered into an agreement with B&W on August 25, 2006 to supply flue gas desulfurization systems for the reduction of SO_2 emissions. Selective Catalytic Reduction (SCR) systems for the reduction of NOx emissions also are being installed at the W.H. Sammis Plant under a 1999 agreement with B&W. The above requirements will be the responsibility of FGCO.

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 paid by OE and Penn of $7.8 million and $0.7 million, respectively. OE and Penn also recognized liabilities in the first quarter of 2005 of $9.2 million and $0.8 million, respectively, for probable future cash contributions toward environmentally beneficial projects.

See Note 10(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 potentially material items not otherwise discussed above are described below.

Power Outages and Related Litigation-

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 Web site (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 is also proceeding with the implementation of the recommendations 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 may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future as a result of adoption of mandatory reliability standards pursuant to the EPACT that could require additional material expenditures.

FirstEnergy companies also are defending six separate complaint cases before the PUCO relating to the August 14, 2003 power outages. Two cases were originally filed in Ohio State courts but were subsequently dismissed for lack of subject matter jurisdiction and further appeals were unsuccessful. In these 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. Three other pending PUCO complaint cases were filed by various insurance carriers either in their own name as subrogees or in the name of their insured. In each of these three cases, the carrier seeks reimbursement from various FirstEnergy companies (and, in one case, from PJM, MISO and American Electric Power Company, Inc., as well) for claims paid to insureds for damages allegedly arising as a result of 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 sixth case involves the claim of a non-customer seeking reimbursement for losses incurred when its store was burglarized on August 14, 2003. That case has been dismissed. On March 7, 2006, the PUCO issued a ruling, based on motions filed by the parties, applicable to all pending cases. Among its various rulings, the PUCO consolidated all of the pending outage cases for hearing; limited the litigation to service-related claims by customers of the Ohio operating companies; dismissed FirstEnergy as a defendant; ruled that the U.S.-Canada Power System Outage Task Force Report was not admissible into evidence; and gave the plaintiffs additional time to amend their complaints to otherwise comply with the PUCO's underlying order. Also, most complainants, along with the FirstEnergy companies, filed applications for rehearing with the PUCO over various rulings contained in the March 7, 2006 order. On April 26, 2006, the PUCO granted rehearing to allow the insurance company claimants, as insurers, to prosecute their claims in their name so long as they also identify the underlying insured entities and the Ohio utilities that provide their service. The PUCO denied all other motions for rehearing. The plaintiffs in each case have since filed an amended complaint and the named FirstEnergy companies have answered and also have filed a motion to dismiss each action. On September 27, 2006, the PUCO dismissed certain parties and claims and otherwise ordered the complaints to go forward to hearing. The cases have been set for hearing on October 16, 2007.

On October 10, 2006, various insurance carriers refiled a complaint in Cuyahoga County Common Pleas Court seeking reimbursement for claims paid to numerous insureds who allegedly suffered losses as a result of the August 14, 2003 outages. All of the insureds appear to be non-customers. The plaintiff insurance companies are the same claimants in one of the pending PUCO cases. FirstEnergy, the Ohio Companies and Penn were served on October 27, 2006, and expect to seek summary dismissal of these cases based on the prior court rulings noted above. No estimate of potential liability is available for any of these cases.

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. Although unable to predict the impact of these proceedings, 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.

Nuclear Plant Matters-

As of December 16, 2005, NGC acquired ownership of the nuclear generation assets transferred from OE, Penn, CEI and TE with the exception of leasehold interests of OE and TE in certain of the nuclear plants that are subject to sale and leaseback arrangements with non-affiliates. Excluding OE's retained leasehold interests in Beaver Valley Unit 2 (21.66%) and the Perry Nuclear Power Plant (12.58%), the transfer included the OE Companies' prior owned interests in Beaver Valley Unit 1 (100%), Beaver Valley Unit 2 (33.96%) and the Perry Nuclear Power Plant (22.66%).

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 corrective action. FENOC operates the Perry Nuclear Power 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 Nuclear Power 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 September 28, 2005, the NRC sent a CAL to FENOC describing commitments that FENOC had made to improve the performance at the Perry Nuclear Power Plant 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. In the NRC's 2005 annual assessment letter dated March 2, 2006 and associated meetings to discuss the performance of Perry on March 14, 2006, the NRC again stated that the Perry Nuclear Power Plant continued to operate in a manner that "preserved public health and safety." However, the NRC also stated that increased levels of regulatory oversight would continue until sustained improvement in the performance of the facility was realized. 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. Although FirstEnergy is unable to predict the impact of the ultimate disposition of this matter, it could have a material adverse effect on FirstEnergy's or its subsidiaries' financial condition, results of operations and cash flows.

Other Legal Matters-

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 now repealed 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 related disclosures, which FirstEnergy has provided. 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 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. On October 18, 2006, the Ohio Supreme Court transferred this case to a Tuscarawas County Common Pleas Court judge due to concerns over potential class membership by the Jefferson County Common Pleas Court.

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. Both filings were consolidated for hearing and decision. 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. On May 10, 2006, the PUCO issued its Opinion and Order dismissing the City's complaint and approving the related tariffs, thus affirming OE's entitlement to recovery of its transition charges. The City of Huron filed an application for rehearing of the PUCO's decision on June 9, 2006 and OE filed a memorandum in opposition to that application on June 19, 2006. The PUCO denied the City's application for rehearing on June 28, 2006. The City of Huron has taken no further action and the period for filing an appeal has expired.

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

NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

SAB 108 - "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements"

In September 2006, the SEC issued SAB 108, which provides interpretive guidance on how registrants should quantify financial statement misstatements. There is currently diversity in practice, with the two commonly used methods to quantify misstatements being the "rollover" method (which primarily focuses on the income statement impact of misstatements) and the "iron curtain" method (which focuses on the balance sheet impact). SAB 108 requires registrants to use a dual approach whereby both of these methods are considered in evaluating the materiality of financial statement errors. Prior materiality assessments will need to be reconsidered using both the rollover and iron curtain methods. This guidance will be effective for OE in the fourth quarter of 2006. OE does not expect this Statement to have a material impact on its financial statements.

SFAS 157 - "Fair Value Measurements"

In September 2006, the FASB issued SFAS 157 that establishes how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under GAAP. This Statement addresses the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. The key changes to current practice are: (1) the definition of fair value which focuses on an exit price rather than entry price; (2) the methods used to measure fair value such as emphasis that fair value is a market-based measurement, not an entity-specific measurement, as well as the inclusion of an adjustment for risk, restrictions and credit standing; and (3) the expanded disclosures about fair value measurements.

This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. OE is currently evaluating the impact of this Statement on its financial statements.

SFAS 158 - "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)"

In September 2006, the FASB issued SFAS 158, which requires companies to recognize a net liability or asset to report the overfunded or underfunded status of their defined benefit pension and other postretirement benefit plans on their balance sheets and recognize changes in funded status in the year in which the changes occur through other comprehensive income. The funded status to be measured is the difference between plan assets at fair value and the benefit obligation. This Statement requires that gains and losses and prior service costs or credits, net of tax, that arise during the period be recognized as a component of other comprehensive income and not as components of net periodic benefit cost. Additional information should also be disclosed in the notes to the financial statements about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and transition asset or obligation. Upon the initial application of this Statement and subsequently, an employer should continue to apply the provisions in Statements 87, 88 and 106 in measuring plan assets and benefit obligations as of the date of its statement of financial position and in determining the amount of net periodic benefit cost. This Statement is effective for OE as of December 31, 2006. OE is currently evaluating the impact of this Statement on its financial statements.

FIN 48 - "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109."

In June 2006, the FASB issued FIN 48 which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, "Accounting for Income Taxes." This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken on a tax return. This interpretation also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation will be a two-step process. The first step will determine if it is more likely than not that a tax position will be sustained upon examination and should therefore be recognized. The second step will measure a tax position that meets the more likely than not recognition threshold to determine the amount of benefit to recognize in the financial statements. This interpretation is effective for fiscal years beginning after December 15, 2006. OE is currently evaluating the impact of this Statement.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
		(In thousands)		
STATEMENTS OF INCOME				
REVENUES	$ 515,923	$ 526,421	$ 1,356,104	$ 1,408,341
EXPENSES:				
Fuel	12,748	24,701	39,724	64,138
Purchased power	229,779	129,640	531,490	411,366
Nuclear operating costs	-	26,252	-	121,765
Other operating costs	81,510	89,475	222,841	227,759
Provision for depreciation	17,524	36,100	45,775	100,602
Amortization of regulatory assets	38,826	68,455	99,832	177,497
Deferral of new regulatory assets	(39,060)	(60,519)	(101,283)	(126,508)
General taxes	34,228	40,054	100,808	115,546
Total expenses	375,555	354,158	939,187	1,092,165
OPERATING INCOME	140,368	172,263	416,917	316,176
OTHER INCOME (EXPENSE):				
Investment income	24,715	36,629	76,325	65,826
Miscellaneous income (expense)	813	411	6,209	(8,353)
Interest expense	(34,774)	(31,786)	(104,140)	(96,404)
Capitalized interest	836	1,129	2,346	2,012
Total other income (expense)	(8,410)	6,383	(19,260)	(36,919)
INCOME BEFORE INCOME TAXES	131,958	178,646	397,657	279,257
INCOME TAXES	48,496	68,209	150,730	114,679
NET INCOME	83,462	110,437	246,927	164,578
PREFERRED STOCK DIVIDEND REQUIREMENTS	-	-	-	2,918
EARNINGS ON COMMON STOCK	$ 83,462	$ 110,437	$ 246,927	$ 161,660

STATEMENTS OF COMPREHENSIVE INCOME								
NET INCOME	$	83,462	$	110,437	$	246,927	$	164,578
OTHER COMPREHENSIVE INCOME (LOSS):								
Unrealized loss on available for sale securities		-		(6,574)		-		(9,144)
Income tax benefit related to other comprehensive loss		-		2,510		-		3,433
Other comprehensive loss, net of tax		-		(4,064)		-		(5,711)
TOTAL COMPREHENSIVE INCOME	$	83,462	$	106,373	$	246,927	$	158,867

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, 2006	December 31, 2005
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 223	$ 207
Receivables-		
Customers (less accumulated provisions of $6,819,000 and $5,180,000, respectively, for uncollectible accounts)	283,267	268,427
Associated companies	63,926	86,564
Other	24,075	16,466
Notes receivable from associated companies	29,184	19,378
Prepayments and other	2,290	1,903
	402,965	392,945
UTILITY PLANT:		
In service	2,082,224	2,030,935
Less - Accumulated provision for depreciation	808,728	788,967
	1,273,496	1,241,968
Construction work in progress	75,127	51,129
	1,348,623	1,293,097
OTHER PROPERTY AND INVESTMENTS:		
Long-term notes receivable from associated companies	940,786	1,057,337
Investment in lessor notes	519,613	564,166
Other	13,631	12,840
	1,474,030	1,634,343
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,688,521	1,688,966
Regulatory assets	854,525	862,193
Prepaid pension costs	136,116	139,012
Property taxes	63,500	63,500
Other	26,261	27,614
	2,768,923	2,781,285
	$ 5,994,541	$ 6,101,670
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 120,556	$ 75,718
Short-term borrowings-		
Associated companies	302,588	212,256
Other	-	140,000
Accounts payable-		
Associated companies	103,449	74,993
Other	5,889	4,664

Accrued taxes		106,899		121,487
Accrued interest		31,313		18,886
Lease market valuation liability		60,200		60,200
Other		48,661		61,308
		779,555		769,512
CAPITALIZATION:				
Common stockholder's equity-				
Common stock, without par value, authorized 105,000,000 shares -				
79,590,689 shares outstanding		1,355,957		1,354,924
Retained earnings		716,077		587,150
Total common stockholder's equity		2,072,034		1,942,074
Long-term debt and other long-term obligations		1,766,195		1,939,300
		3,838,229		3,881,374
NONCURRENT LIABILITIES:				
Accumulated deferred income taxes		547,307		554,828
Accumulated deferred investment tax credits		21,185		23,908
Lease market valuation liability		562,900		608,000
Retirement benefits		83,615		83,414
Deferred revenues - electric service programs		57,638		71,261
Other		104,112		109,373
		1,376,757		1,450,784
COMMITMENTS AND CONTINGENCIES (Note 10)				
	$	5,994,541	$	6,101,670

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)

	Nine Months Ended September 30,	
	2006	**2005**
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 246,927	$ 164,578
Adjustments to reconcile net income to net cash from operating activities -		
Provision for depreciation	45,775	100,602
Amortization of regulatory assets	99,832	177,497
Deferral of new regulatory assets	(101,283)	(126,508)
Nuclear fuel and capital lease amortization	179	19,017
Deferred rents and lease market valuation liability	(55,166)	(67,130)
Deferred income taxes and investment tax credits, net	(9,513)	14,934
Accrued compensation and retirement benefits	2,681	2,997
Decrease (increase) in operating assets-		
Receivables	189	(87,567)
Materials and supplies	-	(13,584)
Prepayments and other current assets	(387)	(633)
Increase (decrease) in operating liabilities-		
Accounts payable	29,681	(118,908)
Accrued taxes	(14,588)	27,176
Accrued interest	12,427	5,140
Electric service prepayment programs	(13,623)	55,311
Other	(5,449)	(26,328)
Net cash provided from operating activities	237,682	126,594
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	-	141,056
Short-term borrowings, net	-	53,369
Equity contributions from parent	-	75,000
Redemptions and Repayments-		
Preferred stock	-	(101,900)
Long-term debt	(118,295)	(147,789)
Short-term borrowings, net	(58,819)	-
Dividend Payments-		
Common stock	(118,000)	(141,000)
Preferred stock	-	(2,260)
Net cash used for financing activities	(295,114)	(123,524)

CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions		(89,771)		(98,053)
Loan repayments from associated companies, net		108,034		89,236
Investments in lessor notes		44,553		32,476
Proceeds from nuclear decommissioning trust fund sales		-		376,309
Investments in nuclear decommissioning trust funds		-		(398,077)
Other		(5,368)		(4,951)
Net cash provided from (used for) investing activities		57,448		(3,060)
Net increase in cash and cash equivalents		16		10
Cash and cash equivalents at beginning of period		207		197
Cash and cash equivalents at end of period	$	223	$	207

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 Stockholder 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, 2006, and the related consolidated statements of income and comprehensive income for each of the three-month and nine-month periods ended September 30, 2006 and 2005 and the consolidated statements of cash flows for the nine-month periods ended September 30, 2006 and 2005. 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 have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2005, and the related consolidated statements of income, capitalization, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report [which contained references to the Company's change in its method of accounting for asset retirement obligations as of January 1, 2003 and conditional asset retirement obligations as of December 31, 2005 as discussed in Note 2(G) and Note 11 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 February 27, 2006, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2005, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers
LLP
Cleveland, Ohio
October 31, 2006

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's power supply requirements are primarily provided by FES - an affiliated company.

FirstEnergy Intra-System Generation Asset Transfers

In 2005, the Ohio Companies and Penn entered into certain agreements implementing a series of intra-system generation asset transfers that were completed in the fourth quarter of 2005. The asset transfers resulted in the respective undivided ownership interests of the Ohio Companies and Penn in FirstEnergy's nuclear and non-nuclear generation assets being owned by NGC and FGCO, respectively. The generating plant interests transferred did 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 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 FGCO's purchase option under the Master Facility Lease.

On December 16, 2005, CEI completed the intra-system transfer of its ownership interests in the nuclear generation assets to NGC through a sale at net book value. FENOC continues to operate and maintain the nuclear generation assets.

These transactions were undertaken 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 essentially completed the divestitures contemplated by the restructuring plans by transferring the ownership interests to NGC and FGCO without impacting the operation of the plants.

The transfers will affect CEI's comparative earnings results with reductions in both revenues and expenses. Revenues are reduced due to the termination of certain arrangements with FES, under which CEI previously sold its nuclear-generated KWH to FES and leased its non-nuclear generation assets to FGCO, a subsidiary of FES. CEI's expenses are lower due to the nuclear fuel and operating costs assumed by NGC as well as depreciation and property tax expenses assumed by FGCO and NGC related to the transferred generating assets. With respect to CEI's retained leasehold interests in the Bruce Mansfield Plant, CEI has continued the fossil generation KWH sales arrangement with FES and continues to be obligated on the applicable portion of expenses related to those interests. In addition, CEI receives interest income on associated company notes receivable from the transfer of its generation net assets. FES continues to provide CEI's PLR requirements under revised purchased power arrangements covering the three-year period beginning January 1, 2006 (see Regulatory Matters).

The effects on CEI's results of operations in the third quarter and nine months ended September 30, 2006 compared to the same periods of 2005 from the generation asset transfers (also reflecting CEI's retained leasehold interests discussed above) are summarized in the following table:

Intra-System Generation Asset Transfers

Income Statement Effects Increase (Decrease)		**Three Months**	**Nine Months**
		(In millions)	
Revenues:			
Non-nuclear generating units rent	(a)	$ (15)	$ (44)
Nuclear-generated KWH sales	(b)	(80)	(190)
Total - Revenues Effect		(95)	(234)
Expenses:			
Fuel costs - nuclear	(c)	(10)	(24)
Nuclear operating costs	(c)	(27)	(122)
Provision for depreciation	(d)	(16)	(48)
General taxes	(e)	(3)	(11)
Total - Expenses Effect		(56)	(205)
Operating Income Effect		(39)	(29)
Other Income:			
Interest income from notes receivable	(f)	14	44
Nuclear decommissioning trust earnings	(g)	(23)	(27)
Capitalized interest	(h)	(1)	(1)
Total - Other Income Effect		(10)	16
Income taxes	(i)	(20)	(5)
Net Income Effect		$ (29)	$ (8)

(a) Elimination of non-nuclear generation assets lease to FGCO.

(b) Reduction of nuclear-generated wholesale KWH sales to FES.

(c) Reduction of nuclear fuel and operating costs.

(d) Reduction of depreciation expense and asset retirement obligation accretion related to generation assets.
(e) Reduction of property tax expense on generation assets.
(f) Interest income on associated company notes receivable from the transfer of generation net assets.
(g) Reduction of earnings on nuclear decommissioning trusts.
(h) Reduction of allowance for borrowed funds used during construction on nuclear capital expenditures.
(i) Income tax effect of the above adjustments.

Results of Operations

Earnings on common stock in the third quarter of 2006 decreased to $83 million from $110 million in the third quarter of 2005. In the first nine months of 2006, earnings on common stock increased to $247 million from $162 million in the same period of 2005. The change in earnings in both periods reflected the effects of the generation asset transfer shown in the table above. Expenses during the third quarter of 2006 included $19 million of costs associated with the proposed FERC settlement (see Note 11) applicable to the first half of 2006. The increase in the nine month period also reflected the absence of the $2 million Davis-Besse fine in the first quarter of 2005 and the $8 million impact of the Ohio tax change implementation in the second quarter of 2005.

Revenues

Revenues decreased by $10 million or 2.0% in the third quarter of 2006 from the same period in 2005. Excluding the effects of the generation asset transfers displayed above, revenues increased $85 million due to a $137 million increase in retail generation sales revenues and a $41 million reduction in customer shopping incentives, partially offset by a $76 million decrease in distribution revenues and a $17 million decrease in non-affiliated wholesale sales. In the first nine months of 2006 compared to the same period in 2005, revenues decreased by $52 million or 3.7%. Excluding the effects of the generation asset transfers discussed above, revenues increased $182 million due to a $331 million increase in retail generation sales revenues and an $88 million reduction in customer shopping incentives, partially offset by a $182 million decrease in distribution revenues and a $55 million decrease in non-affiliated wholesale sales.

The non-affiliated wholesale sales revenues decreases for the third quarter and the first nine months of 2006 compared with the same periods in 2005 resulted from the December 2005 cessation of the MSG sales arrangements under CEI's transition plan. CEI had been required to provide the MSG to non-affiliated alternative suppliers.

Changes in electric generation KWH sales and revenues in the third quarter and first nine months of 2006 from the corresponding periods of 2005 are summarized in the following tables.

Changes in Generation KWH Sales Increase (Decrease)	**Three Months**	**Nine Months**
Electric Generation:		
Retail	61.6%	52.9%
Wholesale	(81.6)%	(75.5)%
Net Decrease in Generation Sales	**(26.8)%**	**(21.1)%**

Changes in Generation Revenues Increase (Decrease)	**Three Months**	**Nine Months**
	(In millions)	
Retail Generation:		
Residential	$ 55	$ 132
Commercial	48	118
Industrial	34	81
Total Retail Generation	137	331
Wholesale*	(17)	(55)
Net Increase in Generation Revenues	**$ 120**	**$ 276**

*Excludes impact of generation asset transfers related to nuclear generated KWH sales.

Increased retail generation revenues for the third quarter of 2006 compared with the same period of 2005 (as shown in the table above) were due to higher unit prices and increased KWH sales. The higher unit prices for generation reflected the rate stabilization charge that became effective in the first quarter of 2006 under provisions of the RSP and RCP. The increase in generation KWH sales resulted from decreased customer shopping. Generation services provided by alternative suppliers as a percent of total sales delivered in CEI's service area decreased by: residential - 62.4 percentage points, commercial - 46.1 percentage points and industrial - 9.8 percentage points. The decreased shopping resulted from certain alternative energy suppliers terminating their supply arrangements with CEI's shopping customers in the fourth quarter of 2005.

Increased retail generation revenues in the first nine months of 2006 compared with the same period in 2005 were due to the reasons discussed above. The increase in generation KWH sales reflected a similar decrease in customer shopping also as discussed above. This resulted in similar percentage decreases in the first nine months of 2006 in generation services provided by alternative suppliers as a percentage of total sales deliveries in CEI's service area (residential - 60.9 percentage points, commercial - 42.9 percentage points and industrial - 8.3 percentage points).

Changes in distribution KWH deliveries and revenues in the third quarter and first nine months of 2006 from the corresponding periods of 2005 are summarized in the following tables.

Changes in Distribution KWH Sales	**Three Months**	**Nine Months**
Increase (Decrease)		
Distribution Deliveries:		
Residential	(6.3)%	(4.7)%
Commercial	(3.5)%	(4.0)%
Industrial	1.2%	(1.3)%
Net Decrease in Distribution Deliveries	**(2.3)%**	**(3.0)%**

Changes in Distribution Revenues	**Three Months**	**Nine Months**
Increase (Decrease)	***(In millions)***	
Residential	$ (25)	$ (46)
Commercial	(29)	(74)
Industrial	(22)	(62)
Net Decrease in Distribution Revenues	**$ (76)**	**$ (182)**

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Lower distribution revenues shown in the table above for the third quarter and first nine months of 2006 primarily reflected lower unit prices and decreased KWH deliveries. The lower unit prices reflected the completion of the generation-related transition cost recovery under CEI's transition plan in 2005, partially offset by increased transmission rates to recover MISO costs beginning in 2006 (see Outlook -- Regulatory Matters). The lower KWH distribution deliveries to residential and commercial customers were primarily due to milder weather conditions in the third quarter and first nine months of 2006, compared to the same periods of 2005.

Under the Ohio transition plan, CEI provided incentives to customers to encourage switching to alternative energy providers, reducing CEI's revenues. These revenue reductions, which were deferred for future recovery and did not affect earnings, ceased in 2006, resulting in a $41 million revenue increase for the third quarter of 2006 and an $88 million increase for the first nine months of 2006 compared to the same periods of 2005, as discussed above.

Expenses

Total expenses increased by $22 million in the third quarter of 2006 and decreased by $159 million in the first nine months of 2006 from the same periods of 2005. The change in both periods was impacted by the effects of the generation asset transfers shown in the table above. Excluding the asset transfer effects, the following table presents changes from the prior year by expense category:

Expenses - Changes Increase (Decrease)	**Three Months**	**Nine Months**
	(In millions)	
Fuel costs	$ (1)	$ -
Purchased power costs	100	120
Other operating costs	(8)	(5)
Provision for depreciation	(3)	(7)
Amortization of regulatory assets	(30)	(78)
Deferral of new regulatory assets	21	25
General taxes	(2)	(3)
Net increase in expenses	$ 77	$ 52

Higher purchased power costs in the third quarter and the first nine months of 2006 as compared to the same periods of 2005 resulted from increased KWH purchases and higher unit prices. Greater KWH purchases primarily reflected higher retail generation sales requirements and the higher unit prices are primarily due to the current power supply agreement with FES. Lower other operating costs in both periods of 2006 compared with the same periods in 2005 reflected the absence in 2006 of transmission expenses related to the 2005 competitive retail energy supplier reimbursements which were discontinued at the end of 2005. In addition, decreased employee and contractor costs resulted from lower storm-related expenses and decreased contractor costs for vegetation management. Partially offsetting the lower other operating costs were greater transmission expenses in both periods that primarily relate to MISO Day 2 operations that began on April 1, 2005.

Excluding the effects of the generation asset transfers, the depreciation decrease in the first nine months of 2006 compared to 2005 was primarily attributable to a second quarter 2006 pretax credit adjustment of $6.5 million ($4 million net of tax) applicable to prior periods. Lower amortization of regulatory assets in both periods of 2006 reflected the completion of generation-related transition cost amortization under CEI's transition plan, partially offset by the amortization of deferred MISO costs that are being recovered in 2006. The decreased deferral of new regulatory assets in the third quarter and first nine months of 2006 compared with the same periods in 2005 was primarily due to the termination of the shopping incentive deferrals ($41 million and $87 million, respectively) and lower MISO cost deferrals ($12 million and $16 million, respectively), partially offset by the deferrals of distribution costs ($16 million and $44 million, respectively) and fuel costs ($16 million and $34 million, respectively) under the RCP. The deferral of interest on the unamortized shopping incentive balances continues under the RCP.

Other Income

The change in other income for both periods reflected the generation asset transfers discussed above. Excluding the effects of the asset transfer, other income decreased by $6 million in the third quarter of 2006 as a result of greater interest expense due to the absence of refinancing cost reductions recognized in 2005. Excluding the effects of the asset transfer, other income increased by $2 million in the first nine months of 2006 and was primarily due to a $6 million benefit recognized in the second quarter of 2006 related to the sale of the Ashtabula C Plant, partially offset by increased interest expense in 2006.

