FIRSTENERGY CORP
Form 10-Q
August 07, 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 June 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, Pennsylvania Power Company, The Cleveland Electric Illuminating Company, The Toledo Edison 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 AUGUST 7, 2006
FirstEnergy Corp., $.10 par value	329,836,276
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, Pennsylvania Power Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. No registrant makes any representation as to information relating to any other registrant, except that information relating to any of the

FirstEnergy subsidiary registrants is also attributed to FirstEnergy 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 PUCO by the Ohio Supreme Court regarding the RSP) 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 implementation of the share repurchase program approved by the Board of Directors in June 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	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
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”
DOJ	United States Department of Justice

GLOSSARY OF TERMS, Cont'd.

DRA	Division of the Ratepayer Advocate
ECAR	East Central Area Reliability Coordination Agreement
EDCP	Executive Deferred Compensation Plan
EITF	Emerging Issues Task Force
EITF 04-13	EITF Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty"
EPA	Environmental Protection Agency
EPACT	Energy Policy Act of 2005
ERO	Electric Reliability Organization
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	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
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
MTC	Market Transition Charge
MW	Megawatts
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	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
RTC	Regulatory Transition Charge
RTO	Regional Transmission Organization
RTOR	Through and Out Rates
S&P	Standard & Poor's Ratings Service
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 140	SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities"
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"
SO^2	Sulfur Dioxide
SRM	Special Reliablity 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 first and second quarters of 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.

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. The following table reconciles the computation of basic and diluted earnings per share of common stock before discontinued operations:

1

Reconciliation of Basic and Diluted Earnings per Share	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(In millions, except per share amounts)			
Income Before Discontinued Operations	$ 304	$ 179	$ 525	$ 320
Less: Redemption premium on subsidiary preferred stock	(3)	-	(3)	-
Earnings on Common Stock Before Discontinued Operations	$ 301	$ 179	$ 522	$ 320
Weighted Average Shares of Common Stock Outstanding:				
Denominator for basic earnings per share	328	328	328	328
Assumed exercise of dilutive stock options and awards	2	2	2	2
Denominator for diluted earnings per share	330	330	330	330
Earnings Before Discontinued Operations per Common Share:				
Basic	$ 0.92	$ 0.54	$ 1.59	$ 0.98
Diluted	$ 0.91	$ 0.54	$ 1.58	$ 0.97

3. - GOODWILL

FirstEnergy's goodwill primarily relates to its regulated services segment. In the six months ended June 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 an adjustment to the former GPU companies due to the realization of a tax benefit that had been reserved in purchase accounting. Adjustments to goodwill in the second quarter of 2006 were immaterial. The following table reconciles changes to goodwill for the six months ended June 30, 2006.

Goodwill Reconciliation	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	(16)			(8)	(4)	(4)
Balance as of June 30, 2006	$ 5,940	$ 1,688	$ 501	$ 1,978	$ 860	$ 878

4. - DIVESTITURES AND DISCONTINUED OPERATIONS

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 six 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. 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 remaining FSG assets, with a net carrying value of $48 million as of June 30, 2006, will qualify for recognition as completed sales within one year. As of June 30, 2006, the FSG subsidiaries classified as held for sale did not meet the criteria for discontinued operations. The carrying amounts of FSG's assets and liabilities held for sale are not material and have not been classified as assets held for sale on FirstEnergy's Consolidated Balance Sheets. See Note 13 for FSG's segment financial information.

Net results (including the gains on sales of assets discussed above) for Cranston, Elliott-Lewis, Power Piping and FES' retail natural gas business of $(1) million and $18 million for the three months and six months ended June 30, 2005, respectively, are reported as discontinued operations on FirstEnergy's Consolidated Statements of Income. Pre-tax operating results for these entities were $(2) million and $2 million for the three months and six months ended June 30, 2005, respectively. Revenues associated with discontinued operations for the three months and six months ended June 30, 2005 were $11 million and $206 million, respectively. The following table summarizes the sources of income from discontinued operations for the three months and six months ended June 30, 2005:

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	Three Months		Six Months
	(In millions)		
Discontinued Operations (Net of tax)			
Gain on sale:			
Natural gas business	$ -		$ 5
FSG and MYR subsidiaries	-		12
Reclassification of operating income (loss)	(1)		1
Total	$ (1)		$ 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 $30 million included in AOCL as of June 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 $35 million decrease related to current hedging activity and a $13 million decrease due to net hedge losses included in earnings during the six months ended June 30, 2006. Approximately $9 million (after tax) of the net deferred losses on derivative instruments in AOCL as of June 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 first six months of 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 June 30, 2006, the aggregate notional value of interest rate swap agreements outstanding was $750 million.

During 2005 and the first six 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 six months of 2006. FirstEnergy terminated and revised its forward swaps, ultimately terminating swaps with an aggregate notional value of $600 million as its subsidiaries issued long term debt in the second quarter. As required by SFAS 133, FirstEnergy assessed the amount of ineffectiveness of the hedges at each termination. FirstEnergy received cash gains of $41 million, of which approximately $6 million ($4 million net of tax) was deemed ineffective and recognized in earnings in the first six months of 2006. The remaining gain deemed effective in the amount of approximately $35 million ($22 million net of tax) was recorded in other comprehensive income and will subsequently be recognized in earnings over the terms of the respective forward swaps. As of June 30, 2006, FirstEnergy had forward swaps with an aggregate notional amount of $550million and a long-term debt securities fair value of $29 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 second quarter and six months ended June 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) 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 second quarter and six months ended June 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 six months ended June 30, 2005, as if FirstEnergy had adopted SFAS 123(R) as of January 1, 2005:

	Three Months	Six Months
	(In millions, except per share amounts)	
Net Income, as reported	$ 178	$ 338
Add back compensation expense reported in net income, net of tax (based on APB 25)*	14	22
Deduct compensation		

expense based upon estimated fair value, net of tax*		(17)		(28)
Pro forma net income	$	175	$	332
Earnings Per Share of Common Stock -				
Basic				
As Reported	$	0.54	$	1.03
ProForma	$	0.53	$	1.01
Diluted				
As Reported	$	0.54	$	1.02
Pro Forma	$	0.53	$	1.01

* 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 six months ended June 30, 2005, the impact on earnings would have been immaterial.

The ARO liability of $1.2 billion as of June 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 June 30, 2006, the fair value of the decommissioning trust assets was $1.8 billion.

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

Three Months Ended	FirstEnergy	OE	CEI	TE	Penn	JCP&L	Met-Ed	Penelec
				(In millions)				
ARO Reconciliation								
Balance, April 1, 2006	$ 1,148	$ 84	$ 8	$ 25	$ -	$ 81	$ 144	$ 73
Liabilities incurred	-	-	-	-	-	-	-	-
Liabilities settled	(6)	-	(6)	-	-	-	-	-
Accretion	18	1	-	1	-	1	2	1
Revisions in estimated cashflows	-	-	-	-	-	-	-	-
Balance, June 30, 2006	$ 1,160	$ 85	$ 2	$ 26	$ -	$ 82	$ 146	$ 74
Balance, April 1, 2005	$ 1,095	$ 204	$ 276	$ 198	$ 141	$ 74	$ 135	$ 67
Liabilities incurred	-	-	-	-	-	-	-	-
Liabilities settled	-	-	-	-	-	-	-	-
Accretion	18	4	5	3	2	1	2	1
Revisions in estimated cashflows	-	-	-	-	-	-	-	-
Balance, June 30, 2005	$ 1,113	$ 208	$ 281	$ 201	$ 143	$ 75	$ 137	$ 68

Six Months Ended	FirstEnergy	OE	CEI	TE	Penn	JCP&L	Met-Ed	Penelec
				(In millions)				
ARO Reconciliation								
	$ 1,126	$ 83	$ 8	$ 25	$ -	$ 80	$ 142	$ 72

Balance, January 1, 2006								
Liabilities incurred	-	-	-	-	-	-	-	-
Liabilities settled	(6)	-	(6)	-	-	-	-	-
Accretion	36	2	-	1	-	2	4	2
Revisions in estimated cashflows	4	-	-	-	-	-	-	-
Balance, June 30, 2006	$ 1,160	$ 85	$ 2	$ 26	$ -	$ 82	$ 146	$ 74
Balance, January 1, 2005	$ 1,078	$ 201	$ 272	$ 195	$ 138	$ 72	$ 133	$ 67
Liabilities incurred	-	-	-	-	-	-	-	-
Liabilities settled	-	-	-	-	-	-	-	-
Accretion	35	7	9	6	5	3	4	1
Revisions in estimated cashflows	-	-	-	-	-	-	-	-
Balance, June 30, 2005	$ 1,113	$ 208	$ 281	$ 201	$ 143	$ 75	$ 137	$ 68

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 other postretirement benefits to employees, their beneficiaries and covered dependents 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 six months ended June 30, 2006 and 2005 consisted of the following:

Pension Benefits	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(In millions)			
Service cost	$ 21	$ 19	$ 41	$ 38
Interest cost	66	64	133	128
Expected return on plan assets	(99)	(86)	(198)	(173)
Amortization of prior service cost	2	2	5	4
Recognized net actuarial loss	15	9	29	18
Net periodic cost	$ 5	$ 8	$ 10	$ 15

Other Postretirement Benefits	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(In millions)			
Service cost	$ 9	$ 10	$ 17	$ 20
Interest cost	26	27	52	55
Expected return on plan assets	(12)	(11)	(23)	(22)
Amortization of prior service cost	(19)	(11)	(37)	(22)
Recognized net actuarial loss	14	10	27	20
Net periodic cost	$ 18	$ 25	$ 36	$ 51

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 six months ended June 30, 2006 and 2005 were as follows:

Pension Benefit Cost (Credit)	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(In millions)			
OE	$ (1.1)	$ 0.2	$ (2.1)	$ 0.4
Penn	(0.4)	(0.2)	(0.8)	(0.4)
CEI	1.0	0.3	1.9	0.7
TE	0.2	0.3	0.4	0.6

JCP&L	(1.4)	(0.3)	(2.7)	(0.5)
Met-Ed	(1.7)	(1.1)	(3.5)	(2.2)
Penelec	(1.3)	(1.3)	(2.7)	(2.7)
Other FirstEnergy subsidiaries	9.9	9.6	20.0	19.1
	$ 5.2	$ 7.5	$ 10.5	$ 15.0

Other Postretirement Benefit Cost	Three Months Ended June 30, 2006	2005	Six Months Ended June 30, 2006	2005
	(In millions)			
OE	$ 3.4	$ 5.8	$ 6.8	$ 11.5
Penn	0.8	1.2	1.6	2.4
CEI	2.8	3.8	5.5	7.6
TE	2.0	2.2	4.0	4.3
JCP&L	0.6	1.5	1.2	4.2
Met-Ed	0.7	0.4	1.5	0.8
Penelec	1.8	2.0	3.6	4.0
Other FirstEnergy subsidiaries	6.1	8.1	12.1	16.2
	$ 18.2	$ 25.0	$ 36.3	$ 51.0

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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 $640 million, $98 million and $498 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 June 30, 2006, the net above-market loss liability projected for these eight NUG agreements was $74 million. Purchased power costs from these entities during the three months and six months ended June 30, 2006 and 2005 are shown in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
	(In millions)			
JCP&L	$ 19	$ 21	$ 34	$ 42
Met-Ed	16	14	33	30
Penelec	7	7	14	14
Total	$ 42	$ 42	$ 81	$ 86

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Securitized Transition Bonds

The consolidated financial statements of FirstEnergy and JCP&L include the results of JCP&L Transition, a wholly owned limited liability company of JCP&L. In June 2002, JCP&L Transition sold $320 million of transition bonds to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station.

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

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 the transition bonds and other fees and expenses associated with their issuance. JCP&L sold the bondable transition property to JCP&L Transition and, as servicer, manages and administers the bondable transition property, including the billing, collection and remittance of the TBC, pursuant to a servicing agreement with JCP&L Transition. JCP&L is entitled to a quarterly servicing fee of $100,000 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 June 30, 2006, outstanding guarantees and other assurances totaled approximately $3.5 billion consisting of contract guarantees ($1.9 billion), surety bonds ($0.1 billion) and LOCs ($1.5 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 subsidiary financing principally for the acquisition of 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 $0.8 billion (included in the $1.9 billion discussed above) as of June 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 June 30, 2006, FirstEnergy's maximum exposure under these collateral provisions was $501 million.

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related FirstEnergy guarantees of $146 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.

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

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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 June 30, 2006), which is renewable and declines yearly based upon the senior outstanding debt of TEBSA.

(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 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 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 has been scheduled for August 8, 2006 to discuss the alleged violations with the EPA.

FirstEnergy believes it is complying 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 from 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 State Implementation Plans 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 this approach is based on output, new and non-emitting generating facilities, including renewables and nuclear, would be entitled to their proportionate share of the allowances. Consequently, FirstEnergy would be disadvantaged if these model rules were implemented 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 (the primary portion of which is expected to be spent in the 2008 to 2011 time period). 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 sulfur dioxide emissions. The settlement agreement also requires OE and Penn to spend up to $25 million toward environmentally beneficial projects, which include wind energy purchased power agreements over a 20-year term. OE and Penn agreed to pay a civil penalty of $8.5 million. Results for the first quarter of 2005 included the penalties 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 June 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 $70 million (JCP&L - $55 million, CEI - $2 million, and other subsidiaries- $13 million) have been accrued through June 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. On September 8, 2004, the New Jersey Supreme Court denied the motions filed by plaintiffs and JCP&L for leave to appeal the decision of the Appellate Division. In December 2005, JCP&L argued its motion for summary judgment before the New Jersey Superior Court on its renewed motion to decertify the class and on remaining plaintiffs' negligence and breach of contract claims. These motions remain pending. FirstEnergy is unable to predict the outcome of these matters and no liability has been accrued as of June 30, 2006.

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 the 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 outage. 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. FirstEnergy filed a Motion to Dismiss on June 13, 2006. It is currently expected that this case will be summarily dismissed, although the Motion is still pending. On March 7, 2006, the PUCO issued a ruling 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. These motions are pending. Additionally, on June 23, 2006, one of the insurance carrier complainants filed an appeal with the Ohio Supreme Court over the PUCO's denial of motion for rehearing on the issue of the admissibility of the Task Force Report and the dismissal of FirstEnergy Corp. as a respondent. Briefing is expected to be completed on this appeal by mid-September. It is unknown when the Supreme Court will rule on the appeal. No estimate of potential liability is available for any of these cases.

In addition to the above proceedings, FirstEnergy was named in a complaint filed in Michigan State Court by an individual who is not a customer of any FirstEnergy company. FirstEnergy's motion to dismiss the matter was denied on June 2, 2006. FirstEnergy has since filed an appeal, which is pending. A responsive pleading to this matter has been filed. Also, the complaint has been amended to include an additional party. No estimate of potential liability has been undertaken in this matter.

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 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 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.

As of December 16, 2005, NGC acquired ownership of the nuclear generation assets transferred from OE, CEI, TE and Penn 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.

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.

JCP&L's bargaining unit employees filed a grievance challenging JCP&L's 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties' collective bargaining agreement. At the conclusion of the June 1, 2005 hearing, the Arbitrator decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the Arbitrator issued an opinion to award approximately $16 million to the bargaining unit employees. On February 6, 2006, the federal court granted a Union motion to dismiss JCP&L's appeal of the award as premature. JCP&L will file its 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 described above. 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 60 days from the denial of rehearing to appeal the PUCO’s decision.

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.

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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, 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 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.

The EPACT provides for the creation of an ERO to establish and enforce reliability standards for the bulk power system, subject to FERC 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 entities. The new FERC rule referred to above, further provides for reorganizing regional reliability organizations (regional entities) that would replace the current regional councils and for rearranging the 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 NERC as the ERO to implement the provisions of Section 215 of the Federal Power Act. The FERC directed NERC to make a compliance filing within ninety days addressing such issues as the regional delegation agreements.

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, on the current NERC Version O reliability standards with some additional 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 chairman has indicated that the FERC intends to act on the proposed reliability standards by issuing a NOPR in September of this year. Interested parties will be given the opportunity to comment on the NOPR. NERC has requested an effective date of January 1, 2007 for the proposed reliability standards.

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.

FirstEnergy believes it is in compliance with all current NERC reliability standards. However, it is expected that the FERC will adopt stricter reliability standards than those contained in the current NERC 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.

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 September 28, 2005, the Supreme Court of Ohio heard oral arguments on the appeals. 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 one matter back to the PUCO for further consideration of the issue as to whether the RSP, as adopted by the PUCO, provided for sufficient means for customer participation in the competitive marketplace. On May 12, 2006, the Ohio Companies filed a Motion for Reconsideration with the Supreme Court of Ohio which was denied by the Court on June 21, 2006. 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.

The Ohio Companies filed an application and stipulation with the PUCO on September 9, 2005 seeking approval of the RCP. 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 are due on August 4, 2006. Appellants' Reply Briefs will then be due on August 24, 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 May 1, 2006, the Ohio Companies filed a modification to the rider to determine revenues ($141 million) from July 2006 through June 2007.

The second application sought authority to defer costs associated with transmission and ancillary service related costs incurred during the period 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 unable to predict when a decision may be issued.

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 September 30, 2004 as the date for Met-Ed's and Penelec's NUG trust fund refunds. The PPUC order also denied their accounting treatment request regarding the CTC rate/shopping credit swap by requiring Met-Ed and Penelec to treat the stipulated CTC rates that were in effect from January 1, 2002 on a retroactive basis. On October 22, 2003, Met-Ed and Penelec filed an Objection with the Commonwealth Court asking that the Court reverse this PPUC finding; a Commonwealth Court judge subsequently denied their Objection on October 27, 2003 without explanation. On October 31, 2003, Met-Ed and Penelec filed an Application for Clarification of the Court order with the 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.

As of June 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 $335 million and $57 million, respectively. Penelec's $57 million is subject to the pending resolution of taxable income issues associated with NUG trust fund proceeds. The PPUC is reviewing a January 2006 change in Met-Ed's and Penelec's NUG purchase power stranded cost accounting methodology. If the PPUC orders Met-Ed and Penelec to reverse the change in accounting methodology, this would result in a pre-tax loss of $10.3 million for Met-Ed.

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 below. On May 4, 2006, the PPUC approved the modified request. Accordingly, Met-Ed and Penelec have deferred approximately $46 million and $12 million, respectively, representing transmission costs that were incurred from January 1, 2006 through June 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 below.

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.

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, 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 are scheduled for late August 2006 and a PPUC decision is expected early in the first quarter of 2007.

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. To the extent that an affiliate of Penn supplies a portion of the PLR load included in the RFP, authorization to make the affiliate sale must be obtained from the FERC. 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 to obtain Penn's power supply requirements after 2006 through two separate solicitations. An initial solicitation was held for Penn in May 2006 with all tranches fully subscribed. On June 2, 2006, the PPUC approved the bid results for the first solicitation. 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 only acquired for three of the five tranches for the Large Commercial Group. On July 20, 2006, the PPUC approved the submissions for the second bid. A residual solicitation is scheduled to be held on August 15, 2006 for the two remaining Large Commercial Group tranches. Acceptance of the winning bids is subject to approval by the PPUC.

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 its recovery of certain PLR costs via a reconciliation mechanism and its 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 June 30, 2006, the accumulated deferred cost balance totaled approximately $638 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 4, 2006, JCP&L Transition Funding II, a wholly owned subsidiary of JCP&L, secured pricing on the issuance of $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. A schedule for the proceeding was established, including a discovery period and evidentiary hearings scheduled for September 2006.

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 last of the quarterly reliability reports was submitted on June 12, 2006. As of June 30, 2006, there were no performance penalties issued by the NJBPU.

In a reaction 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. A final decision as to the procurement method for the Commercial Industrial Energy Price Class is expected in October 2006.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004 supporting a continuation of the current level and duration of the funding of TMI-2 decommissioning costs by New Jersey customers without a reduction, termination or capping of the funding. On September 30, 2004, JCP&L filed an updated TMI-2 decommissioning study. This study resulted in an updated total decommissioning cost estimate of $729 million (in 2003 dollars) compared to the estimated $528 million (in 2003 dollars) from the prior 1995 decommissioning study. The DRA filed comments on February 28, 2005 requesting that decommissioning funding be suspended. On March 18, 2005, JCP&L filed a response to those comments. A schedule for further 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. The NJBPU Staff issued a 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. JCP&L is unable to predict the outcome of this proceeding.

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 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 $33 million has been deferred as of June 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 21, 2006, the FERC issued an order stating that it needs more time to consider the matter. In light of that order, there is no time period by which the FERC must act on the pending rehearing request. 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.

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 FERC has ordered the Presiding Judge to issue an initial decision by August 11, 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. The Companies, as part of the Responsible Pricing Alliance, intend to submit a brief on exceptions within thirty days of the initial decision. Following submission of reply exceptions, the case is expected to 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. The PPUC approved Penn's plan with modifications on April 20, 2006 to use an RFP process to obtain its power supply requirements after 2006 through two separate solicitations. An initial solicitation was held for Penn in May 2006 with all tranches fully subscribed. On June 2, 2006, the PPUC approved the bid results for the first solicitation. 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 only acquired for three of the five tranches for the Large Commercial Group. On July 20, 2006, the PPUC approved the submission for the second bid. A residual solicitation is scheduled to be held on August 15, 2006 for the two remaining Large Commercial Group tranches. Acceptance of the winning bids is subject to approval by the PPUC.

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. The procedural schedule has been suspended pending settlement discussions among the parties.

12. - NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

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 June 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 all of the electric power needs of FirstEnergy's end-use customers through retail and wholesale arrangements, including regulated retail sales to meet 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 from the wholesale market when needed 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)					
June 30, 2006						
External revenues	$ 1,045	$ 1,678	$ 58	$ 16	$ (11)	$ 2,786
Internal revenues	-	-	-	-	-	-
Total revenues	1,045	1,678	58	16	(11)	2,786
Depreciation and amortization	228	(36)	-	1	5	198
Investment Income	75	2	-	1	(47)	31
Net interest charges	96	54	1	1	21	173
Income taxes	155	90	1	2	(31)	217
Net income	229	135	(11)	(4)	(45)	304
Total assets	24,630	6,740	56	299	853	32,578
Total goodwill	5,916	24	-	-	-	5,940
Property additions	161	103	-	1	13	278
June 30, 2005						
External revenues	$ 1,226	$ 1,416	$ 59	$ 135	$ 7	$ 2,843
Internal revenues	80	-	-	-	(80)	-
Total revenues	1,306	1,416	59	135	(73)	2,843
Depreciation and amortization	344	(16)	-	-	7	335
Investment income	47	-	-	-	-	47
Net interest charges	99	9	-	2	51	161
Income taxes	193	(5)	5	1	47	241
Income before discontinued operations	288	(5)	(2)	6	(108)	179
Discontinued operations	-	-	-	(1)	-	(1)
Net income	288	(5)	(2)	5	(108)	178
Total assets	28,454	1,601	78	512	566	31,211
Total goodwill	5,946	24	-	63	-	6,033
Property additions	158	66	-	2	7	233
Six Months Ended						
June 30, 2006						
External revenues	$ 2,128	$ 3,297	$ 104	$ 136	$ (34)	$ 5,631
Internal revenues	-	-	-	-	-	-
Total revenues	2,128	3,297	104	136	(34)	5,631
Depreciation and amortization	486	(11)	-	2	10	487
Investment Income	137	17	-	1	(81)	74

Net interest charges	189	103	1	2	38	333
Income taxes	299	117	1	(5)	(61)	351
Net income	440	175	(12)	11	(89)	525
Total assets	24,630	6,740	56	299	853	32,578
Total goodwill	5,916	24	-	-	-	5,940
Property additions	356	347	-	2	20	725
June 30, 2005						
External revenues	$ 2,442	$ 2,793	$ 102	$ 247	$ 9	$ 5,593
Internal revenues	158	-	-	-	(158)	-
Total revenues	2,600	2,793	102	247	(149)	5,593
Depreciation and amortization	718	(3)	-	1	13	729
Investment income	88	-	-	-	-	88
Net interest charges	197	19	-	3	113	332
Income taxes	350	(35)	2	11	34	362
Income before discontinued operations	524	(51)	(4)	11	(160)	320
Discontinued operations	-	-	13	5	-	18
Net income	524	(51)	9	16	(160)	338
Total assets	28,454	1,601	78	512	566	31,211
Total goodwill	5,946	24	-	63	-	6,033
Property additions	299	147	1	4	11	462

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 six months ended June 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 $0.4 million and $0.6 million, respectively, in the second quarter of 2005 and understated by $0.9 million and $1.2 million, respectively, in the first six months of 2005. The effects of these adjustments on JCP&L's Consolidated Statements of Income for the three months and six months ended June 30, 2005 are as follows:

	Three Months		Six Months	
	As Previously Reported	As Restated	As Previously Reported	As Restated
		(In millions)		
Operating Revenues	$ 595.3	$ 595.3	$ 1,124.4	$ 1,124.4
Operating Expenses and Taxes	521.2	521.6	1,015.9	1,016.8
Operating Income	74.1	73.7	108.5	107.6

Other Income		0.3		0.3		0.3		0.3
Net Interest Charges		19.1		19.7		39.0		40.2
Net Income	$	55.3	$	54.3	$	69.8	$	67.7
Earnings Applicable to Common Stock	$	55.2	$	54.2	$	69.6	$	67.5

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

16. - SUBSEQUENT EVENTS

Pennsylvania Law Change

On July 12, 2006, the Governor of Pennsylvania signed House Bill 859, which increases the net operating loss deduction allowed for the corporate net income tax from $2 million to $3 million, or the greater of 12.5% of taxable income. As a result, FirstEnergy expects to recognize a net operating loss benefit of $2.2 million (net of federal tax benefit) in the third quarter of 2006.

New Jersey Law Change

On July 8, 2006, the Governor of New Jersey signed tax legislation that increased the current New Jersey Corporate Business tax by an additional 4% surtax, which increases the effective tax rate from 9% to 9.36%. This increase applies to JCP&L's 2006 through 2008 tax years and is not expected to have a material impact on FirstEnergy's or JCP&L's results of operations.

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(In millions, except per share amounts)			
REVENUES:				
Electric utilities	$ 2,341	$ 2,283	$ 4,681	$ 4,550
Unregulated businesses	445	560	950	1,043
Total revenues	2,786	2,843	5,631	5,593
EXPENSES:				
Fuel and purchased power	992	933	1,990	1,828
Other operating expenses	760	873	1,653	1,757
Provision for depreciation	144	149	292	292
Amortization of regulatory assets	199	306	421	617
Deferral of new regulatory assets	(145)	(120)	(226)	(180)
General taxes	173	168	366	353
Total expenses	2,123	2,309	4,496	4,667
OPERATING INCOME	663	534	1,135	926
OTHER INCOME (EXPENSE):				
Investment income	31	47	74	88
Interest expense	(178)	(162)	(343)	(326)
Capitalized interest	7	5	14	4
Subsidiaries' preferred stock dividends	(2)	(4)	(4)	(10)
Net interest charges	(142)	(114)	(259)	(244)
INCOME TAXES	217	241	351	362
INCOME BEFORE DISCONTINUED OPERATIONS	304	179	525	320
Discontinued operations (net of income tax benefits of $1 million and $9 million in the three months and six months ended June 30, 2005, respectively) (Note 4)	-	(1)	-	18

NET INCOME	$	304	$	178	$	525	$	338
BASIC EARNINGS PER SHARE OF COMMON STOCK:								
Earnings before discontinued operations (Note 2)	$	0.92	$	0.54	$	1.59	$	0.98
Discontinued operations (Note 4)		-		-		-		0.05
Net earnings per basic share	$	0.92	$	0.54	$	1.59	$	1.03
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING		328		328		328		328
DILUTED EARNINGS PER SHARE OF COMMON STOCK:								
Earnings before discontinued operations (Note 2)	$	0.91	$	0.54	$	1.58	$	0.97
Discontinued operations (Note 4)		-		-		-		0.05
Net earnings per diluted share	$	0.91	$	0.54	$	1.58	$	1.02
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING		330		330		330		330
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$	0.45	$	0.4125	$	0.90	$	0.825

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 June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(In millions)			
NET INCOME	$ 304	$ 178	$ 525	$ 338
OTHER COMPREHENSIVE INCOME (LOSS):				
Unrealized gain (loss) on derivative hedges	36	(6)	73	1
Unrealized gain (loss) on available for sale securities	(24)	(16)	13	(24)
Other comprehensive income (loss)	12	(22)	86	(23)
Income tax expense (benefit) related to other comprehensive income	4	(6)	31	(6)
Other comprehensive income (loss), net of tax	8	(16)	55	(17)
COMPREHENSIVE INCOME	$ 312	$ 162	$ 580	$ 321

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)

	June 30, 2006	December 31, 2005
	(In millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 583	$ 64
Receivables -		
Customers (less accumulated provisions of $36 million and $38 million, respectively, for uncollectible accounts)	1,173	1,293
Other (less accumulated provisions of $27 million for uncollectible accounts in both periods)	173	205
Materials and supplies, at average cost	629	518
Prepayments and other	254	237
	2,812	2,317
PROPERTY, PLANT AND EQUIPMENT:		
In service	23,661	22,893
Less - Accumulated provision for depreciation	9,883	9,792
	13,778	13,101
Construction work in progress	642	897
	14,420	13,998
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,796	1,752
Investments in lease obligation bonds	830	890
Other	745	709
	3,371	3,351
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	5,940	6,010
Regulatory assets	4,396	4,486
Prepaid pension costs	1,013	1,023
Other	626	656
	11,975	12,175
	$ 32,578	$ 31,841
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 2,004	$ 2,043
Short-term borrowings	1,101	731
Accounts payable	682	727
Accrued taxes	750	800
Other	852	1,152
	5,389	5,453
CAPITALIZATION:		
Common stockholders’ equity -		

Common stock, $.10 par value, authorized 375,000,000 shares -				
329,836,276 shares outstanding		33		33
Other paid-in capital		7,052		7,043
Accumulated other comprehensive income (loss)		35		(20)
Retained earnings		2,385		2,159
Unallocated employee stock ownership plan common stock -				
960,651 and 1,444,796 shares, respectively		(17)		(27)
Total common stockholders' equity		9,488		9,188
Preferred stock of consolidated subsidiaries		154		184
Long-term debt and other long-term obligations		8,729		8,155
		18,371		17,527
NONCURRENT LIABILITIES:				
Accumulated deferred income taxes		2,792		2,726
Asset retirement obligations		1,160		1,126
Power purchase contract loss liability		1,123		1,226
Retirement benefits		1,355		1,316
Lease market valuation liability		809		851
Other		1,579		1,616
		8,818		8,861
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 10)				
	$	32,578	$	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)

	Six Months Ended June 30,	
	2006	**2005**
	(In millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 525	$ 338
Adjustments to reconcile net income to net cash from operating activities -		
Provision for depreciation	292	292
Amortization of regulatory assets	421	617
Deferral of new regulatory assets	(226)	(180)
Nuclear fuel and lease amortization	30	38
Deferred purchased power and other costs	(239)	(210)
Deferred income taxes and investment tax credits, net	32	62
Deferred rents and lease market valuation liability	(105)	(101)
Accrued compensation and retirement benefits	33	11
Commodity derivative transactions, net	25	(6)
Income from discontinued operations	-	(18)
Cash collateral	(55)	22
Decrease (increase) in operating assets -		
Receivables	83	(135)
Materials and supplies	(71)	(52)
Prepayments and other current assets	(81)	(159)
Increase (decrease) in operating liabilities -		
Accounts payable	(40)	104
Accrued taxes	(45)	39
Accrued interest	-	(4)
Electric service prepayment programs	(29)	226
Other	1	37
Net cash provided from operating activities	551	921
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing -		
Long-term debt	1,053	245
Short-term borrowings, net	371	386
Redemptions and Repayments -		
Preferred stock	(30)	(140)
Long-term debt	(487)	(689)
Net controlled disbursement activity	5	-

Common stock dividend payments	(296)	(270)
Net cash provided from (used for) financing activities	616	(468)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(725)	(462)
Proceeds from asset sales	59	61
Proceeds from nuclear decommissioning trust fund sales	925	608
Investments in nuclear decommissioning trust funds	(932)	(659)
Cash investments	40	35
Other	(15)	(39)
Net cash used for investing activities	(648)	(456)
Net increase (decrease) in cash and cash equivalents	519	(3)
Cash and cash equivalents at beginning of period	64	53
Cash and cash equivalents at end of period	$ 583	$ 50

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

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

We have reviewed the accompanying consolidated balance sheet of FirstEnergy Corp. and its subsidiaries as of June 30, 2006, and the related consolidated statements of income and comprehensive income for each of the three-month and six-month periods ended June 30, 2006 and 2005 and the consolidated statement of cash flows for the six-month period ended June 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
August 4, 2006

FIRSTENERGY CORP.

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

EXECUTIVE SUMMARY

Net income in the second quarter of 2006 was $304 million, or basic earnings of $0.92 per share of common stock ($0.91 diluted), compared with net income of $178 million, or basic and diluted earnings of $0.54 per share of common stock in the second quarter of 2005. FirstEnergy's earnings increase was driven primarily by increased electric sales revenues, reduced nuclear operating expenses, cost deferrals authorized by the PUCO and PPUC, and reduced transition cost amortization for the Ohio Companies. Earnings in the second quarter and the first six 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. Net income in the second quarter and the first six months of 2006 reflected net after-tax charges associated with the sale and impairment of non-core assets of $9 million (or $0.03 per share) and $11 million (or $0.03 per share), respectively. The following Non-GAAP Reconciliation displays the unusual items resulting in the difference between GAAP and non-GAAP earnings.

Reconciliation of non-GAAP to GAAP	**2006**		**2005**	
Three Months Ended June 30,	**After-tax Amount (Millions)**	**Basic Earnings Per Share**	**After-tax Amount (Millions)**	**Basic Earnings Per Share**
Earnings Before Unusual Items (Non-GAAP)	$ 313	$ 0.95	$ 233	$ 0.71
Unusual Items:				
Non-core asset sales/impairments	(9)	(0.03)	-	-
New regulatory assets - JCP&L rate settlement	-	-	16	0.05
Ohio tax write-off	-	-	(71)	(0.22)
Net Income (GAAP)	$ 304	$ 0.92	$ 178	$ 0.54
Six Months Ended June 30,				
Earnings Before Unusual Items (Non-GAAP)	$ 536	$ 1.62	$ 388	$ 1.18
Unusual Items:				
Non-core asset sales/impairments	(11)	(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
Ohio tax write-off	-	-	(71)	(0.22)
Net Income (GAAP)	$ 525	$ 1.59	$ 338	$ 1.03

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 item refers to a finite set of energy-related assets that had been previously disclosed as held for sale, a substantial portion of which has already been sold. Similarly, the NRC fine in 2005 and further litigation settlements similar to the class action settlements 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.

Total electric generation sales were up by 3.9% over last year’s second quarter. For the six months ended June 30, 2006, electric generation sales rose 3.0% compared to the same period last year. The increase for both periods was primarily due to the return of customers to the Ohio Companies from third-party suppliers that exited the Ohio marketplace. Electric distribution deliveries were down 1.8% and 2.2% for the quarter and year-to-date periods ending June 30, reflecting milder weather conditions in 2006.

FirstEnergy's generating fleet produced a second quarter record 20.3 billion KWH during the second quarter of 2006 compared to 19.1 billion KWH in the second quarter of 2005. FirstEnergy's non-nuclear fleet produced a record 13.4 billion KWH, while its nuclear facilities produced 6.9 billion KWH.

Ohio Supreme Court Decision - On May 3, 2006, the Ohio Supreme Court affirmed, in all but one aspect, the provisions of FirstEnergy's RSP for its Ohio customers. An issue related to customer pricing options was remanded to the PUCO for further consideration. The Court found that FirstEnergy must provide an alternative market-based offering to customers in addition to that which they already have through their rate stabilization price, even if the alternative is higher than that offered through the RSP. On July 20, 2006, FirstEnergy filed a notice with the PUCO to address this issue through a proposed RFP program under which Ohio customers would have the opportunity to switch to alternative generation suppliers at prices established through the RFP program. FirstEnergy also provided notice of potential termination of certain portions of the RSP in the event that the issue is not resolved within a reasonable time frame or if modifications to the RSP are not acceptable. On July 26, 2006, the PUCO directed FirstEnergy to file within 45 days its plan to address the Court's concern.

Pennsylvania Rate Matters - On May 31, 2006, the ALJ in the Met-Ed and Penelec rate transition plan filing established a procedural schedule with a goal of reaching a recommended decision in this proceeding by November 8, 2006. In accordance with this schedule, intervening parties submitted their written testimony by July 10, 2006. Ten public input hearings were held in various locations throughout the Met-Ed and Penelec service areas between June 20, 2006 and July 20, 2006.

Met-Ed and Penelec Transmission Charges - On May 4, 2006, the PPUC granted authority for Met-Ed and Penelec to defer, for accounting and financial reporting purposes, certain incremental transmission charges during 2006. The PPUC order allows Met-Ed and Penelec to defer, commencing January 1, 2006, the costs that are incremental to the levels currently reflected in the transmission component of Met-Ed's and Penelec's base rate tariffs. Recovery of the deferred costs will be considered in their pending comprehensive rate transition plan filing.

Penn RFP - On June 2, 2006, the PPUC approved the bid results for the first bid. On July 18, 2006, the second PLR bid process was held for Penn. On July 20, 2006, the PPUC approved the submissions for the second bid. As a result of bids one and two, supply has been successfully acquired for all seven tranches of the Residential Group and all six of the Small Commercial Group. However, supply has only been acquired for three of the five tranches for the Large Commercial Group. Therefore, a residual third bid is scheduled to be held on August 15, 2006 for the two remaining Large Commercial Group tranches.

Environmental Update - In June 2006, FirstEnergy finalized its air quality compliance strategy for 2006 through 2011. The program, which is expected to cost approximately $1.7 billion with the majority of those expenditures occurring between 2007 and 2009, is consistent with previous estimates and assumptions reflected in FirstEnergy's long-term financial planning for air and water quality and other environmental matters.

Share Repurchase Program - On June 20, 2006, FirstEnergy's Board of Directors authorized a share repurchase program for up to 12 million shares of common stock. At management's discretion, shares may be acquired 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 purchase any shares and the program may be terminated at any time. The 12 million shares represent 3.6% of the approximately 330 million shares of common stock currently outstanding.

OE Senior Notes Offering - On June 26, 2006, OE issued $600 million of unsecured senior notes, comprised of $250 million due 2016 and $350 million due 2036. Proceeds from these offerings were used in July 2006 to repurchase $500 million of OE's common stock from FirstEnergy, to redeem $61 million of OE's preferred stock and to reduce short-term debt. FirstEnergy primarily used the proceeds to redeem, on July 31, 2006, $400 million principal amount of its $1 billion, 5.5% Notes, Series A, in advance of the November 15, 2006 maturity date. This represents an important part of FirstEnergy's 2006 financing strategy to obtain additional financing flexibility at the holding company level and to capitalize its regulated utilities more appropriately from a regulatory context.

JCP&L Senior Notes Offering - 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.

JCP&L Securitization - On June 8, 2006, the NJBPU approved JCP&L's request to issue securitization bonds associated with BGS stranded cost deferrals. On August 4, 2006, JCP&L Transition Funding II, a wholly owned subsidiary of JCP&L, secured pricing on the issuance of $182 million of transition bonds with a weighted average interest rate of 5.5%.

New Coal Supply Agreement - On June 22, 2006, FGCO entered into a new coal supply agreement with CONSOL Energy, Inc. under which CONSOL will supply a total of more than 128 million tons of high-Btu coal to FirstEnergy for a 20-year period beginning in 2009. The new agreement replaces an existing coal supply agreement that took effect in January 2003 and ran through 2020. Under the new agreement, CONSOL will increase its coal shipments by approximately 2 million tons per year.

Ratified Contract Agreements - On May 11, 2006, employees represented by Local 270 of the Utility Workers Union of America (UWUA) voted to ratify a five-year contract agreement. UWUA Local 270 represents approximately 1,075 linemen, substation electricians, meter readers, and support personnel in the greater Cleveland area. On May 26, 2006, employees of Penelec represented by the International Brotherhood of Electrical Workers (IBEW) Local 459 ratified a three-year collective bargaining agreement. IBEW Local 459 includes 482 linemen, substation electricians, meter readers and support personnel.

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 in the states where the utility subsidiaries operate.

- **Power Supply Management Services** supplies all of the electric power needs of end-use customers through retail and wholesale arrangements, including regulated retail sales to meet 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 from the wholesale market 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 a wide range of services, including heating, ventilation, air-conditioning, refrigeration, electrical and facility control systems, high-efficiency electrotechnologies and telecommunication services. FirstEnergy is in the process of divesting 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.

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 June 30,			Six Months Ended June 30,		
	2006	2005	Increase (Decrease)	2006	2005	Increase (Decrease)
	(In millions, except per share amounts)					
Net Income (Loss) By Business Segment:						
Regulated Services	$ 229	$ 288	$ (59)	$ 440	$ 524	$ (84)
Power supply management services	135	(5)	140	175	(51)	226
Other and reconciling adjustments*	(60)	(105)	45	(90)	(135)	45
Total	$ 304	$ 178	$ 126	$ 525	$ 338	$ 187
Basic Earnings Per Share:						
Income before discontinued operations	$ 0.92	$ 0.54	$ 0.38	$ 1.59	$ 0.98	$ 0.61
Discontinued operations	-	-	-	-	0.05	(0.05)
Net earnings per basic share	$ 0.92	$ 0.54	$ 0.38	$ 1.59	$ 1.03	$ 0.56
Diluted Earnings Per Share:						
Income before discontinued operations	$ 0.91	$ 0.54	$ 0.37	$ 1.58	$ 0.97	$ 0.61
Discontinued operations	-	-	-	-	0.05	(0.05)
Net earnings per diluted share	$ 0.91	$ 0.54	$ 0.37	$ 1.58	$ 1.02	$ 0.56

* 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 second quarter and the first six months of 2006 included net losses associated with the sale and impairment of non-core assets of $9 million (or $0.03 per share) and $11 million (or $0.03 per share), respectively.

Net income in the second quarter of 2005 included a net gain resulting from the JCP&L rate settlement of $16 million (or $0.05 per share) and additional income tax expense of $71 million (or $0.22 per share) from the enactment of tax legislation in Ohio. In the first six months of 2005, net income was also increased by $0.02 per share from the combined impact of $0.07 per share of gains from the sale of non-core assets, offset by $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.