Income Taxes

Income taxes decreased by $20 million in the third quarter of 2006 and increased by $36 million in the first nine months of 2006 compared to the same periods of 2005. Excluding the effects of the generation asset transfer, income taxes were unchanged in the third quarter of 2006 and increased by $41 million in first nine months of 2006. The increase in the first nine months of 2006 was primarily due to an increase in taxable income, partially offset by the absence in 2006 of $8 million of additional income tax expenses from the implementation of Ohio tax legislation changes in the second quarter of 2005.

Preferred Stock Dividend Requirements

Preferred stock dividend requirements decreased by $3 million in the first nine months of 2006, compared to the same period last year, as a result of the optional redemption of CEI's remaining outstanding preferred stock in 2005.

Capital Resources and Liquidity

During the remainder of 2006, CEI expects to meet its contractual obligations with cash from operations, short-term credit arrangements and funds from capital markets. 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, 2006, CEI had $223,000 of cash and cash equivalents, compared with $207,000 as of December 31, 2005. The major sources of changes in these balances are summarized below.

Cash Flows from Operating Activities

Cash provided from operating activities during the first nine months of 2006, compared with the same period last year, were as follows:

Operating Cash Flows	Nine Months Ended September 30, 2006	2005
	(In millions)	
Cash earnings*	$ 216	$ 274
	22	(147)

Working capital and other		
Net cash provided from operating activities	$ 238	$ 127

* Cash earnings are a non-GAAP measure (see reconciliation below).

Cash earnings (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. Generally, a non-GAAP financial measure is a numerical measure of a company's historical or future financial performance, financial position, or cash flows that either excludes or includes amounts, or is subject to adjustment that has the effect of excluding or including amounts, that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with GAAP. In addition, cash earnings (non-GAAP) are not defined under GAAP. Management believes presenting this non-GAAP measure provides useful information to investors in assessing CEI's operating performance from a cash perspective without the effects of material unusual economic events. CEI's management frequently references these non-GAAP financial measures in its decision-making, using them to facilitate historical and ongoing performance comparisons as well as comparisons to the performance of peer companies. These non-GAAP measures should be considered in addition to, and not as a substitute for, their most directly comparable financial measures prepared in accordance with GAAP.

Reconciliation of Cash Earnings	**Nine Months Ended September 30, 2006**	**2005**
	(In millions)	
Net Income (GAAP)	$ 247	$ 165
Non-cash charges (credits):		
Provision for depreciation	46	101
Amortization of regulatory assets	100	177
Deferral of new regulatory assets	(101)	(127)
Nuclear fuel and capital lease amortization	-	19
Amortization of electric service obligation	(14)	(12)
Deferred rents and lease market valuation liability	(55)	(67)
Deferred income taxes and investment tax credits, net	(10)	15
Accrued compensation and retirement benefits	3	3
Cash earnings (Non-GAAP)	$ 216	$ 274

Net cash provided from operating activities increased by $111 million in the first nine months of 2006 from the same period last year as a result of a $169 million increase in working capital and other cash flows, partially offset by a $58 million decrease in cash earnings described above under "Results of Operations." The largest factors contributing to the changes in working capital and other operating cash flows for the first nine months of 2006 are changes in accounts receivable related to the 2005 conversion of the CFC receivables financing ($155 million) to on-balance sheet transactions and changes in accounts payable, offset in part by the absence of funds received in 2005 for prepaid electric service under the Energy for Education Program.

Cash Flows from Financing Activities

Net cash used for financing activities increased by $172 million in the first nine months of 2006 from the same period last year. The increase in funds used for financing activities primarily resulted from a $122 million increase in net preferred stock and debt redemptions and the absence of a $75 million equity contribution from FirstEnergy in 2005, partially offset by a $23 million decrease in common stock dividend payments to FirstEnergy.

CEI had $29 million of cash and temporary investments (which included short-term notes receivable from associated companies) and approximately $303 million of short-term indebtedness as of September 30, 2006. CEI has obtained authorization from the PUCO to incur short-term debt of up to $600 million (including the bank facility and utility money pool described below).

As of September 30, 2006, CEI had the capability to issue $259 million of additional FMB on the basis of property additions and retired bonds under the terms of its mortgage indenture. 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, CEI is permitted under the indenture to incur additional secured debt not otherwise permitted by a specified exception of up to $579 million as of September 30, 2006. 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, 2006, the facility was not drawn.

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 first nine months of 2006 was 5.09%.

On August 24, 2006, CEI, FirstEnergy, OE, Penn, TE, JCP&L, Met-Ed, Penelec, FES and ATSI, as Borrowers, have entered into a new $2.75 billion five-year revolving credit facility which replaced the prior $2 billion credit facility. FirstEnergy may request an increase in the total commitments available under the new facility up to a maximum of $3.25 billion. Borrowings under the facility are available to each Commitments under the new facility are available until August 24, 2011, unless the lenders agree, at the request of the Borrowers, to two additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each Borrower are subject to a specified sub-limit, as well as applicable regulatory and other limitations. CEI's borrowing limit under the facility is $250 million subject to applicable regulatory approvals.

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 LOC 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 was $450 million as of September 30, 2006.

The revolving credit facility contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%, measured at the end of each fiscal quarter. As of September 30, 2006, CEI's debt to total capitalization as defined under the revolving credit facility was 49%.

The revolving credit facility does not contain 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.

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

In April and May of 2006, pollution control notes that were formerly obligations of CEI were refinanced and became obligations of FGCO and NGC. The proceeds from the refinancings were used to repay a portion of FGCO's and NGC's associated company notes payable to CEI. CEI redeemed $117.8 million of pollution control notes having variable interest rates.

A CEI shelf registration for $550 million of unsecured debt securities was declared effective by the SEC on October 31, 2006 and remains unused.

Cash Flows from Investing Activities

Net cash provided from investing activities increased by $61 million in the first nine months of 2006 from the same period last year. The change was primarily due to increased loan repayments from associated companies and the absence of net investments in nuclear decommissioning trust funds due to the intra-system nuclear generation asset transfer.

In the last quarter of 2006, CEI's capital spending is expected to be approximately $35 million. These cash requirements are expected to be satisfied from internal cash and short-term credit arrangements. CEI's capital spending for the period 2006-2010 is expected to be approximately $622 million of which approximately $129 million applies to 2006.

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, 2006, the present value of these operating lease commitments, net of trust investments, total $95 million.

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

Regulatory assets are costs which have been authorized by the PUCO and the FERC 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 under the provisions of CEI’s transition plan. CEI’s regulatory assets as of September 30, 2006 and December 31, 2005, were $855 million and $862 million, respectively.

On October 21, 2003, the Ohio Companies filed their RSP case with the PUCO. 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 CBP. The RSP was intended to establish generation service rates beginning January 1, 2006, in response to the PUCO’s 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 the proceeding as well as the associated entries on rehearing. On May 3, 2006, the Supreme Court of Ohio issued an opinion affirming the PUCO's order with respect to the approval of the rate stabilization charge, approval of the shopping credits, the granting of interest on shopping credit incentive deferral amounts, and approval of the Ohio Companies’ financial separation plan. It remanded back to the PUCO the matter of ensuring the availability of sufficient means for customer participation in the competitive marketplace. The RSP contained a provision that permitted the Ohio Companies to withdraw and terminate the RSP in the event that the PUCO, or the Supreme Court of Ohio, rejected all or part of the RSP. In such event, the Ohio Companies have 30 days from the final order or decision to provide notice of termination. On July 20, 2006 the Ohio Companies filed with the PUCO a Request to Initiate a Proceeding on Remand. In their Request, the Ohio Companies provided notice of termination to those provisions of the RSP subject to termination, subject to being withdrawn, and also set forth a framework for addressing the Supreme Court of Ohio’s findings on customer participation, requesting the PUCO to initiate a proceeding to consider the Ohio Companies’ proposal. If the PUCO approves a resolution to the issues raised by the Supreme Court of Ohio that is acceptable to the Ohio Companies, the Ohio Companies’ termination will be withdrawn and considered to be null and void. Separately, the OCC and NOAC also submitted to the PUCO on July 20, 2006 a conceptual proposal dealing with the issue raised by the Supreme Court of Ohio. On July 26, 2006, the PUCO issued an Entry acknowledging the July 20, 2006 filings of the Ohio Companies and the OCC and NOAC, and giving the Ohio Companies 45 days to file a plan in a new docket to address the Court’s concern. On September 19, 2006, the PUCO issued an Entry granting the Ohio Companies’ motion for extension of time to file the remand proposal. The Ohio Companies filed their RSP Remand CBP on September 29, 2006. No further proceedings have been scheduled at this time.

The Ohio Companies filed an application and stipulation with the PUCO on September 9, 2005 seeking approval of the RCP, a supplement to the RSP. On November 4, 2005, the Ohio Companies filed a supplemental stipulation with the PUCO, which constituted an additional component of the RCP filed on September 9, 2005. Major provisions of the RCP include:

- Maintaining the existing level of base distribution rates through April 30, 2009 for CEI;

- Deferring and capitalizing for future recovery (over a 25-year period) with carrying charges 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;

- Adjusting 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;

- Reducing 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

- Deferring and capitalizing (for recovery over a 25-year period) increased fuel costs above the amount collected through the Ohio Companies' fuel recovery mechanism.

The following table provides CEI's estimated amortization of regulatory transition costs and deferred shopping incentives (including associated carrying charges) under the RCP for the period 2006 through 2010:

Amortization Period	**Amortization**	
	(In millions)	
2006	$	96
2007		113
2008		130
2009		211
2010		264
Total Amortization	**$**	**814**

On January 4, 2006, the PUCO approved, with modifications, the Ohio Companies' RCP to supplement the RSP to provide customers with more certain rate levels than otherwise available under the RSP during the plan period. On January 10, 2006, the Ohio Companies filed a Motion for Clarification of the PUCO order approving the RCP. The Ohio Companies sought clarity on issues related to distribution deferrals, including requirements of the review process, timing for recognizing certain deferrals and definitions of the types of qualified expenditures. The Ohio Companies also sought confirmation that the list of deferrable distribution expenditures originally included in the revised stipulation fall within the PUCO order definition of qualified expenditures. On January 25, 2006, the PUCO issued an Entry on Rehearing granting in part, and denying in part, the Ohio Companies' previous requests and clarifying issues referred to above. The PUCO granted the Ohio Companies' requests to:

- Recognize fuel and distribution deferrals commencing January 1, 2006;
- Recognize distribution deferrals on a monthly basis prior to review by the PUCO Staff;
- Clarify that the types of distribution expenditures included in the Supplemental Stipulation may be deferred; and
- Clarify that distribution expenditures do not have to be "accelerated" in order to be deferred.

The PUCO approved the Ohio Companies' methodology for determining distribution deferral amounts, but denied the Motion in that the PUCO Staff must verify the level of distribution expenditures contained in current rates, as opposed to simply accepting the amounts contained in the Ohio Companies' Motion. On February 3, 2006, several other parties filed applications for rehearing on the PUCO's January 4, 2006 Order. The Ohio Companies responded to the applications for rehearing on February 13, 2006. In an Entry on Rehearing issued by the PUCO on March 1, 2006, all motions for rehearing were denied. Certain of these parties have subsequently filed notices of appeal with the Supreme Court of Ohio alleging various errors made by the PUCO in its order approving the RCP. The Ohio Companies' Motion to Intervene in the appeals was granted by the Supreme Court on June 8, 2006. The Appellants' Merit Briefs were filed at the Supreme Court on July 5, 2006. The Appellees include the PUCO and the Ohio Companies. The Appellees' Merit Briefs were filed on August 24, 2006 and the Appellants' Reply Briefs were filed on September 21 2006. The OCC filed an amicus brief on August 4, 2006, which the Ohio Companies moved to strike as improperly filed. The Supreme Court denied the Ohio Companies' motion on October 18, 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 sought recovery of these costs beginning January 1, 2006. 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 parties reached a settlement agreement that was approved by the PUCO on August 31, 2005. The incremental transmission and ancillary service revenues recovered from January 1 through June 30, 2006 were approximately $23.5 million. That amount included the recovery of a portion of the 2005 deferred MISO expenses as described below. On April 27, 2006, CEI filed the annual update rider to determine revenues ($50 million) from July 2006 through June 2007. The filed rider went into effect on July 1, 2006.

The second application sought authority to defer costs associated with transmission and ancillary service related costs incurred during the period 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 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 the Ohio Companies to accrue carrying charges on the deferred balances. On August 31, 2005, the OCC appealed the PUCO's decision. On January 20, 2006, the OCC sought rehearing of the PUCO’s approval of the recovery of deferred costs through the rider during the period January 1, 2006 through June 30, 2006. The PUCO denied the OCC's application on February 6, 2006. On March 23, 2006, the OCC appealed the PUCO's order to the Ohio Supreme Court. On March 27, 2006, the OCC filed a motion to consolidate this appeal with the deferral appeals discussed above and to postpone oral arguments in the deferral appeal until after all briefs are filed in this most recent appeal of the rider recovery mechanism. On March 20, 2006, the Ohio Supreme Court, on its own motion, consolidated the OCC's appeal of the Ohio Companies' case with a similar case involving Dayton Power & Light Company. Oral arguments were heard on May 10, 2006. The Ohio Companies are awaiting a final ruling from the Ohio Supreme Court, which is expected before the end of 2006.

On November 1, 2005, FES filed two power sales agreements for approval with the FERC. One power sales agreement provided for FES to provide the PLR requirements of the Ohio Companies at a price equal to the retail generation rates approved by the PUCO for a period of three years beginning January 1, 2006. The Ohio Companies will be relieved of their obligation to obtain PLR power requirements from FES if the Ohio CBP results in a lower price for retail customers. A similar power sales agreement between FES and Penn permits Penn to obtain its PLR power requirements from FES at a fixed price equal to the retail generation price during 2006.

On December 29, 2005, the FERC issued an order setting the two power sales agreements for hearing. The order criticized the Ohio CBP, and required FES to submit additional evidence in support of the reasonableness of the prices charged in the power sales agreements. A pre-hearing conference was held on January 18, 2006 to determine the hearing schedule in this case. Under the procedural schedule approved in this case, FES expected an initial decision to be issued in late January 2007. However, on July 14, 2006, the Chief Judge granted the joint motion of FES and the Trial Staff to appoint a settlement judge in this proceeding and the procedural schedule was suspended pending settlement discussions among the parties. A settlement conference was held on September 5, 2006. FES and the Ohio Companies, Penn, and the PUCO, along with other parties, reached an agreement to settle the case. The settlement was filed with the FERC on October 17, 2006, and was unopposed by the remaining parties, including the FERC Trial Staff. Initial comments to the settlement are due by November 6, 2006.

The terms of the settlement provide for modification of both the Ohio and Penn power supply agreements with FES. Under the Ohio power supply agreement, separate rates are established for the Ohio Companies’ PLR requirements, special retail contracts requirements, wholesale contract requirements, and interruptible buy-through retail load requirements. For their PLR and special retail contract requirements, the Ohio Companies will pay FES no more than the lower of (i) the sum of the retail generation charge, the rate stabilization charge, the fuel recovery mechanism charge, and FES’ actual incremental fuel costs for such sales; or (ii) the wholesale price cap. Different wholesale price caps are imposed for PLR sales, special retail contracts, and wholesale contracts. The wholesale price for interruptible buy-through retail load requirements is limited to the actual spot price of power obtained by FES to provide this power. The Ohio Companies have recognized the estimated additional amount payable to FES for power supplied during the nine months ended September 30, 2006. The wholesale rate charged by FES under the Penn power supply agreement will be no greater than the generation component of charges for retail PLR load in Pennsylvania. The FERC is expected to act on this case by the end of the fourth quarter of 2006.

See Note 11 to the consolidated financial statements for further details and a complete discussion of regulatory matters in Ohio.

Environmental Matters

CEI accrues environmental liabilities when 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 CEI's determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

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, 2006, based on estimates of the total costs of cleanup, CEI's proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Included in Other Noncurrent Liabilities are accrued liabilities aggregating approximately $1 million as of September 30, 2006.

See Note 10(B) to the consolidated financial statements for further details and a complete discussion of environmental matters.

Other Legal Proceedings

Power Outages and Related Litigation-

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 Web site (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 is also proceeding with the implementation of the recommendations 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 may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future as a result of adoption of mandatory reliability standards pursuant to the EPACT that could require additional material expenditures.

FirstEnergy companies also are defending six separate complaint cases before the PUCO relating to the August 14, 2003 power outages. Two cases were originally filed in Ohio State courts but were subsequently dismissed for lack of subject matter jurisdiction and further appeals were unsuccessful. In these 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. Three other pending PUCO complaint cases were filed by various insurance carriers either in their own name as subrogees or in the name of their insured. In each of these three cases, the carrier seeks reimbursement from various FirstEnergy companies (and, in one case, from PJM, MISO and American Electric Power Company, Inc., as well) for claims paid to insureds for damages allegedly arising as a result of 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 sixth case involves the claim of a non-customer seeking reimbursement for losses incurred when its store was burglarized on August 14, 2003. That case has been dismissed. On March 7, 2006, the PUCO issued a ruling, based on motions filed by the parties, applicable to all pending cases. Among its various rulings, the PUCO consolidated all of the pending outage cases for hearing; limited the litigation to service-related claims by customers of the Ohio operating companies; dismissed FirstEnergy as a defendant; ruled that the U.S.-Canada Power System Outage Task Force Report was not admissible into evidence; and gave the plaintiffs additional time to amend their complaints to otherwise comply with the PUCO's underlying order. Also, most complainants, along with the FirstEnergy companies, filed applications for rehearing with the PUCO over various rulings contained in the March 7, 2006 order. On April 26, 2006, the PUCO granted rehearing to allow the insurance company claimants, as insurers, to prosecute their claims in their name so long as they also identify the underlying insured entities and the Ohio utilities that provide their service. The PUCO denied all other motions for rehearing. The plaintiffs in each case have since filed an amended complaint and the named FirstEnergy companies have answered and also have filed a motion to dismiss each action. On September 27, 2006, the PUCO dismissed certain parties and claims and otherwise ordered the complaints to go forward to hearing. The cases have been set for hearing on October 16, 2007.

On October 10, 2006, various insurance carriers refiled a complaint in Cuyahoga County Common Pleas Court seeking reimbursement for claims paid to numerous insureds who allegedly suffered losses as a result of the August 14, 2003 outages. All of the insureds appear to be non-customers. The plaintiff insurance companies are the same claimants in one of the pending PUCO cases. FirstEnergy, the Ohio Companies and Penn were served on October 27, 2006, and expect to seek summary dismissal of these cases based on the prior court rulings noted above. No estimate of potential liability is available for any of these cases.

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. Although unable to predict the impact of these proceedings, 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

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 potentially material items not otherwise discussed above are described below.

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 now repealed 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 related disclosures, which FirstEnergy has provided. 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. Both filings were consolidated for hearing and decision. 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. On May 10, 2006, the PUCO issued its Opinion and Order dismissing the City's complaint and approving the related tariffs, thus affirming OE's entitlement to recovery of its transition charges. The City of Huron filed an application for rehearing of the PUCO's decision on June 9, 2006 and OE filed a memorandum in opposition to that application on June 19, 2006. The PUCO denied the City's application for rehearing on June 28, 2006. The City of Huron has taken no further action and the period for filing an appeal has expired.

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

New Accounting Standards and Interpretations

SAB 108 - "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements"

In September 2006, the SEC issued SAB 108, which provides interpretive guidance on how registrants should quantify financial statement misstatements. There is currently diversity in practice, with the two commonly used methods to quantify misstatements being the "rollover" method (which primarily focuses on the income statement impact of misstatements) and the "iron curtain" method (which focuses on the balance sheet impact). SAB 108 requires registrants to use a dual approach whereby both of these methods are considered in evaluating the materiality of financial statement errors. Prior materiality assessments will need to be reconsidered using both the rollover and iron curtain methods. This guidance will be effective for CEI in the fourth quarter of 2006. CEI does not expect this Statement to have a material impact on its financial statements.

SFAS 157 - "Fair Value Measurements"

In September 2006, the FASB issued SFAS 157, that establishes how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under GAAP. This Statement addresses the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. The key changes to current practice are: (1) the definition of fair value which focuses on an exit price rather than entry price; (2) the methods used to measure fair value such as emphasis that fair value is a market-based measurement, not an entity-specific measurement, as well as the inclusion of an adjustment for risk, restrictions and credit standing; and (3) the expanded disclosures about fair value measurements.

This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. CEI is currently evaluating the impact of this Statement on its financial statements.

SFAS 158 - "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)"

In September 2006, the FASB issued SFAS 158, which requires companies to recognize a net liability or asset to report the overfunded or underfunded status of their defined benefit pension and other postretirement benefit plans on their balance sheets and recognize changes in funded status in the year in which the changes occur through other comprehensive income. The funded status to be measured is the difference between plan assets at fair value and the benefit obligation. This Statement requires that gains and losses and prior service costs or credits, net of tax, that arise during the period be recognized as a component of other comprehensive income and not as components of net periodic benefit cost. Additional information should also be disclosed in the notes to the financial statements about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and transition asset or obligation. Upon the initial application of this Statement and subsequently, an employer should continue to apply the provisions in Statements 87, 88 and 106 in measuring plan assets and benefit obligations as of the date of its statement of financial position and in determining the amount of net periodic benefit cost. This Statement is effective for CEI as of December 31, 2006. CEI is currently evaluating the impact of this Statement on its financial statements.

FIN 48 - "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109."

In June 2006, the FASB issued FIN 48 which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, "Accounting for Income Taxes." This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken on a tax return. This interpretation also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation will be a two-step process. The first step will determine if it is more likely than not that a tax position will be sustained upon examination and should therefore be recognized. The second step will measure a tax position that meets the more likely than not recognition threshold to determine the amount of benefit to recognize in the financial statements. This interpretation is effective for fiscal years beginning after December 15, 2006. CEI is currently evaluating the impact of this Statement.

THE TOLEDO EDISON COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
STATEMENTS OF INCOME	*(In thousands)*			
REVENUES	$ 262,837	$ 286,960	$ 706,412	$ 787,824
EXPENSES:				
Fuel	9,399	16,501	28,799	43,474
Purchased power	112,389	73,144	268,468	225,600
Nuclear operating costs	19,252	39,207	54,450	145,059
Other operating costs	44,253	48,164	124,396	123,823
Provision for depreciation	8,386	18,835	24,723	48,724
Amortization of regulatory assets	27,336	39,576	73,909	107,672
Deferral of new regulatory assets	(15,340)	(19,379)	(43,186)	(41,473)
General taxes	13,406	14,159	38,590	41,960
Total expenses	219,081	230,207	570,149	694,839
OPERATING INCOME	43,756	56,753	136,263	92,985
OTHER INCOME (EXPENSE):				
Investment income	9,724	22,807	28,449	39,879
Miscellaneous expense	(1,933)	(2,408)	(6,543)	(8,810)
Interest expense	(4,940)	(6,870)	(13,614)	(16,847)
Capitalized interest	277	372	835	117
Total other income	3,128	13,901	9,127	14,339
INCOME BEFORE INCOME TAXES	46,884	70,654	145,390	107,324
INCOME TAXES	17,706	28,427	54,834	57,056
NET INCOME	29,178	42,227	90,556	50,268
PREFERRED STOCK DIVIDEND REQUIREMENTS	1,161	1,687	3,597	6,109
EARNINGS ON COMMON STOCK	$ 28,017	$ 40,540	$ 86,959	$ 44,159
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$ 29,178	$ 42,227	$ 90,556	$ 50,268

OTHER COMPREHENSIVE INCOME (LOSS):								
Unrealized gain (loss) on available for sale securities		1,379		(4,511)		432		(6,695)
Income tax expense (benefit) related to other comprehensive income		498		(1,743)		156		(2,534)
Other comprehensive income (loss), net of tax		881		(2,768)		276		(4,161)
TOTAL COMPREHENSIVE INCOME	$	30,059	$	39,459	$	90,832	$	46,107

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, 2006	December 31, 2005
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 20	$ 15
Receivables-		
Customers	527	2,209
Associated companies	46,252	16,311
Other	3,220	6,410
Notes receivable from associated companies	109,972	48,349
Prepayments and other	1,134	1,059
	161,125	74,353
UTILITY PLANT:		
In service	862,462	824,677
Less - Accumulated provision for depreciation	387,114	372,845
	475,348	451,832
Construction work in progress	33,912	33,920
	509,260	485,752
OTHER PROPERTY AND INVESTMENTS:		
Long-term notes receivable from associated companies	382,668	436,178
Investment in lessor notes	169,523	178,798
Nuclear plant decommissioning trusts	60,826	59,209
Other	1,802	1,781
	614,819	675,966
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	500,576	501,022
Regulatory assets	255,869	287,095
Prepaid pension costs	34,903	35,566
Property taxes	18,047	18,047
Other	27,159	24,164
	836,554	865,894
	$ 2,121,758	$ 2,101,965
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 30,000	$ 53,650
Accounts payable-		
Associated companies	47,214	46,386
Other	2,946	2,672
Notes payable to associated companies	178,575	64,689
Accrued taxes	52,802	49,344
Lease market valuation liability	24,600	24,600

Other	33,055	40,049
	369,192	281,390
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	473,924	473,638
Accumulated other comprehensive income	4,966	4,690
Retained earnings	225,613	189,428
Total common stockholder's equity	900,173	863,426
Preferred stock	66,000	96,000
Long-term debt	207,660	237,753
	1,173,833	1,197,179
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	195,552	221,149
Accumulated deferred investment tax credits	11,217	11,824
Lease market valuation liability	224,950	243,400
Retirement benefits	42,740	40,353
Asset retirement obligations	26,105	24,836
Deferred revenues - electric service programs	25,862	32,606
Other	52,307	49,228
	578,733	623,396
COMMITMENTS AND CONTINGENCIES (Note 10)		
	$ 2,121,758	$ 2,101,965

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

THE TOLEDO EDISON COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 90,556	$ 50,268
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	24,723	48,724
Amortization of regulatory assets	73,909	107,672
Deferral of new regulatory assets	(43,186)	(41,473)
Nuclear fuel and capital lease amortization	-	13,816
Deferred rents and lease market valuation liability	(27,114)	(34,156)
Deferred income taxes and investment tax credits, net	(28,603)	(4,605)
Accrued compensation and retirement benefits	2,766	3,438
Decrease (increase) in operating assets-		
Receivables	(25,069)	15,962
Materials and supplies	-	(2,124)
Prepayments and other current assets	(75)	(562)
Increase (decrease) in operating liabilities-		
Accounts payable	1,102	(80,586)
Accrued taxes	3,458	25,257
Accrued interest	(709)	(565)
Electric service prepayment programs	(6,744)	34,653
Other	1,716	(22,999)
Net cash provided from operating activities	66,730	112,720
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	-	45,000
Short-term borrowings, net	113,886	-
Redemptions and Repayments-		
Preferred stock	(30,000)	(30,000)
Long-term debt	(53,650)	(83,754)
Short-term borrowings, net	-	(51,327)
Dividend Payments-		
Common stock	(50,000)	(10,000)
Preferred stock	(3,597)	(6,109)
Net cash used for financing activities	(23,361)	(136,190)

CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions		(45,661)		(50,119)
Loans to associated companies, net		(61,549)		(40,491)
Collection of principal on long-term notes receivable		53,766		123,546
Investments in lessor notes		9,275		11,927
Proceeds from nuclear decommissioning trust fund sales		49,744		284,968
Investments in nuclear decommissioning trust funds		(49,922)		(306,374)
Other		983		13
Net cash provided from (used for) investing activities		(43,364)		23,470
Net change in cash and cash equivalents		5		-
Cash and cash equivalents at beginning of period		15		15
Cash and cash equivalents at end of period	$	20	$	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 Stockholder and Board of
Directors of The Toledo Edison Company:

We have reviewed the accompanying consolidated balance sheet of The Toledo Edison Company and its subsidiaries as of September 30, 2006, and the related consolidated statements of income and comprehensive income for each of the three-month and nine-month periods ended September 30, 2006 and 2005 and the consolidated statements of cash flows for the nine-month periods ended September 30, 2006 and 2005. 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 have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2005, and the related consolidated statements of income, capitalization, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report [which contained references to the Company's change in its method of accounting for asset retirement obligations as of January 1, 2003 as discussed in Note 2(G) and Note 11 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 February 27, 2006, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2005, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers
LLP
Cleveland, Ohio
October 31, 2006

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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's power supply requirements are provided by FES - an affiliated company.