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

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

2nd Quarter 2006 Financial Results	**Regulated Services**	**Power Supply Management Services**	**Other and Reconciling Adjustments**	**FirstEnergy Consolidated**
		(In millions)		
Revenues:				
External				
Electric	$ 913	$ 1,640	$ -	$ 2,553
Other	132	38	63	233
Internal	-	-	-	-
Total Revenues	1,045	1,678	63	2,786
Expenses:				
Fuel and purchased power	-	992	-	992
Other operating expenses	283	406	71	760
Provision for depreciation	88	50	6	144
Amortization of regulatory assets	195	4	-	199
Deferral of new regulatory assets	(55)	(90)	-	(145)
General taxes	129	39	5	173
Total Expenses	640	1.401	82	2,123
Operating Income (Loss)	405	277	(19)	663
Other Income (Expense):				
Investment income	75	2	(46)	31
Interest expense	(96)	(56)	(26)	(178)
Capitalized interest	5	2	-	7
Subsidiaries' preferred stock dividends	(5)	-	3	(2)
Total Other Income (Expense)	(21)	(52)	(69)	(142)
Income taxes (benefit)	155	90	(28)	217
Income before discontinued operations	229	135	(60)	304
Discontinued operations	-	-	-	-

Net Income (Loss)	$ 229	$ 135	$ (60)	$ 304

2nd Quarter 2005 Financial Results	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)	
Revenues:				
External Electric	$ 1,087	$ 1,391	$ -	$ 2,478
Other	139	25	201	365
Internal	80	-	(80)	-
Total Revenues	1,306	1,416	121	2,843
Expenses:				
Fuel and purchased power	-	933	-	933
Other operating expenses	297	469	107	873
Provision for depreciation	138	4	7	149
Amortization of regulatory assets	306	-	-	306
Deferral of new regulatory assets	(100)	(20)	-	(120)
General taxes	132	31	5	168
Total Expenses	773	1,417	119	2,309
Operating Income (Loss)	533	(1)	2	534
Other Income (Expense):				
Investment income	47	-	-	47
Interest expense	(99)	(10)	(53)	(162)
Capitalized interest	4	1	-	5
Subsidiaries' preferred stock dividends	(4)	-	-	(4)
Total Other Income (Expense)	(52)	(9)	(53)	(114)
Income taxes (benefit)	193	(5)	53	241
Income before discontinued operations	288	(5)	(104)	179
Discontinued operations	-	-	(1)	(1)
Net Income (Loss)	$ 288	$ (5)	$ (105)	$ 178

Change Between 2nd Quarter 2006 and 2nd Quarter 2005 Financial Results Increase (Decrease)	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$ (174)	$ 249	$ -	$ 75
Other	(7)	13	(138)	(132)
Internal	(80)	-	80	-
Total Revenues	(261)	262	(58)	(57)
Expenses:				
Fuel and purchased power	-	59	-	59
Other operating expenses	(14)	(63)	(36)	(113)
Provision for depreciation	(50)	46	(1)	(5)
Amortization of regulatory assets	(111)	4	-	(107)
Deferral of new regulatory assets	45	(70)	-	(25)
General taxes	(3)	8	-	5
Total Expenses	(133)	(16)	(37)	(186)
Operating Income	(128)	278	(21)	129
Other Income (Expense):				
Investment income	28	2	(46)	(16)
Interest expense	3	(46)	27	(16)
Capitalized interest	1	1	-	2
Subsidiaries' preferred stock dividends	(1)	-	3	2
Total Other Income (Expense)	31	(43)	(16)	(28)
Income taxes	(38)	95	(81)	(24)
Income before discontinued operations	(59)	140	44	125

Discontinued operations	-	-	1	1
Net Income	$ (59)	$ 140	$ 45	$ 126

Regulated Services - Second Quarter 2006 Compared to Second Quarter 2005

Net income decreased $59 million (20.5%) to $229 million in the second quarter of 2006 compared to $288 million in the second quarter of 2005, primarily due to decreased operating revenues partially offset by lower operating expenses and taxes.

Revenues -

The decrease in total revenues resulted from the following sources:

	Three Months Ended June 30,		
Revenues By Type of Service	**2006**	**2005**	**Increase (Decrease)**
		(In millions)	
Distribution services	$ 913	$ 1,087	$ (174)
Transmission services	87	105	(18)
Internal lease revenues	-	80	(80)
Other	45	34	11
Total Revenues	$ 1,045	$ 1,306	$ (261)

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

Electric Distribution Deliveries	
Residential	(4.8)%
Commercial	(1.1)%
Industrial	0.4%
Total Distribution Deliveries	(1.8)%

The completion of the Ohio Companies' generation transition cost recovery under their respective transition plans and Penn's transition plan in 2005 was the primary reason 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 unseasonably milder weather during the second quarter of 2006. The following table summarizes major factors contributing to the $174 million decrease in distribution service revenues in the second quarter of 2006:

Sources of Change in Distribution Revenues	**Increase (Decrease)** *(In millions)*
Changes in customer usage	$ (54)
Ohio shopping incentives	58
Changes in prices:	
Rate mix and other	(178)
Net Decrease in Distribution Revenues	$ (174)

The decrease in internal 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.

Expenses-

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

- Other operating expenses were $14 million lower in 2006 due, in part, to the following factors:

1) The absence in 2006 of expenses for ancillary service refunds to third parties of $6 million in 2005 due to the RCP, which provides that alternate suppliers of ancillary services now bill customers directly for those services;

2) A $27 million decrease in employee and contractor costs resulting from lower storm-related expenses, 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

3) An $18 million increase due in part to insurance premium costs, financing fees and other administrative costs.

- Lower depreciation expense of $50 million that resulted from the impact of the generation asset transfers;

- Reduced amortization of regulatory assets of $111 million principally due to the completion of Ohio generation transition cost recovery and Penn's transition plan in 2005; and

- General taxes decreased by $3 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 the 2005 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 -

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 second quarter of 2006 was partially offset by the absence in 2006 of the majority of nuclear decommissioning trust income which is now included in the power supply management services segment.

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

Net income for this segment was $135 million in the second quarter of 2006 compared to a net loss of $5 million in the same period last year. An improvement in the gross generation margin was partially offset by higher depreciation, general taxes and interest expense resulting from the generation asset transfers.

Revenues -

Electric generation sales revenues increased $224 million in the second 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 Ohio marketplace, and higher unit prices resulting from the 2006 rate stabilization and fuel recovery charges. Additional retail sales reduced energy available for sale to the wholesale market. Increased transmission revenues reflected new revenues of approximately $27 million under the MISO transmission rider that began in the first quarter of 2006.

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

Revenues By Type of Service	Three Months Ended June 30, 2006	2005	Increase (Decrease)
		(In millions)	
Electric Generation Sales:			
Retail	$ 1,285	$ 989	$ 296
Wholesale	253	325	(72)
Total Electric Generation Sales	1,538	1,314	224
Transmission	134	93	41
Other	6	9	(3)
Total Revenues	$ 1,678	$ 1,416	$ 262

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 customer usage	$ 76
Increased prices	220
	296
Wholesale:	
Effect of 8.4% decrease in KWH sales	(27)
Lower prices	(45)
	(72)
Net Increase in Electric Generation Sales	$ 224

Expenses -

Total operating expenses decreased by $16 million. The decrease was due to the following factors:

- Lower non-fuel operating expenses of $63 million reflect the absence in 2006 of generating lease rents of $80 million in 2005 due to the generation asset transfers, partially offset by higher transmission expenses of $11 million related to the transmission revenues discussed above; and

- The $70 million increase in the deferral of new regulatory assets represents 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 deferrals in 2006 also include the Ohio RCP fuel deferral of $29 million.

The above decreases were partially offset by the following:

- Higher fuel and purchased power costs of $59 million, including increased fuel costs of $23 million - coal costs increased $40 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 $20 million. Purchased power costs increased $36 million due to higher prices and increased 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	$ 5
Change due to volume consumed	18
	23
Purchased Power:	
Change due to increased unit costs	53
Change due to volume purchased	2
Increase in NUG costs deferred	(19)
	36
Net Increase in Fuel and Purchased Power Costs	$ 59

- Increased depreciation expenses of $46 million resulted principally from the generation asset transfers; and

- Higher general taxes of $8 million due to additional property taxes resulting from the generation asset transfers.

Other Income and Expense -

- Investment income in the second quarter of 2006 increased by $2 million over the prior year period primarily due to nuclear decommissioning trust investments acquired through the generation asset transfers; and

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

Other - Second Quarter 2006 Compared to Second 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 $45 million increase to FirstEnergy’s net income in the second quarter of 2006 compared to the same quarter of 2005. The increase was primarily due to the absence of an adjustment from the effect of Ohio tax legislation in June 2005, which resulted in additional 2005 tax expenses of $71 million, and a $3 million gain related to interest rate swap financing arrangements. These increases were partially offset by a $5 million reduction in investment income, non-core asset sales gains/impairments of $9 million and a $7 million reduction in gas commodity trading results.

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

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

First Six Months of 2006 Financial Results	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$ 1,848	$ 3,216	$ -	$ 5,064
Other	280	81	206	567
Internal	-	-	-	-
Total Revenues	2,128	3,297	206	5,631
Expenses:				
Fuel and purchased power	-	1,990	-	1,990
Other operating expenses	582	856	215	1,653
Provision for depreciation	184	96	12	292
Amortization of regulatory assets	412	9	-	421
Deferral of new regulatory assets	(110)	(116)	-	(226)
General taxes	269	84	13	366
Total Expenses	1,337	2,919	240	4,496
Operating Income (Loss)	791	378	(34)	1,135
Other Income (Expense):				
Investment income	137	17	(80)	74
Interest expense	(190)	(109)	(44)	(343)
Capitalized interest	8	6	-	14
Subsidiaries' preferred stock dividends	(7)	-	3	(4)
Total Other Income (Expense)	(52)	(86)	(121)	(259)
Income taxes (benefit)	299	117	(65)	351
Income before discontinued operations	440	175	(90)	525
Discontinued operations	-	-	-	-
Net Income (Loss)	$ 440	$ 175	$ (90)	$ 525

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First Six Months of 2005 Financial Results	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$ 2,169	$ 2,746	$ -	$ 4,915
Other	273	47	358	678
Internal	158	-	(158)	-
Total Revenues	2,600	2,793	200	5,593
Expenses:				
Fuel and purchased power	-	1,828	-	1,828
Other operating expenses	625	968	164	1,757
Provision for depreciation	261	17	14	292
Amortization of regulatory assets	617	-	-	617
Deferral of new regulatory assets	(160)	(20)	-	(180)
General taxes	274	67	12	353
Total Expenses	1,617	2,860	190	4,667
Operating Income (Loss)	983	(67)	10	926
Other Income (Expense):				
Investment income	88	-	-	88
Interest expense	(194)	(16)	(116)	(326)
Capitalized interest	7	(3)	-	4
Subsidiaries' preferred stock dividends	(10)	-	-	(10)
Total Other Income (Expense)	(109)	(19)	(116)	(244)
Income taxes (benefit)	350	(35)	47	362
Income before discontinued operations	524	(51)	(153)	320
Discontinued operations	-	-	18	18
Net Income (Loss)	$ 524	$ (51)	$ (135)	$ 338

Change Between First Six Months of 2006 and First Six Months of 2005 Financial Results - Increase (Decrease)	Regulated Services	Power Supply Management Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				

External								
Electric	$	(321)	$	470	$	-	$	149
Other		7		34		(152)		(111)
Internal		(158)		-		158		-
Total Revenues		(472)		504		6		38
Expenses:								
Fuel and purchased power		-		162		-		162
Other operating expenses		(43)		(112)		51		(104)
Provision for depreciation		(77)		79		(2)		-
Amortization of regulatory assets		(205)		9		-		(196)
Deferral of new regulatory assets		50		(96)		-		(46)
General taxes		(5)		17		1		13
Total Expenses		(280)		59		50		(171)
Operating Income		(192)		445		(44)		209
Other Income (Expense):								
Investment income		49		17		(80)		(14)
Interest expense		4		(93)		72		(17)
Capitalized interest		1		9		-		10
Subsidiaries' preferred stock dividends		3		-		3		6
Total Other Income (Expense)		57		(67)		(5)		(15)
Income taxes		(51)		152		(112)		(11)
Income before discontinued operations		(84)		226		63		205
Discontinued operations		-		-		(18)		(18)
Net Income	$	(84)	$	226	$	45	$	187

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

Net income decreased $84 million (16.0%) to $440 million in the first six months of 2006 compared to $524 million in the first six months of 2005, primarily due to decreased operating revenues partially offset by lower operating expenses and taxes.

Revenues -

The decrease in total revenues resulted from the following sources:

	Six Months Ended June 30,		
Revenues By Type of Service	**2006**	**2005**	**Increase (Decrease)**
		(In millions)	
Distribution services	$ 1,848	$ 2,169	$ (321)
Transmission services	181	197	(16)
Internal lease revenues	-	158	(158)
Other	99	76	23
Total Revenues	$ 2,128	$ 2,600	$ (472)

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

Electric Distribution Deliveries	
Residential	(3.6)%
Commercial	(1.6)%
Industrial	(1.2)%
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 was the primary reason 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 unseasonably milder weather during the first six months of 2006 as compared to the same period in 2005. The following table summarizes major factors contributing to the $321 million decrease in distribution service revenues in the first six months of 2006:

Sources of Change in Distribution Revenues	**Increase (Decrease)**
	(In millions)
Changes in customer usage	$ (102)
Ohio shopping incentives	100

Changes in prices:		
Rate mix and other		(319)
Net Decrease in Distribution Revenues	$	(321)

The decrease in internal 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.

Expenses-

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

· Other operating expenses were $43 million lower in 2006 due, in part, to the following factors:

1) The absence in 2006 of expenses for ancillary service refunds to third parties of $13 million in 2005 due to the RCP, which provides that alternate suppliers of ancillary services now bill customers directly for those services;

2) The absence in 2006 of receivables factoring discount expenses of approximately $6 million incurred in 2005; and

3) A $33 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.

- Lower depreciation expense of $77 million resulted from the impact of the generation asset transfers;

- Reduced amortization of regulatory assets of $205 million resulted principally from the completion of Ohio generation transition cost recovery and Penn's transition plan in 2005; and

- General taxes decreased by $5 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 the 2005 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 six months of 2006 is partially offset by the absence in 2006 of the majority of nuclear decommissioning trust income which is now included in the power supply management services segment; and

- Subsidiaries' preferred stock dividends decreased by $3 million in 2006 due to redemption activity in 2005.

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

Net income for this segment was $175 million in the first six months of 2006 compared to a net loss of $51 million in the same period last year. An improvement in the gross generation margin was partially offset by higher depreciation, general taxes and interest expense resulting from the generation asset transfers.

Revenues -

Electric generation sales revenues increased $423 million in the first six months of 2006 compared to the same period in 2005. This increase primarily resulted from a 7.2% increase in retail KWH sales, mostly due to the return of customers as a result of third-party suppliers leaving the Ohio marketplace, and higher unit prices resulting from the RSP and RCP that were effective in 2006. The higher retail sales reduced energy available for sale to the wholesale market. Increased transmission revenues reflected new revenues of approximately $54 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:

	Six Months Ended June 30,		
			Increase
Revenues By Type of Service	2006	2005	(Decrease)
		(In millions)	

Electric Generation Sales:			
Retail	$ 2,524	$ 1,969	$ 555
Wholesale	488	620	(132)
Total Electric Generation Sales	3,012	2,589	423
Transmission	262	182	80
Other	23	22	1
Total Revenues	$ 3,297	$ 2,793	$ 504

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 7.2% increase in customer usage	$	141
Change in prices		414
		555
Wholesale:		
Effect of 11.9% decrease in KWH sales		(74)
Change in prices		(58)
		(132)
Net Increase in Electric Generation Sales	$	423

Expenses -

Total operating expenses increased by $59 million. The increase was due to the following factors:

- Higher fuel and purchased power costs of $162 million, including increased fuel costs of $73 million - coal costs increased $81 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 $16 million. Purchased power costs increased $89 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	$	37
Change due to volume consumed		36
		73
Purchased Power:		
Change due to increased unit costs		130
Change due to volume purchased		(31)
		(10)

Increase in NUG costs deferred		89
Net Increase in Fuel and Purchased Power Costs	$	162

- Higher transmission expenses of $42 million related to the transmission revenues discussed above;

- Increased depreciation expenses of $79 million, resulting principally from the generation asset transfers; and

- Higher general taxes of $17 million due to additional property taxes resulting from the generation asset transfers.

Partially offsetting these higher costs were lower non-fuel operating expenses of $112 million, which reflect the absence in 2006 of generating asset lease rents of $158 million charged in 2005 due to the generation asset transfers. Also absent in 2006 were: (1) 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 settlement; and (2) a $3.5 million penalty related to the Davis-Besse outage.

The $96 million increase in the deferral of new regulatory assets represents PJM/MISO costs incurred that are expected to be recovered from customers through future rates. The deferrals also include the Ohio RCP fuel deferral of $51 million.

Other Income and Expense -

- Investment income in the first six months of 2006 was $17 million higher primarily due to nuclear decommissioning trust investments acquired through the generation asset transfers; and

- Interest expense increased by $93 million, primarily due to interest on the associated company notes payable from the generation asset transfers. This increase was partially offset by an additional $9 million of capitalized interest.

Other - First Six Months of 2006 Compared to First Six 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 $45 million increase to FirstEnergy's net income in the first six months of 2006 compared to the same period of 2005. The increase was primarily due to the absence of the write-off of income tax benefits due to the 2005 change in Ohio tax legislation, the financing swap gain described in the Other - Second Quarter 2006 Compared to Second Quarter 2005 results analysis above and a $3 million increase in other investment income in the first half of 2006. These increases were partially offset by the FSG impairment charge and gas commodity trading results reduction and the absence of 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 for the six months ended June 30, 2005:

	(In millions)	
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

During 2006 and thereafter, FirstEnergy expects to meet its 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 $2.0 billion of short-term financing under a revolving credit facility which expires in 2010, 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 such facility. FirstEnergy paid cash dividends to common shareholders of $148 million in each quarter of 2006 totaling $296 million for the first six months of 2006. FirstEnergy received $148 million of cash dividends from its subsidiaries in the first quarter of 2006 and borrowed against the $2.0 billion revolving credit facility for the second quarter dividend payment. In July, FirstEnergy received $500 million from OE as a result of OE’s repurchase of common stock. There are no material restrictions on the payment of cash dividends by FirstEnergy's subsidiaries.

As of June 30, 2006, FirstEnergy had $583 million of cash and cash equivalents compared with $64 million as of December 31, 2005. Temporary cash investments of $544 million were used principally to redeem $400 million of the outstanding $1 billion of FirstEnergy’s 5.5% notes in July 2006, in advance of their November 15, 2006 maturity date. The remainder was used in July 2006 to redeem $61 million of OE’s preferred stock and reduce short-term borrowings. The major sources for 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 $551 million and $921 million in the first six months of 2006 and 2005, respectively, summarized as follows:

	Six Months Ended June 30,	
Operating Cash Flows	**2006**	**2005**
	(In millions)	
Cash earnings *	$ 771	$ 827
Working capital and other	(220)	94
Net cash provided from operating activities	$ 551	$ 921

* 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 are a useful financial measure because it provides investors and management with an additional means of evaluating its cash-based operating performance. The following table reconciles cash earnings with net income.

	Six Months Ended June 30,	
Reconciliation of Cash Earnings	**2006**	**2005**
	(In millions)	
Net income (GAAP)	$ 525	$ 338
Non-cash charges (credits):		
Provision for depreciation	292	292
Amortization of regulatory assets	421	617
Deferral of new regulatory assets	(226)	(180)
Nuclear fuel and lease amortization	30	38
Deferred purchased power and other costs	(239)	(210)
Deferred income taxes and investment tax credits	32	62
Deferred rents and lease market	(105)	(101)

valuation liability		
Accrued compensation and retirement benefits	33	11
Income from discontinued operations	-	(18)
Other non-cash expenses	8	(22)
Cash earnings (Non-GAAP)	$ 771	$ 827

Net cash provided from operating activities decreased by $370 million in the first six months of 2006 compared to the first six months of 2005 primarily due to a $314 million decrease from working capital and a $56 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 $144 million for payables primarily caused by higher fuel and purchased power costs, and $77 million of cash collateral returned to suppliers. These decreases were partially offset by an increase in cash provided from the settlement of receivables of $218 million, reflecting increased electric sales revenues.

Cash Flows From Financing Activities

In the first six months of 2006, cash provided from financing activities was $616 million compared to cash used for financing activities of $468 million in the first six months of 2005. The following table summarizes security issuances and redemptions.

Securities Issued or Redeemed	Six Months Ended June 30, 2006	2005
	(In millions)	
New issues		
Pollution control notes	$ 253	$ 245
Secured notes	200	-
Unsecured notes	600	-
	$ 1,053	$ 245
Redemptions		
First mortgage bonds	$ 1	$ 178
Pollution control notes	307	247
Secured notes	179	49
Long-term revolving credit	-	215
Preferred stock	30	140
	$ 517	$ 829
Short-term borrowings, net	$ 371	$ 386

FirstEnergy had approximately $1.1 billion of short-term indebtedness as of June 30, 2006 compared to approximately $731 million as of December 31, 2005. This increase was due primarily to higher capital expenditures and common dividend payments compared to Net Cash from Operating Activities during the first half of the year. Available bank borrowing capability as of June 30, 2006 included the following:

Borrowing Capability	*(In millions)*
Short-term credit facilities[(1)]	$ 2,120
	550

Accounts receivable financing facilities		
Utilized		(1,096)
LOCs		(123)
Net	$	1,451

[1] A $2 billion revolving credit facility that expires in 2010 is available in various amounts to FirstEnergy and certain of its subsidiaries. A $100 million revolving credit facility that expires in December 2006 and a $20 million uncommitted line of credit facility that expires in September 2006 are both available to FirstEnergy only.