FirstEnergy Intra-System Generation Asset Transfers

In 2005, the Ohio Companies and Penn entered into certain agreements implementing a series of intra-system generation asset transfers that were completed in the fourth quarter of 2005. The asset transfers resulted in the respective undivided ownership interests of the Ohio Companies and Penn in FirstEnergy's nuclear and non-nuclear generation assets being owned by NGC and FGCO, respectively. The generating plant interests transferred did 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 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 FGCO's purchase option under the Master Facility Lease.

On December 16, 2005, TE completed the intra-system transfer of its ownership interests in the nuclear generation assets to NGC through a sale at net book value. FENOC continues to operate and maintain the nuclear generation assets.

These transactions were undertaken 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 essentially completed the divestitures contemplated by the restructuring plans by transferring the ownership interests to NGC and FGCO without impacting the operation of the plants.

The transfers affect TE's comparative earnings results with reductions in both revenues and expenses. Revenues are reduced due to the termination of certain arrangements with FES, under which TE previously sold its nuclear-generated KWH to FES and leased its non-nuclear generation assets to FGCO, a subsidiary of FES. TE's expenses are lower due to the nuclear fuel and operating costs assumed by NGC as well as depreciation and property tax expenses assumed by FGCO and NGC related to the transferred generating assets. With respect to TE's retained leasehold interests in the Bruce Mansfield Plant and Beaver Valley Unit 2, TE has continued the generation KWH sales arrangement with FES and its Beaver Valley Unit 2 leased capacity sales arrangement with CEI, and continues to be obligated on the applicable portion of expenses related to those interests. In addition, TE receives interest income on associated company notes receivable from the transfer of its generation net assets. FES continues to provide TE's PLR requirements under revised purchased power arrangements covering the three-year period beginning January 1, 2006 (see Outlook - Regulatory Matters).

The effects on TE's results of operations in the third quarter and nine months ended September 30, 2006 compared to the same periods of 2005 from the generation asset transfers are summarized in the following table:

Intra-System Generation Asset Transfers - Income Statement Effects			**Three Months**		**Nine Months**
Increase (Decrease)			***(In millions)***		
Revenues:					
Non-nuclear generating units rent	(a)	$	(4)	$	(11)
Nuclear-generated KWH sales	(b)		(38)		(89)
Total - Revenues Effect			(42)		(100)
Expenses:					
Fuel costs - nuclear	(c)		(7)		(15)
Nuclear operating costs	(c)		(21)		(83)
Provision for depreciation	(d)		(7)		(23)
General taxes	(e)		(2)		(5)
Total - Expenses Effect			(37)		(126)
Operating Income Effect			(5)		26
Other Income:					
Interest income from notes receivable	(f)		4		12
Nuclear decommissioning trust earnings	(g)		(17)		(21)
Total - Other Income Effect			(13)		(9)
Income taxes	(h)		(7)		7
Net Income Effect		$	(11)	$	10

(a) Elimination of non-nuclear generation assets lease to FGCO.
(b) Reduction of nuclear-generated wholesale KWH sales to FES.
(c) Reduction of nuclear fuel and operating costs.
(d) Reduction of depreciation expense and asset retirement obligation accretion related to generation assets.
(e) Reduction of property tax expense on generation assets.
(f) Interest income on associated company notes receivable from the transfer of generation net assets.
(g) Reduction of earnings on nuclear decommissioning trusts.
(h) Income tax effect of the above adjustments.

<u>Results of Operations</u>

Earnings on common stock in the third quarter of 2006 decreased to $28 million from $41 million in the third quarter of 2005. This decrease resulted primarily from lower revenues and lower other income, partially offset by reduced operating expenses. Expenses during the third quarter of 2006 included $7 million of costs associated with the proposed FERC settlement (see Note 11) applicable to the first half of 2006. Earnings on common stock in the first nine months of 2006 increased to $87 million from $44 million in the first nine months of 2005. This increase resulted primarily from reduced operating expenses and the absence of additional income taxes of $17.5 million from the implementation of Ohio tax legislation changes in the second quarter of 2005, partially offset by lower revenues and other income. The earnings results for both periods included the effects of the generation asset transfer shown in the table above.

Revenues

Revenues decreased by $24 million or 8.4% in the third quarter of 2006 compared with the same period of 2005, primarily due to the generation asset transfer impact displayed in the table above. Excluding the effects of the generation asset transfers, revenues increased $17 million due to a $44 million increase in generation sales revenues, a $12 million reduction in customer shopping incentives and a $2 million increase in other revenues, partially offset by decreased distribution revenues of $41 million.

In the first nine months of 2006, revenues decreased by $81 million or 10.3% compared with the same period of 2005, primarily due to the generation asset transfer impact displayed in the table above. Excluding the effects of the generation asset transfers, revenues increased $18 million due to an $88 million increase in generation sales revenues, a $27 million reduction in customer shopping incentives and a $3 million increase in other revenues, partially offset by a $100 million decrease in distribution revenues.

Changes in electric generation KWH sales and revenues in the third quarter and first nine months of 2006 from the corresponding periods of 2005 are summarized in the following table.

Changes in Generation KWH Sales Increase (Decrease)	**Three Months**	**Nine Months**
Electric Generation:		
Retail	16.1%	14.0%
Wholesale	(63.7)%	(59.4)%
Net Decrease in Generation Sales	**(29.2)%**	**(25.8)%**

Changes in Generation Revenues Increase (Decrease)	**Three Months**	**Nine Months**
	(In millions)	
Retail Generation:		
Residential	$ 24	$ 56
Commercial	15	37
Industrial	7	16
Total Retail Generation	46	109
Wholesale*	(2)	(21)
Net Increase in Generation Revenues	**$ 44**	**$ 88**

* Excludes impact of generation asset transfers related to nuclear-generated KWH sales.

Retail generation revenues increased in all customer sectors in the third quarter of 2006 compared to the corresponding quarter of 2005 (as shown in the table above) due to higher unit prices and increased KWH sales. The higher unit prices for generation reflected the rate stabilization charge and the fuel cost recovery rider that both became effective in the first quarter of 2006 under provisions of the RSP and RCP. The increase in generation KWH sales (residential - 65.4%, commercial - 15.4% and industrial - 2.3%) primarily resulted from decreased customer shopping. The decreased shopping resulted from certain alternative energy suppliers terminating their supply arrangements with TE's shopping customers in the first quarter of 2006. Generation services provided by alternative suppliers as a percentage of total sales delivered in TE's franchise area decreased in all customer classes by: residential - 38.4 percentage points, commercial - 10.3 percentage points and industrial - 2.1 percentage points.

In the first nine months of 2006, retail generation revenues increased from the corresponding period of 2005 for the reasons described above. The decreased customer shopping resulted in generation KWH sales increases in all customer classes (residential - 51.4%, commercial - 14.2% and industrial - 3.3%). Similar to the third quarter of 2006, generation services provided by alternative suppliers as a percentage of total sales deliveries in TE's franchise area decreased in all customer classes by: residential - 32.6 percentage points, commercial - 10.1 percentage points and industrial - 1.9 percentage points.

Lower wholesale revenues in the third quarter and first nine months of 2006 reflected decreased revenues from non-affiliates ($5 million and $13 million, respectively). Revenues from associated companies increased $3 million in the third quarter of 2006, but decreased $7 million for the first nine months of 2006. The non-affiliated wholesale revenue decreases in 2006 were primarily due to the December 2005 cessation in the MSG sales arrangements under TE’s transition plan. TE had been required to provide the MSG to non-affiliated alternative suppliers. The higher wholesale revenues from associated companies in the third quarter of 2006 reflected higher unit prices and higher volumes sold than in the third quarter of 2005. The lower wholesale revenues from associated companies in the first nine months of 2006 reflected lower unit prices due to this year’s absence of expenses related to the Beaver Valley Unit 2 nuclear refueling outage in April 2005, which were included as a component of the associated company billing for the 2005 period.

Changes in distribution KWH deliveries and revenues in the third quarter and first nine months of 2006 from the corresponding periods of 2005 are summarized in the following table.

Changes in Distribution KWH Deliveries Increase (Decrease)	**Three Months**	**Nine Months**
Distribution Deliveries:		
Residential	(6.7)%	(4.9)%
Commercial	(3.8)%	(4.2)%
Industrial	0.1%	1.3%
Net Decrease in Distribution Deliveries	**(2.8)%**	**(1.8)%**

Changes in Distribution Revenues Increase (Decrease)	**Three Months**	**Nine Months**
	(In millions)	
Residential	$ (19)	$ (44)
Commercial	(17)	(46)
Industrial	(5)	(10)
Net Decrease in Distribution Revenues	**$ (41)**	**$ (100)**

The distribution revenue decreases shown in the table above for the third quarter and first nine months of 2006 compared to the same periods of 2005 primarily reflected lower unit prices in all customer sectors and decreased KWH deliveries to residential and commercial customers. The lower unit prices resulted from the completion of the generation-related transition cost recovery under TE’s transition plan in 2005, partially offset by increased transmission rates to recover MISO costs beginning in the first quarter of 2006 (see Outlook - Regulatory Matters). The lower KWH deliveries to residential and commercial customers in both periods reflected the impact of milder weather in the third quarter and the first nine months of 2006 compared to the same periods of 2005. KWH deliveries to industrial customers increased in both periods of 2006 due to increased sales to automotive, oil refinery and steel industry customers.

Under the Ohio transition plan, TE had provided incentives to customers to encourage switching to alternative energy providers which reduced TE's revenues. These revenue reductions, which were deferred for future recovery and did not affect current period earnings, ceased in 2006, thereby increasing revenues in the third quarter and first nine months of 2006 by $12 million and $27 million, respectively. The deferred shopping incentives (Extended RTC) are currently being recovered under the RCP (see Outlook - Regulatory Matters).

Expenses

Total expenses decreased by $11 million and $125 million in the third quarter and the first nine months of 2006, respectively, from the same periods of 2005 principally due to the generation asset transfer effects as shown in the table above. Excluding the asset transfer effects, the following table presents changes from the prior year by expense category:

Expenses - Changes Increase (Decrease)	**Three Months**	**Nine Months**
	(In millions)	
Fuel	$ (1)	$ -
Purchased power costs	39	43
Nuclear operating	1	(8)

costs				
Other operating costs		(3)		1
Provision for depreciation		(2)		-
Amortization of regulatory assets		(13)		(34)
Deferral of new regulatory assets		4		(2)
General taxes		1		1
Net increase in expenses	$	26	$	1

Lower fuel expense in the third quarter of 2006 compared to the third quarter of 2005 was attributable to the September 2006 turbine outage related to TE's leasehold interest in Mansfield Unit 2. Higher purchased power costs in the third quarter of 2006 compared to the third quarter of 2005 primarily reflected an increase in KWH purchased to meet the higher retail generation sales requirements and higher unit prices associated with the new power supply agreement with FES. The higher nuclear operating costs associated with TE's leasehold interest in Beaver Valley Unit 2 in the third quarter of 2006 reflected costs related to preparations for the nuclear refueling outage which began October 2, 2006. Lower other operating costs in the third quarter of 2006 primarily reflected the absence of consulting fees related to a 2005 investment tax credit claim.

Higher purchased power costs in the first nine months of 2006 compared to the first nine months of 2005 were due to the same reasons as discussed above in the third quarter results. Decreased nuclear operating costs in the 2006 nine-month period resulted from the absence in 2006 of Beaver Valley Unit 2's 25-day nuclear refueling outage expenses in April 2005. Higher other operating costs primarily reflected increased transmission expenses related to MISO Day 2 operations that began on April 1, 2005, partially offset by the absence of the consulting fees in the 2006 period.

Excluding the effects of the generation asset transfers, lower depreciation charges in the third quarter of 2006 compared to the same period of 2005 resulted from the absence of a one-time adjustment in the third quarter of 2005 for reduced amortization periods for expenditures on leased generating plants to conform to the lease terms.

Lower amortization of regulatory assets in both periods of 2006 reflected the completion of generation-related transition cost recovery under TE's transition plan, partially offset by the amortization of deferred MISO costs that are being recovered in 2006. The net change in deferrals of new regulatory assets in the third quarter and first nine months of 2006 primarily resulted from the deferrals of distribution costs ($6 million and $19 million in the third quarter and the first nine months of 2006, respectively) and incremental fuel costs ($6 million and $13 million in the third quarter and the first nine months of 2006, respectively) that began in 2006 under the RCP. This was partially offset by the impact of the termination of shopping incentive deferrals in 2006 ($13 million and $28 million in the third quarter and the first nine months of 2006, respectively). The deferral of interest on the unamortized shopping incentive balances continues under the RCP. MISO transmission cost deferrals decreased by $3 million and $1 million in the third quarter and the first nine months of 2006, respectively, compared with the same periods in 2005.

Other Income

Other income decreased $11 million and $5 million in the third quarter and first nine months of 2006 compared to the same periods of 2005, primarily due to the effects of the generation asset transfers. Excluding the asset transfer effects, increases of $2 million and $4 million in other income were primarily due to lower interest expense in the third quarter and first nine months of 2006, respectively, due to redemptions of long-term debt subsequent to the end of the third quarter of 2005.

Income Taxes

Income taxes decreased by $10 million in the third quarter of 2006 and $2 million in the first nine months of 2006 compared to the same periods of 2005. Excluding the effects of the generation asset transfer, income taxes decreased in the third quarter of 2006 by $3 million and in the first nine months of 2006 by $9 million. The decrease in the first nine months of 2006 was primarily due to the absence in 2006 of $17.5 million of additional income tax expenses from the implementation of Ohio tax legislation changes in the second quarter of 2005 and the subsequent reduction in the tax rates, partially offset by the effect of an increase in taxable income.

Preferred Stock Dividend Requirements

Lower preferred stock dividend requirements in the third quarter of 2006 compared to the same quarter of 2005 were the result of $30 million of optional preferred stock redemptions in January 2006. Lower preferred stock dividend requirements in the first nine months of 2006 compared to the corresponding 2005 period resulted from $30 million of optional preferred stock redemptions in July 2005 and the January 2006 redemption.

Capital Resources and Liquidity

During the remainder of 2006, TE expects to meet its contractual obligations with a combination of cash from operations and short-term credit arrangements.

Changes in Cash Position

As of September 30, 2006, TE had $20,000 of cash and cash equivalents, compared with $15,000 as of December 31, 2005. The major changes in these balances are summarized below.

Cash Flows From Operating Activities

Cash provided from operating activities during the first nine months of 2006, compared with the first nine months of 2005, were as follows:

Operating Cash Flows	Nine Months Ended September 30, 2006	2005
	(In millions)	
Cash earnings*	$ 86	$ 140
Working capital and other	(19)	(27)
Net cash provided from operating activities	$ 67	$ 113

*Cash earnings are a non-GAAP measure (see reconciliation below).

Cash earnings (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. Generally, a non-GAAP financial measure is a numerical measure of a company's historical or future financial performance, financial position, or cash flows that either excludes or includes amounts, or is subject to adjustment that has the effect of excluding or including amounts, that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with GAAP. In addition, cash earnings (non-GAAP) are not defined under GAAP. Management believes presenting this non-GAAP measure provides useful information to investors in assessing TE's operating performance from a cash perspective without the effects of material unusual economic events. TE's management frequently references these non-GAAP financial measures in its decision-making, using them to facilitate historical and ongoing performance comparisons as well as comparisons to the performance of peer companies. These non-GAAP measures should be considered in addition to, and not as a substitute for, their most directly comparable financial measures prepared in accordance with GAAP.

Reconciliation of Cash Earnings	Nine Months Ended September 30, 2006	2005
	(In millions)	
Net Income (GAAP)	$ 90	$ 50

Non-Cash Charges (Credits):		
Provision for depreciation	25	49
Amortization of regulatory assets	74	108
Deferral of new regulatory assets	(43)	(42)
Nuclear fuel and capital lease amortization	-	14
Amortization of electric service obligation	(7)	(3)
Deferred rents and lease market valuation liability	(27)	(34)
Deferred income taxes and investment tax credits, net	(29)	(5)
Accrued compensation and retirement benefits	3	3
Cash earnings (Non-GAAP)	$ 86	$ 140

Net cash provided from operating activities decreased by $46 million in the first nine months of 2006 from the first nine months of 2005 as a result of a $54 million decrease in cash earnings described above under "Results of Operations" and an $8 million increase from working capital and other changes.

Cash Flows From Financing Activities

Net cash used for financing activities decreased to $23 million in the first nine months of 2006 from $136 million in the same period of 2005. The decrease resulted primarily from a $165 million increase in net short-term borrowings, partially offset by a $15 million net increase in preferred stock and long-term debt redemptions and a $40 million increase in common stock dividend payments to FirstEnergy in 2006.

TE had $110 million of cash and temporary investments (which included short-term notes receivable from associated companies) and $179 million of short-term indebtedness as of September 30, 2006. TE has authorization from the PUCO to incur short-term debt of up to $500 million through the bank facility and utility money pool described below. As of September 30, 2006, TE had the capability to issue $654 million of additional FMB on the basis of property additions and retired bonds under the terms of its mortgage indenture. Based upon applicable earnings coverage tests, TE could issue up to $1.0 billion of preferred stock (assuming no additional debt was issued) as of September 30, 2006.

On August 24, 2006, TE, FirstEnergy, OE, Penn, CEI, JCP&L, Met-Ed, Penelec, FES and ATSI, as Borrowers, entered into a new $2.75 billion five-year revolving credit facility that expires in August 2011 which replaced the prior $2 billion credit facility. FirstEnergy may request an increase in the total commitments available under the new facility up to a maximum of $3.25 billion. Commitments under the new facility are available until August 24, 2011, unless the lenders agree, at the request of the Borrowers, to two additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each Borrower are subject to a specified sub-limit, as well as applicable regulatory and other limitations. TE's borrowing limit under the facility is $250 million subject to applicable regulatory approval.

Under the revolving credit facility, borrowers may request the issuance of LOCs expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under the facility and against the applicable borrower's borrowing sub-limit.

The revolving credit facility contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%, measured at the end of each fiscal quarter. As of September 30, 2006, TE's debt to total capitalization, as defined under the revolving credit facility, was 30%.

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

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 first nine months of 2006 was 5.09%.

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

In April 2006, pollution control notes that were formerly obligations of TE were refinanced and became obligations of FGCO and NGC. The proceeds from the refinancings were used to repay a portion of FGCO's and NGC's associated company notes payable to TE. With those repayments, TE redeemed pollution control notes in the aggregate principal amount of $54 million having variable interest rates.

A TE shelf registration statement for $300 million of unsecured debt securities was declared effective by the SEC on October 31, 2006 and remains unused.

Cash Flows From Investing Activities

Net cash used for investing activities was $43 million in the first nine months of 2006 compared to net cash of $23 million provided from investing activities in the first nine months of 2005. The change was primarily due to a decrease in the collection of principal on long-term notes receivable and an increase in loans to associated companies. The decrease in the collection of principal resulted from the receipt in April 2006 of $54 million from FGCO and NGC following the pollution control notes refinancing discussed above as compared to the receipt in May 2005 of a $123 million balloon payment from FGCO for gas-fired combustion turbines sold in 2001. The decrease in cash receipts and increase in loans were partially offset by reduced property additions and net activity for the nuclear decommissioning trust funds due to the generation asset transfers.

TE’s capital spending for the last quarter of 2006 is expected to be approximately $16 million. These cash requirements are expected to be satisfied from a combination of internal cash and short-term credit arrangements. TE’s capital spending for the period 2006-2010 is expected to be approximately $236 million, of which approximately $62 million applies to 2006.

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, 2006, the present value of these operating lease commitments, net of trust investments, totaled $506 million.

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

Regulatory assets are costs which have been authorized by the PUCO and the FERC 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 under the provisions of TE's regulatory plans. TE's regulatory assets as of September 30, 2006 and December 31, 2005 were $256 million and $287 million, respectively.

On October 21, 2003, the Ohio Companies filed their RSP case with the PUCO. 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 CBP. The RSP was intended to establish generation service rates beginning January 1, 2006, in response to the PUCO's 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 the proceeding as well as the associated entries on rehearing. On May 3, 2006, the Supreme Court of Ohio issued an opinion affirming the PUCO's order with respect to the approval of the rate stabilization charge, approval of the shopping credits, the granting of interest on shopping credit incentive deferral amounts, and approval of the Ohio Companies' financial separation plan. It remanded back to the PUCO the matter of ensuring the availability of sufficient means for customer participation in the competitive marketplace. The RSP contained a provision that permitted the Ohio Companies to withdraw and terminate the RSP in the event that the PUCO, or the Supreme Court of Ohio, rejected all or part of the RSP. In such event, the Ohio Companies have 30 days from the final order or decision to provide notice of termination. On July 20, 2006 the Ohio Companies filed with the PUCO a Request to Initiate a Proceeding on Remand. In their Request, the Ohio Companies provided notice of termination to those provisions of the RSP subject to termination, subject to being withdrawn, and also set forth a framework for addressing the Supreme Court of Ohio's findings on customer participation, requesting the PUCO to initiate a proceeding to consider the Ohio Companies' proposal. If the PUCO approves a resolution to the issues raised by the Supreme Court of Ohio that is acceptable to the Ohio Companies, the Ohio Companies' termination will be withdrawn and considered to be null and void. Separately, the OCC and NOAC also submitted to the PUCO on July 20, 2006 a conceptual proposal dealing with the issue raised by the Supreme Court of Ohio. On July 26, 2006, the PUCO issued an Entry acknowledging the July 20, 2006 filings of the Ohio Companies and the OCC and NOAC, and giving the Ohio Companies 45 days to file a plan in a new docket to address the Court's concern. On September 19, 2006, the PUCO issued an Entry granting the Ohio Companies' Motion for extension of time to file the remand proposal. The Ohio Companies filed their RSP Remand CBP on September 29, 2006. No further proceedings have been scheduled at this time.

The Ohio Companies filed an application and stipulation with the PUCO on September 9, 2005 seeking approval of the RCP, a supplement to the RSP. On November 4, 2005, the Ohio Companies filed a supplemental stipulation with the PUCO, which constituted an additional component of the RCP filed on September 9, 2005. Major provisions of the RCP include:

- Maintaining the existing level of base distribution rates through December 31, 2008 for TE;

- Deferring and capitalizing for future recovery (over a 25-year period) with carrying charges certain distribution costs to be incurred by all the Ohio Companies during the period January 1, 2006 through December 31, 2008, not to exceed $150 million in each of the three years;

- Adjusting 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;

- Reducing 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

- Recovering increased fuel costs (compared to a 2002 baseline) 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, TE, and CEI may defer and capitalize (for recovery over a 25-year period) increased fuel costs above the amount collected through the fuel recovery mechanism.

The following table provides TE's estimated amortization of regulatory transition costs and deferred shopping incentives (including associated carrying charges) under the RCP for the period 2006 through 2008:

Amortization Period	**Amortization** *(In millions)*
2006	$ 87
2007	90
2008	112
Total Amortization	**$ 289**

On January 4, 2006, the PUCO approved, with modifications, the Ohio Companies' RCP to supplement the RSP to provide customers with more certain rate levels than otherwise available under the RSP during the plan period. On January 10, 2006, the Ohio Companies filed a Motion for Clarification of the PUCO order approving the RCP. The Ohio Companies sought clarity on issues related to distribution deferrals, including requirements of the review process, timing for recognizing certain deferrals and definitions of the types of qualified expenditures. The Ohio Companies also sought confirmation that the list of deferrable distribution expenditures originally included in the revised stipulation fall within the PUCO order definition of qualified expenditures. On January 25, 2006, the PUCO issued an Entry on Rehearing granting in part, and denying in part, the Ohio Companies' previous requests and clarifying issues referred to above. The PUCO granted the Ohio Companies' requests to:

- Recognize fuel and distribution deferrals commencing January 1, 2006;
- Recognize distribution deferrals on a monthly basis prior to review by the PUCO Staff;
- Clarify that the types of distribution expenditures included in the Supplemental Stipulation may be deferred; and
- Clarify that distribution expenditures do not have to be "accelerated" in order to be deferred.

The PUCO approved the Ohio Companies' methodology for determining distribution deferral amounts, but denied the Motion in that the PUCO Staff must verify the level of distribution expenditures contained in current rates, as opposed to simply accepting the amounts contained in the Ohio Companies' Motion. On February 3, 2006, several other parties filed applications for rehearing on the PUCO's January 4, 2006 Order. The Ohio Companies responded to the applications for rehearing on February 13, 2006. In an Entry on Rehearing issued by the PUCO on March 1, 2006, all motions for rehearing were denied. Certain of these parties have subsequently filed notices of appeal with the Supreme Court of Ohio alleging various errors made by the PUCO in its order approving the RCP. The Ohio Companies' Motion to Intervene in the appeals was granted by the Supreme Court on June 8, 2006. The Appellant's Merit Briefs were filed at the Supreme Court on July 5, 2006. The Appellees include the PUCO and the Ohio Companies. The Appellees' Merit Briefs were filed on August 24, 2006 and the Appellants' Reply Briefs were filed on

September 21 2006. The OCC filed an amicus brief on August 4, 2006, which the Ohio Companies moved to strike as improperly filed. The Supreme Court denied the Ohio Companies' motion on October 18, 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 sought recovery of these costs beginning January 1, 2006. TE requested that these costs be recovered through a rider that would be effective on January 1, 2006 and adjusted each July 1 thereafter. The parties reached a settlement agreement that was approved by the PUCO on August 31, 2005. The incremental transmission and ancillary service revenues recovered from January 1 through June 30, 2006 were approximately $6.5 million. That amount included the recovery of a portion of the 2005 deferred MISO expenses as described below. On April 27, 2006, the Ohio Companies filed the annual update rider to determine revenues ($139 million) from July 2006 through June 2007 ($19 million for TE). The filed rider went into effect on July 1, 2006.

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 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 the Ohio Companies to accrue carrying charges on the deferred balances. On August 31, 2005, the OCC appealed the PUCO's decision. On January 20, 2006, the OCC sought rehearing of the PUCO approval of the recovery of deferred costs through the rider during the period January 1, 2006 through June 30, 2006. The PUCO denied the OCC's application on February 6, 2006. On March 23, 2006, the OCC appealed the PUCO's order to the Ohio Supreme Court. On March 27, 2006, the OCC filed a motion to consolidate this appeal with the deferral appeals discussed above and to postpone oral arguments in the deferral appeal until after all briefs are filed in this most recent appeal of the rider recovery mechanism. On March 20, 2006, the Ohio Supreme Court, on its own motion, consolidated the OCC's appeal of the Ohio Companies' case with a similar case involving Dayton Power & Light Company. Oral arguments were heard on May 10, 2006. The Ohio Companies are awaiting a final ruling from the Ohio Supreme Court, which is expected before the end of 2006.

On November 1, 2005, FES filed two power sales agreements for approval with the FERC. One power sales agreement provided for FES to provide the PLR requirements of the Ohio Companies at a price equal to the retail generation rates approved by the PUCO for a period of three years beginning January 1, 2006. The Ohio Companies will be relieved of their obligation to obtain PLR power requirements from FES if the Ohio CBP results in a lower price for retail customers. A similar power sales agreement between FES and Penn permits Penn to obtain its PLR power requirements from FES at a fixed price equal to the retail generation price during 2006.

On December 29, 2005, the FERC issued an order setting the two power sales agreements for hearing. The order criticized the Ohio CBP, and required FES to submit additional evidence in support of the reasonableness of the prices charged in the power sales agreements. A pre-hearing conference was held on January 18, 2006 to determine the hearing schedule in this case. Under the procedural schedule approved in this case, FES expected an initial decision to be issued in late January 2007. However, on July 14, 2006, the Chief Judge granted the joint motion of FES and the Trial Staff to appoint a settlement judge in this proceeding and the procedural schedule was suspended pending settlement discussions among the parties. A settlement conference was held on September 5, 2006. FES and the Ohio Companies, Penn, and the PUCO, along with other parties, reached an agreement to settle the case. The settlement was filed with the FERC on October 17, 2006, and was unopposed by the remaining parties, including the FERC Trial Staff. Initial comments to the settlement are due by November 6, 2006.

The terms of the settlement provide for modification of both the Ohio and Penn power supply agreements with FES. Under the Ohio power supply agreement, separate rates are established for the Ohio Companies’ PLR requirements, special retail contracts requirements, wholesale contract requirements, and interruptible buy-through retail load requirements. For their PLR and special retail contract requirements, the Ohio Companies will pay FES no more than the lower of (i) the sum of the retail generation charge, the rate stabilization charge, the fuel recovery mechanism charge, and FES’ actual incremental fuel costs for such sales; or (ii) the wholesale price cap. Different wholesale price caps are imposed for PLR sales, special retail contracts, and wholesale contracts. The wholesale price for interruptible buy-through retail load requirements is limited to the actual spot price of power obtained by FES to provide this power. The Ohio Companies have recognized the estimated additional amount payable to FES for power supplied during the nine months ended September 30, 2006. The wholesale rate charged by FES under the Penn power supply agreement will be no greater than the generation component of charges for retail PLR load in Pennsylvania. The FERC is expected to act on this case by the end of the fourth quarter of 2006.

See Note 11 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.

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, 2006, based on estimates of the total costs of cleanup, TE’s proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Included in Other Noncurrent Liabilities are accrued liabilities aggregating approximately $0.2 million as of September 30, 2006.

See Note 10(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. The other potentially material items not otherwise discussed above are described below.

Power Outages and Related Litigation-

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 Web site (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 is also proceeding with the implementation of the recommendations 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 may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future as a result of adoption of mandatory reliability standards pursuant to the EPACT that could require additional material expenditures.

FirstEnergy companies also are defending six separate complaint cases before the PUCO relating to the August 14, 2003 power outages. Two cases were originally filed in Ohio State courts but were subsequently dismissed for lack of subject matter jurisdiction and further appeals were unsuccessful. In these 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. Three other pending PUCO complaint cases were filed by various insurance carriers either in their own name as subrogees or in the name of their insured. In each of these three cases, the carrier seeks reimbursement from various FirstEnergy companies (and, in one case, from PJM, MISO and American Electric Power Company, Inc., as well) for claims paid to insureds for damages allegedly arising as a result of 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 sixth case involves the claim of a non-customer seeking reimbursement for losses incurred when its store was burglarized on August 14, 2003. That case has been dismissed. On March 7, 2006, the PUCO issued a ruling, based on motions filed by the parties, applicable to all pending cases. Among its various rulings, the PUCO consolidated all of the pending outage cases for hearing; limited the litigation to service-related claims by customers of the Ohio operating companies; dismissed FirstEnergy as a defendant; ruled that the U.S.-Canada Power System Outage Task Force Report was not admissible into evidence; and gave the plaintiffs additional time to amend their complaints to otherwise comply with the PUCO’s underlying order. Also, most complainants, along with the FirstEnergy companies, filed applications for rehearing with the PUCO over various rulings contained in the March 7, 2006 order. On April 26, 2006, the PUCO granted rehearing to allow the insurance company claimants, as insurers, to prosecute their claims in their name so long as they also identify the underlying insured entities and the Ohio utilities that provide their service. The PUCO denied all other motions for rehearing. The plaintiffs in each case have since filed an amended complaint and the named FirstEnergy companies have answered and also have filed a motion to dismiss each action. On September 27, 2006, the PUCO dismissed certain parties and claims and otherwise ordered the complaints to go forward to hearing. The cases have been set for hearing on October 16, 2007.

On October 10, 2006, various insurance carriers refiled a complaint in Cuyahoga County Common Pleas Court seeking reimbursement for claims paid to numerous insureds who allegedly suffered losses as a result of the August 14, 2003 outages. All of the insureds appear to be non-customers. The plaintiff insurance companies are the same claimants in one of the pending PUCO cases. FirstEnergy, the Ohio Companies and Penn were served on October 27, 2006, and expect to seek summary dismissal of these cases based on the prior court rulings noted above. No estimate of potential liability is available for any of these cases.

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. Although unable to predict the impact of these proceedings, 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-

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 now repealed 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 related disclosures, which FirstEnergy has provided. 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. Both filings were consolidated for hearing and decision. 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. On May 10, 2006, the PUCO issued its Opinion and Order dismissing the City's complaint and approving the related tariffs, thus affirming OE's entitlement to recovery of its transition charges. The City of Huron filed an application for rehearing of the PUCO's decision on June 9, 2006 and OE filed a memorandum in opposition to that application on June 19, 2006. The PUCO denied the City's application for rehearing on June 28, 2006. The City of Huron has taken no further action and the period for filing an appeal has expired.

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

New Accounting Standards and Interpretations

SAB 108 - "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements"

In September 2006, the SEC issued SAB 108, which provides interpretive guidance on how registrants should quantify financial statement misstatements. There is currently diversity in practice, with the two commonly used methods to quantify misstatements being the "rollover" method (which primarily focuses on the income statement impact of misstatements) and the "iron curtain" method (which focuses on the balance sheet impact). SAB 108 requires registrants to use a dual approach whereby both of these methods are considered in evaluating the materiality of financial statement errors. Prior materiality assessments will need to be reconsidered using both the rollover and iron curtain methods. This guidance will be effective for TE in the fourth quarter of 2006. TE does not expect this Statement to have a material impact on its financial statements.

SFAS 157 - "Fair Value Measurements"

In September 2006, the FASB issued SFAS 157 that establishes how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under GAAP. This Statement addresses the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. The key changes to current practice are: (1) the definition of fair value which focuses on an exit price rather than entry price; (2) the methods used to measure fair value such as emphasis that fair value is a market-based measurement, not an entity-specific measurement, as well as the inclusion of an adjustment for risk, restrictions and credit standing; and (3) the expanded disclosures about fair value measurements.

This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. TE is currently evaluating the impact of this Statement on its financial statements.

SFAS 158 - "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)"

In September 2006, the FASB issued SFAS 158, which requires companies to recognize a net liability or asset to report the overfunded or underfunded status of their defined benefit pension and other postretirement benefit plans on their balance sheets and recognize changes in funded status in the year in which the changes occur through other comprehensive income. The funded status to be measured is the difference between plan assets at fair value and the benefit obligation. This Statement requires that gains and losses and prior service costs or credits, net of tax, that arise during the period be recognized as a component of other comprehensive income and not as components of net periodic benefit cost. Additional information should also be disclosed in the notes to the financial statements about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and transition asset or obligation. Upon the initial application of this Statement and subsequently, an employer should continue to apply the provisions in Statements 87, 88 and 106 in measuring plan assets and benefit obligations as of the date of its statement of financial position and in determining the amount of net periodic benefit cost. This Statement is effective for TE as of December 31, 2006. TE is currently evaluating the impact of this Statement on its financial statements.

FIN 48 - "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109."

In June 2006, the FASB issued FIN 48 which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, "Accounting for Income Taxes." This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken on a tax return. This interpretation also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation will be a two-step process. The first step will determine if it is more likely than not that a tax position will be sustained upon examination and should therefore be recognized. The second step will measure a tax position that meets the more likely than not recognition threshold to determine the amount of benefit to recognize in the financial statements. This interpretation is effective for fiscal years beginning after December 15, 2006. TE is currently evaluating the impact of this Statement.

PENNSYLVANIA POWER COMPANY

CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(In thousands)			
REVENUES	$ 88,700	$ 145,540	$ 252,069	$ 414,306
EXPENSES:				
Fuel	-	6,205	-	17,351
Purchased power	60,490	42,242	171,759	131,948
Nuclear operating costs	-	16,997	-	56,710
Other operating costs	16,448	19,030	44,776	48,541
Provision for depreciation	2,383	3,847	6,509	11,351
Amortization of regulatory assets	-	9,784	3,411	29,499
General taxes	6,098	6,836	17,602	19,752
Total expenses	85,419	104,941	244,057	315,152
OPERATING INCOME	3,281	40,599	8,012	99,154
OTHER INCOME (EXPENSE):				
Miscellaneous income	3,468	698	10,319	475
Interest expense	(1,461)	(2,371)	(6,823)	(7,477)
Capitalized interest	62	1,665	144	4,508
Total other income (expense)	2,069	(8)	3,640	(2,494)
INCOME BEFORE INCOME TAXES	5,350	40,591	11,652	96,660
INCOME TAXES	2,117	17,551	4,924	42,907
NET INCOME	3,233	23,040	6,728	53,753
PREFERRED STOCK DIVIDEND REQUIREMENTS	156	156	467	1,534
EARNINGS ON COMMON STOCK	$ 3,077	$ 22,884	$ 6,261	$ 52,219

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, 2006	December 31, 2005
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 36	$ 24
Receivables -		
Customers (less accumulated provisions of $1,135,000 and $1,087,000, respectively, for uncollectible accounts)	37,978	44,555
Associated companies	86,656	115,441
Other	1,778	2,889
Notes receivable from associated companies	1,851	1,699
Restricted cash	-	78,248
Prepayments and other	12,744	8,747
	141,043	251,603
UTILITY PLANT:		
In service	371,575	359,069
Less - Accumulated provision for depreciation	132,749	129,118
	238,826	229,951
Construction work in progress	3,865	3,775
	242,691	233,726
OTHER PROPERTY AND INVESTMENTS:		
Long-term notes receivable from associated companies	275,924	283,248
Other	350	351
	276,274	283,599
DEFERRED CHARGES AND OTHER ASSETS:		
Prepaid pension costs	43,462	42,243
Other	1,794	3,829
	45,256	46,072
	$ 705,264	$ 815,000
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 15,474	$ 69,524
Short-term borrowings -		
Associated companies	1,607	12,703
Other	19,000	-
Accounts payable -		
Associated companies	18,194	73,444
Other	1,581	1,828
Accrued taxes	20,629	28,632

Accrued interest		1,075		1,877
Other		7,484		8,086
		85,044		196,094
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		71,136		71,136
Retained earnings		43,268		37,097
Total common stockholder's equity		303,104		296,933
Preferred stock		14,105		14,105
Long-term debt and other long-term obligations		123,344		130,677
		440,553		441,715
NONCURRENT LIABILITIES:				
Accumulated deferred income taxes		63,321		66,576
Retirement benefits		47,268		45,967
Regulatory liabilities		63,679		58,637
Other		5,399		6,011
		179,667		177,191
COMMITMENTS AND CONTINGENCIES (Note 10)				
	$	705,264	$	815,000

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)

	Nine Months Ended September 30, 2006	2005
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 6,728	$ 53,753
Adjustments to reconcile net income to net cash from operating activities -		
Provision for depreciation	6,509	11,351
Amortization of regulatory assets	3,411	29,499
Nuclear fuel and other amortization	-	12,912
Deferred income taxes and investment tax credits, net	(2,809)	(7,567)
Decrease (increase) in operating assets -		
Receivables	36,473	15,141
Materials and supplies	-	(51)
Prepayments and other current assets	(3,997)	(3,186)
Increase (decrease) in operating liabilities -		
Accounts payable	(55,497)	(29,056)
Accrued taxes	(8,003)	12,108
Accrued interest	(802)	(237)
Other	2,012	1,027
Net cash provided from (used for) operating activities	(15,975)	95,694
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing -		
Short-term borrowings, net	7,904	22,969
Redemptions and Repayments -		
Preferred stock	-	(37,750)
Long-term debt	(61,899)	(849)
Dividend Payments -		
Common stock	-	(8,000)
Preferred stock	(467)	(1,534)
Net cash used for financing activities	(54,462)	(25,164)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(14,811)	(69,630)
Proceeds from nuclear decommissioning trust fund sales	-	57,003

Investments in nuclear decommissioning trust funds		-		(58,199)
Loan repayments from associated companies		7,172		(14)
Cash investments		78,248		-
Other		(160)		296
Net cash provided from (used for) investing activities		70,449		(70,544)
Net increase (decrease) in cash and cash equivalents		12		(14)
Cash and cash equivalents at beginning of period		24		38
Cash and cash equivalents at end of period	$	36	$	24

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

Report of Independent Registered Public Accounting Firm

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

We have reviewed the accompanying consolidated balance sheet of Pennsylvania Power Company and its subsidiaries as of September 30, 2006, and the related consolidated statement of income for each of the three-month and nine-month periods ended September 30, 2006 and 2005 and the consolidated statements of cash flows for the nine-month periods ended September 30, 2006 and 2005. 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 have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2005, and the related consolidated statements of income, capitalization, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report [which contained references to the Company's change in its method of accounting for asset retirement obligations as of January 1, 2003 as discussed in Note 2(G) and Note 8 to those consolidated financial statements] dated February 27, 2006, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2005, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers
LLP
Cleveland, Ohio
October 31, 2006

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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's rate restructuring plan and its associated transition charge revenue recovery was completed in 2005. Its power supply requirements are provided by FES - an affiliated company.

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 that were completed in the fourth quarter of 2005. The asset transfers resulted in the respective undivided ownership interests of the Ohio Companies and Penn in FirstEnergy's nuclear and non-nuclear generation assets being owned by NGC and FGCO, respectively.

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 FGCO's purchase option under the Master Facility Lease.

On December 16, 2005, the Ohio Companies and Penn completed the intra-system transfer of their respective ownership in the nuclear generation assets to NGC through, in the case of OE and Penn, an asset spin-off by way of dividend. FENOC continues to operate and maintain the nuclear generation assets.

These transactions were 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 essentially completed the divestitures contemplated by the restructuring plans by transferring the ownership interests to NGC and FGCO without impacting the operation of the plants.

The transfers will affect Penn's comparative earnings results with reductions in both revenues and expenses. Revenues are reduced due to the termination of certain arrangements with FES, under which Penn previously sold its nuclear-generated KWH to FES and leased its non-nuclear generation assets to FGCO, a subsidiary of FES. Penn's expenses are lower due to the nuclear fuel and operating costs assumed by NGC as well as depreciation and property tax expenses assumed by FGCO and NGC related to the transferred generating assets. In addition, Penn receives interest income on associated company notes receivable from the transfer of its generation net assets. FES will continue to provide Penn's PLR requirements under revised purchased power arrangements during 2006 (see Outlook -- Regulatory Matters).

The effects on Penn's results of operations in the third quarter and nine months ended September 30, 2006 compared to the same periods of 2005 from the generation asset transfers are summarized in the following table:

Intra-System Generation Asset Transfers Income Statement Effects		**Three Months**		**Nine Months**	
Increase (Decrease)			***(In millions)***		
Revenues:					
Non-nuclear generating units rent	(a)	$	(5)	$	(15)
Nuclear generated KWH sales	(b)		(42)		(118)
Total - Revenues Effect			(47)		(133)
Expenses:					
Fuel costs - nuclear	(c)		(6)		(17)
Nuclear operating costs	(c)		(17)		(57)
Provision for depreciation	(d)		(1)		(4)
General taxes	(e)		(1)		(1)
Total - Expenses Effect			(25)		(79)
Operating Income Effect			(22)		(54)
Other income:					
Interest income from notes receivable	(f)		2		7
Capitalized interest	(g)		(1)		(4)
Total - Other Income Effect			1		3
Income taxes	(h)		(9)		(21)
Net Income Effect		$	(12)	$	(30)

(a) Elimination of non-nuclear generation assets lease to FGCO.
(b) Reduction of nuclear generated wholesale KWH sales to FES.
(c) Reduction of nuclear fuel and operating costs.
(d) Reduction of depreciation expense and asset retirement obligation accretion related to generation assets.
(e) Reduction of property tax expense on generation assets.
(f) Interest income on associated company notes receivable from the transfer of generation net assets.
(g) Reduction of allowance for borrowed funds used during construction on nuclear capital expenditures.
(h) Income tax effect of the above adjustments.

<u>Results of Operations</u>

Earnings on common stock in the third quarter of 2006 decreased to $3 million from $23 million in the third quarter of 2005. During the first nine months of 2006 earnings on common stock decreased to $6 million from $52 million in the first nine months of 2005. The lower earnings in both periods of 2006 resulted principally from the generation asset transfer effects shown in the table above, lower revenues and higher purchased power costs, partially offset by a reduction in regulatory asset amortization due to the completion of Penn’s rate restructuring plan in 2005.

Revenues

Revenues decreased by $57 million, or 39%, and $162 million, or 39%, in the third quarter and the first nine months of 2006, respectively, as compared with the same periods of 2005, primarily due to the generation asset transfer impact summarized in the table above. Excluding the effects of the asset transfer, revenues decreased by $10 million, or 7.0% and $29 million, or 7.1%, in the third quarter and the first nine months of 2006, respectively. These decreases resulted from lower distribution revenues ($9 million and $26 million, respectively) primarily reflecting the completion of Penn's generation-related transition cost recovery under Penn’s rate restructuring plan and lower wholesale revenues ($6 million and $18 million, respectively) resulting from the termination of a wholesale sales agreement with a non-affiliate in December 2005. Partially offsetting these decreases were increases in retail generation revenues of $5 million in the third quarter and $15 million in the first nine months of 2006, primarily from higher composite unit prices associated with a 5% rate increase for generation permitted by the PPUC for all customer classes.

Distribution KWH deliveries were lower to residential customers in the third quarter and to both residential and commercial sectors in the first nine months of 2006 due to the impact of milder weather conditions compared to the same periods of 2005. Higher KWH deliveries to industrial customers in both periods of 2006 were largely due to increased demand from the steel sector.

Changes in KWH sales by customer class in the third quarter and the first nine months of 2006 from the same periods of 2005 are summarized in the following tables:

Changes in KWH Sales Increase (Decrease)	**Three Months**	**Nine Months**
Retail Electric Generation:		
Residential	(1.4)%	(3.6)%
Commercial	0.8 %	(1.4)%
Industrial	4.8 %	6.4 %
Total Retail Electric Generation Sales	**1.4 %**	**0.5 %**
Distribution Deliveries:		
Residential	(1.7)%	(3.8)%
Commercial	0.8 %	(1.5)%
Industrial	4.8 %	6.4 %
Total Distribution Deliveries	**1.3 %**	**0.4 %**

Expenses

Total expenses decreased by $20 million in the third quarter and $71 million in the first nine months of 2006 from the same periods of 2005 principally due to the generation asset transfer impact as shown previously. Excluding the asset transfer effects, the following table presents changes from the prior year by expense category:

Expenses - Changes Increase (Decrease)	**Three Months**	**Nine Months**
	(In millions)	
Purchased power costs	$ 18	$ 40
Other operating costs	(3)	(4)
	-	(1)

Provision for depreciation				
Amortization of regulatory assets		(10)		(26)
General Taxes		-		(1)
Net increase in expenses	**$**	**5**	**$**	**8**

Increased purchased power costs in the third quarter and the first nine months of 2006, compared with the same periods of 2005, resulted from higher unit prices associated with a new power supply agreement with FES, partially offset by decreases in KWH purchased due to lower generation sales requirements. Other operating costs decreased primarily due to lower employee benefit costs.

Amortization of regulatory assets was lower in the third quarter and the first nine months of 2006 as compared to the same periods of 2005 due to the completion of Penn's rate restructuring plan at the end of 2005.

Other Income (Expense)

Miscellaneous income increased $3 million in the third quarter and $10 million in the first nine months of 2006, compared with the same periods of 2005, primarily due to the impact of the generation asset transfer. Excluding the effects of the asset transfer, miscellaneous income was substantially unchanged in the third quarter and was $3 million higher in the first nine months of 2006, compared with the same periods of 2005. The increase in the first nine months of 2006 was primarily due to the absence in 2006 of changes for a $0.7 million civil penalty payable to the DOJ and a $0.8 million settlement for environmental projects in connection with the Sammis New Source Review settlement in the first quarter of 2005 (see Outlook Environmental Matters).

Net Interest Charges

Net interest charges increased $1 million in the third quarter and $4 million in the first nine months of 2006 as compared to the same periods of 2005 primarily due to the reduction of capitalized interest related to the generation asset transfer. Excluding the effect of the asset transfer, interest expense decreased by $1 million in the third quarter and was substantially unchanged in the first nine months of 2006 as compared to the same periods of 2005 due to Penn’s debt redemptions.

Capital Resources and Liquidity

Penn's cash requirements for the remainder of 2006 for operating expenses, construction expenditures and scheduled debt maturities are expected to be met with a combination of internal cash and short-term credit arrangements. Available borrowing capacity under credit facilities is used to manage working capital requirements.

Changes in Cash Position

Penn had $36,000 of cash and cash equivalents as of September 30, 2006 compared with $24,000 as of December 31, 2005. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Net cash provided from operating activities in the first nine months of 2006, compared with the corresponding 2005 period, was as follows:

Operating Cash Flows	Nine Months Ended September 30, 2006	2005
	(In millions)	
Cash earnings (*)	$ 14	$ 101
Working capital and other	(30)	(5)
Net cash provided from operating activities	$ (16)	$ 96

(*) Cash earnings are a non-GAAP measure (see reconciliation below).

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. Generally, a non-GAAP financial measure is a numerical measure of a company's historical or future financial performance, financial position, or cash flows that either excludes or includes amounts, or is subject to adjustment that has the effect of excluding or including amounts, that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with GAAP. In addition, cash earnings (non-GAAP) are not defined under GAAP. Management believes presenting this non-GAAP measure provides useful information to investors in assessing Penn's operating performance from a cash perspective without the effects of material unusual economic events. Penn's management frequently references these non-GAAP financial measures in its decision-making, using them to facilitate historical and ongoing performance comparisons as well as comparisons to the performance of peer companies. These non-GAAP measures should be considered in addition to, and not as a substitute for, their most directly comparable financial measures prepared in accordance with GAAP.