As of June 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 $735 million and $576 million, respectively, as of June 30, 2006. Under the provisions of its senior note indenture, JCP&L may issue additional FMB only as collateral for senior notes. As of June 30, 2006, JCP&L had the capability to issue $610 million of additional senior notes upon the basis of FMB collateral.

Based upon applicable earnings coverage tests in their respective charters, OE, Penn, TE and JCP&L could issue a total of $5 billion of preferred stock (assuming no additional debt was issued) as of June 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 on July 7, 2006, the applicable earnings coverage test is inoperative for OE. Accordingly, as of July 7, 2006, Penn, TE and JCP&L could issue a total of $2.6 billion of preferred stock (assuming no additional debt was issued). 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 June 30, 2006, approximately $1 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 June 30, 2006, OE had approximately $400 million of capacity remaining unused under its existing shelf registration for unsecured debt securities.

FirstEnergy's working capital and short-term borrowing needs are met principally with a $2 billion five-year revolving credit facility (included in the table above). Borrowings under the facility are available to each borrower separately and mature on the earlier of 364 days from the date of borrowing or the June 16, 2010 commitment expiration date.

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

Borrower	Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations[1]
	(In millions)	
FirstEnergy	$ 2,000	$ 1,500
OE	500	500
Penn	50	44
CEI	250	500
TE	250	500
JCP&L	425	412
Met-Ed	250	300
Penelec	250	300
FES	(2)	n/a
ATSI	(2)	26

(1) As of June 30, 2006.

(2) 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- LC b 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 ($249 million unused as of June 30, 2006) of accounts receivable financing facilities for OE, CEI, TE, Met-Ed, Penelec and Penn, are intended to provide liquidity to meet short-term working capital requirements for FirstEnergy and its subsidiaries.

Under the revolving credit facility, borrowers may request the issuance of 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 $1.5 billion as of June 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 June 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	40%
Penn	34%
CEI	49%
TE	28%
JCP&L	29%
Met-Ed	38%
Penelec	36%

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 six months of 2006 was approximately 4.86% 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 July 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-
	Preferred stock	BB+	Ba2	BB
Penn	Senior secured	BBB+	Baa1	BBB+
	Senior unsecured(1)	BBB-	Baa2	BBB
	Preferred stock	BB+	Ba1	BBB-
JCP&L	Senior secured	BBB+	Baa1	BBB+
	Preferred stock	BB+	Ba1	BBB-
Met-Ed	Senior secured	BBB+	Baa1	BBB+
	Senior unsecured	BBB	Baa2	BBB

Penelec	Senior unsecured	BBB	Baa2	BBB

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

On 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 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%) in April and May 2006. These refinancings were undertaken in furtherance of FirstEnergy's intra-system generation asset transfers (see Note 14). 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 debt.

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 8, 2006, the NJBPU approved JCP&L's request to issue securitization bonds associated with BGS stranded cost deferrals. On August 4, 2006, JCP&L Transition Funding II, a wholly owned subsidiary of JCP&L, secured pricing on the issuance of $182 million of transition bonds with a weighted average interest rate of 5.5%.

On June 20, 2006, FirstEnergy's Board of Directors authorized a share repurchase program for up to 12 million shares of common stock. At management's discretion shares may be acquired 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 purchase any shares and the program may be terminated at any time. The 12 million shares represent 3.6% of the common stock currently outstanding.

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. This offering represented an important part of FirstEnergy's 2006 financing strategy to obtain additional financing flexibility at the holding company level and to capitalize the 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 six months ended June 30, 2006 and 2005 by segment:

Summary of Cash Flows Used for Investing Activities Sources (Uses)	**Property Additions**	**Investments**	**Other**	**Total**
		(In millions)		
Six Months Ended June 30, 2006				
Regulated services	$ (356)	$ 66	$ (9)	$ (299)
Power supply management services	(347)	(24)	1	(370)
Other	(2)	1	(5)	(6)
Reconciling items	(20)	37	10	27
Total	$ (725)	$ 80	$ (3)	$ (648)
Six Months Ended June 30, 2005				
Regulated services	$ (299)	$ 9	$ (7)	$ (297)
Power supply management services	(147)	14	(5)	(138)
Other	(5)	4	(19)	(20)
Reconciling items	(11)	10	-	(1)
Total	$ (462)	$ 37	$ (31)	$ (456)

Net cash used for investing activities in the first six months of 2006 increased by $192 million compared to the first six months of 2005. The increase was principally due to a $263 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 $44 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.

During the last half of 2006, capital requirements for property additions and capital leases are expected to be approximately $582 million. FirstEnergy and the Companies have additional requirements of approximately $1.2 billion 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 $745 million, of which approximately $164 million applies to 2006. During the same period, FirstEnergy's nuclear fuel investments are expected to be reduced by approximately $564 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 June 30, 2006, FirstEnergy's maximum exposure to potential future payments under outstanding guarantees and other assurances totaled approximately $3.5 billion, as summarized below:

Guarantees and Other Assurances		Maximum Exposure *(In millions)*
FirstEnergy Guarantees of Subsidiaries:		
Energy and Energy-Related Contracts[1]	$	814
Other[2]		1,081
		1,895
Surety Bonds		146
LOC[3][4]		1,471
Total Guarantees and Other Assurances	$	3,512

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

(2) Issued for various terms.

(3) Includes $122 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 Perry 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 subsidiary financing principally for the acquisition of 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 June 30, 2006, FirstEnergy's maximum exposure under these collateral provisions was $501 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 June 30, 2006) which is renewable and declines yearly based upon the senior outstanding debt of TEBSA.

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 $1.2 billion as of June 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 certain power purchase agreements with NUG entities that were structured pursuant to the Public Utility Regulatory Policies Act of 1978. These non-trading contracts are 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 with 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 six months ended June 30, 2006 is summarized in the following table:

Increase (Decrease) in the Fair Value of Commodity Derivative Contracts	Three Months Ended June 30, 2006			Six Months Ended June 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	$ (1,129)	$ (5)	$ (1,134)	$ (1,170)	$ (3)	$ (1,173)
New contract value when entered	-	-	-	-	-	-

Additions/change in value of existing contracts		(17)		(3)		(20)		(30)		(10)		(40)
Change in techniques/assumptions		-		-		-		-		-		-
Settled contracts		78		4		82		132		9		141
Other		(13)		-		(13)		(13)		-		(13)
Outstanding net liability at end of period(1)		(1,081)		(4)		(1,085)		(1,081)		(4)		(1,085)
Non-commodity Net Liabilities at End of Period:												
Interest Rate Swaps(2)		-		(25)		(25)		-		(25)		(25)
Net Liabilities - Derivative Contracts at End of Period	$	(1,081)	$	(29)	$	(1,110)	$	(1,081)	$	(29)	$	(1,110)
Impact of Changes in Commodity Derivative Contracts(3)												
Income Statement effects (pre-tax)	$	(1)	$	-	$	(1)	$	(3)	$	-	$	(3)
Balance Sheet effects:												
Other comprehensive income (pre-tax)	$	-	$	1	$	1	$	-	$	(1)	$	(1)
Regulatory assets (net)	$	(62)	$	-	$	(62)	$	(105)	$	-	$	(105)

(1) Includes $1,078 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 June 30, 2006 as follows:

Balance Sheet Classification	**Non-Hedge**	**Hedge**	**Total**
		(In millions)	
Current-			
Other assets	$ 1	$ 1	$ 2
Other liabilities	(6)	(4)	(10)
Non-Current-			
Other deferred charges	47	29	76
Other noncurrent liabilities	(1,123)	(55)	(1,178)
Net liabilities	$ (1,081)	$ (29)	$ (1,110)

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 June 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]	$ (1)	$ (1)	$ -	$ -	$ -	$ -	$ (2)
Other external sources[3]	(144)	(251)	(220)	-	-	-	(615)
Prices based on models	-	-	-	(161)	(138)	(169)	(468)
Total[4]	$ (145)	$ (252)	$ (220)	$ (161)	$ (138)	$ (169)	$ (1,085)

(1) For the last two quarters of 2006.
(2) Exchange traded.
(3) Broker quote sheets.
(4) Includes $1,078 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 June 30, 2006. Based on derivative contracts held as of June 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 six 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 maturity of each respective hedged security as increased interest expense. As of June 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 6.68%.

	June 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	$ (4)	100	$ 2008	$ (3)
	50	2010	(2)	50	2010	-
	-	2011	-	50	2011	-
	300	2013	(17)	450	2013	(4)
	150	2015	(16)	150	2015	(9)
	-	2016	-	150	2016	-
	50	2025	(4)	50	2025	(1)
	100	2031	(11)	100	2031	(5)
	$ 750		$ (54)	$ 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 six months of 2006, FirstEnergy revised the tenor and timing of its financing plans, and in the second quarter 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 respective forward swaps. As of June 30, 2006, FirstEnergy had outstanding forward swaps with an aggregate notional amount of $550 million and an aggregate fair value of $29 million.

	June 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	$ 1	$ 25	2015	$ -
	300	2016	14	600	2016	2
	50	2017	3	25	2017	-
	125	2018	8	275	2018	1
	50	2020	3	50	2020	-
	$ 550		$ 29	$ 975		$ 3

Equity Price Risk

Included in nuclear decommissioning trusts are marketable equity securities carried at their market value of approximately $1.1 billion as of June 30, 2006 and December 31, 2005. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $111 million reduction in fair value as of June 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 June 30, 2006, the largest credit concentration with one party (currently rated investment grade) represented 8.1% 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 June 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 $237 million as of June 30, 2006. The following table discloses the regulatory assets by company and by source:

Regulatory Assets*	June 30, 2006	December 31, 2005	Increase (Decrease)
		(In millions)	
OE	$ 756	$ 775	$ (19)
CEI	859	862	(3)
TE	267	287	(20)
JCP&L	2,122	2,227	(105)
Met-Ed	359	310	49
ATSI	33	25	8
Total	$ 4,396	$ 4,486	$ (90)

* Penn had net regulatory liabilities of approximately $59 million as of June 30, 2006 and December 31, 2005. Penelec had net regulatory liabilities of approximately $135 million and $163 million as of June 30, 2006 and

December 31, 2005, respectively. These net regulatory liabilities are included in Other Noncurrent Liabilities on the Consolidated Balance Sheets.

Regulatory assets by source are as follows:

Regulatory Assets By Source	**June 30, 2006**	**December 31, 2005**	**Increase (Decrease)**
		(In millions)	
Regulatory transition costs	$ 3,365	$ 3,576	$ (211)
Customer shopping incentives	644	884	(240)
Customer receivables for future income taxes	219	217	2
Societal benefits charge	19	29	(10)
Loss on reacquired debt	40	41	(1)
Employee postretirement benefits costs	51	55	(4)
Nuclear decommissioning, decontamination and spent fuel disposal costs	(124)	(126)	2
Asset removal costs	(163)	(365)	202
Property losses and unrecovered plant costs	24	29	(5)
MISO/PJM transmission costs	135	91	44
Fuel costs - RCP	51	-	51
Distribution costs - RCP	81	-	81
JCP&L reliability costs	19	23	(4)
Other	35	32	3
Total	$ 4,396	$ 4,486	$ (90)

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 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 entities. The new FERC rule referred to above, further provides for reorganizing regional reliability organizations (regional entities) that would replace the current regional councils and for rearranging the 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 NERC as the ERO to implement the provisions of Section 215 of the Federal Power Act. The FERC directed NERC to make a compliance filing within ninety days addressing such issues as the regional delegation agreements.

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, on the current NERC Version O reliability standards with some additional 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 chairman has indicated that the FERC intends to act on the proposed reliability standards by issuing a NOPR in September of this year. Interested parties will be given the opportunity to comment on the NOPR. NERC has requested an effective date of January 1, 2007 for the proposed reliability standards.

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.

FirstEnergy believes that it is in compliance with all current NERC reliability standards. However, it is expected that the FERC will adopt stricter reliability standards than those contained in the current NERC 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 September 28, 2005, the Supreme Court of Ohio heard oral arguments on the appeals. 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 one matter back to the PUCO for further consideration of the issue as to whether the RSP, as adopted by the PUCO, provided for sufficient means for customer participation in the competitive marketplace. On May 12, 2006, the Ohio Companies filed a Motion for Reconsideration with the Supreme Court of Ohio which was denied by the Court on June 21, 2006. 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.

The Ohio Companies filed an application and stipulation with the PUCO on September 9, 2005 seeking approval of the RCP. 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	$ 177	$ 95	$ 86	$ 358
2007	180	113	90	383
2008	208	130	111	449
2009	-	211	-	211
2010	-	266	-	266
Total Amortization	**$ 565**	**$ 815**	**$ 287**	**$ 1,667**

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 are due on August 4, 2006. Appellants’ Reply Briefs will then be due on August 24, 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 May 1, 2006, the Ohio Companies filed a modification to the rider to determine revenues ($141 million) from July 2006 through June 2007.

The second application sought authority to defer costs associated with transmission and ancillary service related costs incurred during the period 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 unable to predict when a decision may be issued.

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

Pennsylvania

As of June 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 $335 million and $57 million, respectively. Penelec's $57 million is subject to the pending resolution of taxable income issues associated with NUG trust fund proceeds. The PPUC is reviewing a January 2006 change in Met-Ed’s and Penelec’s NUG purchase power stranded cost accounting methodology. If the PPUC orders Met-Ed and Penelec to reverse the change in accounting methodology, this would result in a pre-tax loss of $10.3 million for Met-Ed.

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 below. On May 4, 2006, the PPUC approved the modified request. Accordingly, Met-Ed and Penelec have deferred approximately $46 million and $12 million, respectively, representing transmission costs that were incurred from January 1, 2006 through June 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 below.

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;

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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.

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, 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 the 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 are scheduled for late August 2006 and a PPUC decision is expected early in the first quarter of 2007.

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. To the extent that an affiliate of Penn supplies a portion of the PLR load included in the RFP, authorization to make the affiliate sale must be obtained from the FERC. 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 to obtain Penn's power supply requirements after 2006 through two separate solicitations. An initial solicitation was held for Penn in May 2006 with all tranches fully subscribed. On June 2, 2006, the PPUC approved the bid results for the first solicitation. 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 only acquired for three of the five tranches for the Large Commercial Group. On July 20, 2006, the PPUC approved the submissions for the second bid. A residual solicitation is scheduled to be held on August 15, 2006 for the two remaining Large Commercial Group tranches. Acceptance of the winning bids is subject to approval by the PPUC.

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 its recovery of certain PLR costs via a reconciliation mechanism and its 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 June 30, 2006, the accumulated deferred cost balance totaled approximately $638 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 4, 2006, JCP&L Transition Funding II, a wholly owned subsidiary of JCP&L, secured pricing on the issuance of $182 million of transition bonds with a weighted average interest rate of 5.5%.

On December 2, 2005, JCP&L filed a 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 cost incurred since July 31, 2003. On March 29, 2006, a pre-hearing conference was held with the presiding ALJ. A schedule for the proceeding was established including a discovery period and evidentiary hearings scheduled for September 2006.

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 last of the quarterly reliability reports was submitted on June 12, 2006. As of June 30, 2006, there were no performance penalties issued by the NJBPU.

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. The NJBPU Staff issued a 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. JCP&L is unable to predict the outcome of this proposal.

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 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 FERC has ordered the Presiding Judge to issue an initial decision by August 11, 2006.

On November 1, 2004, ATSI filed with 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 $33 million deferred as of June 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 21, 2006, the FERC issued an order stating that it needs more time to consider the matter. In light of that order, there is no time period by which the FERC must act on the pending rehearing request. On July 14, 2006, the FERC accepted the ATSI's June 13, 2006 compliance filing. The estimated annual revenues to ATSI from the VMEP cost recovery is $12 million.

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 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. The Companies, as part of the Responsible Pricing Alliance, intend to submit a brief on exceptions within thirty days of the initial decision. Following submission of reply exceptions, the case is expected to 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. The PPUC approved Penn's plan with modifications on April 20, 2006 to use an RFP process to obtain its power supply requirements after 2006 through two separate solicitations. An initial solicitation was held for Penn in May 2006 with all tranches fully subscribed. On June 2, 2006, the PPUC approved the bid results for the first solicitation. 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 only acquired for three of the five tranches for the Large Commercial Group. On July 20, 2006, the PPUC approved the submission for the second bid. A residual solicitation is scheduled to be held on August 15, 2006 for the two remaining Large Commercial Group tranches. Acceptance of the winning bids is subject to approval by the PPUC.

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, aproved 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. The procedural schedule has been suspended pending negotiations among the parties.

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 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 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 has been scheduled for August 8, 2006 to discuss the alleged violations with the EPA.

FirstEnergy believes it is complying 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 from 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 State Implementation Plans 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 the Companies operate affected facilities.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. 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 this approach is based on output, new and non-emitting generating facilities, including renewables and nuclear, would be entitled to their proportionate share of the allowances. Consequently, FirstEnergy would be disadvantaged if these model rules were implemented 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 (the primary portion of which is expected to be spent in the 2008 to 2011 time period). 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 sulfur dioxide emissions. The settlement agreement also requires OE and Penn to spend up to $25 million toward environmentally beneficial projects, which include wind energy purchased power agreements over a 20-year term. OE and Penn agreed to pay a civil penalty of $8.5 million. Results for the first quarter of 2005 included the penalties 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 the Companies is lower than many regional competitors due to the Companies' diversified generation sources which include low or non-CO_2 emitting gas-fired and nuclear generators.

Regulation of Hazardous Waste

The Companies have been named as PRPs at waste disposal sites, which may require cleanup under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site are liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of June 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 $70 million have been accrued through June 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 the 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 outage. 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. FirstEnergy filed a Motion to Dismiss on June 13, 2006. It is currently expected that this case will be summarily dismissed, although the Motion is still pending. On March 7, 2006, the PUCO issued a ruling 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. These motions are pending. Additionally, on June 23, 2006, one of the insurance carrier complainants filed an appeal with the Ohio Supreme Court over the PUCO's denial of their motion for rehearing on the issue of the admissibility of the Task Force Report and the dismissal of FirstEnergy Corp. as a respondent. Briefing is expected to be completed on this appeal by mid-September. It is unknown when the Supreme Court will rule on the appeal. No estimate of potential liability is available for any of these cases.

In addition to the above proceedings, FirstEnergy was named in a complaint filed in Michigan State Court by an individual who is not a customer of any FirstEnergy company. FirstEnergy's motion to dismiss the matter was denied on June 2, 2006. FirstEnergy has since filed an appeal, which is pending. A responsive pleading to this matter has been filed. Also, the complaint has been amended to include an additional party. No estimate of potential liability has been undertaken in this matter.

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 First Energy'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 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.

As of December 16, 2005, NGC acquired ownership of the nuclear generation assets transferred from OE, CEI, TE and Penn 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.

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.

JCP&L's bargaining unit employees filed a grievance challenging JCP&L's 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties' collective bargaining agreement. At the conclusion of the June 1, 2005 hearing, the Arbitrator decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the Arbitrator issued an opinion to award approximately $16 million to the bargaining unit employees. On February 6, 2006, the federal court granted a Union motion to dismiss JCP&L's appeal of the award as premature. JCP&L will file its 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 described above. 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 60 days from the denial of rehearing to appeal the PUCO’s decision.

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

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.

SUBSEQUENT EVENTS

Pennsylvania Law Change

On July 12, 2006, the Governor of Pennsylvania signed House Bill 859, which increases the net operating loss deduction allowed for the corporate net income tax from $2 million to $3 million, or the greater of 12.5% of taxable income. As a result, FirstEnergy expects to recognize a net operating loss benefit of $2.2 million (net of federal tax benefit) in the third quarter of 2006.

New Jersey Law Change

On July 8, 2006, the Governor of New Jersey signed tax legislation that increased the current New Jersey Corporate Business tax by an additional 4% surtax, which increases the effective tax from 9% to 9.36%. This increase applies to JCP&L’s 2006 through 2008 tax years and is not expected to have a material impact on FirstEnergy’s or JCP&L’s results of operations.

OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
STATEMENTS OF INCOME		*(In thousands)*		
REVENUES	$ 573,092	$ 716,612	$ 1,159,295	$ 1,442,970
EXPENSES:				
Fuel	2,821	12,006	5,772	23,922
Purchased power	293,033	227,507	576,053	474,097
Nuclear operating costs	43,506	92,607	84,590	188,260
Other operating costs	91,604	95,589	182,414	178,768
Provision for depreciation	17,547	31,654	35,563	57,706
Amortization of regulatory assets	43,444	109,670	97,305	221,441
Deferral of new regulatory assets	(42,083)	(39,026)	(78,323)	(63,821)
General taxes	43,931	46,043	89,826	94,121
Total expenses	493,803	576,050	993,200	1,174,494
OPERATING INCOME	79,289	140,562	166,095	268,476
OTHER INCOME (EXPENSE):				
Investment income	32,818	22,482	65,860	43,089
Miscellaneous expense	(1,001)	(2,161)	(804)	(23,897)
Interest expense	(17,366)	(21,402)	(35,598)	(39,605)
Capitalized interest	643	3,006	1,134	5,241
Subsidiary's preferred stock dividend requirements	(155)	(738)	(311)	(1,378)
Total other income (expense)	14,939	1,187	30,281	(16,550)
INCOME TAXES	35,019	94,653	73,337	148,073
NET INCOME	59,209	47,096	123,039	103,853
PREFERRED STOCK DIVIDEND REQUIREMENTS AND REDEMPTION PREMIUM	3,587	658	4,246	1,317
EARNINGS ON COMMON STOCK	$ 55,622	$ 46,438	$ 118,793	$ 102,536

STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$ 59,209	$ 47,096	$ 123,039	$ 103,853
OTHER COMPREHENSIVE INCOME (LOSS):				
Unrealized gain (loss) on available for sale securities	(4,063)	(12,960)	1,672	(15,677)
Income tax expense (benefit) related to other comprehensive income	(1,466)	(4,546)	603	(5,670)
Other comprehensive income (loss), net of tax	(2,597)	(8,414)	1,069	(10,007)
TOTAL COMPREHENSIVE INCOME	$ 56,612	$ 38,682	$ 124,108	$ 93,846

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)

	June 30, 2006	December 31, 2005
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 545,292	$ 929
Receivables-		
Customers (less accumulated provisions of $8,627,000 and $7,619,000, respectively, for uncollectible accounts)	250,079	290,887
Associated companies	165,501	187,072
Other (less accumulated provisions of $52,000 and $4,000, respectively, for uncollectible accounts)	11,491	15,327
Notes receivable from associated companies	506,337	536,629
Prepayments and other	22,794	93,129
	1,501,494	1,123,973
UTILITY PLANT:		
In service	2,558,212	2,526,851
Less - Accumulated provision for depreciation	996,261	984,463
	1,561,951	1,542,388
Construction work in progress	63,277	58,785
	1,625,228	1,601,173
OTHER PROPERTY AND INVESTMENTS:		
Long-term notes receivable from associated companies	1,676,228	1,758,776
Investment in lease obligation bonds	310,285	325,729
Nuclear plant decommissioning trusts	106,360	103,854
Other	40,968	44,210
	2,133,841	2,232,569
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	756,481	774,983
Prepaid pension costs	227,815	224,813
Property taxes	52,897	52,875
Unamortized sale and leaseback costs	52,637	55,139
Other	26,988	31,752
	1,116,818	1,139,562
	$ 6,377,381	$ 6,097,277

LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 225,625	$ 280,255
Short-term borrowings-		
Associated companies	2,161	57,715
Other	22,431	143,585
Accounts payable-		
Associated companies	123,912	172,511
Other	12,312	9,607
Accrued taxes	173,248	163,870
Accrued interest	7,150	8,333
Other	64,098	61,726
	630,937	897,602
CAPITALIZATION:		
Common stockholder's equity-		
Common stock, without par value, authorized 175,000,000 shares - 100 shares outstanding	2,296,525	2,297,253
Accumulated other comprehensive income	5,163	4,094
Retained earnings	285,434	200,844
Total common stockholder's equity	2,587,122	2,502,191
Preferred stock not subject to mandatory redemption	60,965	60,965
Preferred stock of consolidated subsidiary not subject to mandatory redemption	14,105	14,105
Long-term debt and other long-term obligations	1,521,863	1,019,642
	4,184,055	3,596,903
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	747,568	769,031
Accumulated deferred investment tax credits	22,307	24,081
Asset retirement obligation	85,578	82,527
Retirement benefits	294,755	291,051
Deferred revenues - electric service programs	104,855	121,693
Other	307,326	314,389
	1,562,389	1,602,772
COMMITMENTS AND CONTINGENCIES (Note 10)		
	$ 6,377,381	$ 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)

	Six Months Ended June 30, 2006	2005
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 123,039	$ 103,853
Adjustments to reconcile net income to net cash from operating activities -		
Provision for depreciation	35,563	57,706
Amortization of regulatory assets	97,305	221,441
Deferral of new regulatory assets	(78,323)	(63,821)
Nuclear fuel and lease amortization	(11,337)	18,663
Amortization of lease costs	(4,334)	(2,952)
Deferred income taxes and investment tax credits, net	(17,351)	(5,142)
Accrued compensation and retirement benefits	930	3,504
Decrease (increase) in operating assets -		
Receivables	66,215	77,745
Materials and supplies	-	(18,149)
Prepayments and other current assets	70,335	(7,220)
Increase (decrease) in operating liabilities -		
Accounts payable	(45,894)	(85,227)
Accrued taxes	9,378	19,078
Accrued interest	(1,183)	(791)
Electric service prepayment programs	(16,838)	132,151
Other	(8,772)	12,876
Net cash provided from operating activities	218,733	463,715
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing -		
Long-term debt	599,778	146,450
Short-term borrowings, net	-	47,442
Redemptions and Repayments -		
Preferred stock	-	(37,750)
Long-term debt	(146,893)	(260,508)
Short-term borrowings, net	(176,708)	-
Dividend Payments -		
Common stock	(35,000)	(177,000)
Preferred stock	(1,317)	(1,317)
	239,860	(282,683)

Net cash provided from (used for) financing activities				
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions		(49,659)		(121,458)
Proceeds from nuclear decommissioning trust fund sales		30,269		122,374
Investments in nuclear decommissioning trust funds		(30,961)		(138,144)
Loan repayments from (loans to) associated companies, net		112,840		(58,540)
Other		23,281		14,789
Net cash provided from (used for) investing activities		85,770		(180,979)
Net increase in cash and cash equivalents		544,363		53
Cash and cash equivalents at beginning of period		929		1,230
Cash and cash equivalents at end of period	$	545,292	$	1,283

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

Report of Independent Registered Public Accounting Firm

To the 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 June 30, 2006, and the related consolidated statements of income and comprehensive income for each of the three-month and six-month periods ended June 30, 2006 and 2005 and the consolidated statement of cash flows for the six-month period ended June 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
August 4, 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 will continue to provide OE's PLR requirements under revised purchased power arrangements for the three-year period beginning January 1, 2006 and Penn's during 2006 (see Outlook - Regulatory Matters).

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The effects on the OE Companies' results of operations in the second quarter and first six months of 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 Increase (Decrease)		**Three Months**	**Six Months**
		(In millions)	
Revenues:			
Non-nuclear generating units rent	(a)	$ (44)	$ (89)
Nuclear generated KWH sales	(b)	(67)	(131)
Total - Revenues Effect		(111)	(220)
Expenses:			
Fuel costs - nuclear	(c)	(9)	(18)
Nuclear operating costs	(c)	(43)	(89)
Provision for depreciation	(d)	(17)	(28)
General taxes	(e)	(3)	(6)
Total - Expenses Effect		(72)	(141)
Operating Income Effect		(39)	(79)
Other Income:			
Interest income from notes receivable	(f)	14	30
Nuclear decommissioning trust earnings	(g)	(4)	(6)
Capitalized Interest	(h)	(2)	(4)
Total - Other Income Effect		8.	20.
Income taxes	(i)	(13)	(24)
Net Income Effect		$ (18)	$ (35)

(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 second quarter of 2006 increased to $56 million from $46 million in the second quarter of 2005. In the first six months of 2006, earnings on common stock increased to $119 million from $103 million in the same period of 2005. The increase in earnings in both periods of 2006 primarily resulted from lower expenses and increased other income, partially offset by lower revenues principally from the asset transfer effects shown in the table above. Earnings in both periods of 2005 were also reduced by a one-time income tax charge of $36 million from the enactment of tax legislation in Ohio. Earnings in the first six months of 2005 was additionally reduced by charges relating to a $8.5 million civil penalty payable to the Department of Justice and $10 million for environmental projects in connection with the Sammis Plant settlement (see Outlook — Environmental Matters).

Revenues

Revenues decreased by $144 million or 20.0% in the second 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 second quarter of 2006 decreased $33 million, primarily due to decreases of $70 million and $112 million in wholesale sales and distribution revenues, respectively, partially offset by increases in retail generation revenues of $125 million and reduced customer shopping incentives of $21 million.

In the first six months of 2006 compared with the same period in 2005, revenues decreased by $284 million or 19.7%, primarily from the generation asset transfer impact summarized in the table above. Excluding the effects of the asset transfer, revenues in the first six months of 2006 decreased $64 million, primarily due to decreases of $130 million and $210 million in wholesale sales and distribution revenues, respectively, partially offset by increases in retail generation revenues of $232 million and reduced customer shopping incentives of $38 million.

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

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

Changes in Generation KWH Sales Increase (Decrease)	**Three Months**	**Six Months**
Electric Generation:		
Retail	13.8 %	12.5 %
Wholesale	(84.2)%	(82.8)%
Net Decrease in Generation Sales	**(31.4)%**	**(29.7)%**

Changes in Generation Revenues	**Three Months**	**Six Months**
Increase (Decrease)	***(In millions)***	
Retail Generation:		
Residential	$ 41	$ 84
Commercial	38	70
Industrial	46	78
Total Retail Generation	125	232
Wholesale*	(70)	(130)
Net Increase in Generation Revenues	**$ 55**	**$ 102**

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

Increased retail generation revenues for the second 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 - 10.4 percentage points; commercial - 12.5 percentage points; and industrial - 11.2 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 six 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 - 9.5 percentage points; commercial - 11.8 percentage points; and industrial - 10.2 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 second quarter and first six months of 2006 from the corresponding periods of 2005 are summarized in the following table.

Changes in Distribution KWH Deliveries Increase (Decrease)	**Three Months**	**Six Months**
Distribution Deliveries:		
Residential	(6.3)%	(3.8)%
Commercial	(2.2)%	(1.6)%
Industrial	2.7 %	0.5 %
Net Decrease in Distribution Deliveries	**(1.7)%**	**(1.6)%**

Changes in Distribution Revenues Increase (Decrease)		**Three Months**		**Six Months**
		(In millions)		
Residential	$	(48)	$	(88)
Commercial		(34)		(65)
Industrial		(30)		(57)
Net Decrease in Distribution Revenues	**$**	**(112)**	**$**	**(210)**

Lower distribution throughput revenues as shown in the table above in the second quarter and first six months of 2006 reflects lower composite prices and reduced KWH deliveries. The lower unit prices in both periods were due to 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 distribution KWH deliveries to residential and commercial customers reflected the impact of milder weather conditions in the second quarter and first six 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 had provided incentives to customers to encourage switching to alternative energy providers, which reduced OE's revenues by $21 million in the second quarter of 2005 and $38 million in the first six 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 decreased by $82 million in the second quarter of 2006 and $181 million in the first six months of 2006 from the same periods of 2005 principally due to the effects of the generation asset transfer 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**	**Six Months**
	(In millions)	
Purchased power costs	$ 66	$ 102
Nuclear operating costs	(6)	(14)
Other operating costs	(4)	4
Provision for depreciation	2	6
Amortization of regulatory assets	(66)	(124)
Deferral of new regulatory assets	(3)	(15)
General taxes	1	2
Net decrease in expenses	**$ (10)**	**$ (39)**

Increased purchased power costs in the second quarter and first six 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 for OE's nuclear leasehold interests were primarily due to the absence in 2006 of the Beaver Valley Unit 2 refueling outage and 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 second quarter 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 customer in the fourth quarter of 2005. The increase in other operating costs in the first six months of 2006 was primarily due to increased 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 second quarter and first six months of 2006 reflected capital additions subsequent to the second 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 second quarter and first six months of 2006 primarily resulted from the deferral of fuel ($14 million and $25 million, respectively) and distribution costs ($22 million and $39 million, respectively) under the RCP, partially offset by lower MISO cost deferrals ($12 million and $11 million, respectively) and the decrease in shopping incentive deferrals ($21 million and $38 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.

Excluding the effects of the generation asset transfers, higher general taxes in both periods reflects the phase-in of the Ohio commercial activity tax that became effective July 1, 2005.

Other Income

Other income increased $14 million in the second quarter of 2006 and $47 million in the first six months of 2006 as compared with the same periods of 2005, primarily due to the effects of the generation asset transfers. Excluding the effects of the generation asset transfers, the $5 million increase in the second quarter is primarily due to lower interest expense, reflecting debt redemptions subsequent to the second quarter of 2005.

Excluding the effects of the generation asset transfers, the $28 million increase in the first six months is primarily due to lower interest expense and 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).

Income Taxes

Income taxes decreased $60 million in the second quarter of 2006 and $75 million in the first six months of 2006 compared with the same periods of 2005. Excluding the effects of the generation asset transfer, income taxes decreased $47 million in the second quarter of 2006 and $50 million in the first six months of 2006. As a result of new Ohio tax legislation in 2005, OE wrote off $36 million in net deferred tax benefits in the second quarter of 2005. The remainder of the net change in both the second quarter and the six-month period was mainly due to an increase 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.

Capital Resources and Liquidity

OE's cash requirements in 2006 for operating expenses, construction expenditures and scheduled debt maturities are expected to be met with cash from operations, short-term credit arrangements and funds from capital markets. OE repurchased $500 million of common stock from FirstEnergy and redeemed $64 million of preferred stock 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 $545 million of cash and cash equivalents as of June 30, 2006 compared with $1 million 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 six months of 2006, compared with the corresponding period in 2005, was as follows:

Operating Cash Flows	Six Months Ended June 30, 2006	2005
	(In millions)	
Cash earnings (1)	$ 129	$ 329
Working capital and other	90	135
	$ 219	$ 464

Net cash provided from operating activities

[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 are a useful financial measure because it provides investors and management with an additional means of evaluating its cash-based operating performance. The following table reconciles cash earnings with net income:

Reconciliation of Cash Earnings	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(In millions)	
Net income (GAAP)	$ 123	$ 104
Non-cash charges (credits):		
Provision for depreciation	36	58
Amortization of regulatory assets	97	221
Deferral of new regulatory assets	(78)	(64)
Nuclear fuel and capital lease amortization	(11)	19
Amortization of electric service obligation	(17)	(4)
Amortization of lease costs	(4)	(3)
Deferred income taxes and investment tax credits, net	(17)	(5)
Accrued compensation and retirement benefits	--	3
Cash earnings (Non-GAAP)	$ 129	$ 329

Net cash provided from operating activities decreased $245 million in the first six months of 2006, compared with the same period in 2005, due to a $45 million decrease from changes in working capital and a $200 million decrease in cash earnings as described above under “Results from Operations.” The decrease in working capital primarily reflects the absence in 2006 of $136 million in funds received for the Energy for Education program in 2005, partially offset by changes in prepayments and other current assets of $78 million and accounts payable of $39 million.

Cash Flows From Financing Activities

Net cash provided from financing activities increased to $240 million in the first six months of 2006 from $283 million used for financing activities in the first six months of 2005. The increase primarily reflected more long-term debt financing, and decreases of $151 million in redemptions of preferred stock and long-term debt and $142 million in common stock dividend payments to FirstEnergy, partially offset by higher repayments of short-term borrowings to associated companies.

OE had approximately $1.1 billion of cash and temporary cash investments (which include short-term notes receivable from associated companies) and $25 million of short-term indebtedness as of June 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 SEC, continued by FERC rules adopted as a result of EPACT's repeal of PUHCA, to incur short-term debt up to its charter limit of $44 million as of June 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 June 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 June 30, 2006, the facility was drawn for $19 million.

As of June 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 $735 million as of June 30, 2006. Based upon applicable earnings coverage tests in their respective charters, OE and Penn could issue a total of $2.7 billion of preferred stock (assuming no additional debt was issued) as of June 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 June 30, 2006, OE had approximately $400 million of capacity remaining unused under its existing shelf registration.

FirstEnergy, OE, Penn, CEI, TE, JCP&L, Met-Ed, Penelec, FES and ATSI, as Borrowers, have entered into a syndicated $2 billion five-year revolving credit facility with a syndicate of banks that expires in June 2010. Borrowings under the facility are available to each Borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. OE's 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 existing credit facilities and accounts receivable financing facilities totaled $726 million as of June 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 June 30, 2006, debt to total capitalization as defined under the revolving credit facility was 40% for OE and 34% for Penn.

The 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 six months of 2006 was 4.86%.

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 their 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.

Cash Flows From Investing Activities

Net cash provided from investing activities was $86 million in the first six months of 2006 compared to $181 million used for investing activities in the first six months of 2005. The change resulted primarily from a $171 million increase in loan repayments from associated companies and a $72 million decrease in property additions, which reflects the impact of the generation asset transfers.

During the second half of 2006, capital requirements for property additions and capital leases are expected to be approximately $46 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 $624 million, of which approximately $108 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 $640 million as of June 30, 2006.

Equity Price Risk

Included in OE’s nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $70 million and $67 million as of June 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 June 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 to income as incurred. All regulatory assets are expected to be recovered under the provisions of the OE Companies’ transition plans and rate restructuring plans. OE‘s regulatory assets were $756 million and $775 million as of June 30, 2006 and December 31, 2005, respectively. Penn had net regulatory liabilities of $59 million as of June 30, 2006 and December 31, 2005, which are included in Other Noncurrent Liabilities on the Consolidated Balance Sheets as of June 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 September 28, 2005, the Supreme Court of Ohio heard oral arguments on the appeals. 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 one matter back to the PUCO for further consideration of the issue as to whether the RSP, as adopted by the PUCO, provided for sufficient means for customer participation in the competitive marketplace. On May 12, 2006, the Ohio Companies filed a Motion for Reconsideration with the Supreme Court of Ohio which was denied by the Court on June 21, 2006. 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.

The Ohio Companies filed an application and stipulation with the PUCO on September 9, 2005 seeking approval of the RCP. 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	$	177
2007		180
2008		208
Total Amortization	**$**	**565**

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 are due on August 4, 2006. Appellants' Reply Briefs will then be due on August 24, 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. 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 $31 million. That amount included the recovery of a portion of the 2005 deferred MISO expenses as described below. On May 1, 2006, OE filed a modification to the rider to determine revenues ($71 million) from July 2006 through June 2007.

The second application sought authority to defer costs associated with transmission and ancillary service related costs incurred during the period 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 unable to predict when a decision may be issued.

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. To the extent that an affiliate of Penn supplies a portion of the PLR load included in the RFP, authorization to make the affiliate sale must be obtained from the FERC. 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 to obtain Penn's power supply requirements after 2006 through two separate solicitations. An initial solicitation was held for Penn in May 2006 with all tranches fully subscribed. On June 2, 2006, the PPUC approved the bid results for the first solicitation. 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 only acquired for three of the five tranches for the Large Commercial Group. On July 20, 2006, the PPUC approved the submissions for the second bid. A residual solicitation is scheduled to be held on August 15, 2006 for the two remaining Large Commercial Group tranches. Acceptance of the winning bids is subject to approval by the PPUC.

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 its recovery of certain PLR costs via a reconciliation mechanism and its 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. The PPUC approved Penn's plan with modifications on April 20, 2006 to use an RFP process to obtain its power supply requirements after 2006 through two separate solicitations. An initial solicitation was held for Penn in May 2006 with all tranches fully subscribed. On June 2, 2006, the PPUC approved the bid results for the first solicitation. 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 only acquired for three of the five tranches for the Large Commercial Group. On July 20, 2006, the PPUC approved the submission for the second bid. A residual solicitation is scheduled to be held on August 15, 2006 for the two remaining Large Commercial Group tranches. Acceptance of the winning bids is subject to approval by the PPUC.

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. The procedural schedule has been suspended pending negotiations among the parties.

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. Those 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 the 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 outage. 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. FirstEnergy filed a Motion to Dismiss on June 13, 2006. It is currently expected that this case will be summarily dismissed, although the Motion is still pending. On March 7, 2006, the PUCO issued a ruling 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. These motions are pending. Additionally, on June 23, 2006, one of the insurance carrier complainants filed an appeal with the Ohio Supreme Court over the PUCO’s denial of their motion for rehearing on the issue of the admissibility of the Task Force Report and the dismissal of FirstEnergy Corp. as a respondent. Briefing is expected to be completed on this appeal by mid-September. It is unknown when the Supreme Court will rule on the appeal. 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 Perry (12.58%), the transfer included the OE Companies’ prior owned interests in Beaver Valley Unit 1 (100%), Beaver Valley Unit 2 (33.96%) and Perry (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 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 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.

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 described above. 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 60 days from the denial of rehearing to appeal the PUCO’s decision.