Reconciliation of Cash Earnings	Nine Months Ended September 30, 2006	2005
	(In millions)	
Net income (GAAP)	$ 7	$ 54
Non-cash charges (credits):		
Provision for depreciation	7	11
Amortization of regulatory assets	3	29
Nuclear fuel and other amortization	-	13
Deferred income taxes and investment tax credits, net	(3)	(8)
Other non-cash items	-	2
Cash earnings (Non-GAAP)	$ 14	$ 101

The $87 million decrease in cash earnings for the first nine months of 2006, as compared to the corresponding period of 2005 resulted principally from the generation asset transfer, as is described above under "Results of Operations". The $25 million change in working capital was primarily due to increased cash outflows from the settlement of accounts payable of $26 million and a $20 million change in accrued taxes. These variances were partially offset by an increase in cash of $21 million provided from the collection of receivables.

Cash Flows From Financing Activities

Net cash used for financing activities totaled $54 million in the first nine months of 2006, compared with $25 million in the same period of 2005. The $29 million increase resulted from $62 million of long-term debt redemptions in 2006 principally related to the generation asset transfer discussed above and a $15 million decrease in short-term borrowings, partially offset by a $38 million decrease in preferred stock redemptions and an $8 million decrease in common stock dividend payments to OE.

As of September 30, 2006, Penn had $2 million of cash and temporary investments (which included short-term notes receivable from associated companies) and $21 million of short-term indebtedness. Penn has authorization from the FERC to incur short-term debt up to its charter limit of $44 million (including the utility money pool). Penn had the capability to issue $68 million of additional FMB on the basis of property additions and retired bonds as of September 30, 2006. Based upon applicable earnings coverage tests, Penn could issue up to $136 million of preferred stock (assuming no additional debt was issued) as of September 30, 2006.

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 which expires on June 28, 2007. The financing arrangements require payment of an annual facility fee of 0.125% on the entire finance limit. As a separate legal entity with separate creditors, Penn Funding would have to satisfy its separate obligations to creditors before any of its remaining assets could be made available to Penn. As of September 30, 2006, the facility was drawn for $19 million.

On August 24, 2006, Penn, FirstEnergy, OE, CEI, TE, JCP&L, Met-Ed, Penelec, FES and ATSI as Borrowers, entered into a new $2.75 billion five-year revolving credit facility that expires in August 2011, which replaced the prior $2 billion credit facility. FirstEnergy may request an increase in the total commitments available under the new facility up to a maximum of $3.25 billion. Borrowings under the facility are available to each Borrower separately and will mature on the earlier of 364 days from the date of borrowing or the August 24, 2011 commitment expiration date. Penn's borrowing limit under the facility is $50 million.

Under the revolving credit facility, Borrowers may request the issuance of LOCs expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under the facility and against the applicable borrower’s borrowing sub-limit. Total unused borrowing capability under the existing credit facility and accounts receivable financing facilities totaled $56 million as of September 30, 2006.

The revolving credit facility contains financial covenants requiring each Borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%, measured at the end of each fiscal quarter. As of September 30, 2006, Penn's debt to total capitalization as defined under the revolving credit facility was 33%.

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

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, 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 first nine months of 2006 was 5.09%.

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

In the first nine months of 2006, pollution control notes that were formerly obligations of Penn were refinanced and became obligations of FGCO and NGC. The proceeds from the refinancings were used to repay a portion of their associated company notes payable to Penn. With those repayments, Penn redeemed pollution control notes in the principal amount of $16.8 million at 5.9%; $12.7 million at 6.15%; $14.25 million at 6%; $10.3 million at 3.61%; and $6.95 million at 5.45%.

Cash Flows From Investing Activities

Net cash provided from investing activities totaled $70 million in the first nine months of 2006, compared with $71 million of net cash used in the same period of 2005. The $141 million increase in the 2006 period reflects a $55 million reduction in property additions and $78 million from liquidating investments (restrictions on short-term investments expired for an escrow fund and a mortgage indenture deposit), principally as a result of the generation asset transfer discussed above, and a $7 million increase in loan repayments from associated companies.

During the last quarter of 2006, capital requirements for property additions are expected to be approximately $4 million. Penn has sinking fund requirements of approximately $0.5 million for maturing long-term debt during the remainder of 2006. These cash requirements are expected to be satisfied from internal cash and short-term credit arrangements.

Penn’s capital spending for the period 2006-2010 is expected to be approximately $91 million of which approximately $19 million applies to 2006. Penn had no other material obligations as of September 30, 2006 that have not been recognized on its Consolidated Balance Sheet.

OUTLOOK

The electric industry continues to transition to a more competitive environment and all of Penn’s customers can select alternative energy suppliers. Penn 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. Penn has a continuing responsibility to provide power to those customers not choosing to receive power from an alternative energy supplier subject to certain limits.

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 $64 million as of September 30, 2006 and $59 million as of December 31, 2005, and are included under Noncurrent Liabilities on the Consolidated Balance Sheets.

Under Pennsylvania's electric competition law, Penn is required to secure generation supply for customers who do not choose alternative suppliers for their electricity. 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 recommended that the RFP process cover the period January 1, 2007 through May 31, 2008. Hearings before the PPUC were held on January 10, 2006 with main briefs filed on January 27, 2006 and reply briefs filed on February 3, 2006. On February 16, 2006, the ALJ issued a Recommended Decision to adopt Penn's RFP process with modifications. On April 20, 2006, the PPUC approved the Recommended Decision with additional modifications to use an RFP process with two separate solicitations. An initial solicitation was held for Penn in May 2006 with all tranches fully subscribed, which was approved by the PPUC on June 2, 2006. On July 18, 2006, the second PLR solicitation was held for Penn. The tranches for the Residential Group and Small Commercial Group were fully subscribed. However, supply was not acquired for two tranches for the Large Commercial Group. On July 20, 2006, the PPUC approved the submissions for the second bid. A contingency solicitation was held on August 15, 2006 for the two remaining Large Commercial Group tranches. The PPUC rejected the bids from the contingency solicitation and directed Penn’s independent auction manager to offer the two unfilled Large Commercial tranches to the companies which had won tranches in the prior solicitations. This resulted in the acquisition of a supplier for the two remaining tranches, which were filed and accepted by the PPUC in a secretarial letter that was entered on

September 22, 2006. On August 24, 2006, Penn made a compliance filing. OCA and OSBA filed exceptions to the compliance filing. Penn filed reply exceptions on September 5, 2006. On September 21, 2006, Penn submitted a revised compliance filing to the PPUC for the Residential Group and Small Commercial Group as a result of an agreement between Penn, OCA and OSBA. The PPUC approved proposed rates for the large commercial and industrial customers at the PPUC Public meeting on October 19, 2006, and found that the results of the competitive solicitation process were consistent with prevailing market prices.

On May 25, 2006, Penn filed a Petition for Review of the PPUC’s Orders of April 28, 2006 and May 4, 2006, which together decided the issues associated with Penn’s proposed Interim PLR Supply Plan. Penn has asked the Commonwealth Court to review the PPUC’s decision to deny Penn’s recovery of certain PLR costs through a reconciliation mechanism and the PPUC’s decision to impose a geographic limitation on the sources of alternative energy credits. On June 7, 2006, the PaDEP filed a Petition for Review appealing the PPUC’s ruling on the method by which alternative energy credits may be acquired and traded. Penn is unable to predict the outcome of this appeal.

On December 29, 2005, the FERC issued an order setting the two power sales agreements for hearing. The order criticized the Ohio CBP, and required FES to submit additional evidence in support of the reasonableness of the prices charged in the power sales agreements. A pre-hearing conference was held on January 18, 2006 to determine the hearing schedule in this case. Under the procedural schedule approved in this case, FES expected an initial decision to be issued in late January 2007. However, on July 14, 2006, the Chief Judge granted the joint motion of FES and the Trial Staff to appoint a settlement judge in this proceeding and the procedural schedule was suspended pending settlement discussions among the parties. A settlement conference was held on September 5, 2006. FES and the Ohio Companies, Penn, and the PUCO, along with other parties, reached an agreement to settle the case. The settlement was filed with the FERC on October 17, 2006, and was unopposed by the remaining parties, including the FERC Trial Staff. Initial comments to the settlement are due by November 6, 2006.

The terms of the settlement provide for modification of both the Ohio and Penn power supply agreements with FES. The wholesale rate charged by FES under the Penn power supply agreement will be no greater than the generation component of charges for retail PLR load in Pennsylvania. The FERC is expected to act on this case by the end of the fourth quarter of 2006.

As a result of Penn's PLR competitive solicitation process approved by the PPUC, FES was selected as the winning bidder for a number of the tranches for individual customer classes. The balance of the tranches will be supplied by unaffiliated power suppliers. On October 2, 2006, FES filed an application with FERC under Section 205 of the Federal Power Act for authorization to make these affiliate sales to Penn. Interventions or protests were due on this filing on October 23, 2006. Penn was the only party to file an intervention in this proceeding. The FERC is expected to act on this filing on or before December 1, 2006.

See Note 11 to the consolidated financial statements for further details and a complete discussion of regulatory matters in Pennsylvania.

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.

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 was approved by the Court on July 11, 2005, and requires reductions of NO_X and SO_2 emissions at the W. H. Sammis Plant and other coal-fired plants through the installation of pollution control devices and provides for stipulated penalties for failure to install and operate such pollution controls in accordance with that agreement. Consequently, if FirstEnergy fails to install such pollution control devices, for any reason, including, but not limited to, the failure of any third-party contractor to timely meet its delivery obligations for such devices, FirstEnergy could be exposed to penalties under the settlement agreement. Capital expenditures necessary to meet those requirements are currently estimated to be $1.5 billion ($400 million of which is expected to be spent in 2007 with the primary portion of the remaining $1.1 billion expected to be spent in 2008 and 2009). On August 26, 2005, FGCO entered into an agreement with Bechtel Power Corporation under which Bechtel will engineer, procure, and construct air quality control systems for the reduction of SO_2 emissions. FGCO also entered into an agreement with B&W on August 25, 2006 to supply flue gas desulfurization systems for the reduction of SO_2 emissions. Selective Catalytic Reduction (SCR) systems for the reduction of NOx emissions also are being installed at the W.H. Sammis Plant under a 1999 agreement with B&W. The above requirements will be the responsibility of FGCO.

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 paid by OE and Penn of $7.8 million and $0.7 million, respectively. OE and Penn also recognized liabilities in the first quarter of 2005 of $9.2 million and $0.8 million, respectively, for probable future cash contributions toward environmentally beneficial projects.

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.

Power Outages and Related Litigation

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 Web site (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 is also proceeding with the implementation of the recommendations 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 may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future as a result of adoption of mandatory reliability standards pursuant to the EPACT that could require additional material expenditures.

On October 10, 2006, various insurance carriers refiled a complaint in Cuyahoga County Common Pleas Court seeking reimbursement for claims paid to numerous insureds who allegedly suffered losses as a result of the August 14, 2003 outages. All of the insureds appear to be non-customers. The plaintiff insurance companies are the same claimants in one of the pending PUCO cases. FirstEnergy, the Ohio Companies and Penn were served on October 27, 2006, and expect to seek summary dismissal of these cases. No estimate of potential liability is available for any of these cases.

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. Although unable to predict the impact of these proceedings, 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 10(C) to the consolidated financial statements for further details and a complete discussion of other legal proceedings.

New Accounting Standards and Interpretations

SAB 108 - "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements"

In September 2006, the SEC issued SAB 108, which provides interpretive guidance on how registrants should quantify financial statement misstatements. There is currently diversity in practice, with the two commonly used methods to quantify misstatements being the "rollover" method (which primarily focuses on the income statement impact of misstatements) and the "iron curtain" method (which focuses on the balance sheet impact). SAB 108 requires registrants to use a dual approach whereby both of these methods are considered in evaluating the materiality of financial statement errors. Prior materiality assessments will need to be reconsidered using both the rollover and iron curtain methods. This guidance will be effective for Penn in the fourth quarter of 2006. Penn does not expect this Statement to have a material impact on its financial statements.

SFAS 157 - "Fair Value Measurements"

In September 2006, the FASB issued SFAS 157 that establishes how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under GAAP. This Statement addresses the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. The key changes to current practice are: (1) the definition of fair value which focuses on an exit price rather than entry price; (2) the methods used to measure fair value such as emphasis that fair value is a market-based measurement, not an entity-specific measurement, as well as the inclusion of an adjustment for risk, restrictions and credit standing; and (3) the expanded disclosures about fair value measurements.

This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. Penn is currently evaluating the impact of this Statement on its financial statements.

SFAS 158 - "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)"

In September 2006, the FASB issued SFAS 158, which requires companies to recognize a net liability or asset to report the overfunded or underfunded status of their defined benefit pension and other postretirement benefit plans on their balance sheets and recognize changes in funded status in the year in which the changes occur through other comprehensive income. The funded status to be measured is the difference between plan assets at fair value and the benefit obligation. This Statement requires that gains and losses and prior service costs or credits, net of tax, that arise during the period be recognized as a component of other comprehensive income and not as components of net periodic benefit cost. Additional information should also be disclosed in the notes to the financial statements about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and transition asset or obligation. Upon the initial application of this Statement and subsequently, an employer should continue to apply the provisions in Statements 87, 88 and 106 in measuring plan assets and benefit obligations as of the date of its statement of financial position and in determining the amount of net periodic benefit cost. This Statement is effective for Penn as of December 31, 2006. Penn is currently evaluating the impact of this Statement on its financial statements.

FIN 48 - "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109."
In

In June 2006, the FASB issued FIN 48 which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, "Accounting for Income

Taxes.” This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken on a tax return. This interpretation also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation will be a two-step process. The first step will determine if it is more likely than not that a tax position will be sustained upon examination and should therefore be recognized. The second step will measure a tax position that meets the more likely than not recognition threshold to determine the amount of benefit to recognize in the financial statements. This interpretation is effective for fiscal years beginning after December 15, 2006. Penn is currently evaluating the impact of this Statement.

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005 Restated	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005 Restated
STATEMENTS OF INCOME		*(In thousands)*		
REVENUES	$ 911,068	$ 900,247	$ 2,098,344	$ 2,024,630
EXPENSES				
Purchased power	546,125	517,213	1,204,880	1,115,738
Other operating costs	90,578	112,690	245,711	293,996
Provision for depreciation	21,099	19,659	62,553	59,721
Amortization of regulatory assets	78,052	85,485	210,323	224,109
Deferral of new regulatory assets	-	(1,097)	-	(28,862)
General taxes	19,187	19,538	49,691	49,802
Total expenses	755,041	753,488	1,773,158	1,714,504
OPERATING INCOME	156,027	146,759	325,186	310,126
OTHER INCOME (EXPENSE):				
Miscellaneous income	2,091	4,777	8,162	5,264
Interest expense	(21,437)	(19,960)	(62,420)	(60,963)
Capitalized interest	1,004	497	2,933	1,337
Total other expense	(18,342)	(14,686)	(51,325)	(54,362)
INCOME BEFORE INCOME TAXES	137,685	132,073	273,861	255,764
INCOME TAXES	58,316	58,197	120,506	114,136
NET INCOME	79,369	73,876	153,355	141,628
PREFERRED STOCK DIVIDEND REQUIREMENTS	917	125	1,167	375
EARNINGS ON COMMON STOCK	$ 78,452	$ 73,751	$ 152,188	$ 141,253
STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$ 79,369	$ 73,876	$ 153,355	$ 141,628

OTHER COMPREHENSIVE INCOME:				
Unrealized gain on derivative hedges	100	103	207	208
Income tax expense related to other comprehensive income	41	42	84	85
Other comprehensive income, net of tax	59	61	123	123
TOTAL COMPREHENSIVE INCOME	$ 79,428	$ 73,937	$ 153,478	$ 141,751

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, 2006	December 31, 2005
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 58	$ 102
Receivables-		
Customers (less accumulated provisions of $4,066,000 and $3,830,000, respectively, for uncollectible accounts)	310,347	258,077
Associated companies	161	203
Other (less accumulated provisions of $216,000 and $204,000, respectively, for uncollectible accounts)	39,565	41,456
Notes receivable - associated companies	27,056	18,419
Materials and supplies, at average cost	2,017	2,104
Prepaid taxes	40,060	10,137
Other	9,045	6,928
	428,309	337,426
UTILITY PLANT:		
In service	4,008,742	3,902,684
Less - Accumulated provision for depreciation	1,467,604	1,445,718
	2,541,138	2,456,966
Construction work in progress	77,450	98,720
	2,618,588	2,555,686
OTHER PROPERTY AND INVESTMENTS:		
Nuclear fuel disposal trust	168,375	164,203
Nuclear plant decommissioning trusts	156,205	145,975
Other	2,080	2,580
	326,660	312,758
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	2,178,460	2,226,591
Goodwill	1,977,551	1,985,858
Prepaid pension costs	152,113	148,054
Other	17,587	17,733
	4,325,711	4,378,236
	$ 7,699,268	$ 7,584,106
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 70,140	$ 207,231
Notes payable-		
Associated companies	137,184	181,346

Accounts payable-		
Associated companies	9,754	37,955
Other	169,570	149,501
Accrued taxes	37,365	54,356
Accrued interest	36,212	19,916
Cash collateral from suppliers	48,582	141,225
Other	65,148	86,884
	573,955	878,414
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	2,995,029	3,003,190
Accumulated other comprehensive loss	(1,907)	(2,030)
Retained earnings	163,079	55,890
Total common stockholder's equity	3,309,914	3,210,763
Preferred stock	-	12,649
Long-term debt and other long-term obligations	1,327,809	972,061
	4,637,723	4,195,473
NONCURRENT LIABILITIES:		
Power purchase contract loss liability	1,205,064	1,237,249
Accumulated deferred income taxes	814,236	812,034
Nuclear fuel disposal costs	181,317	175,156
Asset retirement obligations	83,188	79,527
Retirement benefits	71,785	72,454
Other	132,000	133,799
	2,487,590	2,510,219
COMMITMENTS AND CONTINGENCIES (Note 10)		
	$ 7,699,268	$ 7,584,106

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

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
	2006	**2005 Restated**
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 153,355	$ 141,628
Adjustments to reconcile net income to net cash from operating activities -		
Provision for depreciation	62,553	59,721
Amortization of regulatory assets	210,323	224,109
Deferral of new regulatory assets	-	(28,862)
Deferred purchased power and other costs	(213,621)	(168,646)
Deferred income taxes and investment tax credits, net	25,217	5,204
Accrued compensation and retirement benefits	(4,196)	(6,545)
Cash collateral from (returned to) suppliers	(108,926)	76,674
Decrease (increase) in operating assets -		
Receivables	(50,337)	(25,626)
Materials and supplies	86	572
Prepaid taxes	(29,923)	1,264
Other current assets	(2,118)	(3,028)
Increase (decrease) in operating liabilities -		
Accounts payable	(8,131)	26,214
Accrued taxes	(16,992)	77,341
Accrued interest	16,296	14,931
Other	(15,130)	25,814
Net cash provided from operating activities	18,456	420,765
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	382,400	-
Redemptions and Repayments-		
Long-term debt	(162,157)	(67,648)
Short-term borrowings, net	(44,162)	(133,600)
Preferred stock	(13,461)	-
Dividend Payments-		
Common stock	(45,000)	(83,000)
Preferred stock	(354)	(375)
	117,266	(284,623)

Net cash provided from (used for) financing activities				
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions		(123,540)		(133,498)
Loan repayments from (loans to) associated companies, net		(8,638)		685
Proceeds from nuclear decommissioning trust fund sales		138,936		103,360
Investments in nuclear decommissioning trust funds		(141,107)		(105,531)
Other		(1,417)		(749)
Net cash used for investing activities		(135,766)		(135,733)
Net increase (decrease) in cash and cash equivalents		(44)		409
Cash and cash equivalents at beginning of period		102		162
Cash and cash equivalents at end of period	$	58	$	571

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 Stockholder 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, 2006, and the related consolidated statements of income and comprehensive income for each of the three-month and nine-month periods ended September 30, 2006 and 2005 and the consolidated statements of cash flows for the nine-month periods ended September 30, 2006 and 2005. 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 have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2005, and the related consolidated statements of income, capitalization, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report [which contained references to the Company's restatement of its previously issued consolidated financial statements for the years ended December 31, 2004 and 2003 as discussed in Note 2(I) to those consolidated financial statements] dated February 27, 2006, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2005, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers
LLP
Cleveland, Ohio
October 31, 2006

JERSEY CENTRAL POWER & LIGHT COMPANY

MANAGEMENT'S DISCUSSION ANDANALYSIS 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.

Restatements

As further discussed in Note 15 to the Consolidated Financial Statements, JCP&L restated its consolidated financial statements for the three months and nine months ended September 30, 2005. The revisions are the result of a tax audit from the State of New Jersey, in which JCP&L became aware that the New Jersey Transitional Energy Facilities Assessment is not an allowable deduction for state income tax purposes.

Results of Operations

Earnings on common stock in the third quarter of 2006 increased to $78 million from $74 million in 2005. The increase was principally due to higher revenues, decreased other operating costs and lower amortization of regulatory assets, partially offset by increased purchased power costs. In the first nine months of 2006, earnings on common stock increased to $152 million compared to $141 million for the same period in 2005. The increase was primarily due to higher revenues, lower other operating costs and reduced amortization of regulatory assets, partially offset by increased purchased power costs and the absence of the new regulatory asset recognized in 2005.

Revenues

Revenues increased $11 million or 1.2% in the third quarter of 2006 and $74 million or 3.6% for the first nine months of 2006 compared with the same periods of 2005. The higher revenues in both periods were primarily due to retail generation revenue increases ($49 million and $115 million in the third quarter and the first nine months of 2006, respectively), partially offset by decreases in wholesale revenue ($22 million in the third quarter and $28 million in the first nine months of 2006). Distribution revenues declined $20 million in the third quarter and $15 million in the first nine months of 2006 compared to the same periods of the prior year.

The retail generation revenue increases in both the third quarter and the first nine months of 2006, as compared to the previous year, were due to higher unit prices resulting from the BGS auction effective in May 2006, which offset declines in retail generation KWH sales. Revenue from residential customers increased $20 million and $48 million in the third quarter and the first nine months of 2006, respectively, as compared to the same periods in 2005. Generation revenue from commercial customers also increased for the same periods by $26 million and $63 million, respectively. The milder weather in the third quarter (cooling degree days were 18.6% below the previous year) and in the first nine months of 2006 (heating degree days were 17.7% below and cooling degree days were 15.3% below the previous year) resulted in lower KWH sales to residential customers in the third quarter and the first nine months of 2006. KWH sales to commercial customers increased 0.4% in the third quarter and 2.1% for the first nine months of 2006 as an increase in the number of commercial customers more than offset the impact of milder weather. Revenues from industrial customers increased $2 million in the third quarter of 2006 as a result of higher unit prices and KWH sales. The industrial sector revenue increase of $4 million in the first nine months of 2006 also reflected higher unit prices but were partially offset by lower sales compared to the prior year period. Wholesale sales revenues decreased $22 million in the third quarter and $28 million for the first nine months of 2006 as compared to 2005 due to lower unit prices.

The decrease in distribution revenues in the third quarter of 2006 resulted from lower KWH throughput and the impact of the new securitization (see “Regulatory Matters” further below) which reduced distribution revenues and increased other revenues. Distribution KWH deliveries declined for the first nine months of 2006 as compared to the previous year which decreased revenues by $15 million. The distribution revenue reduction was primarily due to lower KWH throughput partially offset by higher prices resulting from a distribution rate increase pursuant to the stipulated settlements approved by the NJBPU on May 25, 2005. Other revenues increased $4 million and $2 million in the third quarter and in the first nine months of 2006, respectively, as compared to the comparable periods in 2005 due to the new transition bond charge revenue.

Changes in KWH sales by customer class in the third quarter and the first nine months of 2006 compared to the same periods of 2005 are summarized in the following table:

Changes in KWH Sales	Three Months	Nine Months
Increase (Decrease)		
Electric Generation:		
Retail	(3.6)%	(2.3)%
Wholesale	(0.4)%	0.6 %
Total Electric Generation Sales	**(3.0)%**	**(1.7)%**
Distribution Deliveries:		
Residential	(6.6)%	(5.5)%
Commercial	1.4 %	0.1 %
Industrial	(8.8)%	(7.5)%
Total Distribution Deliveries	**(3.7)%**	**(3.5)%**

Expenses

Total operating expenses increased by $2 million in the third quarter and $59 million in the first nine months of 2006 as compared to the same periods of the prior year. The following table presents changes from the prior year by expense category:

Expenses - Changes	Three Months	Nine Months
	(In millions)	
Increase (Decrease)		
Purchased power costs	$ 29	$ 89
Other operating costs	(22)	(48)
Provision for depreciation	1	3
Amortization of regulatory assets	(7)	(14)

Deferral of new regulatory assets	1	29
Net increase in expenses	$ 2	$ 59

The increases in purchased power costs reflected higher unit prices resulting from the 2006 BGS auction. Other operating costs in the third quarter of 2005 included the affect of an arbitration decision in connection with a JCP&L bargaining union grievance challenging JCP&L's call out procedure. As a result of the arbitration decision, JCP&L reserved $16 million in the third quarter of 2005. Other operating costs were also higher in both periods of 2005 due to an extensive effort to improve system reliability as well as impacts from a labor union strike that ended on March 15, 2005. Amortization of regulatory assets decreased $7 million in the third quarter and $14 million in the first nine months of 2006 compared to the same periods in 2005 due to a reduction in the level of MTC revenue recovery. The changes in the deferral of new regulatory assets reflect the NJBPU’s 2005 approval for JCP&L to defer accelerated tree trimming and other reliability costs that were incurred in 2003 and 2004.

Miscellaneous income decreased $3 million in the third quarter of 2006, but increased $3 million for the first nine months compared to the same periods in 2005. The decrease in the third quarter of 2006 was due to the absence in 2006 of a gain from the sale of property in 2005, while the increase for the first nine months of 2006 was attributable to income received from customer requested service projects.

Capital Resources and Liquidity

JCP&L’s cash requirements for the remainder of 2006 for expenses, construction expenditures and scheduled debt maturities are expected to be met with cash from operations.

Changes in Cash Position

As of September 30, 2006, JCP&L had $58,000 of cash and cash equivalents compared with $102,000 as of December 31, 2005. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Cash provided from operating activities in the first nine months of 2006 and 2005 were as follows:

Operating Cash Flows	Nine Months Ended September 30, 2006	2005
	(In millions)	
Cash earnings [(1)]	$ 234	$ 227
Working capital and other	(216)	194
Net cash provided from operating activities	$ 18	$ 421

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

Cash earnings (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. Generally, a non-GAAP financial measure is a numerical measure of a company's historical or future financial performance, financial position, or cash flows that either excludes or includes amounts, or is subject to adjustment that has the effect of excluding or including amounts, that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with GAAP. In addition, cash earnings (non-GAAP) are not defined under GAAP. Management believes presenting this non-GAAP measure provides useful information to investors in assessing JCP&L's operating performance from a cash perspective without the effects of material unusual economic events. JCP&L's management frequently references these non-GAAP financial measures in its decision-making, using them to facilitate historical and ongoing performance comparisons as well as comparisons to the performance of peer companies. These non-GAAP measures should be considered in addition to, and not as a substitute for, their most directly comparable financial measures prepared in accordance with GAAP.

Reconciliation of Cash Earnings	Nine Months Ended September 30, 2006	2005
	(In millions)	
Net income (GAAP)	$ 153	$ 142
Non-cash charges (credits):		

Provision for depreciation	63	60
Amortization of regulatory assets	210	224
Deferral of new regulatory assets	-	(29)
Deferred purchased power and other costs	(214)	(169)
Deferred income taxes	26	6
Other non-cash items	(4)	(7)
Cash earnings (Non-GAAP)	$ 234	$ 227

The $7 million increase in cash earnings is described under "Results of Operations." The $410 million change in working capital primarily resulted from a $186 million change in cash collateral returned to suppliers, changes in accrued taxes of $94 million, payables of $34 million, prepaid taxes of $30 million, receivables of $25 million, and the 2005 arbitration decision of $16 million. In the year 2005, JCP&L received cash collateral payments from its suppliers of $135 million. During the first nine months of 2006, JCP&L returned $109 million back to its suppliers.

Cash Flows From Financing Activities

Net cash provided from financing activities was $117 million in the first nine months of 2006 as compared to net cash used of $285 million in same period of 2005. The change resulted from a $382 million issuance of long-term debt, a $90 million decrease in short-term debt redemptions and a $38 million reduction in common stock dividend payments to FirstEnergy, partially offset by $108 million of additional debt and preferred stock redemptions in the first nine months of 2006.

JCP&L had $27 million of cash and temporary investments (which includes short-term notes receivable from associated companies) and approximately $137 million of short-term indebtedness as of September 30, 2006. JCP&L has authorization from the FERC to incur short-term debt up to its charter limit of $429 million (including the utility money pool). JCP&L will not issue FMB other than as collateral for senior notes, since its senior note indenture prohibits (subject to certain exceptions) JCP&L from issuing any debt which is senior to the senior notes. As of September 30, 2006, JCP&L had the capability to issue $626 million of additional senior notes based upon FMB collateral. As of September 30, 2006, based upon applicable earnings coverage tests and its charter, JCP&L could issue $1.3 billion of preferred stock (assuming no additional debt was issued).

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 agreement 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 first nine months of 2006 was 5.09%.

On August 24, 2006, JCP&L, FirstEnergy, OE, Penn, CEI, TE, Penelec, Met-Ed, FES and ATSI, as Borrowers, entered into a new $2.75 billion five-year revolving credit facility, which replaced the prior $2 billion credit facility. FirstEnergy may request an increase in the total commitments available under the new facility up to a maximum of $3.25 billion. Commitments under the new facility are available until August 24, 2011, unless the lenders agree, at the request of the Borrowers, to two additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each Borrower are subject to a specified sub-limit, as well as applicable regulatory and other limitations. JCP&L's borrowing limit under the facility is $425 million.

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.

The revolving credit facility contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%. As of September 30, 2006, JCP&L's debt to total capitalization as defined under the revolving credit facility was 23%.

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

JCP&L's access to the capital markets and the costs of financing are dependent on the ratings of its securities and that of FirstEnergy. As of September 30, 2006, JCP&L's and FirstEnergy’s ratings outlook from S&P on all securities was stable. The ratings outlook from Moody’s and Fitch on all securities is positive.

On June 8, 2006, the NJBPU approved JCP&L’s request to issue securitization bonds associated with BGS stranded cost deferrals. On August 10, 2006, JCP&L Transition Funding II, a wholly owned subsidiary of JCP&L, issued $182 million of transition bonds with a weighted average interest rate of 5.5%. As required by the Electric Discount and Energy Competition Act of 1999, as amended, JCP&L used the proceeds principally to reduce stranded costs, including basic generation transition costs, through the retirement of debt, including short-term debt, or equity or both, and also to pay related expenses.

On May 12, 2006, JCP&L issued $200 million of 6.40% secured Senior Notes due 2036. The proceeds of the offering were used to repay at maturity $150 million aggregate principal amount of JCP&L’s 6.45% Senior Notes due May 15, 2006 and for general corporate purposes.

Cash Flows From Investing Activities

Net cash used for investing activities was $136 million in the first nine months of 2006, unchanged from the previous year. The $10 million reduction in property additions was completely offset by $10 million of loans to associated companies.

During the last quarter of 2006, capital requirements for property additions and improvements are expected to be about $36 million. These cash requirements are expected to be satisfied from cash from operations.

JCP&L's capital spending for the period 2006-2010 is expected to be approximately $909 million for property additions, of which approximately $159 million applies to 2006.

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 oversight to risk management activities.

Commodity Price Risk

JCP&L is exposed to market risk primarily due to fluctuations in electricity, energy transmission and natural gas prices. To manage the volatility relating to these exposures, JCP&L 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. Derivatives that fall within the scope of SFAS 133 must be recorded at their fair value and marked to market. The majority of JCP&L's derivative hedging contracts qualify for the normal purchase and normal sale exception under SFAS 133 and are therefore excluded from the table below. Contracts that are not exempt from such treatment include the power purchase agreements with NUG entities that were structured pursuant to the Public Utility Regulatory Policies Act of 1978. These non-trading contracts had been adjusted to fair value at the end of each quarter, with a corresponding regulatory asset recognized for above-market costs. The changes in the fair value of commodity derivative contracts related to energy production during the third quarter and first nine months of 2006 are summarized in the following table:

Increase (Decrease) in the Fair Value of Commodity Derivative Contracts	Three Months Ended September 30, 2006			Nine Months Ended September 30, 2006		
	Non-Hedge	**Hedge**	**Total**	**Non-Hedge**	**Hedge**	**Total**
			(In millions)			
Change in the Fair Value of Commodity Derivative Contracts:						
Outstanding net liability at beginning of period	$ (1,111)	$ -	$ (1,111)	$ (1,223)	$ -	$ (1,223)
Additions/change in value of existing contracts	(164)	-	(164)	(193)	-	(193)
Settled contracts	81	-	81	222	-	222
Net Liabilities - Derivative Contracts at End of Period (1)	$ (1,194)	$ -	$ (1,194)	$ (1,194)	$ -	$ (1,194)
Impact of Changes in Commodity Derivative Contracts(2)						
Income Statement effects (pre-tax)	$ (2)	$ -	$ (2)	$ (1)	$ -	$ (1)
Balance Sheet effects:		-				
Regulatory assets (net)	$ 81	$ -	$ 81	$ (30)	$ -	$ (30)

(1) These represent NUG contracts that are offset by a regulatory asset.
(2) 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, 2006 as follows:

Balance Sheet Classification	**Non-Hedge**	**Hedge**	**Total**
		(In millions)	
Non-Current-			
Other deferred charges	$ 11	$ -	$ 11
Other noncurrent liabilities	(1,205)	-	(1,205)
Net liabilities	**$ (1,194)**	**$ -**	**$ (1,194)**

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, JCP&L relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. JCP&L uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making. Sources of information for the valuation of commodity derivative contracts as of September 30, 2006 are summarized by year in the following table:

Source of Information Fair Value by Contract Year	**2006**[(1)]	**2007**	**2008**	**2009**	**2010**	**Thereafter**	**Total**
				(In millions)			
Other external sources [(2)]	$ (66)	$ (269)	$ (248)	$ (197)	$ -	$ -	$ (780)
Prices based on models	-	-	-	-	(181)	(233)	(414)
Total[(3)]	**$ (66)**	**$ (269)**	**$ (248)**	**$ (197)**	**$ (181)**	**$ (233)**	**$ (1,194)**

(1) For the last quarter of 2006.
(2) Broker quote sheets.
(3) These represent NUG contracts that are offset by a regulatory asset .

JCP&L performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% adverse shift in quoted market prices in the near term on both its trading and non-trading derivative instruments would not have had a material effect on JCP&L's consolidated financial position or cash flows as of September 30, 2006. JCP&L estimates that if energy commodity prices experienced an adverse 10% change, net income for the next twelve months would not change, as the prices for all commodity positions are already above the contract price caps.

Equity Price Risk

Included in nuclear decommissioning trusts are marketable equity securities carried at their current fair value of approximately $91 million and $84 million as of September 30, 2006 and December 31, 2005, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $9 million reduction in fair value as of September 30, 2006.

Regulatory Matters

Regulatory assets are costs which have been authorized by the NJBPU and the FERC 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 of JCP&L's regulatory assets are expected to continue to be recovered under the provisions of the regulatory proceedings discussed below. JCP&L's regulatory assets totaled $2.2 billion as of September 30, 2006 and December 31, 2005.

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 NUGC rates and market sales of NUG energy and capacity. As of September 30, 2006, the accumulated deferred cost balance totaled approximately $340 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 to securitize the July 31, 2003 deferred balance. On June 8, 2006, the NJBPU approved JCP&L’s request to issue securitization bonds associated with BGS stranded cost deferrals. On August 10, 2006, JCP&L Transition Funding II, a wholly owned subsidiary of JCP&L, issued $182 million of transition bonds with a weighted average interest rate of 5.5%.

On December 2, 2005, JCP&L filed its request for recovery of $165 million of actual above-market NUG costs incurred from August 1, 2003 through October 31, 2005 and forecasted above-market NUG costs for November and December 2005. On February 23, 2006, JCP&L filed updated data reflecting actual amounts through December 31, 2005 of $154 million of costs incurred since July 31, 2003. On March 29, 2006, a pre-hearing conference was held with the presiding ALJ. On July 18, 2006, JCP&L filed rebuttal testimony that included a request for an additional $14 million of costs that had been eliminated from the securitized amount. Evidentiary hearings were held during September 2006 and the briefing schedule has been postponed pending settlement discussions.

An NJBPU Decision and Order approving a Phase II Stipulation of Settlement and resolving the Motion for Reconsideration of the Phase I Order was issued on May 31, 2005. The Phase II Settlement includes a performance standard pilot program with potential penalties of up to 0.25% of allowable equity return. The Order requires that JCP&L file quarterly reliability reports (CAIDI and SAIFI information related to the performance pilot program) through December 2006 and updates to reliability related project expenditures until all projects are completed. The latest quarterly reliability reports were submitted on September 12, 2006. As of September 30, 2006, there were no performance penalties issued by the NJBPU.

Reacting to the higher closing prices of the 2006 BGS fixed rate auction, the NJBPU, on March 16, 2006, initiated a generic proceeding to evaluate the auction process and potential options for the future. On April 6, 2006, initial comments were submitted. A public meeting was held on April 21, 2006 and a legislative-type hearing was held on April 28, 2006. On June 21, 2006, the NJBPU approved the continued use of a descending block auction for the Fixed Price Residential Class. JCP&L filed its 2007 BGS company specific addendum on July 10, 2006. On October 27, 2006, the NJBPU approved the auction format to procure the 2007 Commercial Industrial Energy Price as well as the specific rules for both the Fixed Price and Commercial Industrial Energy Price auctions. These rules were essentially unchanged from the prior auctions.

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 DRA filed comments on February 28, 2005 requesting that decommissioning funding be suspended. On March 18, 2005, JCP&L filed a response to the Ratepayer Advocate’s comments. A schedule for further NJBPU proceedings has not yet been set.

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of PUHCA pursuant to the EPACT. An NJBPU proposed rulemaking to address the issues was published in the NJ Register on December 19, 2005. The proposal would prevent a holding company that owns a gas or electric public utility from investing more than 25% of the combined assets of its utility and utility-related subsidiaries into businesses unrelated to the utility industry. A public hearing was held on February 7, 2006 and comments were submitted to the NJBPU. On August 16, 2006, the NJBPU approved the regulations with an effective date of October 2, 2006. These regulations are not expected to materially impact FirstEnergy or JCP&L. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. Comments on the alternative proposal were submitted on June 15, 2006.

On December 21, 2005, the NJBPU initiated a generic proceeding and requested comments in order to formulate an appropriate regulatory treatment for investment tax credits related to generation assets divested by New Jersey’s four electric utility companies. Comments were filed by the utilities and by the DRA. JCP&L filed a request with the IRS for a ruling on the issue. JCP&L was advised by the IRS on April 10, 2006 that the ruling was tentatively adverse. On April 28, 2006, the NJBPU directed JCP&L to withdraw its request for a private letter ruling on this issue, which had been previously filed with the IRS as ordered by the NJBPU. On May 11, 2006, after a JCP&L Motion for Reconsideration was denied by the NJBPU, JCP&L filed to withdraw the request for a private letter ruling. On July 19, 2006, the IRS acknowledged that the JCP&L ruling request was withdrawn.

On November 18, 2004, the FERC issued an order eliminating the RTOR for transmission service between the MISO and PJM regions. The FERC also ordered the MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a SECA mechanism to recover lost RTOR revenues during a 16-month transition period from load serving entities. The FERC issued orders in 2005 setting the SECA for hearing. ATSI, JCP&L, Met-Ed, Penelec, and FES continue to be involved in the FERC hearings concerning the calculation and imposition of the SECA charges. The hearing was held in May 2006. Initial briefs were submitted on June 9, 2006, and reply briefs were filed on June 27, 2006. The Presiding Judge issued an Initial Decision on August 10, 2006, rejecting the compliance filings made by the RTOs and transmission owners, ruling on various issues and directing new compliance filings. This decision is subject to review and approval by the FERC. Briefs addressing the Initial Decision were filed on September 11, 2006 and October 20, 2006. A final order could be issued by the FERC by the end of 2006.

On January 31, 2005, certain PJM transmission owners made three filings with the FERC 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. American Electric Power Company, Inc. filed in opposition proposing to create a "postage stamp" rate for high voltage transmission facilities across PJM. Second, the FERC approved the proposed Schedule 12 rate harmonization. Third, the FERC accepted the proposed formula rate, subject to refund and hearing procedures. On June 30, 2005, the settling PJM transmission owners filed a request for rehearing of the May 31, 2005 order. On March 20, 2006, a settlement was filed with FERC in the formula rate proceeding that generally accepts the companies' formula rate proposal. The FERC issued an order approving this settlement on April 19, 2006. Hearings in the PJM rate design case concluded in April 2006. On July 13, 2006, an Initial Decision was issued by the ALJ. The ALJ adopted the Trial Staff's position that the cost of all PJM transmission facilities should be recovered through a postage stamp rate. The ALJ recommended an April 1, 2006 effective date for this change in rate design. If the FERC accepts this recommendation, the transmission rate applicable to many load zones in PJM would increase. FirstEnergy believes that significant additional transmission revenues would have to be recovered from the JCP&L, Met-Ed and Penelec transmission zones within PJM. JCP&L, Met-Ed and Penelec as part of the Responsible Pricing Alliance, filed a brief addressing the Initial Decision on August 14, 2006 and September 5, 2006. The case will be reviewed by the FERC with a decision anticipated in the fourth quarter of 2006.

See Note 11 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 determine 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 as a PRP at waste disposal sites which may require cleanup under the Comprehensive Environmental Responsive, Comprehension 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 PRPs for a particular site are held liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of September 30, 2006, based on estimates of the total costs of cleanup, JCP&L's proportionate responsibility for such costs and the financial ability of other unaffiliated 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 $55 million have been accrued through September 30, 2006.

See Note 10(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 JCP&L's normal business operations pending against JCP&L. The other material items not otherwise discussed below are described in Note 10(C) to the consolidated financial statements.

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 Web site (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 is also proceeding with the implementation of the recommendations 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 may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future as a result of adoption of mandatory reliability standards pursuant to the EPACT that could require additional material expenditures.

FirstEnergy was also named, along with several other entities, in a complaint in New Jersey State Court. The allegations against FirstEnergy were based, in part, on an alleged failure to protect the citizens of Jersey City from an electrical power outage. None of FirstEnergy’s subsidiaries serve customers in Jersey City. A responsive pleading has been filed. On April 28, 2006, the Court granted FirstEnergy's motion to dismiss. The plaintiff has not appealed.

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. Although unable to predict the impact of these proceedings, 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.

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 arbitration panel decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the arbitration panel issued an opinion to award approximately $16 million to the bargaining unit employees. On February 6, 2006, a federal district court granted a union motion to dismiss as premature a JCP&L appeal of the award filed on October 18, 2005. JCP&L intends to re-file an appeal again in federal district court once the damages associated with this case are identified at an individual employee level. JCP&L recognized a liability for the potential $16 million award in 2005.

The other material items not otherwise discussed above are described in Note 10(C) to the consolidated financial statements.

New Accounting Standards and Interpretations

SAB 108 - "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements"

In September 2006, the SEC issued SAB 108, which provides interpretive guidance on how registrants should quantify financial statement misstatements. There is currently diversity in practice, with the two commonly used methods to quantify misstatements being the "rollover" method (which primarily focuses on the income statement impact of misstatements) and the "iron curtain" method (which focuses on the balance sheet impact). SAB 108 requires registrants to use a dual approach whereby both of these methods are considered in evaluating the materiality of financial statement errors. Prior materiality assessments will need to be reconsidered using both the rollover and iron curtain methods. This guidance will be effective for JCP&L in the fourth quarter of 2006. JCP&L does not expect this Statement to have a material impact on its financial statements.

SFAS 157 - "Fair Value Measurements"

In September 2006, the FASB issued SFAS 157, that establishes how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under GAAP. This Statement addresses the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. The key changes to current practice are: (1) the definition of fair value which focuses on an exit price rather than entry price; (2) the methods used to measure fair value such as emphasis that fair value is a market-based measurement, not an entity-specific measurement, as well as the inclusion of an adjustment for risk, restrictions and credit standing; and (3) the expanded disclosures about fair value measurements.

This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. JCP&L is currently evaluating the impact of this Statement on its financial statements.

SFAS 158 - "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)"

In September 2006, the FASB issued SFAS 158, which requires companies to recognize a net liability or asset to report the overfunded or underfunded status of their defined benefit pension and other postretirement benefit plans on their balance sheets and recognize changes in funded status in the year in which the changes occur through other comprehensive income. The funded status to be measured is the difference between plan assets at fair value and the benefit obligation. This Statement requires that gains and losses and prior service costs or credits, net of tax, that arise during the period be recognized as a component of other comprehensive income and not as components of net periodic benefit cost. Additional information should also be disclosed in the notes to the financial statements about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and transition asset or obligation. Upon the initial application of this Statement and subsequently, an employer should continue to apply the provisions in Statements 87, 88 and 106 in measuring plan assets and benefit obligations as of the date of its statement of financial position and in determining the amount of net periodic benefit cost. This Statement is effective for JCP&L as of December 31, 2006. JCP&L is currently evaluating the impact of this Statement on its financial statements.

FSP FIN 46(R)-6 - "Determining the Variability to Be Considered in Applying FASB interpretation No. 46(R)"

In April 2006, the FASB issued FSP FIN 46(R)-6 that addresses how a reporting enterprise should determine the variability to be considered in applying FASB interpretation No. 46 (revised December 2003). JCP&L adopted FIN

46(R) in the first quarter of 2004, consolidating VIE's when JCP&L or one of its subsidiaries is determined to be the VIE's primary beneficiary. The variability that is considered in applying interpretation 46(R) affects the determination of (a) whether the entity is a VIE; (b) which interests are variable interests in the entity; and (c) which party, if any, is the primary beneficiary of the VIE. This FSP states that the variability to be considered shall be based on an analysis of the design of the entity, involving two steps:

Step 1:	Analyze the nature of the risks in the entity
Step 2:	Determine the purpose(s) for which the entity was created and determine the variability the entity is designed to create and pass along to its interest holders.

After determining the variability to consider, the reporting enterprise can determine which interests are designed to absorb that variability. The guidance in this FSP is applied prospectively to all entities (including newly created entities) with which that enterprise first becomes involved and to all entities previously required to be analyzed under interpretation 46(R) when a reconsideration event has occurred after July 1, 2006. JCP&L does not expect this Statement to have a material impact on its financial statements.

FIN 48 - "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109."

In June 2006, the FASB issued FIN 48 which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, "Accounting for Income Taxes." This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken on a tax return. This interpretation also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation will be a two-step process. The first step will determine if it is more likely than not that a tax position will be sustained upon examination and should therefore be recognized. The second step will measure a tax position that meets the more likely than not recognition threshold to determine the amount of benefit to recognize in the financial statements. This interpretation is effective for fiscal years beginning after December 15, 2006. JCP&L is currently evaluating the impact of this Statement.

METROPOLITAN EDISON COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	(In thousands)			
REVENUES	$ 356,181	$ 333,180	$ 949,613	$ 892,097
EXPENSES:				
Purchased power	184,508	186,148	487,465	467,911
Other operating costs	108,740	81,774	229,394	192,892
Provision for depreciation	10,197	9,323	31,390	32,221
Amortization of regulatory assets	33,560	32,853	89,277	86,760
Deferral of new regulatory assets	(44,213)	-	(89,794)	-
General taxes	21,362	19,906	60,578	56,201
Total expenses	314,154	330,004	808,310	835,985
OPERATING INCOME	42,027	3,176	141,303	56,112
OTHER INCOME (EXPENSE):				
Interest income	8,053	9,109	25,767	27,578
Miscellaneous income	1,477	2,296	5,881	6,725
Interest expense	(12,291)	(10,891)	(35,546)	(33,512)
Capitalized interest	355	150	966	401
Total other income (expense)	(2,406)	664	(2,932)	1,192
INCOME BEFORE INCOME TAXES	39,621	3,840	138,371	57,304
INCOME TAXES	14,631	2,835	55,390	24,160
NET INCOME	24,990	1,005	82,981	33,144
OTHER COMPREHENSIVE INCOME:				
Unrealized gain on derivative hedges	83	84	251	252
Unrealized gain on available for sale securities	-	67	-	67
Other comprehensive income	83	151	251	319
Income tax expense related to other comprehensive income	34	62	104	132
Other comprehensive income, net of tax	49	89	147	187

TOTAL COMPREHENSIVE INCOME	$	25,039	$	1,094	$	83,128	$	33,331

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, 2006	December 31, 2005
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 133	$ 120
Receivables-		
Customers (less accumulated provisions of $4,301,000 and $4,352,000, respectively, for uncollectible accounts)	130,777	129,854
Associated companies	6,179	37,267
Other	11,265	8,780
Notes receivable from associated companies	32,720	27,867
Prepayments and other	16,159	7,912
	197,233	211,800
UTILITY PLANT:		
In service	1,901,091	1,856,425
Less - Accumulated provision for depreciation	730,720	721,566
	1,170,371	1,134,859
Construction work in progress	19,669	20,437
	1,190,040	1,155,296
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	256,198	234,854
Other	1,363	1,453
	257,561	236,307
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	860,227	864,438
Regulatory assets	364,889	309,556
Prepaid pension costs	94,205	89,005
Other	66,417	51,285
	1,385,738	1,314,284
	$ 3,030,572	$ 2,917,687
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 50,000	$ 100,000
Short-term borrowings-		
Associated companies	181,871	140,240
Other	75,000	-
Accounts payable-		
Associated companies	14,004	37,220
Other	49,170	27,507

Accrued taxes	7,460	17,911
Accrued interest	9,130	9,438
Other	22,905	24,274
	409,540	356,590
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 900,000 shares-		
859,000 shares outstanding	1,282,846	1,287,093
Accumulated other comprehensive loss	(1,422)	(1,569)
Retained earnings	108,556	30,575
Total common stockholder's equity	1,389,980	1,316,099
Long-term debt and other long-term obligations	541,979	591,888
	1,931,959	1,907,987
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	375,544	344,929
Accumulated deferred investment tax credits	9,444	10,043
Nuclear fuel disposal costs	40,958	39,567
Asset retirement obligations	148,782	142,020
Retirement benefits	56,674	57,809
Other	57,671	58,742
	689,073	653,110
COMMITMENTS AND CONTINGENCIES (Note 10)		
	$ 3,030,572	$ 2,917,687

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)

	Nine Months Ended September 30, 2006	2005
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 82,981	$ 33,144
Adjustments to reconcile net income to net cash from operating activities -		
Provision for depreciation	31,390	32,221
Amortization of regulatory assets	89,277	86,760
Deferred costs recoverable as regulatory assets	(53,406)	(48,156)
Deferral of new regulatory assets	(89,794)	-
Deferred income taxes and investment tax credits, net	27,895	(10,336)
Accrued compensation and retirement benefits	(6,007)	(4,506)
Cash collateral to suppliers	(21,500)	-
Decrease (increase) in operating assets -		
Receivables	27,680	113,298
Prepayments and other current assets	(8,247)	(2,228)
Increase (decrease) in operating liabilities -		
Accounts payable	(1,553)	(44,505)
Accrued taxes	(10,451)	(9,710)
Accrued interest	(308)	(2,156)
Other	(1,777)	2,602
Net cash provided from operating activities	66,180	146,428
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Short-term borrowings, net	116,624	-
Redemptions and Repayments-		
Long-term debt	(100,000)	(37,830)
Short-term borrowings, net	-	(3,335)
Dividend Payments-		
Common stock	(5,000)	(44,000)
Net cash provided from (used for) financing activities	11,624	(85,165)
CASH FLOWS FROM INVESTING ACTIVITIES:		

Property additions	(65,332)	(56,075)
Proceeds from nuclear decommissioning trust fund sales	151,593	119,207
Investments in nuclear decommissioning trust funds	(158,705)	(126,319)
Loan repayments from (loans to) associated companies, net	(4,853)	2,267
Other	(494)	(343)
Net cash used for investing activities	(77,791)	(61,263)
Net change in cash and cash equivalents	13	-
Cash and cash equivalents at beginning of period	120	120
Cash and cash equivalents at end of period	$ 133	$ 120

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

Report of Independent Registered Public Accounting Firm

To the Stockholder 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, 2006, and the related consolidated statements of income and comprehensive income for each of the three-month and nine-month periods ended September 30, 2006 and 2005 and the consolidated statements of cash flows for the nine-month periods ended September 30, 2006 and 2005. 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 have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2005, and the related consolidated statements of income, capitalization, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report [which contained references to the Company's change in its method of accounting for asset retirement obligations as of January 1, 2003 and conditional asset retirement obligations as of December 31, 2005 as discussed in Note 2(G) and Note 9 to those consolidated financial statements] dated February 27, 2006, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2005, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers
LLP

Cleveland, Ohio
October 31, 2006

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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.