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

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 June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(In thousands)			
STATEMENTS OF INCOME				
REVENUES	$ 432,371	$ 448,747	$ 840,181	$ 881,920
EXPENSES:				
Fuel	13,413	21,110	26,976	39,437
Purchased power	157,942	138,842	301,711	281,726
Nuclear operating costs	-	36,786	-	95,513
Other operating costs	68,436	74,711	141,331	138,284
Provision for depreciation	11,050	33,387	28,251	64,502
Amortization of regulatory assets	29,476	55,016	61,006	109,042
Deferral of new regulatory assets	(31,698)	(40,701)	(62,223)	(65,989)
General taxes	31,510	36,605	66,580	75,492
Total expenses	280,129	355,756	563,632	738,007
OPERATING INCOME	152,242	92,991	276,549	143,913
OTHER INCOME (EXPENSE):				
Investment income	24,674	14,049	51,610	29,197
Miscellaneous income (expense)	5,642	(2,292)	5,396	(8,764)
Interest expense	(34,634)	(30,152)	(69,366)	(64,618)
Capitalized interest	837	1,294	1,510	883
Total other income (expense)	(3,481)	(17,101)	(10,850)	(43,302)
INCOME TAXES	57,709	37,221	102,234	46,470
NET INCOME	91,052	38,669	163,465	54,141
PREFERRED STOCK DIVIDEND REQUIREMENTS	-	-	-	2,918
EARNINGS ON COMMON STOCK	$ 91,052	$ 38,669	$ 163,465	$ 51,223

STATEMENTS OF COMPREHENSIVE INCOME

NET INCOME	$	91,052	$	38,669	$	163,465	$	54,141
OTHER COMPREHENSIVE INCOME (LOSS):								
Unrealized loss on available for sale securities		-		(1,349)		-		(2,570)
Income tax benefit related to other comprehensive income		-		419		-		923
Other comprehensive loss, net of tax		-		(930)		-		(1,647)
TOTAL COMPREHENSIVE INCOME	$	91,052	$	37,739	$	163,465	$	52,494

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)

	June 30, 2006	December 31, 2005
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 217	$ 207
Receivables-		
Customers (less accumulated provisions of $5,836,000 and $5,180,000, respectively, for uncollectible accounts)	273,324	268,427
Associated companies	37,168	86,564
Other	14,703	16,466
Notes receivable from associated companies	29,048	19,378
Prepayments and other	1,504	1,903
	355,964	392,945
UTILITY PLANT:		
In service	2,063,137	2,030,935
Less - Accumulated provision for depreciation	800,356	788,967
	1,262,781	1,241,968
Construction work in progress	73,869	51,129
	1,336,650	1,293,097
OTHER PROPERTY AND INVESTMENTS:		
Long-term notes receivable from associated companies	940,786	1,057,337
Investment in lessor notes	519,615	564,166
Other	13,710	12,840
	1,474,111	1,634,343
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,688,521	1,688,966
Regulatory assets	858,618	862,193
Prepaid pension costs	137,082	139,012
Property taxes	63,500	63,500
Other	33,130	27,614
	2,780,851	2,781,285
	$ 5,947,576	$ 6,101,670
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 543	$ 75,718
Short-term borrowings-		
Associated companies	154,731	212,256
Other	149,000	140,000
Accounts payable-		
Associated companies	65,148	74,993

Other		8,121		4,664
Accrued taxes		119,555		121,487
Accrued interest		18,810		18,886
Lease market valuation liability		60,200		60,200
Other		39,512		61,308
		615,620		769,512
CAPITALIZATION:				
Common stockholder's equity-				
Common stock, without par value, authorized 105,000,000 shares -				
79,590,689 shares outstanding		1,355,926		1,354,924
Retained earnings		687,615		587,150
Total common stockholder's equity		2,043,541		1,942,074
Long-term debt and other long-term obligations		1,886,636		1,939,300
		3,930,177		3,881,374
NONCURRENT LIABILITIES:				
Accumulated deferred income taxes		551,553		554,828
Accumulated deferred investment tax credits		22,093		23,908
Lease market valuation liability		577,900		608,000
Retirement benefits		83,604		83,414
Deferred revenues - electric service programs		63,566		71,261
Other		103,063		109,373
		1,401,779		1,450,784
COMMITMENTS AND CONTINGENCIES (Note 10)				
	$	5,947,576	$	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)

	Six Months Ended June 30, 2006	2005
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 163,465	$ 54,141
Adjustments to reconcile net income to net cash from operating activities -		
Provision for depreciation	28,251	64,502
Amortization of regulatory assets	61,006	109,042
Deferral of new regulatory assets	(62,223)	(65,989)
Nuclear fuel and capital lease amortization	120	10,781
Deferred rents and lease market valuation liability	(55,043)	(53,691)
Deferred income taxes and investment tax credits, net	(4,745)	4,450
Accrued compensation and retirement benefits	1,584	(373)
Decrease (increase) in operating assets-		
Receivables	46,262	(98,074)
Materials and supplies	-	(28,791)
Prepayments and other current assets	399	188
Increase (decrease) in operating liabilities-		
Accounts payable	(6,388)	38,280
Accrued taxes	(1,932)	(6,779)
Accrued interest	(76)	(320)
Electric service prepayment programs	(7,695)	57,466
Other	(4,162)	(7,871)
Net cash provided from operating activities	158,823	76,962
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	-	53,284
Short-term borrowings, net	-	58,874
Equity contributions from parent	-	75,000
Redemptions and Repayments-		
Preferred stock	-	(101,900)
Long-term debt	(118,152)	(56,930)
Short-term borrowings, net	(57,675)	-
Dividend Payments-		
Common stock	(63,000)	(124,000)
Preferred stock	-	(2,260)
Net cash used for financing activities	(238,827)	(97,932)

CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions		(65,551)		(60,244)
Loan repayments from associated companies, net		108,169		66,927
Investments in lessor notes		44,551		32,473
Proceeds from nuclear decommissioning trust fund sales		-		198,974
Investments in nuclear decommissioning trust funds		-		(213,486)
Other		(7,155)		(3,664)
Net cash provided from investing activities		80,014		20,980
Net increase in cash and cash equivalents		10		10
Cash and cash equivalents at beginning of period		207		197
Cash and cash equivalents at end of period	$	217	$	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 June 30, 2006, and the related consolidated statements of income and comprehensive income for each of the three-month and six-month periods ended June 30, 2006 and 2005 and the consolidated statement of cash flows for the six-month period ended June 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
August 4, 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 their 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 will continue to provide CEI's PLR requirements under revised purchased power arrangements for the three-year period beginning January 1, 2006 (see Regulatory Matters).

The effects on CEI's results of operations in the second quarter and first six months of 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		**Three Months**	**Six Months**
Increase (Decrease)		***(In millions)***	
Revenues:			
Non-nuclear generating units rent	(a)	$ (14)	$ (29)
Nuclear generated KWH sales	(b)	(57)	(110)
Total - Revenues Effect		(71)	(139)
Expenses:			
Fuel costs - nuclear	(c)	(8)	(14)
Nuclear operating costs	(c)	(37)	(95)
Provision for depreciation	(d)	(13)	(32)
General taxes	(e)	(4)	(8)
Total - Expenses Effect		(62)	(149)
Operating Income Effect		(9)	10
Other Income:			
Interest income from notes receivable	(f)	14	30
Nuclear decommissioning trust earnings	(g)	(2)	(4)
Capitalized interest	(h)	(1)	-
Total - Other Income Effect		11	26
Income taxes	(i)	1	15
Net Income Effect		$ 1	$ 21

(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 second quarter of 2006 increased to $91 million from $39 million in the second quarter of 2005. In the first six months of 2006, earnings on common stock increased to $163 million from $51 million in the same period of 2005. The increase in earnings in both 2006 periods resulted primarily from lower expenses and increased other income, partially offset by lower revenues. These changes reflected the effects of the generation asset transfer shown in the table above and 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 $16 million or 3.6% in the second quarter of 2006 from the same period in 2005. Excluding the effects of the generation asset transfers displayed above, revenues increased $55 million due to a $105 million increase in retail generation sales revenues and a $28 million reduction in customer shopping incentives, partially offset by a $62 million decrease in distribution revenues and a $19 million decrease in MSG wholesale sales. In the first six months of 2006 compared to the same period in 2005, revenues decreased by $42 million or 4.7%. Excluding the effects of the generation asset transfers discussed above, revenues increased $97 million due to a $193 million increase in retail generation sales revenues and a $47 million reduction in customer shopping incentives, partially offset by a $106 million decrease in distribution revenues and a $37 million decrease in MSG wholesale sales.

Non-affiliated wholesale sales revenues decreased by $19 million for the second quarter of 2006 and $37 million for the first six months of 2006 compared with the same periods in 2005 due to the cessation of the MSG sales arrangements under CEI’s transition plan in December 2005. CEI had been required to provide the MSG to non-affiliated alternative suppliers.

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

Changes in Generation KWH Sales Increase (Decrease)	**Three Months**	**Six Months**
Electric Generation:		
Retail	50.7%	48.5%
Wholesale	(74.0)%	(71.4)%
Net Decrease in Generation Sales	**(21.4)%**	**(17.7)%**

Changes in Generation Revenues Increase (Decrease)	**Three Months**	**Six Months**
	(In millions)	
Retail Generation:		
Residential	$ 39	$ 77
Commercial	38	70
Industrial	28	46
Total Retail Generation	105	193
Wholesale*	(19)	(37)
Net Increase in Generation Revenues	**$ 86**	**$ 156**

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

Increased retail generation revenue as shown in the table above for the second quarter 2006 compared with the same quarter of 2005 was due to increased KWH sales and higher unit prices. 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 - 61.0 percentage points, commercial - 43.5 percentage points and industrial - 8.9 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 six months of 2006 compared with the same period in 2005 were also due to increased KWH sales and the higher unit prices under provisions of the RSP and RCP. The increase in generation KWH sales reflected a similar decrease in customer shopping as discussed above. This resulted in similar percentage decreases in the first half of 2006 in generation services provided by alternative suppliers as a percentage of total sales deliveries in CEI's service area (residential - 60.0 percentage points, commercial - 41.1 percentage points and industrial - 7.6 percentage points).

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

Changes in Distribution KWH	**Three Months**	**Six Months**

Sales Increase (Decrease)		
Distribution Deliveries:		
Residential	(5.6)%	(3.8)%
Commercial	(2.7)%	(4.3)%
Industrial	(1.5)%	(2.6)%
Net Decrease in Distribution Deliveries	**(2.8)%**	**(3.3)%**

Changes in Distribution Revenues	Three Months		Six Months	
Increase (Decrease)		*(In millions)*		
Residential	$	(16)	$	(21)
Commercial		(23)		(45)
Industrial		(23)		(40)
Net Decrease in Distribution Revenues	**$**	**(62)**	**$**	**(106)**

Lower distribution revenues as shown in the table above in the second quarter and first six 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 reflected the impact of milder weather conditions in the second quarter and first six months of 2006, compared to the same periods of 2005.

Under the Ohio transition plan, CEI had 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 $28 million revenue increase for the second quarter of 2006 and a $47 million increase for the first six months of 2006 compared to the same periods of 2005, as discussed above.

Expenses

Total expenses decreased by $76 million in the second quarter and $174 million in the first six months of 2006 from the same periods of 2005, principally due to the 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**	**Six Months**
	(In millions)	
Fuel costs	$ -	$ 1
Purchased power costs	19	20
Other operating costs	(6)	3
Provision for depreciation	(9)	(4)
Amortization of regulatory assets	(26)	(48)
Deferral of new regulatory assets	9	4
General taxes	(1)	(1)
Net decrease in expenses	$ (14)	$ (25)

Higher purchased power costs in the second quarter and in the first six months of 2006 compared with the same periods in 2005 primarily reflected increases in KWH purchased to meet higher retail generation sales requirements. These increases were partially offset by the impact of lower unit prices associated with the new power supply agreement with FES and purchased power lease credit amortizations of $8 million and $16 million in the second quarter and the first six months of 2006, respectively. The amortization is for the above-market lease liability related to an existing Beaver Valley Unit 2 purchased power arrangement with TE. The lease credit amortization had been previously included in CEI's nuclear operating costs and the related nuclear generation KWH purchased from TE had then been sold to FES. Subsequent to the generation asset transfer, CEI now retains this purchased power from TE to meet a portion of its PLR obligation and, consequently, the lease amortization is now included as part of CEI's purchased power costs. Lower other operating costs in the second quarter of 2006 compared with the same period 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. Higher other operating costs in the first six months of 2006 compared with the same period in 2005 reflect increased transmission expenses, primarily related to MISO Day 2 operations that began on April 1, 2005.

Excluding the effects of the generation asset transfers, the decrease in depreciation in the second quarter and first six months of 2006 compared with the same periods of 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 second quarter and first six months of 2006 compared with the same periods in 2005 was primarily due to the termination of the shopping incentive deferrals ($28 million and $47 million, respectively) and lower deferred MISO costs ($6 million and $5 million, respectively), partially offset by the deferrals of distribution costs ($14 million and $29 million, respectively) and fuel costs ($11 million and $19 million, respectively) under the RCP.

Other Income

The increase in other income of $14 million in the second quarter and $32 million in the first six months of 2006 compared with the same periods last year was primarily due to interest income on associated company notes receivable from the generation asset transfers discussed above. Excluding the effects of the asset transfer, other income increased for the second quarter and first six months of 2006 by $2 million and $7 million, respectively. The increase in both periods 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 in both periods due to the absence of financing cost reductions recognized in 2005 related to refinancing activities.

Income Taxes

Increased income taxes in the second quarter and in the first six months of 2006 compared with the same periods last year were primarily due to an increase 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 and the absence of a second quarter 2005 addition to income taxes of approximately $8 million, from the implementation of the Ohio tax legislation.

Preferred Stock Dividend Requirements

Preferred stock dividend requirements decreased by $3 million in the first six 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 2006, CEI expects to meet its contractual obligations with cash from operations and short-term credit arrangements. Thereafter, CEI expects to use a combination of cash from operations and funds from the capital markets.

Changes in Cash Position

As of June 30, 2006, CEI had $217,000 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 six months of 2006, compared with the same period last year, were as follows:

Operating Cash Flows	**Six Months Ended June 30, 2006**	**2005**
	(In millions)	
Cash earnings *	$ 125	$ 113
Working capital and other	34	(36)
Net cash provided from operating activities	$ 159	$ 77

* 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 are a useful financial measure because it provides investors and management with an additional means of evaluating its cash-based operating performance. The following table reconciles cash earnings with net income:

Reconciliation of Cash Earnings	**Six Months Ended June 30, 2006**	**2005**
	(In millions)	
Net Income (GAAP)	$ 163	$ 54
Non-cash charges (credits):		
Provision for depreciation	28	65

Amortization of regulatory assets		61		109
Deferral of new regulatory assets		(62)		(66)
Nuclear fuel and capital lease amortization		-		11
Amortization of electric service obligation		(7)		(10)
Deferred rents and lease market valuation liability		(55)		(54)
Deferred income taxes and investment tax credits, net		(5)		5
Accrued compensation and retirement benefits		2		(1)
Cash earnings (Non-GAAP)	$	125	$	113

Net cash provided from operating activities increased by $82 million in the first six months of 2006 from the same period last year as a result of a $12 million increase in cash earnings described above under "Results of Operations" and a $70 million increase from working capital and other cash flows. The largest factors contributing to the changes in working capital and other operating cash flows for the first six 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, offset in part by changes in accounts payable and 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 $141 million in the first six months of 2006 from the same period last year. The increase in funds used for financing activities primarily resulted from a $129 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 $61 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 $304 million of short-term indebtedness as of June 30, 2006. CEI has obtained authorization from the PUCO to incur short-term debt of up to $500 million (including the bank facility and utility money pool described below). As of June 30, 2006, CEI had the capability to issue $247 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 $576 million as of June 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 June 30, 2006, the facility was drawn for $149 million.

CEI has the ability to borrow from its regulated affiliates and FirstEnergy to meet its short-term working capital requirements. FESC administers this money pool and tracks surplus funds of FirstEnergy and its regulated subsidiaries. Companies receiving a loan under the money pool agreements must repay the principal amount, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from the pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in the first six months of 2006 was 4.86%.

CEI, FirstEnergy, OE, Penn, TE, JCP&L, Met-Ed, Penelec, FES and ATSI, as Borrowers, have entered into a syndicated $2 billion five-year revolving credit facility through a syndicate of banks that expires in June 2010. Borrowings under the facility are available to each Borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment expiration date, as the same may be extended. 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.

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 June 30, 2006, CEI's debt to total capitalization as defined under the revolving credit facility was 49%.

The facility does not contain any provisions that either restrict CEI'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 CEI's credit ratings.

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.

IIn 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 their associated company notes payable to CEI. CEI redeemed $117.8 million of pollution control notes having variable interest rates.

Cash Flows from Investing Activities

Net cash provided from investing activities increased by $59 million in the first six 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.

CEI’s capital spending for the last half of 2006 is expected to be approximately $58 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 $620 million of which approximately $127 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 June 30, 2006, the present value of these operating lease commitments, net of trust investments, total $98 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 June 30, 2006 and December 31, 2005, were $859 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 September 28, 2005, the Supreme Court of Ohio heard oral arguments on the appeals. 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 one matter back to the PUCO for further consideration of the issue as to whether the RSP, as adopted by the PUCO, provided for sufficient means for customer participation in the competitive marketplace. On May 12, 2006, the Ohio Companies filed a Motion for Reconsideration with the Supreme Court of Ohio which was denied by the Court on June 21, 2006. 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.

The Ohio Companies filed an application and stipulation with the PUCO on September 9, 2005 seeking approval of the RCP. 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	$ 95
2007	113
2008	130
2009	211
2010	266
Total Amortization	**$ 815**

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 are due on August 4, 2006. Appellants’ Reply Briefs will then be due on August 24, 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 May 1, 2006, CEI filed a modification to the rider to determine revenues ($51 million) from July 2006 through June 2007.

The second application sought authority to defer costs associated with transmission and ancillary service related costs incurred during the period from October 1, 2003 through December 31, 2005. On May 18, 2005, the PUCO granted the accounting authority for CEI to defer incremental transmission and ancillary service-related charges incurred as a participant in MISO, but only for those costs incurred during the period December 30, 2004 through December 31, 2005. Permission to defer costs incurred prior to December 30, 2004 was denied. The PUCO also authorized CEI to accrue carrying charges on the deferred balances. 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 CEI’s case with a similar case involving Dayton Power & Light Company. Oral arguments were heard on May 10, 2006. CEI is unable to predict when a decision may be issued.

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.

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. The procedural schedule has been suspended pending negotiations among the parties.

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 June 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 $2 million as of June 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 the 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 outage. 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. FirstEnergy filed a Motion to Dismiss on June 13, 2006. It is currently expected that this case will be summarily dismissed, although the Motion is still pending. On March 7, 2006, the PUCO issued a ruling 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. These motions are pending. Additionally, on June 23, 2006, one of the insurance carrier complainants filed an appeal with the Ohio Supreme Court over the PUCO's denial of their motion for rehearing on the issue of the admissibility of the Task Force Report and the dismissal of FirstEnergy Corp. as a respondent. Briefing is expected to be completed on this appeal by mid-September. It is unknown when the Supreme Court will rule on the appeal. 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 has been provided. FirstEnergy has cooperated fully with the informal inquiry and continues 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 described above. 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 60 days from the denial of rehearing to appeal the PUCO's decision.

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 other legal proceedings.

New Accounting Standards and Interpretations

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 June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
STATEMENTS OF INCOME		*(In thousands)*		
REVENUES	$ 225,598	$ 259,109	$ 443,575	$ 500,864
EXPENSES:				
Fuel	9,638	14,404	19,400	26,973
Purchased power	80,659	72,300	156,079	152,456
Nuclear operating costs	17,866	46,689	35,198	105,852
Other operating costs	39,718	41,311	80,143	75,659
Provision for depreciation	8,240	15,209	16,337	29,889
Amortization of regulatory assets	22,117	33,231	46,573	68,096
Deferral of new regulatory assets	(14,190)	(12,670)	(27,846)	(22,094)
General taxes	12,253	13,620	25,184	27,801
Total expenses	176,301	224,094	351,068	464,632
OPERATING INCOME	49,297	35,015	92,507	36,232
OTHER INCOME (EXPENSE):				
Investment income	8,945	8,188	18,725	17,072
Miscellaneous expense	(1,926)	(3,100)	(4,610)	(6,402)
Interest expense	(4,364)	(2,941)	(8,674)	(9,977)
Capitalized interest	344	188	558	(255)
Total other income	2,999	2,335	5,999	438
INCOME TAXES	19,924	29,674	37,128	28,629
NET INCOME	32,372	7,676	61,378	8,041
PREFERRED STOCK DIVIDEND REQUIREMENTS	1,161	2,211	2,436	4,422
EARNINGS ON COMMON STOCK	$ 31,211	$ 5,465	$ 58,942	$ 3,619
STATEMENTS OF COMPREHENSIVE				

INCOME								
NET INCOME	$	32,372	$	7,676	$	61,378	$	8,041
OTHER COMPREHENSIVE INCOME (LOSS):								
Unrealized gain (loss) on available for sale securities		191		(501)		(947)		(2,184)
Income tax expense (benefit) related to other comprehensive income		69		(96)		(342)		(791)
Other comprehensive income (loss), net of tax		122		(405)		(605)		(1,393)
TOTAL COMPREHENSIVE INCOME	$	32,494	$	7,271	$	60,773	$	6,648

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)

	June 30, 2006	December 31, 2005
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 23	$ 15
Receivables-		
Customers	782	2,209
Associated companies	39,407	16,311
Other	2,998	6,410
Notes receivable from associated companies	45,747	48,349
Prepayments and other	5,135	1,059
	94,092	74,353
UTILITY PLANT:		
In service	852,572	824,677
Less - Accumulated provision for depreciation	380,234	372,845
	472,338	451,832
Construction work in progress	28,499	33,920
	500,837	485,752
OTHER PROPERTY AND INVESTMENTS:		
Long-term notes receivable from associated companies	382,733	436,178
Investment in lessor notes	169,493	178,798
Nuclear plant decommissioning trusts	59,126	59,209
Other	1,843	1,781
	613,195	675,966
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	500,576	501,022
Regulatory assets	267,032	287,095
Prepaid pension costs	35,124	35,566
Property taxes	18,047	18,047
Other	39,728	24,164
	860,507	865,894
	$ 2,068,631	$ 2,101,965
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ -	$ 53,650
Accounts payable-		
Associated companies	30,571	46,386
Other	4,256	2,672
Notes payable to associated companies	136,571	64,689
Accrued taxes	53,092	49,344

Lease market valuation liability		24,600		24,600
Other		19,379		40,049
		268,469		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		473,908		473,638
Accumulated other comprehensive income		4,085		4,690
Retained earnings		223,370		189,428
Total common stockholder's equity		897,033		863,426
Preferred stock		66,000		96,000
Long-term debt		237,691		237,753
		1,200,724		1,197,179
NONCURRENT LIABILITIES:				
Accumulated deferred income taxes		209,389		221,149
Accumulated deferred investment tax credits		11,419		11,824
Lease market valuation liability		231,100		243,400
Retirement benefits		41,986		40,353
Asset retirement obligation		25,675		24,836
Deferred revenues - electric service programs		28,151		32,606
Other		51,718		49,228
		599,438		623,396
COMMITMENTS AND CONTINGENCIES (Note 10)				
	$	2,068,631	$	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)

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 61,378	$ 8,041
Adjustments to reconcile net income to net cash from operating activities-		
Provision for depreciation	16,337	29,889
Amortization of regulatory assets	46,573	68,096
Deferral of new regulatory assets	(27,846)	(22,094)
Nuclear fuel and capital lease amortization	-	8,134
Deferred rents and lease market valuation liability	(45,843)	(44,466)
Deferred income taxes and investment tax credits, net	(13,322)	8,193
Accrued compensation and retirement benefits	1,268	1,500
Decrease (increase) in operating assets-		
Receivables	(18,257)	12,539
Materials and supplies	-	(5,912)
Prepayments and other current assets	(4,076)	408
Increase (decrease) in operating liabilities-		
Accounts payable	(14,231)	(74,371)
Accrued taxes	3,748	10,509
Accrued interest	(222)	(196)
Electric service prepayment programs	(4,454)	36,563
Other	3,326	(8,588)
Net cash provided from operating activities	4,379	28,245
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	-	45,000
Short-term borrowings, net	71,882	-
Redemptions and Repayments-		
Preferred stock	(30,000)	-
Long-term debt	(53,650)	(46,933)
Short-term borrowings, net	-	(96,381)
Dividend Payments-		
Common stock	(25,000)	(10,000)
Preferred stock	(2,436)	(4,422)

Net cash used for financing activities		(39,204)		(112,736)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions		(29,361)		(32,168)
Loan repayments from (loans to) associated companies, net		2,611		(4,001)
Collection of principal on long-term notes receivable		53,766		123,546
Investments in lessor notes		9,305		11,895
Proceeds from nuclear decommissioning trust fund sales		30,665		153,940
Investments in nuclear decommissioning trust funds		(30,754)		(168,211)
Other		(1,399)		(510)
Net cash provided from investing activities		34,833		84,491
Net change in cash and cash equivalents		8		-
Cash and cash equivalents at beginning of period		15		15
Cash and cash equivalents at end of period	$	23	$	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 June 30, 2006, and the related consolidated statements of income and comprehensive income for each of the three-month and six-month periods ended June 30, 2006 and 2005 and the consolidated statement of cash flows for the six-month period ended June 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
August 4, 2006

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 will continue to provide TE's PLR requirements under revised purchased power arrangements for the three-year period beginning January 1, 2006 (see Outlook - Regulatory Matters).