Results of Operations

Net income in the third quarter of 2006 increased to $25 million from $1 million in the third quarter of 2005. This increase reflects the deferral of new regulatory assets and higher revenues, partially offset by higher other operating costs as discussed below. For the first nine months of 2006, net income increased to $83 million from $33 million in the same period of 2005. This increase reflects the deferral of new regulatory assets and higher revenues, partially offset by higher purchased power costs, amortization of regulatory assets, general taxes and other operating costs as discussed below.

Revenues

Revenues increased by $23 million, or 6.9%, in the third quarter of 2006 and $58 million, or 6.4%, in the first nine months of 2006, compared with the same periods of 2005. Increases in both periods were primarily due to higher retail generation electric revenues ($12 million for the third quarter and $39 million for the first nine months of 2006), which reflected higher composite prices in all customer classes. For the third quarter of 2006, higher KWH sales to industrial customers were partially offset by lower KWH sales to residential and commercial customers. For the first nine months of 2006, higher KWH sales to industrial and commercial customers were partially offset by lower KWH sales to residential customers. Industrial KWH sales, for both periods, increased primarily due to the return of customers to Met-Ed from alternative suppliers. Sales by alternative suppliers as a percent of total industrial sales in Met-Ed's franchise area decreased by 9.7 percentage points in the third quarter of 2006 and 12.6 percentage points in the first nine months of 2006. Lower KWH sales to residential customers, for both periods of 2006, and to commercial customers, for the third quarter of 2006, primarily resulted from milder weather in 2006 as compared with the same periods of 2005.

Revenues from distribution throughput essentially remained unchanged for the third quarter of 2006 as compared with the same period of 2005. This was the result of higher composite unit prices being substantially offset by a decrease in total KWH deliveries. The decrease in KWH deliveries primarily resulted from milder weather in the third quarter of 2006 (a 19.8% decrease in cooling degree days) compared with the same period in 2005. For the first nine months of 2006, revenues from distribution throughput decreased by $1 million compared with the same period of 2005. A 1.3% decrease in KWH deliveries was partially offset by higher composite prices. KWH deliveries decreased as a result from milder weather in the first nine months of 2006 (a 17.1% decrease in cooling degree days and a 15.7% decrease in heating degree days) as compared with the same period in 2005.

For both periods of 2006, transmission revenues increased primarily due to higher transmission prices, which also resulted in higher transmission expenses as discussed below. Rental revenues also increased by $3 million, for both periods of 2006, due to higher charges for the joint use of Met-Ed's utility poles. In the first nine months of 2006, other revenues also increased due to a $2 million increase in the payment received in the first quarter of 2006 under a contract provision associated with the prior sale of TMI Unit 1, compared to the same period in 2005. Under the contract, additional payments are received if subsequent energy prices rise above specified levels. This payment is credited to Met-Ed's customers, resulting in no net earnings effect.

Changes in KWH sales by customer class in the third quarter and the first nine months of 2006 compared with the same periods in 2005 are summarized in the following table:

Changes in KWH Sales Increase (Decrease)	Three Months	Nine Months
Retail Electric Generation:		
Residential	(1.9)%	(1.9)%
Commercial	(0.2)%	1.3 %
Industrial	8.2 %	11.9 %
Total Retail Electric Generation Sales	**1.3 %**	**2.8 %**
Distribution Deliveries:		
Residential	(2.1)%	(2.1)%
Commercial	(0.9)%	0.4 %
Industrial	(2.3)%	(2.3)%
Total Distribution Deliveries	**(1.8)%**	**(1.3)%**

Expenses

Total expenses decreased by $16 million and $28 million in the third quarter and the first nine months of 2006, respectively, compared with the same periods of 2005. The following table presents changes from the prior year by expense category:

Expenses - Changes Increase (Decrease)	Three Months	Nine Months
	(In millions)	
Purchased power costs	$ (2)	$ 20
Other operating costs	27	36
Provision for depreciation	1	(1)
Amortization of regulatory assets	1	3
Deferral of new regulatory assets	(44)	(90)
General taxes	1	4

Net decrease in expenses	$ (16)	$ (28)

Purchased power costs decreased by $2 million in the third quarter of 2006 due to lower composite unit prices, partially offset by increased purchases to meet higher customer demand and a $10 million charge related to incremental NUG costs deferred in 2005 under a revised accounting methodology. For the first nine months of 2006, purchased power costs increased by $20 million due to increased purchases to meet higher customer demand and higher composite unit prices, offset by increased NUG cost deferrals.

Other operating costs increased for both periods primarily due to higher transmission expenses, which increased as a result of the higher transmission prices discussed above. The deferral of new regulatory assets, for both periods, reflected the May 4, 2006 PPUC approval of Met-Ed's request to defer certain 2006 transmission-related costs (see Regulatory Matters for further discussion). For both periods, general taxes increased primarily due to higher gross receipt taxes.

Capital Resources and Liquidity

Met-Ed's cash requirements for the remainder of 2006 for expenses and construction expenditures are expected to be met with a combination of cash from operations and short-term credit arrangements.

Changes in Cash Position

As of September 30, 2006, Met-Ed had $133,000 of cash and cash equivalents compared with $120,000 as of December 31, 2005. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Cash provided from operating activities in the first nine months of 2006 and 2005 were as follows:

Operating Cash Flows	Nine Months Ended September 30, 2006	2005
	(In millions)	
Cash earnings [1]	$ 82	$ 89
Working capital and other	(16)	57
Net cash provided from operating activities	$ 66	$ 146

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

Cash earnings (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. Generally, a non-GAAP financial measure is a numerical measure of a company's historical or future financial performance, financial position, or cash flows that either excludes or includes amounts, or is subject to adjustment that has the effect of excluding or including amounts, that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with GAAP. In addition, cash earnings (non-GAAP) are not defined under GAAP. Management believes presenting this non-GAAP measure provides useful information to investors in assessing Met-Ed's operating performance from a cash perspective without the effects of material unusual economic events. Met-Ed's management frequently references these non-GAAP financial measures in its decision-making, using them to facilitate historical and ongoing performance comparisons as well as comparisons to the performance of peer companies. These non-GAAP measures should be considered in addition to, and not as a substitute for, their most directly comparable financial measures prepared in accordance with GAAP.

Reconciliation of Cash Earnings	Nine Months Ended September 30, 2006	2005
	(In millions)	
Net income (GAAP)	$ 83	$ 33

Non-cash charges (credits):		
Provision for depreciation	31	32
Amortization of regulatory assets	89	87
Deferred costs recoverable as regulatory assets	(53)	(49)
Deferral of new regulatory assets	(90)	-
Deferred income taxes and investment tax credits, net	28	(10)
Other non-cash charges	(6)	(4)
Cash earnings (Non-GAAP)	$ 82	$ 89

The $7 million decrease in cash earnings is described above under “Results of Operations.” The $73 million working capital change primarily resulted from an $86 million decrease in cash provided from the collection of receivables, a $22 million increase in cash collateral returned to suppliers, a $6 million increase in prepayments, and a $4 million decrease in other accrued liabilities, offset by $43 million in decreased outflows for accounts payable and a $2 million increase in accrued interest.

Cash Flows From Financing Activities

Net cash provided from financing activities was $12 million in first nine months of 2006 compared to $85 million in net cash used for financing activities in the same period of 2005. The increase primarily reflects a $120 million increase in short-term borrowings and a $39 million decrease in common stock dividend payments to FirstEnergy in the first nine months of 2006, offset by a $62 million increase in long-term debt redemptions.

As of September 30, 2006, Met-Ed had approximately $33 million of cash and temporary investments (which included short-term notes receivable from associated companies) and $257 million of short-term borrowings. Met-Ed has authorization from the FERC to incur short-term debt up to $250 million and authorization from the PPUC to incur money pool borrowings up to $300 million. In addition, Met-Ed has $80 million of available accounts receivable financing facilities as of September 30, 2006 through Met-Ed Funding LLC, Met-Ed’s wholly owned subsidiary. 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. In June 2006, the facility was renewed until June 28, 2007. The annual facility fee is 0.125% on the entire finance limit. As of September 30, 2006 the facility was drawn for $75 million.

Under the terms of Met-Ed's senior note indenture, FMBs may no longer be issued so long as senior notes are outstanding. As of September 30, 2006, Met-Ed had the capability to issue $642 million of additional senior notes based upon FMB collateral. Met-Ed had no restrictions on the issuance of preferred stock.

On August 24, 2006, Met-Ed, FirstEnergy, OE, Penn, CEI, TE, JCP&L, Penelec, FES and ATSI, as Borrowers, entered into a new $2.75 billion five-year revolving credit facility, which replaced the prior $2 billion credit facility. FirstEnergy may request an increase in the total commitments available under the new facility up to a maximum of $3.25 billion. Commitments under the new facility are available until August 24, 2011, unless the lenders agree, at the request of the Borrowers, to two additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each Borrower are subject to a specified sub-limit, as well as applicable regulatory and other limitations. Met-Ed's borrowing limit under the facility is $250 million.

Under the revolving credit facility, Borrowers may request the issuance of LOCs expiring up to one year from the date of issuance. The stated amount of outstanding LOCs will count against total commitments available under the facility and against the applicable borrower's borrowing sub-limit. Total unused borrowing capability under the existing credit facilities and accounts receivable financing facilities totaled $255 million as of September 30, 2006.

The revolving credit facility contains financial covenants requiring each Borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%. As of September 30, 2006, Met-Ed's debt to total capitalization as defined under the revolving credit facility was 38%.

The facility does not contain any provisions that either restrict Met-Ed's ability to borrow or accelerate repayment of outstanding advances as a result of any change in its credit ratings. Pricing is defined in "pricing grids", whereby the cost of funds borrowed under the facility is related to Met-Ed's credit ratings.

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 pool and tracks surplus funds of FirstEnergy and its 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 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 in the first nine months of 2006 was 5.09%.

Met-Ed's access to the capital markets and the costs of financing are dependent on the ratings of its securities and that of FirstEnergy. As of September 30, 2006, Met-Ed's and FirstEnergy's ratings outlook from S&P on all securities was stable. The ratings outlook from Moody's and Fitch on all securities is positive.

Cash Flows From Investing Activities

In the final nine months of 2006, Met-Ed's cash used for investing activities totaled $78 million, compared with $61 million in the same period of 2005. The increase primarily resulted from a $9 million increase in property additions and a $7 million increase in loans to associated companies. Expenditures for property additions primarily support Met-Ed's energy delivery operations and reliability initiatives.

During the last quarter of 2006, capital requirements for property additions are expected to be about $15 million. This cash requirement is expected to be satisfied from a combination of internal cash and short-term credit arrangements.

Met-Ed's capital spending for the period 2006 through 2010 is expected to be about $365 million, of which approximately $81 million applies to 2006. The capital spending is primarily for property additions supporting the distribution of electricity.

Market Risk Information

Met-Ed uses various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price fluctuations. FirstEnergy's Risk Policy Committee, comprised of members of senior management, provides general oversight to risk management activities.

Commodity Price Risk

Met-Ed is exposed to market risk primarily due to fluctuations in electricity, energy transmission, natural gas, coal, and emission prices. To manage the volatility relating to these exposures, it uses a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts, and swaps. The derivatives are used principally for hedging purposes. All derivatives that fall within the scope of SFAS 133 must be recorded at their fair value and marked to market. The majority of Met-Ed's derivative hedging contracts qualify for the normal purchase and normal sale exception under SFAS 133. Contracts that are not exempt from such treatment include the power purchase agreements with NUG entities that were structured pursuant to the Public Utility Regulatory Policies Act of 1978. These non-trading contracts had been adjusted to fair value at the end of each quarter, with a corresponding regulatory asset recognized for above-market costs. On April 1, 2006, Met-Ed elected to apply the normal purchase and normal sale exception to certain NUG power purchase agreements having an above-market fair value of $1 million (included in "Other" in the table below) in accordance with guidance in DIG C20. The change in the fair value of commodity derivative contracts related to energy production during the third quarter and first nine months of 2006 is summarized in the following table:

Increase (Decrease) in the Fair Value of Commodity Derivative Contracts	Three Months Ended September 30, 2006			Nine Months Ended September 30, 2006		
	Non-Hedge	Hedge	Total	Non-Hedge	Hedge	Total
			(In millions)			
Change in the Fair Value of Commodity Derivative Contracts:						
Outstanding net asset at beginning of period	$ 23	$ -	$ 23	$ 27	$ -	$ 27
New contract value when entered	-	-	-	-	-	-
Additions/change in value of existing contracts	-	-	-	4	-	4
Change in techniques/assumptions	-	-	-	-	-	-
Settled contracts	-	-	-	(9)	-	(9)
Other	-	-	-	1	-	1
Net Assets - Derivative Contracts at End of Period (1)	$ 23	$ -	$ 23	$ 23	$ -	$ 23
Impact of Changes in Commodity Derivative						

Contracts[2]						
Income Statement effects (pre-tax)	$ -	$ -	$ -	$ (2)	$ -	$ (2)
Balance Sheet effects:						
OCI (pre-tax)	$ -	$ -	$ -	$ -	$ -	$ -
Regulatory liability	$ -	$ -	$ -	$ 3	$ -	$ 3

[1] Includes $23 million in non-hedge commodity derivative contract, which is offset by a regulatory liability.
[2] 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, 2006 as follows:

Balance Sheet Classification	**Non-Hedge**	**Hedge**	**Total**
		(In millions)	
Non-Current-			
Other deferred charges	$ 23	$ -	$ 23
Other noncurrent liabilities	-	-	-
Net assets	$ 23	$ -	$ 23

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, Met-Ed relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. Met-Ed uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making. Sources of information for the valuation of commodity derivative contracts as of September 30, 2006 are summarized by year in the following table:

Source of Information Fair Value by Contract Year	**2006**[1]	**2007**	**2008**	**2009**	**2010**	**Thereafter**	**Total**
				(In millions)			
Other external sources [2] [3]	$ 5	$ 5	$ 5	$ 4	$ -	$ -	$ 19
Prices based on models[3]	-	-	-	-	4	-	4
Total[3]	$ 5	$ 5	$ 5	$ 4	$ 4	$ -	$ 23

(1) For the last quarter of 2006.
(2) Broker quote sheets.
(3) Includes $23 million from a non-hedge commodity derivative contract that is offset by a regulatory liability and does not affect earnings.

Met-Ed performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% adverse shift in quoted market prices in the near term on both of Met-Ed's trading and non-trading derivative instruments would not have had a material effect on its consolidated financial position or cash flows as of September 30, 2006. Met-Ed estimates that if energy commodity prices experienced an adverse 10% change, net income for the next twelve months would not change, as prices for all commodity positions are already above the contract price caps.

Equity Price Risk

Included in Met-Ed's nuclear decommissioning trusts are marketable equity securities carried at their market value of approximately $153 million and $142 million as of September 30, 2006 and December 31, 2005, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $15 million reduction in fair value as of September 30, 2006.

Regulatory Matters

Regulatory assets are costs which have been authorized by the PPUC and the FERC 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 under the provisions of Met-Ed's transition plan and rate restructuring plan. Met-Ed's regulatory assets as of September 30, 2006 and December 31, 2005 were $365 million and $310 million, respectively.

A February 2002 Commonwealth Court of Pennsylvania decision affirmed the June 2001 PPUC decision regarding approval of the FirstEnergy/GPU merger, remanded the issues of quantification and allocation of merger savings to the PPUC and denied Met-Ed and Penelec the rate relief initially approved in the PPUC decision. On October 2, 2003, the PPUC issued an order concluding that the Commonwealth Court reversed the PPUC's June 2001 order in its entirety. In accordance with the PPUC's direction, Met-Ed and Penelec filed supplements to their tariffs that became effective in October 2003 and that reflected the CTC rates and shopping credits in effect prior to the June 2001 order. Met-Ed's and Penelec's combined portion of total net merger savings during 2001 - 2004 is estimated to be approximately $51 million. A procedural schedule was established by the ALJ on January 17, 2006 and the companies filed initial testimony on March 1, 2006. On May 4, 2006, the PPUC consolidated this proceeding with the

April 10, 2006 comprehensive rate filing proceeding discussed below. Met-Ed and Penelec are unable to predict the outcome of this matter.

In an October 16, 2003 order, the PPUC approved June 30, 2004 as the date for Met-Ed's NUG trust fund refunds. The PPUC order also denied its accounting treatment request regarding the CTC rate/shopping credit swap by requiring Met-Ed to treat the stipulated CTC rates that were in effect from January 1, 2002 on a retroactive basis. On October 22, 2003, Met-Ed filed an Objection with the Commonwealth Court asking that the Court reverse this PPUC finding; a Commonwealth Court judge subsequently denied its Objection on October 27, 2003 without explanation. On October 31, 2003, Met-Ed filed an Application for Clarification of the Court order with the Commonwealth Court, 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 Objection was intended to be denied on the merits. The Reargument Brief before the Commonwealth Court was filed on January 28, 2005. Oral arguments were held on June 8, 2006. On July 19, 2006, the Commonwealth Court issued its decision affirming the PPUC’s prior orders. Although the decision denied the appeal of Met-Ed, it had previously accounted for the treatment of costs required by the PPUC’s October 2003 orders.

Met-Ed purchases a portion of its PLR requirements from FES through a wholesale power sales agreement. Under this 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 contracts with NUGs and other unaffiliated suppliers. The FES 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. The wholesale power sales agreement with FES could automatically be extended for each successive calendar year unless any party elects to cancel the agreement by November 1 of the preceding year. On November 1, 2005, FES and the other parties thereto amended the agreement to provide FES the right in 2006 to terminate the agreement at any time upon 60 days notice. On April 7, 2006, the parties to the wholesale power sales agreement entered into a Tolling Agreement that arises out of FES' notice to Met-Ed that FES elected to exercise its right to terminate the wholesale power sales agreement effective midnight December 31, 2006, because that agreement is not economically sustainable to FES.

In lieu of allowing such termination to become effective as of December 31, 2006, the parties agreed, pursuant to the Tolling Agreement, to amend the wholesale power sales agreement to provide as follows:

1. The termination provisions of the wholesale power sales agreement will be tolled for one year until December 31, 2007, provided that during such tolling period:

a. FES will be permitted to terminate the wholesale power sales agreement at any time with sixty days written notice;
b. Met-Ed will procure through arrangements other than the wholesale power sales agreement beginning December 1, 2006 and ending December 31, 2007, approximately 33% of the amounts of capacity and energy necessary to satisfy its PLR obligations for which Committed Resources (i.e., non-utility generation under contract to Met-Ed, Met-Ed-owned generating facilities, purchased power contracts and distributed generation) have not been obtained; and
c. FES will not be obligated to supply additional quantities of capacity and energy in the event that a supplier of Committed Resources defaults on its supply agreement.

2. During the tolling period, FES will not act as an agent for Met-Ed in procuring the services under 1 (b) above; and

3. The pricing provision of the wholesale power sales agreement shall remain unchanged provided Met-Ed complies with the provisions of the Tolling Agreement and any applicable provision of the wholesale power sales agreement.

In the event that FES elects not to terminate the wholesale power sales agreement effective midnight December 31, 2007, similar tolling agreements effective after December 31, 2007 are expected to be considered by FES for subsequent years if Met-Ed procures through arrangements other than the wholesale power sales agreement approximately 64%, 83% and 95% of the additional amounts of capacity and energy necessary to satisfy its PLR obligations for 2008, 2009 and 2010, respectively, for which Committed Resources have not been obtained from the market. On September 26, 2006, Met-Ed successfully conducted a competitive RFP for 33% of its PLR obligation for which Committed Resources had not been obtained for the period December 1, 2006 through December 31, 2008.

The wholesale power sales agreement, as modified by the Tolling Agreement, requires Met-Ed to satisfy the portion of its PLR obligations currently supplied by FES from unaffiliated suppliers at prevailing prices, which are likely to be higher than the current price charged by FES under the current agreement and, as a result, Met-Ed's purchased power costs could materially increase. If Met-Ed were to replace the entire FES supply at current market power prices without corresponding regulatory authorization to increase its generation prices to customers, it would likely incur a significant increase in operating expenses and experience a material deterioration in credit quality metrics. Under such a scenario, Met-Ed's credit profile would no longer be expected to support an investment grade rating for its fixed income securities. There can be no assurance, however, that if FES ultimately determines to terminate, further reduce, or significantly modify the agreement, timely regulatory relief will be granted by the PPUC pursuant to the April 10, 2006 comprehensive rate filing discussed below, or, to the extent granted, adequate to mitigate such adverse consequences.

Met-Ed made a comprehensive rate filing with the PPUC on April 10, 2006 that addresses a number of transmission, distribution and supply issues. If Met-Ed's preferred approach involving accounting deferrals is approved, the filing would increase annual revenues by $216 million. That filing includes, among other things, a request to charge customers for an increasing amount of market priced power procured through a CBP as the amount of supply provided under the existing FES agreement is phased out in accordance with the April 7, 2006 Tolling Agreement described above. Met-Ed also requested approval of the January 12, 2005 petition for the deferral of transmission-related costs discussed above, but only for those costs incurred during 2006. In this rate filing, Met-Ed also requested recovery of annual transmission and related costs incurred on or after January 1, 2007, plus the amortized portion of 2006 costs over a ten-year period, along with applicable carrying charges, through an adjustable rider similar to that implemented in Ohio. Changes in the recovery of NUG expenses and the recovery of Met-Ed's non-NUG stranded costs are also included in the filing. The filing contemplates a reduction in distribution rates for Met-Ed of $37 million annually. The PPUC suspended the effective date (June 10, 2006) of these rate changes for seven months after the filing as permitted under Pennsylvania law. If the PPUC adopts the overall positions taken in the intervenors' testimony as filed, this would have a material adverse effect on the financial statements of FirstEnergy and Met-Ed. Hearings were held in late August 2006 and all reply briefs were filed by October 6, 2006. The ALJ's recommended decision is due by November 8, 2006 and the PPUC decision is expected by January 12, 2007.

The annual goodwill impairment analysis performed in the third quarter of 2006 assumed management's best estimate of the rate increases that are expected to be granted in January 2007 under Met-Ed's comprehensive rate filing. If the PPUC authorizes less than the amounts assumed, an additional impairment analysis would be performed at that time and this could result in a future goodwill impairment loss that could be material. If rate relief were completely denied, it is estimated that approximately $604 million of Met-Ed's goodwill would be impaired and written off. However, no adjustment to FirstEnergy's goodwill on a consolidated basis would be recognized in that circumstance because the fair value of its regulated segment (which represents FirstEnergy's reporting unit to evaluate goodwill) would continue to exceed the carrying value of its investment in the segment.

As of September 30, 2006, Met-Ed's regulatory deferrals pursuant to the 1998 Restructuring Settlement (including the Phase 2 Proceedings) and the FirstEnergy/GPU Merger Settlement Stipulation was $297 million. The PPUC recently conducted a review and audit of a modification to the NUG purchased power stranded cost accounting methodology for Met-Ed. On August 18, 2006, a PPUC Order was entered requiring Met-Ed to reflect the deferred NUG cost balances as if the stranded cost accounting methodology modification had not been implemented. As a result of the PPUC's Order, Met-Ed recognized a pre-tax charge of approximately $10.3 million in the third quarter of 2006, representing incremental costs deferred under the revised methodology in 2005. Met-Ed continues to believe that the stranded cost accounting methodology modification is appropriate and filed a petition with the PPUC pursuant to its Order for authorization to reflect the stranded cost accounting methodology modification effective January 1, 1999.

On January 12, 2005, Met-Ed filed, before the PPUC, a request for deferral of transmission-related costs beginning January 1, 2005. The OCA, OSBA, OTS, MEIUG, PICA, Allegheny Electric Cooperative and Pennsylvania Rural Electric Association all intervened in the case. Met-Ed sought to consolidate this proceeding (and modified its request to provide deferral of 2006 transmission-related costs only) with the comprehensive rate filing it made on April 10, 2006 as described above. On May 4, 2006, the PPUC approved the modified request. Accordingly, Met-Ed has deferred approximately $90 million, representing transmission costs that were incurred from January 1, 2006 through September 30, 2006. On June 5, 2006, the OCA filed before the Commonwealth Court a petition for review of the PPUC's approval of the deferral. On July 12, 2006, the Commonwealth Court granted the PPUC's motion to quash the OCA's appeal. The ratemaking treatment of the deferrals will be determined in the comprehensive rate filing proceeding discussed above.

On November 18, 2004, the FERC issued an order eliminating the RTOR for transmission service between the MISO and PJM regions. The FERC also ordered MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a SECA mechanism to recover lost RTOR revenues during a 16-month transition period from load serving entities. The FERC issued orders in 2005 setting the SECA for hearing. ATSI, JCP&L, Met-Ed, Penelec, and FES continue to be involved in the FERC hearings concerning the calculation and imposition of the SECA charges. The hearing was held in May 2006. Initial briefs were submitted on June 9, 2006, and reply briefs were filed on June 27, 2006. The Presiding Judge issued an Initial Decision on August 10, 2006, rejecting the compliance filings made by the RTOs and transmission owners, ruling on various issues and directing new compliance filings. This decision is subject to review and approval by the FERC. Briefs addressing the Initial Decision were filed on September 11, 2006 and October 20, 2006. A final order could be issued by the FERC by the end of 2006.

On January 31, 2005, certain PJM transmission owners made three filings with the FERC 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. American Electric Power Company, Inc. filed in opposition proposing to create a "postage stamp" rate for high voltage transmission facilities across PJM. Second, the FERC approved the proposed Schedule 12 rate harmonization. Third, the FERC accepted the proposed formula rate, subject to refund and hearing procedures. On June 30, 2005, the settling PJM transmission owners filed a request for rehearing of the May 31, 2005 order. On March 20, 2006, a settlement was filed with FERC in the formula rate proceeding that generally accepts the companies' formula rate proposal. The FERC issued an order approving this settlement on April 19, 2006. Hearings in the PJM rate design case concluded in April 2006. On July 13, 2006, an Initial Decision was issued by the ALJ. The ALJ adopted the Trial Staff’s position that the cost of all PJM transmission facilities should be recovered through a postage stamp rate. The ALJ recommended an April 1, 2006 effective date for this change in rate design. If the FERC accepts this recommendation, the transmission rate applicable to many load zones in PJM would increase. FirstEnergy believes that significant additional transmission revenues would have to be recovered from the JCP&L, Met-Ed and Penelec transmission zones within PJM. JCP&L, Met-Ed and Penelec, as part of the Responsible Pricing Alliance, filed a brief addressing the Initial Decision on August 14, 2006 and September 5, 2006. The case will be reviewed by the FERC with a decision anticipated in the fourth quarter of 2006.

See Note 11 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 when it concludes that it is probable that it has an obligation for such costs and can reasonably determine 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, 2006, based on estimates of the total costs of cleanup, Met-Ed’s proportionate responsibility for such costs, and the financial ability of other unaffiliated entities to pay.

See Note 10(B) to the consolidated financial statements for further details and a complete discussion of environmental matters.

Other Legal Proceedings

Power Outages and Related Litigation

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 below are described in Note 10(C) to the consolidated financial statements.

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 Web site (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 is also proceeding with the implementation of the recommendations 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 may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future as a result of adoption of mandatory reliability standards pursuant to the EPACT that could require additional material expenditures.

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. Although unable to predict the impact of these proceedings, 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.

New Accounting Standards and Interpretations

SAB 108 - “Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements”

In September 2006, the SEC issued SAB 108, which provides interpretive guidance on how registrants should quantify financial statement misstatements. There is currently diversity in practice, with the two commonly used methods to quantify misstatements being the “rollover” method (which primarily focuses on the income statement impact of misstatements) and the “iron curtain” method (which focuses on the balance sheet impact). SAB 108 requires registrants to use a dual approach whereby both of these methods are considered in evaluating the materiality of financial statement errors. Prior materiality assessments will need to be reconsidered using both the rollover and iron curtain methods. This guidance will be effective for Met-Ed in the fourth quarter of 2006. Met-Ed does not expect this Statement to have a material impact on its financial statements.

SFAS 157 - “Fair Value Measurements”

In September 2006, the FASB issued SFAS 157, that establishes how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under GAAP. This Statement addresses the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. The key changes to current practice are: (1) the definition of fair value which focuses on an exit price rather than entry price; (2) the methods used to measure fair value such as emphasis that fair value is a market-based measurement, not an entity-specific measurement, as well as the inclusion of an adjustment for risk, restrictions and credit standing; and (3) the expanded disclosures about fair value measurements.

This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. Met-Ed is currently evaluating the impact of this Statement on its financial statements.

SFAS 158 - "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)"

In September 2006, the FASB issued SFAS 158, which requires companies to recognize a net liability or asset to report the overfunded or underfunded status of their defined benefit pension and other postretirement benefit plans on their balance sheets and recognize changes in funded status in the year in which the changes occur through other comprehensive income. The funded status to be measured is the difference between plan assets at fair value and the benefit obligation. This Statement requires that gains and losses and prior service costs or credits, net of tax, that arise during the period be recognized as a component of other comprehensive income and not as components of net periodic benefit cost. Additional information should also be disclosed in the notes to the financial statements about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and transition asset or obligation. Upon the initial application of this Statement and subsequently, an employer should continue to apply the provisions in Statements 87, 88 and 106 in measuring plan assets and benefit obligations as of the date of its statement of financial position and in determining the amount of net periodic benefit cost. This Statement is effective for Met-Ed as of December 31, 2006. Met-Ed is currently evaluating the impact of this Statement on its financial statements.

FSP FIN 46(R)-6 - "Determining the Variability to Be Considered in Applying FASB interpretation No. 46(R)"

In April 2006, the FASB issued FSP FIN 46(R)-6 that addresses how a reporting enterprise should determine the variability to be considered in applying FASB interpretation No. 46 (revised December 2003). Met-Ed adopted FIN 46(R) in the first quarter of 2004, consolidating VIE's when Met-Ed or one of its subsidiaries is determined to be the VIE's primary beneficiary. The variability that is considered in applying interpretation 46(R) affects the determination of (a) whether the entity is a VIE; (b) which interests are variable interests in the entity; and (c) which party, if any, is the primary beneficiary of the VIE. This FSP states that the variability to be considered shall be based on an analysis of the design of the entity, involving two steps:

Step 1:	Analyze the nature of the risks in the entity
Step 2:	Determine the purpose(s) for which the entity was created and determine the variability the entity is designed to create and

pass along
to its
interest
holders.

After determining the variability to consider, the reporting enterprise can determine which interests are designed to absorb that variability. The guidance in this FSP is applied prospectively to all entities (including newly created entities) with which that enterprise first becomes involved and to all entities previously required to be analyzed under interpretation 46(R) when a reconsideration event has occurred after July 1, 2006. Met-Ed does not expect this Statement to have a material impact on its financial statements.

FIN 48 - "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109."

In June 2006, the FASB issued FIN 48 which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, "Accounting for Income Taxes." This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken on a tax return. This interpretation also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation will be a two-step process. The first step will determine if it is more likely than not that a tax position will be sustained upon examination and should therefore be recognized. The second step will measure a tax position that meets the more likely than not recognition threshold to determine the amount of benefit to recognize in the financial statements. This interpretation is effective for fiscal years beginning after December 15, 2006. Met-Ed is currently evaluating the impact of this Statement.

PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30, 2006	2005	Nine Months Ended September 30, 2006	2005
	(In thousands)			
REVENUES	$ 303,420	$ 290,451	$ 860,171	$ 846,477
EXPENSES:				
Purchased power	165,921	178,090	474,437	467,639
Other operating costs	65,165	66,417	151,640	183,024
Provision for depreciation	11,828	12,736	36,269	37,721
Amortization of regulatory assets	13,060	12,627	40,854	38,930
Deferral of new regulatory assets	(9,235)	-	(21,050)	-
General taxes	18,593	17,552	55,440	51,892
Total expenses	265,332	287,422	737,590	779,206
OPERATING INCOME	38,088	3,029	122,581	67,271
OTHER INCOME (EXPENSE):				
Miscellaneous income	2,182	2,088	6,179	3,356
Interest expense	(11,840)	(9,841)	(33,975)	(29,579)
Capitalized interest	363	285	1,132	674
Total other income (expense)	(9,295)	(7,468)	(26,664)	(25,549)
INCOME (LOSS) BEFORE INCOME TAXES	28,793	(4,439)	95,917	41,722
INCOME TAX EXPENSE (BENEFIT)	10,733	(2,070)	39,251	16,870
NET INCOME (LOSS)	18,060	(2,369)	56,666	24,852
OTHER COMPREHENSIVE INCOME (LOSS):				
Unrealized gain on derivative hedges	17	17	49	49
Unrealized gain (loss) on available for sale securities	14	18	(4)	(3)
Other comprehensive income	31	35	45	46
Income tax expense related to other comprehensive income	13	20	20	20
	18	15	25	26

Other comprehensive income, net of tax				
TOTAL COMPREHENSIVE INCOME (LOSS)	$ 18,078	$ (2,354)	$ 56,691	$ 24,878

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, 2006	December 31, 2005
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 47	$ 35
Receivables-		
Customers (less accumulated provisions of $3,920,000 and $4,184,000, respectively, for uncollectible accounts)	122,232	129,960
Associated companies	5,208	18,626
Other	11,228	12,800
Notes receivable from associated companies	20,599	17,624
Prepayments and other	10,912	7,936
	170,226	186,981
UTILITY PLANT:		
In service	2,119,123	2,043,885
Less - Accumulated provision for depreciation	801,695	784,494
	1,317,428	1,259,391
Construction work in progress	21,704	30,888
	1,339,132	1,290,279
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	120,107	113,368
Non-utility generation trusts	98,864	96,761
Other	532	918
	219,503	211,047
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	873,819	882,344
Prepaid pension costs	93,643	89,637
Other	36,258	38,289
	1,003,720	1,010,270
	$ 2,732,581	$ 2,698,577
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Short-term borrowings-		
Associated companies	$ 216,437	$ 261,159
Other	66,000	-
Accounts payable-		
Associated companies	12,429	33,770
Other	44,063	38,277
Accrued taxes	17,864	27,905
Accrued interest	14,373	8,905
Other	19,489	19,756

	390,655	389,772
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	1,197,480	1,202,551
Accumulated other comprehensive loss	(284)	(309)
Retained earnings	77,489	25,823
Total common stockholder's equity	1,380,497	1,333,877
Long-term debt and other long-term obligations	477,104	476,504
	1,857,601	1,810,381
NONCURRENT LIABILITIES:		
Regulatory liabilities	127,375	162,937
Accumulated deferred income taxes	120,185	106,871
Retirement benefits	107,860	102,046
Asset retirement obligations	75,740	72,295
Other	53,165	54,275
	484,325	498,424
COMMITMENTS AND CONTINGENCIES (Note 10)		
	$ 2,732,581	$ 2,698,577

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)

	Nine Months Ended September 30, 2006	2005
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 56,666	$ 24,852
Adjustments to reconcile net income to net cash from operating activities -		
Provision for depreciation	36,269	37,721
Amortization of regulatory assets	40,854	38,930
Deferral of new regulatory assets	(21,050)	-
Deferred costs recoverable as regulatory assets	(56,272)	(41,301)
Deferred income taxes and investment tax credits, net	14,518	(2,765)
Accrued retirement benefit obligations	1,808	3,005
Accrued compensation, net	999	(1,695)
Decrease (increase) in operating assets -		
Receivables	22,719	97,130
Prepayments and other current assets	(2,977)	(8,620)
Increase (decrease) in operating liabilities -		
Accounts payable	(15,555)	(15,671)
Accrued taxes	(9,841)	11,235
Accrued interest	5,468	5,594
Other	(2,188)	4,433
Net cash provided from operating activities	71,418	152,848
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing -		
Short-term borrowings, net	21,278	-
Redemptions and Repayments -		
Long-term debt	-	(11,534)
Short-term borrowings, net	-	(51,747)
Dividend Payments -		
Common stock	(5,000)	(32,000)
Net cash provided from (used for) financing activities	16,278	(95,281)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(81,228)	(61,680)
	(2,976)	5,724

Loan repayments from (loans to) associated companies, net				
Proceeds from nuclear decommissioning trust fund sales		66,781		59,820
Investments in nuclear decommissioning trust funds		(66,781)		(59,820)
Other, net		(3,480)		(1,612)
Net cash used for investing activities		(87,684)		(57,568)
Net increase (decrease) in cash and cash equivalents		12		(1)
Cash and cash equivalents at beginning of period		35		36
Cash and cash equivalents at end of period	$	47	$	35

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 Stockholder 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, 2006, and the related consolidated statements of income and comprehensive income for each of the three-month and nine-month periods ended September 30, 2006 and 2005 and the consolidated statements of cash flows for the nine-month periods ended September 30, 2006 and 2005. 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 have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2005, and the related consolidated statements of income, capitalization, common stockholder's equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report [which contained references to the Company's change in its method of accounting for asset retirement obligations as of January 1, 2003 and conditional asset retirement obligations as of December 31, 2005 as discussed in Note 2(G) and Note 9 to those consolidated financial statements] dated February 27, 2006, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2005, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers
LLP
Cleveland, Ohio
October 31, 2006

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.

Results of Operations

Net income in the third quarter of 2006 increased to $18 million, compared to a $2 million net loss in the third quarter of 2005. The increase in net income resulted from the deferral of new regulatory assets, higher revenues and lower purchased power costs which were partially offset by higher general taxes and interest expense. In the first nine months of 2006, net income increased to $57 million, compared to $25 million in the first nine months of 2005. The increase in net income resulted from the deferral of new regulatory assets, higher revenues and lower other operating costs which were partially offset by higher purchased power costs, general taxes and interest expense, as discussed below.

Revenues

Revenues increased by $13 million in the third quarter of 2006 and $14 million in the first nine months of 2006, compared to the same periods of 2005. The increase in the third quarter of 2006 was primarily due to higher retail generation revenues and transmission revenues. The increase in the first nine months of 2006 was due primarily to higher retail generation revenues partially offset by lower transmission and distribution revenues. Retail generation revenues increased by $10 million in the third quarter of 2006 and $33 million for the first nine months of 2006 primarily due to higher KWH sales to industrial customers and higher composite unit prices in all customer classes. Industrial sales increased $6 million for the third quarter of 2006 and $21 million for the first nine months of 2006 primarily due to the return of customers from alternative suppliers. Generation service provided by alternative suppliers as a percent of total industrial sales in Penelec's service area decreased by 7.2 percentage points and 11.2 percentage points in the third quarter and the first nine months of 2006, respectively, compared with the corresponding periods of 2005. Higher composite unit prices also increased generation revenues from residential customers by $1 million and $4 million and from commercial customers by $3 million and $8 million in the third quarter and first nine months of 2006, respectively.

Distribution revenues were essentially unchanged in the third quarter of 2006 compared with the same period of 2005. This occurred as a result of the increase from higher composite unit prices substantially offset by a 1.1% decrease in KWH deliveries. The decrease in KWH deliveries primarily resulted from the milder weather in the third quarter of 2006 (a 16.5% decrease in cooling degree days) compared to the same period in 2005. For the first nine months of 2006, distribution revenues decreased $3 million due to a 1.6% decrease in KWH deliveries partially offset by higher composite unit prices. Reduced KWH deliveries reflected milder weather in the first nine months of 2006 (a 22.9% decrease in cooling degree days and a 12.0% decrease in heating degree days) compared with the same period in 2005.

Transmission revenues increased by $2 million in the third quarter of 2006 due to Penelec exercising their right for additional auction revenue rights beginning in June 2006 compared to the same time period in 2005. For the first nine months of 2006, transmission revenues decreased $18 million due to lower transmission load requirements and lower prices. The decreased loads for the first nine months of 2006 (and related lower congestion revenues) resulted from milder weather conditions, as discussed above, and also resulted in decreased transmission expenses discussed further below. For the first nine months of 2006, other revenues also increased by $1 million for a payment received in the first quarter of 2006 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 specified levels, which occurred. This payment was credited to Penelec’s customers, resulting in no net earnings effect.

Changes in KWH sales by customer class in the third quarter and first nine months of 2006 compared to the respective periods in 2005 are summarized in the following table:

Changes in KWH Sales	Three Months	Nine Months
Increase (Decrease)		
Retail Electric Generation:		
Residential	(2.5)%	(2.2)%
Commercial	(0.2)%	(0.5)%
Industrial	8.8 %	12.8 %
Total Retail Electric Generation Sales	**1.6 %**	**2.7 %**
Distribution Deliveries:		
Residential	(2.7)%	(2.4)%
Commercial	(0.8)%	(1.4)%
Industrial	(0.1)%	(1.2)%
Total Distribution Deliveries	**(1.1)%**	**(1.6)%**

Expenses

Total expenses decreased by $22 million or 7.7% in the third quarter of 2006 and $42 million or 5.3% in the first nine months of 2006 compared with the same periods in 2005. The following table presents changes from the prior year by expense category:

Expenses Changes	Three Months	Nine Months
	(In millions)	
Increase (Decrease)		
Purchased power costs	$ (12)	$ 7
Other operating costs	(1)	(31)
Provision for depreciation	(1)	(2)
Amortization of regulatory assets	-	2

Deferral of new regulatory assets	(9)	(21)
General taxes	1	3
Net decrease in expenses	$ (22)	$ (42)

Purchased power costs decreased due to increased NUG cost deferrals of $11 million and a slight decrease of $1 million in purchased power costs due to lower composite unit prices, partially offset by increased volumes purchased to meet higher customer load. The nine month increase in purchased power costs was due to increased purchases to meet higher customer load and higher composite unit prices. This increase was partially offset by higher NUG cost deferrals of $15 million for the first nine months of 2006.

Reduced other operating costs in the third quarter of 2006 compared to the same period in 2005 were due to lower transmission expenses resulting from lower congestion charges. Partially offsetting these lower transmission were increased labor expenses due to higher levels of maintenance activities in the third quarter of 2006 for energy delivery operations and reliability initiatives compared to higher levels of construction activities in the third quarter of 2005. Other operating costs decreased the first nine months of 2006 compared to the same period of 2005 due primarily to lower transmission expenses resulting from lower congestion charges. Expenses were further reduced due to higher levels of construction activities in the first nine months of 2006 compared to a higher level of maintenance activities for the same period of 2005. The deferral of new regulatory assets in 2006 reflected the May 4, 2006 PPUC approval of Penelec's request to defer certain 2006 transmission-related costs (see Regulatory Matters for further discussion). For both periods, general taxes increased primarily due to higher Pennsylvania gross receipt taxes.

Capital Resources and Liquidity

Penelec's cash requirements for the remainder of 2006 for expenses, construction expenditures and scheduled debt maturities, are expected to be met by a combination of cash from operations and short-term credit arrangements.

Changes in Cash Position

As of September 30, 2006, Penelec had $47,000 of cash and cash equivalents compared with $35,000 as of December 31, 2005. The major sources of changes in these balances are summarized below.

Cash Flows From Operating Activities

Cash provided from operating activities in the first nine months of 2006 and 2005 were as follows:

Operating Cash Flows	Nine Months Ended September 30, 2006	2005
	(In millions)	
Cash earnings [1]	$ 74	$ 59
Working capital and other	(3)	94
Net cash provided from operating activities	$ 71	$ 153

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

Cash earnings (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. Generally, a non-GAAP financial measure is a numerical measure of a company's historical or future financial performance, financial position, or cash flows that either excludes or includes amounts, or is subject to adjustment that has the effect of excluding or including amounts, that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with GAAP. In addition, cash earnings (non-GAAP) are not defined under GAAP. Management believes presenting this non-GAAP measure provides useful information to investors in assessing Penelec's operating performance from a cash perspective without the effects of material unusual economic events. Penelec's management frequently references these non-GAAP financial measures in its decision-making, using them to facilitate historical and ongoing performance comparisons as well as comparisons to the performance of peer companies. These non-GAAP measures should be considered in addition to, and not as a substitute for, their most directly comparable financial measures prepared in accordance with GAAP.

Nine Months Ended

Reconciliation of Cash Earnings	**September 30, 2006**	**2005**
	(In millions)	
Net income (GAAP)	$ 57	$ 25
Non-cash charges (credits):		
Provision for depreciation	36	38
Amortization of regulatory assets	41	39
Deferral of new regulatory assets	(21)	-
Deferred costs recoverable as regulatory assets	(56)	(41)
Deferred income taxes and investment tax credits, net	14	(3)
Other non-cash items	3	1
Cash earnings (Non-GAAP)	$ 74	$ 59

The $15 million increase in cash earnings is described above under “Results of Operations.” The $97 million change from working capital primarily resulted from a decrease of $74 million in cash provided from the collection of receivables and a $21 million decrease in accrued taxes.

Cash Flows From Financing Activities

Net cash provided from financing activities was $16 million in the first nine months of 2006 compared to net cash used for financing activities of $95 million in the first nine months of 2005. The change reflects a $73 million increase in short-term borrowings, a $27 million reduction in common stock dividend payments to FirstEnergy and an $11 million decrease in long-term debt redemptions.

Penelec had approximately $21 million of cash and temporary investments (which includes short-term notes receivable from associated companies) and approximately $282 million of short-term indebtedness as of September 30, 2006. Penelec has authorization from the FERC to incur short-term debt of up to $250 million and authorization from the PPUC to incur money pool borrowings of up to $300 million. In addition, Penelec has $75 million of available accounts receivable financing facilities as of September 30, 2006 through Penelec Funding, Penelec's wholly owned subsidiary. 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. As of September 30, 2006 the facility was drawn for $66 million. The annual facility fee is 0.125% on the entire finance limit.

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, 2006, Penelec had the ability to issue $60 million of additional senior notes based upon FMB collateral. Penelec has no restrictions on the issuance of preferred stock.

On August 24, 2006, Penelec, FirstEnergy, OE, Penn, CEI, TE, JCP&L, Met-Ed, FES and ATSI, as Borrowers, entered into a new $2.75 billion five-year revolving credit facility, which replaced the prior $2 billion credit facility. FirstEnergy may request an increase in the total commitments available under the new facility up to a maximum of $3.25 billion. Commitments under the new facility are available until August 24, 2011, unless the lenders agree, at the request of the Borrowers, to two additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each Borrower are subject to a specified sub-limit, as well as applicable regulatory and other limitations. Penelec's borrowing limit under the facility is $250 million.

Under the revolving credit facility, borrowers may request the issuance of LOCs expiring up to one year from the date of issuance. The stated amount of outstanding LOCs 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 $259 million.

The revolving credit facility contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%, measured at the end of each fiscal quarter. As of September 30, 2006, Penelec’s debt to total capitalization as defined under the revolving credit facility was 35%.

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

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 first nine months of 2006 was 5.09%.

Penelec’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 on all securities is stable. The ratings outlook from Moody's and Fitch on all securities is positive.

Cash Flows From Investing Activities

In the first nine months of 2006, net cash used for investing activities totaled $88 million compared to $58 million in the first nine months of 2005. The increase primarily resulted from a $20 million increase in property additions and a $9 million increase in loans to associated companies. Expenditures for property additions primarily support Penelec's energy delivery operations and reliability initiatives.

During the last quarter of 2006, capital requirements for property additions are expected to be approximately $24 million. This cash requirement is expected to be satisfied from a combination of internal cash and short-term credit arrangements.

Penelec's capital spending for the period 2006-2010 is expected to be approximately $494 million, of which approximately $108 million applies to 2006. The capital spending is primarily for property additions supporting the distribution of electricity.

Market Risk Information

Penelec uses various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price fluctuations. FirstEnergy's Risk Policy Committee, comprised of members of senior management, provides general oversight to risk management activities.

Commodity Price Risk

Penelec is exposed to market risk primarily due to fluctuations in electricity, energy transmission, natural gas, coal, and emission prices. To manage the volatility relating to these exposures, Penelec 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. All derivatives that fall within the scope of SFAS 133 must be recorded at their fair value and marked to market. The majority of Penelec's derivative hedging contracts qualify for the normal purchase and normal sale exception under SFAS 133. Contracts that are not exempt from such treatment include the power purchase agreements with NUG entities that were structured pursuant to the Public Utility Regulatory Policies Act of 1978. These non-trading contracts had been adjusted to fair value at the end of each quarter, with a corresponding regulatory asset recognized for above-market costs. On April 1, 2006, Penelec elected to apply the normal purchase and normal sale exception to certain NUG power purchase agreements having a fair value of $14 million (included in "Other" in the table below) in accordance with guidance in DIG C20. The change in the fair value of commodity derivative contracts related to energy production during the third quarter and first nine months of 2006 is summarized in the following table:

Increase (Decrease) in the Fair Value of Commodity Derivative Contracts	Three Months Ended September 30, 2006 Non-Hedge	Hedge	Total	Nine Months Ended September 30, 2006 Non-Hedge	Hedge	Total
			(In millions)			
Change in the Fair Value of Commodity Derivative Contracts:						
Outstanding net asset at beginning of period	$ 12	$ -	$ 12	$ 27	$ -	$ 27
New contract value when entered	-	-	-	-	-	-
Additions/change in value of existing contracts	-	-	-	2	-	2
Change in techniques/assumptions	-	-	-	-	-	-
Settled contracts	-	-	-	(3)	-	(3)
Other	-	-	-	(14)	-	(14)
Net Assets - Derivative Contracts at End of Period (1)	$ 12	$ -	$ 12	$ 12	$ -	$ 12

Impact of Changes in Commodity Derivative

Contracts[2]						
Income Statement effects (pre-tax)	$ -	$ -	$ -	$ (4)	$ -	$ (4)
Balance Sheet effects:						
OCI (pre-tax)	$ -	$ -	$ -	$ -	$ -	$ -
Regulatory liability	$ -	$ -	$ -	$ 3	$ -	$ 3

[1] Includes $11 million in a non-hedge commodity derivative contract which is offset by a regulatory liability.
[2] 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, 2006 as follows:

Balance Sheet Classification	Non-Hedge	Hedge	Total
	(In millions)		
Non-Current-			
Other deferred charges	$ 12	$ -	$ 12
Other noncurrent liabilities	-	-	-
Net assets	$ 12	$ -	$ 12

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, Penelec relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. Penelec uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making. Sources of information for the valuation of commodity derivative contracts as of September 30, 2006 are summarized by year in the following table:

Source of Information Fair Value by Contract Year	2006[1]	2007	2008	2009	2010	Thereafter	Total
				(In millions)			
Other external sources [2] [3]	$ 3	$ 3	$ 2	$ 2	$ -	$ -	$ 10
Prices based on models[3]	-	-	-	-	2	-	2