The effects on TE's results of operations in the second quarter and first six months of 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**	**Six Months**
Increase (Decrease)		***(In millions)***	
Revenues:			
Non-nuclear generating units rent	(a)	$ (3)	$ (7)
Nuclear generated KWH sales	(b)	(29)	(51)
Total - Revenues Effect		(32)	(58)
Expenses:			
Fuel costs - nuclear	(c)	(5)	(8)
Nuclear operating costs	(c)	(22)	(62)
Provision for depreciation	(d)	(7)	(16)
General taxes	(e)	(2)	(3)
Total - Expenses Effect		(36)	(89)
Operating Income Effect		4	31
Other Income:			
Interest income from notes receivable	(f)	4	8
Nuclear decommissioning trust earnings	(g)	(3)	(4)
Capitalized interest	(h)	(1)	-
Total - Other Income Effect		-	4
Income taxes	(i)	1	14
Net Income Effect		$ 3	$ 21

(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 second quarter of 2006 increased to $31 million from $5 million in the second quarter of 2005. This increase resulted primarily from reduced 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. Earnings on common stock in the first six months of 2006 increased to $59 million from $4 million in the first six months of 2005. This increase resulted primarily from reduced expenses, increased other income and the absence of the additional income taxes discussed above, also partially offset by lower revenues. The earnings increases for both periods included the effects of the generation asset transfer shown in the table above.

Revenues

Revenues decreased by $33 million or 12.9% in the second 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 decreased $1 million due to decreased distribution revenues of $34 million, partially offset by a $23 million increase in generation sales revenues, a $9 million reduction in customer shopping incentives and a $1 million increase in other revenues.

In the first six months of 2006, revenues decreased by $57 million or 11.4% 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 $1 million due to a $44 million increase in generation sales revenues, a $15 million reduction in customer shopping incentives and a $1 million increase in other revenues, partially offset by a $59 million decrease in distribution revenues.

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

Changes in Generation KWH Sales Increase (Decrease)	**Three Months**	**Six Months**
Electric Generation:		
Retail	16.1%	12.8%
Wholesale	(57.6)%	(56.7)%
Net Decrease in Generation Sales	**(24.5)%**	**(23.8)%**

Changes in Generation Revenues Increase (Decrease)	**Three Months**	**Six Months**
	(In millions)	
Retail Generation:		
Residential	$ 17	$ 32
Commercial	13	22
Industrial	7	9
Total Retail Generation	37	63
Wholesale*	(14)	(19)
Net Increase in Generation Revenues	**$ 23**	**$ 44**

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

Retail generation revenues increased in all customer sectors as shown in the table above in the second quarter of 2006 compared to the corresponding quarter of 2005 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 - 52.5%, commercial - 15.5% and industrial - 7.1%) 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 - 34.4 percentage points, commercial - 11.4 percentage points and industrial - 2 percentage points.

In the first six 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 - 44.1%, commercial - 13.6% and industrial - 3.8%). Similar to the second 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 - 29 percentage points, commercial - 10 percentage points and industrial - 1.7 percentage points.

Lower wholesale revenues in the second quarter and first six months of 2006 reflected decreased revenues from non-affiliates ($5 million and $8 million, respectively) and decreased revenues from associated companies ($9 million and $11 million, respectively). The non-affiliated wholesale revenue decreases in 2006 were primarily due to the cessation of the MSG sales arrangements under TE's transition plan in December 2005. TE had been required to provide the MSG to non-affiliated alternative suppliers. The lower wholesale revenues from associated companies in 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 second quarter and first six months of 2006 from the corresponding periods of 2005 are summarized in the following table.

Changes in Distribution KWH Deliveries Increase (Decrease)	**Three Months**	**Six Months**
Distribution Deliveries:		
Residential	(6.6)%	(3.8)%
Commercial	(5.1)%	(4.4)%
Industrial	4.9%	1.9%
Net Decrease in Distribution Deliveries	**(0.5)%**	**(1.2)%**

Changes in Distribution Revenues		Three Months		Six Months
Increase (Decrease)		*(In millions)*		
Residential	$	(14)	$	(25)
Commercial		(16)		(29)
Industrial		(4)		(5)
Net Decrease in Distribution Revenues	**$**	**(34)**	**$**	**(59)**

The distribution revenue decreases as shown in the table above in the second quarter and first six 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 reflected 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 distribution deliveries to residential and commercial customers in both periods reflected the impact of milder weather in the second quarter and the first six 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 second quarter and first six months of 2006 by $9 million and $15 million, respectively. The deferred shopping incentives (Extended RTC) are currently being recovered under the RCP (see Outlook - Regulatory Matters).

Expenses

Total expenses decreased by $48 million and $114 million in the second quarter and the first six 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		Three Months		Six Months
Increase (Decrease)		*(In millions)*		
Fuel	$	-	$	1
Purchased power costs		8		4
Nuclear operating costs		(6)		(9)
Other operating costs		(1)		4
Provision for depreciation		-		2
Amortization of regulatory assets		(11)		(21)
Deferral of new regulatory assets		(2)		(6)
Net decrease in expenses	$	(12)	$	(25)

Higher purchased power costs in the second quarter of 2006 compared to the second 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. Decreased nuclear operating costs in the 2006 quarter were due to lower costs associated with TE's leasehold interest in Beaver Valley Unit 2. The decrease reflected the absence in 2006 of expenses in the second quarter of 2005 related to Beaver Valley Unit 2's 25-day nuclear refueling outage in April 2005.

Higher purchased power costs in the first six months of 2006 compared to the same period of 2005 reflected an increase in KWH purchased to meet higher retail generation sales requirements, partially offset by lower unit prices. The nuclear operating costs decrease in the first six months of 2006 was due to the reasons described above for the second quarter. Higher other operating costs reflect increased transmission expenses, primarily related to MISO Day 2 operations that began on April 1, 2005.

Excluding the effects of the generation asset transfers, depreciation charges in the first six months of 2006 increased due to distribution plant additions.

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 second quarter and first six months of 2006 primarily resulted from the deferrals of distribution costs ($7 million and $13 million in the second quarter and the first six months of 2006, respectively) and incremental fuel costs ($4 million and $7 million in the second quarter and the first six months of 2006, respectively) that began in 2006 under the RCP, partially offset by the impact of the termination of shopping incentive deferrals in 2006 ($9 million and $16 million in the second quarter and the first six months of 2006, respectively).

Other Income

Other income increased $5 million in the first six months of 2006 compared to the same period of 2005, primarily due to the effects of the generation asset transfers. Excluding the asset transfer effects, the $1 million increase reflected lower net interest charges and the absence of a charge of $1.6 million for an NRC fine related to Davis-Besse Plant in the first quarter of 2005, partially offset by the absence of interest income on a note from FGCO, which had a balloon repayment in May 2005.

Income Taxes

Income taxes decreased $10 million in the second quarter of 2006 and increased by $8 million in the first six months of 2006 compared to the same periods of 2005. Excluding the effects of the generation asset transfer, income taxes decreased in the second quarter and first six months of 2006 by $11 million and $6 million, respectively. These decreases were 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 increases in taxable income.

Preferred Stock Dividend Requirements

Lower preferred stock dividend requirements in the second quarter and first six months of 2006 compared to the corresponding 2005 periods were the result of $60 million of optional preferred stock redemptions subsequent to the end of the second quarter of 2005.

Capital Resources and Liquidity

During 2006, TE expects to meet its contractual obligations with a combination of cash from operations and short-term credit arrangements. In connection with a plan to realign its capital structure, TE may issue up to $300 million of new long-term debt in 2006 with proceeds expected to fund a return of equity capital to FirstEnergy.

Changes in Cash Position

As of June 30, 2006, TE had $23,000 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 six months of 2006, compared with the first six months of 2005, were as follows:

Operating Cash Flows	Six Months Ended June 30, 2006	2005
	(In millions)	
Cash earnings*	$ 34	$ 56
Working capital and other	(30)	(28)
Net cash provided from operating activities	$ 4	$ 28

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

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

Reconciliation of Cash Earnings	Six Months Ended June 30, 2006	2005
	(In millions)	
Net Income (GAAP)	$ 61	$ 8
Non-Cash Charges (Credits):		
Provision for depreciation	16	30
Amortization of regulatory assets	47	68
Deferral of new regulatory assets	(28)	(22)
Nuclear fuel and capital lease amortization	-	8
Amortization of electric service obligation	(4)	(1)
Deferred rents and lease market valuation liability	(46)	(44)
Deferred income taxes and investment tax credits, net	(13)	8
Accrued compensation and retirement benefits	1	1
Cash earnings (Non-GAAP)	$ 34	$ 56

Net cash provided from operating activities decreased by $24 million in the first six months of 2006 from the first six months of 2005 as a result of a $22 million decrease in cash earnings described above under “Results of Operations” and a $2 million decrease from working capital and other changes. The decrease in working capital and other primarily resulted from the absence in 2006 of funds received in 2005 for a prepaid electric service program and a reduction in cash received from the settlement of receivables, partially offset by lower cash payments on accounts payable.

Cash Flows From Financing Activities

Net cash used for financing activities decreased to $39 million in the first six months of 2006 from $113 million in the same period of 2005. The decrease resulted primarily from a $168 million increase in net short-term borrowings, partially offset by an $82 million net increase in preferred stock and long-term debt redemptions and a $15 million increase in common stock dividend payments to FirstEnergy in 2006.

TE had $46 million of cash and temporary investments (which included short-term notes receivable from associated companies) and $137 million of short-term indebtedness as of June 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 June 30, 2006, TE had the capability to issue $634 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 $1.1 billion of preferred stock (assuming no additional debt) was issued as of June 30, 2006.

TE, FirstEnergy, OE, Penn, CEI, JCP&L, Met-Ed, Penelec, FES and ATSI, as Borrowers, have entered into a syndicated $2 billion five-year revolving credit facility with a syndicate of banks that expires in June 2010. Borrowings under the facility are available to each Borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment expiration date, as the same may be extended. 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 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 June 30, 2006, TE's debt to total capitalization, as defined under the revolving credit facility, was 28%.

The 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 six months of 2006 was 4.86%.

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 their 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.

Cash Flows From Investing Activities

Net cash provided from investing activities decreased by $50 million in the first six months of 2006 from the same period of 2005 primarily due to a decrease in the collection of principal on long-term notes receivable. This 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. This decrease in cash receipts was 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 half of 2006 is expected to be approximately $29 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 $232 million, of which approximately $58 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 June 30, 2006, the present value of these operating lease commitments, net of trust investments, totaled $498 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 June 30, 2006 and December 31, 2005 were $267 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 September 28, 2005, the Supreme Court of Ohio heard oral arguments on the appeals. 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 one matter back to the PUCO for further consideration of the issue as to whether the RSP, as adopted by the PUCO, provided for sufficient means for customer participation in the competitive marketplace. On May 12, 2006, the Ohio Companies filed a Motion for Reconsideration with the Supreme Court of Ohio which was denied by the Court on June 21, 2006. 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.

The Ohio Companies filed an application and stipulation with the PUCO on September 9, 2005 seeking approval of the RCP. 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	$	86
2007		90
2008		111
Total Amortization	**$**	**287**

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 their 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 are due on August 4, 2006. Appellent’s Reply Briefs will then be due in August 24, 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 May 1, 2006, TE filed a modification to the rider to determine revenues ($19 million) from July 2006 through June 2007.

The second application sought authority to defer costs associated with transmission and ancillary service related costs incurred during the period from October 1, 2003 through December 31, 2005. On May 18, 2005, the PUCO granted the accounting authority for the Ohio Companies to defer incremental transmission and ancillary service-related charges incurred as a participant in 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 unable to predict when a decision may be issued.

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.

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 upon the procedural schedule, approved in the case, FES expected an initial decision to be issued inin 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. The procedural schedule has been suspended pending negotiations among the parties.

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 June 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 June 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 the 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 outage. 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. FirstEnergy filed a Motion to Dismiss on June 13, 2006. It is currently expected that this case will be summarily dismissed, although the Motion is still pending. On March 7, 2006, the PUCO issued a ruling 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. These motions are pending. Additionally, on June 23, 2006, one of the insurance carrier complainants filed an appeal with the Ohio Supreme Court over the PUCO’s denial of their motion for rehearing on the issue of the admissibility of the Task Force Report and the dismissal of FirstEnergy Corp. as a respondent. Briefing is expected to be completed on this appeal by mid-September. It is unknown when the Supreme Court will rule on the appeal. 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 described above. 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 60 days from the denial of rehearing to appeal the PUCO's decision.

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 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

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 June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
STATEMENTS OF INCOME		*(In thousands)*		
REVENUES	$ 80,650	$ 134,282	$ 163,369	$ 268,766
EXPENSES:				
Fuel	-	5,526	-	11,146
Purchased power	56,513	42,726	111,269	89,706
Nuclear operating costs	-	19,765	-	39,713
Other operating costs	14,124	16,743	28,328	29,511
Provision for depreciation	1,695	3,810	4,126	7,504
Amortization of regulatory assets	-	9,833	3,411	19,715
General taxes	5,670	6,444	11,504	12,916
Total expenses	78,002	104,847	158,638	210,211
OPERATING INCOME	2,648	29,435	4,731	58,555
OTHER INCOME (EXPENSE):				
Miscellaneous income	3,388	924	6,851	(223)
Interest expense	(1,407)	(2,787)	(5,362)	(5,106)
Capitalized interest	48	1,476	82	2,843
Total other income (expense)	2,029	(387)	1,571	(2,486)
INCOME TAXES	1,928	13,337	2,807	25,356
NET INCOME	2,749	15,711	3,495	30,713
PREFERRED STOCK DIVIDEND REQUIREMENTS	155	738	311	1,378
EARNINGS ON COMMON STOCK	$ 2,594	$ 14,973	$ 3,184	$ 29,335

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)

	June 30, 2006	December 31, 2005
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 38	$ 24
Receivables -		
Customers (less accumulated provisions of $1,073,000 and $1,087,000, respectively, for uncollectible accounts)	38,303	44,555
Associated companies	81,688	115,441
Other	1,332	2,889
Notes receivable from associated companies	1,838	1,699
Prepayments and other	17,728	86,995
	140,927	251,603
UTILITY PLANT:		
In service	365,959	359,069
Less - Accumulated provision for depreciation	131,181	129,118
	234,778	229,951
Construction work in progress-	5,457	3,775
	240,235	233,726
OTHER PROPERTY AND INVESTMENTS:		
Long-term notes receivable from associated companies	276,052	283,248
Other	350	351
	276,402	283,599
DEFERRED CHARGES AND OTHER ASSETS:		
Prepaid pension costs	43,056	42,243
Other	1,775	3,829
	44,831	46,072
	$ 702,395	$ 815,000
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 15,474	$ 69,524
Short-term borrowings -		
Associated companies	2,161	12,703
Other	19,000	-
Accounts payable -		
Associated companies	20,420	73,444

Other		2,073		1,828
Accrued taxes		23,029		28,632
Accrued interest		1,070		1,877
Other		6,874		8,086
		90,101		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		40,281		37,097
Total common stockholder's equity		300,117		296,933
Preferred stock		14,105		14,105
Long-term debt and other long-term obligations		123,343		130,677
		437,565		441,715
NONCURRENT LIABILITIES:				
Accumulated deferred income taxes		63,698		66,576
Retirement benefits		46,845		45,967
Regulatory liabilities		58,822		58,637
Other		5,364		6,011
		174,729		177,191
COMMITMENTS AND CONTINGENCIES (Note 10)				
	$	702,395	$	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)

	Six Months Ended June 30, 2006	2005
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 3,495	$ 30,713
Adjustments to reconcile net income to net cash from operating activities -		
Provision for depreciation	4,126	7,504
Amortization of regulatory assets	3,411	19,715
Nuclear fuel and other amortization	-	8,278
Deferred income taxes and investment tax credits, net	(2,383)	(4,955)
Decrease (increase) in operating assets -		
Receivables	41,562	10,838
Materials and supplies	-	(806)
Prepayments and other current assets	69,267	(8,260)
Increase (decrease) in operating liabilities -		
Accounts payable	(52,779)	(19,895)
Accrued taxes	(5,602)	12,103
Accrued interest	(807)	116
Other	(3,290)	463
Net cash provided from operating activities	57,000	55,814
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing -		
Short-term borrowings, net	8,458	33,745
Redemptions and Repayments -		
Preferred stock	-	(37,750)
Long-term debt	(61,899)	(810)
Short-term borrowings, net	-	-
Dividend Payments -		
Common stock	-	(8,000)
Preferred stock	(311)	(1,378)
Net cash used for financing activities	(53,752)	(14,193)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(10,216)	(41,093)

Proceeds from nuclear decommissioning trust fund sales		-		36,995
Investments in nuclear decommissioning trust funds		-		(37,792)
Loan repayments from associated companies		7,057		173
Other		(75)		82
Net cash used for investing activities		(3,234)		(41,635)
Net increase (decrease) in cash and cash equivalents		14		(14)
Cash and cash equivalents at beginning of period		24		38
Cash and cash equivalents at end of period	$	38	$	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 June 30, 2006, and the related consolidated statement of income for each of the three-month and six-month periods ended June 30, 2006 and 2005 and the consolidated statement of cash flows for the six-month period ended June 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
August 4, 2006

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

In 2005, Penn and 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, 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, Penn completed the intra-system transfer of its 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 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 second quarter and first six months of 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				
Increase (Decrease)		**Three Months**	***(In millions)***	**Six Months**
Revenues:				
Non-nuclear generating units rent	(a)	$ (5)		$ (10)
Nuclear generated KWH sales	(b)	(38)		(76)
Total - Revenues Effect		(43)		(86)
Expenses:				
Fuel costs - nuclear	(c)	(5)		(11)
Nuclear operating costs	(c)	(20)		(40)
Provision for depreciation	(d)	(1)		(3)
General taxes	(e)	(1)		(1)
Total - Expenses Effect		(27)		(54)
Operating Income Effect		(16)		(32)
Other Income:				
Interest income from notes receivable	(f)	2		5)
Capitalized Interest	(g)	(1)		(3)
Total - Other Income Effect		1		2
Income taxes	(h)	(6)		(12)
Net Income Effect		$ (9)		$ (18)

(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.

Results of Operations

Earnings on common stock in the second quarter of 2006 decreased to $2.6 million from $15 million in the second quarter of 2005. During the first six months of 2006 earnings on common stock decreased to $3.2 million from $29 million in the first six months of 2005. The lower earnings resulted principally from the generation asset transfer effects shown in the table above.

Revenues

Revenues decreased by $54 million, or 40%, and $105 million, or 39%, in the second quarter of 2006 and the first six months of 2006, respectively, as 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 asset transfer, revenues decreased by $11 million, or 12% and $19 million, or 11%, in the second quarter and the first six months of 2006, respectively. The decreases in the second quarter and the first half of 2006 resulted from lower distribution revenues ($9 million and $18 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 $12 million, respectively) resulting from the termination of a wholesale sales agreement with a non-affiliate in December 2005. These decreases were partially offset by an increase in retail generation revenues of $5 million in the second quarter of 2006 and $11 million in the first six 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 - total retail generation KWH sales remained substantially unchanged.

Lower distribution KWH deliveries to residential and commercial customers in the second quarter and first six months of 2006 reflect the impact of milder weather conditions compared to the same periods of 2005. Higher KWH deliveries to industrial customers in both periods of 2006 are largely due to increased demand from the steel sector.

Changes in distribution deliveries in the second quarter and the first six months of 2006 from the same periods of 2005 are summarized in the following table:

Changes in Distribution Deliveries	Three Months	Six Months
Increase (Decrease)		
Distribution Deliveries:		
Residential	(7.8)%	(4.9)%
Commercial	(4.1)%	(2.7)%
Industrial	10.3%	7.2%
Total Distribution Deliveries	**-%**	**(0.04)%**

Expenses

Total expenses decreased by $27 million in the second quarter and $52 million in the first six 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 presents changes from the prior year by expense category:

Expenses - Changes	Three Months	Six Months
	(In millions)	
Increase (Decrease)		
Purchased power costs	$ 14	$ 21
Other operating costs	(3)	(1)
Provision for depreciation	(1)	-
Amortization of regulatory assets	(10)	(16)
General Taxes	-	(1)
Net change in expenses	**$ -**	**$ 3**

Increased purchased power costs in the second quarter and the first six 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 and a decrease in the use of outside contractors for tree trimming. The provision for depreciation included an immaterial pretax adjustment of $0.7 million ($0.4 million net of tax) applicable to prior periods.

Amortization of regulatory assets was lower in the second quarter and the first six months of 2006 as compared to the same periods of 2005 due to the completion of Penn's rate restructuring plan and related transition cost amortization.

Other Income (Expense)

Investment income increased $2 million in the second quarter and $7 million the first six months of 2006, compared with the same periods of 2005, primarily due to the impact of the generation asset transfer.

Net Interest Charges

Net interest charges were substantially unchanged in the second quarter and increased $3 million in the first six months as compared to the same periods of 2005 primarily due to the reduction of capitalized interest related to the generation asset transfer.

Capital Resources and Liquidity

Penn’s cash requirements in 2006 for expenses, construction expenditures and scheduled debt maturities are expected to be met with a combination of cash from operations and short-term credit arrangements. Available borrowing capacity under credit facilities will be used to manage working capital requirements.

Changes in Cash Position

Penn had $38,000 of cash and cash equivalents as of June 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 six months of 2006, compared with the corresponding 2005 period, was as follows:

Operating Cash Flows	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(in millions)	
Cash earnings (*)	$ 9	$ 62
Working capital and other	48	(6)
Net cash provided from operating activities	$ 57	$ 56

(*) 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 are a useful financial measure because it provides investors and management with an additional means of evaluating its cash-based operating performance. The following table reconciles cash earnings with net income:

Reconciliation of Cash Earnings	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(In millions)	
Net income (GAAP)	$ 3	$ 31
Non-cash charges (credits):		
Provision for depreciation	4	8
Amortization of regulatory assets	3	20
Nuclear fuel and other amortization	-	8
Deferred income taxes and investment tax credits, net	(2)	(5)
Other non-cash Items	1	-
Cash earnings (Non-GAAP)	$ 9	$ 62

The $53 million decrease in cash earnings for the first six months of 2006, as compared to the corresponding period of 2005, is described above under “Results of Operations”, and resulted principally from the impact of the generation asset transfer. The $54 million change in working capital was primarily due to increases in cash provided from the settlement of receivables of $31 million and a $78 million change in prepayments and other current assets, principally as a result of the asset transfer discussed above. These variances were partially offset by increased cash outflows from the settlement of accounts payable of $33 million and an $18 million change in accrued taxes.

Cash Flows From Financing Activities

Net cash used for financing activities totaled $54 million in the first six months of 2006, compared with $14 million in the same period of 2005. The $40 million increase resulted from $62 million of long-term debt redemptions in 2006 principally related to the generation asset transfer discussed above and a $25 million decrease in short-term borrowings, partially offset by decreases of $38 million in preferred stock redemptions and reductions of $8 million in common stock dividend payments to OE as compared to the first six months of 2005.

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 as of June 30, 2006. Penn has authorization from the SEC, continued by FERC rules adopted as a result of EPACT's repeal of PUHCA, to incur short-term debt up to its charter limit of $44 million (including the utility money pool). Penn had the capability to issue $66 million of additional FMB on the basis of property additions and retired bonds as of June 30, 2006. Based upon applicable earnings coverage tests, Penn could issue up to $290 million of preferred stock (assuming no additional debt was issued) as of June 30, 2006.

Short-term borrowings outstanding as of June 30, 2006, consisted of $19 million of borrowings from affiliates. 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 at rates based on bank commercial paper rates. The financing arrangements require payment of an annual facility fee of 0.125% on the entire finance limit. Penn Funding's receivables financing agreements expire June 28, 2007. As a separate legal entity with separate creditors, it would have to satisfy its separate obligations to creditors before any of its remaining assets could be made available to Penn.

Penn has the ability to borrow under a syndicated $2 billion five-year revolving credit facility, which expires in June 2010, along with FirstEnergy, OE, CEI, TE, JCP&L, Met-Ed, Penelec, FES, and ATSI. 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 commitment termination date. Penn's borrowing limit under the facility is $50 million.

Under the revolving credit facility, borrowers may request the issuance of LOC's expiring up to one year from the date of issuance. The stated amount of outstanding LOC's 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 June 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 June 30, 2006, Penn's debt to total capitalization as defined under the revolving credit facility was 34%.

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 six months of 2006 was 4.86%.

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 six 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 used for investing activities totaled $3 million in the first six months of 2006, compared with $42 million in the same period of 2005. The $39 million decrease in the 2006 period reflects a $31 million reduction in property additions, 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 half of 2006, capital requirements for property additions are expected to be approximately $8 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 $90 million of which approximately $18 million applies to 2006. Penn had no other material obligations as of June 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 $59 million as of June 30, 2006 and 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. To the extent that an affiliate of Penn supplies a portion of the PLR load included in the RFP, authorization to make the affiliate sale must be obtained from the FERC. 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 to obtain Penn's power supply requirements after 2006 through two separate solicitations. An initial solicitation was held for Penn in May 2006 with all tranches fully subscribed. On June 2, 2006, the PPUC approved the bid results for the first solicitation. 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 only acquired for three of the five tranches for the Large Commercial Group. On July 20, 2006, the PPUC approved the submissions for the second bid. A residual solicitation is scheduled to be held on August 15, 2006 for the two remaining Large Commercial Group tranches. Acceptance of the winning bids is subject to approval by the PPUC.

On November 1, 2005, FES filed a power sales agreement for approval with the FERC that would permit Penn to obtain its PLR power requirements from FES at a fixed price equal to the retail generation price during 2006. As discussed above, subsequent to the PPUC’s approval of Penn's plan for the RFP process to obtain its post 2006 power supply requirements, the customer power supply requirements for all of the residential and the small commercial sectors and the majority of the large commercial sector tranches have been fully subscribed and the bids approved by the PPUC. An additional solicitation for the remaining two large commercial sector tranches is scheduled for August 15, 2006.

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 its recovery of certain PLR costs via a reconciliation mechanism and its 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.

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. Those 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 the 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.

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

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. 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 June 30, 2006	Three Months Ended June 30, 2005 Restated	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005 Restated
STATEMENTS OF INCOME		*(In thousands)*		
REVENUES	$ 611,484	$ 595,291	$ 1,187,276	$ 1,124,383
EXPENSES				
Purchased power	343,045	321,393	658,755	598,525
Other operating costs	72,105	80,239	155,133	181,306
Provision for depreciation	20,826	19,856	41,454	40,062
Amortization of regulatory assets	65,526	70,250	132,271	138,624
Deferral of new regulatory assets	-	(27,765)	-	(27,765)
General taxes	14,272	14,824	30,504	30,264
Total expenses	515,774	478,797	1,018,117	961,016
OPERATING INCOME	95,710	116,494	169,159	163,367
OTHER INCOME (EXPENSE):				
Miscellaneous income	2,528	201	6,071	487
Interest Expense	(20,367)	(20,100)	(40,983)	(41,003)
Capitalized interest	1,037	437	1,929	840
Total other income (expense)	(16,802)	(19,462)	(32,983)	(39,676)
INCOME TAXES	38,632	42,729	62,190	55,939
NET INCOME	40,276	54,303	73,986	67,752
PREFERRED STOCK DIVIDEND REQUIREMENTS	125	125	250	250
EARNINGS ON COMMON STOCK	$ 40,151	$ 54,178	$ 73,736	$ 67,502
STATEMENTS OF COMPREHENSIVE INCOME				

NET INCOME	$	40,276	$	54,303	$	73,986	$	67,752
OTHER COMPREHENSIVE INCOME:								
Unrealized gain on derivative hedges		38		36		107		105
Income tax expense related to other comprehensive income		15		15		43		43
Other comprehensive income, net of tax		23		21		64		62
TOTAL COMPREHENSIVE INCOME	$	40,299	$	54,324	$	74,050	$	67,814

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)

	June 30, 2006	December 31, 2005
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 95	$ 102
Receivables-		
Customers (less accumulated provisions of $3,078,000 and $3,830,000, respectively, for uncollectible accounts)	282,352	258,077
Associated companies	142	203
Other (less accumulated provisions of $206,000 and $204,000, respectively, for uncollectible accounts)	41,317	41,456
Notes receivable - associated companies	27,766	18,419
Materials and supplies, at average cost	2,012	2,104
Prepayments (sales & use, corp. business, TEFA) taxes	110,787	10,137
Prepayments and other	5,210	6,928
	469,681	337,426
UTILITY PLANT:		
In service	3,983,859	3,902,684
Less - Accumulated provision for depreciation	1,454,291	1,445,718
	2,529,568	2,456,966
Construction work in progress	77,325	98,720
	2,606,893	2,555,686
OTHER PROPERTY AND INVESTMENTS:		
Nuclear fuel disposal trust	165,132	164,203
Nuclear plant decommissioning trusts	149,000	145,975
Other	2,069	2,580
	316,201	312,758
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	2,121,811	2,226,591
Goodwill	1,978,141	1,985,858
Prepaid pension costs	150,760	148,054
Other	16,410	17,733
	4,267,122	4,378,236
	$ 7,659,897	$ 7,584,106
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 57,586	$ 207,231
Notes payable-		
Associated companies	365,164	181,346

Accounts payable-				
Associated companies		16,425		37,955
Other		194,619		149,501
Accrued taxes		45,295		54,356
Accrued interest		20,278		19,916
Cash collateral from suppliers		32,434		141,225
Other		78,214		86,884
		810,015		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		2,995,542		3,003,190
Accumulated other comprehensive loss		(1,966)		(2,030)
Retained earnings		104,626		55,890
Total common stockholder's equity		3,251,915		3,210,763
Preferred stock		12,649		12,649
Long-term debt and other long-term obligations		1,162,407		972,061
		4,426,971		4,195,473
NONCURRENT LIABILITIES:				
Power purchase contract loss liability		1,122,933		1,237,249
Accumulated deferred income taxes		827,760		812,034
Nuclear fuel disposal costs		179,039		175,156
Asset retirement obligation		81,949		79,527
Retirement benefits		72,520		72,454
Other		138,710		133,799
		2,422,911		2,510,219
COMMITMENTS AND CONTINGENCIES (Note 10)				
	$	7,659,897	$	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)

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005 Restated
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 73,986	$ 67,752
Adjustments to reconcile net income to net cash from operating activities -		
Provision for depreciation	41,454	40,062
Amortization of regulatory assets	132,271	138,624
Deferral of new regulatory assets	-	(27,765)
Deferred purchased power and other costs	(134,759)	(126,265)
Deferred income taxes and investment tax credits, net	10,942	16,426
Accrued compensation and retirement benefits	(3,436)	(8,029)
Cash collateral from (returned to) suppliers	(108,791)	198
Decrease (increase) in operating assets -		
Receivables	(24,074)	14,271
Materials and supplies	91	177
Prepayments and other current assets	(98,932)	(66,525)
Increase (decrease) in operating liabilities -		
Accounts payable	23,589	32,087
Accrued taxes	(9,062)	58,139
Accrued interest	362	580
Other	(1,642)	16,856
Net cash provided from (used for) operating activities	(98,001)	156,588
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	200,003	-
Short-term borrowings, net	183,818	30,572
Redemptions and Repayments-		
Long-term debt	(157,659)	(63,327)
Dividend Payments-		
Common stock	(25,000)	(40,000)
Preferred stock	(250)	(250)
Net cash provided from (used for) financing activities	200,912	(73,005)

CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions		(91,101)		(82,661)
Loan repayments from (loans to) associated companies, net		(9,347)		670
Proceeds from nuclear decommissioning trust fund sales		109,505		53,782
Investments in nuclear decommissioning trust funds		(110,952)		(55,229)
Other		(1,023)		105
Net cash used for investing activities		(102,918)		(83,333)
Net increase (decrease) in cash and cash equivalents		(7)		250
Cash and cash equivalents at beginning of period		102		162
Cash and cash equivalents at end of period	$	95	$	412

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

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 June 30, 2006, and the related consolidated statements of income and comprehensive income for each of the three-month and six-month periods ended June 30, 2006 and 2005 and the consolidated statement of cash flows for the six-month period ended June 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
August 4, 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 six months ended June 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 second quarter of 2006 decreased to $40.2 million from $54.2 million in 2005. The decrease was principally due to the absence of the deferral of a new regulatory asset in 2005 and increased purchased power costs, partially offset by increased revenues and decreased other operating costs. In the first six months of 2006, earnings on common stock increased to $73.7 million compared to $67.5 million for the same period in 2005. The increase was primarily due to higher revenues and lower other operating costs partially offset by increased purchased power costs and the absence of the regulatory asset deferred in 2005.

Revenues

Revenues increased $16.2 million or 2.7% in the second quarter of 2006 and $62.9 million or 5.6% for the first six months of 2006 compared with the same periods of 2005. The higher revenues in both periods were primarily due to retail generation revenue increases ($28.5 million and $66.3 million in the second quarter and the first six months of 2006, respectively), partially offset by wholesale revenue decreases ($7.6 million in the second quarter and $5.8 million in the first six months of 2006). Distribution revenues declined $1.1 million in the second quarter of 2006 but increased $4.2 million in the first six months of 2006 compared to the same periods of the prior year.

The retail generation revenue increases in both the second quarter and the first six months of 2006 as compared to the previous year were due to higher unit prices resulting from the BGS auctions effective in May 2006 and May 2005, which partially offset declines in retail generation KWH sales. Revenue from residential customers increased $12.7 million and $27.6 million in the second quarter and the first six months of 2006, respectively, as compared to the same periods in 2005. Generation revenue from commercial customers also increased for the same periods by $15.3 million and $36.3 million, respectively. The milder weather in the second quarter and the first six months of 2006 as compared to the previous year (cooling degree days were 3.5% below the previous year and heating degree days were 18.6% below the previous year) resulted in lower KWH sales to residential customers in the second quarter and the first six months of 2006. The milder weather also resulted in overall lower KWH sales to commercial customers in the second quarter and first six months of 2006 - more than offsetting the impact of commercial customers returning to JCP&L from alternative suppliers. Revenues from industrial customers increased $0.3 million and $2.1 million in the second quarter and first six months of 2006, respectively, as compared to the previous year, as a result of higher unit prices offsetting KWH sales decreases in the second quarter and the first six months of 2006. Wholesale sales revenues decreased $7.6 million in the second quarter and $5.8 million for the first six months of 2006 as compared to 2005 as lower unit prices offset KWH sales increases.

The decrease in distribution revenues of $1.1 million in the second quarter of 2006 compared to the same period of 2005 consists of two components, a $1.8 million increase in wires revenue and a $2.9 million reduction in MTC and SBC revenues. The distribution revenue reduction was primarily due to lower KWH throughput partially offset by higher composite unit prices resulting from a distribution rate increase pursuant to the stipulated settlements approved by the NJBPU on May 25, 2005. While distribution KWH deliveries declined for the first six months of 2006 as compared to the previous year, the impact of a full six months of 2006 of the distribution rate increase caused revenues to increase $4.2 million. Wires revenue increased $13.3 million while the MTC and SBC revenues declined $9.1 million. Other revenues declined $3.6 million in the second quarter and $1.8 million in the first six months of 2006 as compared to the comparable periods in 2005 due to reduced transmission revenues.

Changes in KWH sales by customer class in the second quarter and the first six months of 2006 compared to the same periods of 2005 are summarized in the following table:

Changes in KWH Sales	Three Months	Six Months
Increase (Decrease)		
Electric Generation:		
Retail	(3.3)%	(1.4)%
Wholesale	2.2%	1.1 %
Total Electric Generation Sales	**(2.1)%**	**(0.9)%**
Distribution Deliveries:		
Residential	(5.3)%	(4.7)%
Commercial	(0.3)%	(0.7)%
Industrial	(6.5)%	(6.8)%
Total Distribution Deliveries	**(3.2)%**	**(3.3)%**

Expenses

Total expenses and taxes increased by $37.1 million in the second quarter and $57.0 million in the first six 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	Six Months
	(In millions)	
Increase (Decrease)		
Purchased power costs	$ 21.7	$ 60.2
Other operating costs	(8.1)	(26.2)
Provision for depreciation	1.0	1.4
Amortization of regulatory assets	(4.7)	(6.4)
Deferral of new regulatory assets	27.8	27.8
General Taxes	(0.6)	0.2
Net increase in expenses	$ 37.1	$ 57.0

Purchased power costs increased $21.7 million in the second quarter of 2006 and $60.2 million in the first six months compared to the same periods of 2005. The increase reflected higher unit prices resulting from the 2006 and 2005 BGS auctions. The change in the deferral of new regulatory assets of $27.8 million in both periods was due to the absence of a 2005 deferral of reliability expenses reflecting a May 2005 NJBPU rate decision. Other operating costs declined $8.1 million in the second quarter and $26.2 million for the first six months of 2006 due in part to the absence of costs related to the JCP&L labor strike in 2005. Amortization of regulatory assets decreased $4.7 million in the second quarter and $6.4 million in the first six months of 2006 due to a reduction in the level of MTC revenue recovery.

Miscellaneous income increased $2.3 million in the second quarter of 2006 and $5.6 million in the first six months compared to the same periods in 2005. The increases in both periods is attributed to income received from customer requested service projects.

Capital Resources and Liquidity

JCP&L's cash requirements in 2006 for expenses, construction expenditures and scheduled debt maturities are expected to be met with a combination of cash from operations and funds from the capital markets.

Changes in Cash Position

As of June 30, 2006, JCP&L had $95,000 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 six months of 2006 compared with the first six months of 2005 were as follows:

Operating Cash Flows	Six Months Ended June 30, 2006	2005
	(In millions)	
Cash earnings [1]	$ 120	$ 101
Working capital and other	(218)	56
Net cash provided from operating activities	$ (98)	$ 157

[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 are a useful financial sure because it provides investors and management with an additional means of evaluating its cash-based operating performance. The following table reconciles cash earnings with net income:

Reconciliation of Cash Earnings	Six Months Ended June 30, 2006	2005
	(In millions)	
Net income (GAAP)	$ 74	$ 68
Non-cash charges (credits):		
Provision for depreciation	41	40
Amortization of regulatory assets	132	139
Deferral of new regulatory assets	-	(28)
Deferred purchased power and other costs	(135)	(126)
Deferred income taxes	11	16
Other non-cash items	(3)	(8)
Cash earnings (Non-GAAP)	$ 120	$ 101

The $19 million increase in cash earnings is described under "Results of Operations." The $274 million decrease from working capital changes primarily resulted from a $109 million change in cash collateral from suppliers, changes in prepayments of $32 million, accrued taxes of $67 million and receivables of $38 million. In the year 2005, JCP&L received cash collateral payments from its suppliers of $135 million. During the first six months of 2006, JCP&L returned $109 million back to its suppliers.

Cash Flows From Financing Activities

Net cash provided from financing activities was $201 million in the first six months of 2006 as compared to net cash used of $73 million in same period of 2005. The change resulted from a $200 million issuance of long-term debt, a $153 million increase in short-term borrowings and a $15 million reduction in common stock dividend payments to FirstEnergy, partially offset by $94 million of additional debt redemptions in the first six months of 2006.

JCP&L had $28 million of cash and temporary investments (which includes short-term notes receivable from associated companies) and approximately $365 million of short-term indebtedness as of June 30, 2006. JCP&L has authorization from the SEC, continued by FERC rules adopted as a result of EPACT's repeal of PUHCA, to incur short-term debt up to its charter limit of $412 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 June 30, 2006, JCP&L had the capability to issue $610 million of additional senior notes based upon FMB collateral. As of June 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 six months of 2006 was 4.86%.

JCP&L, FirstEnergy, OE, Penn, CEI, TE, Penelec, Met-Ed, FES and ATSI, as Borrowers, have entered into a syndicated $2 billion five-year revolving credit facility which expires in June 2010. Borrowings under the facility are available to each Borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. JCP&L's borrowing limit under the facility is $425 million.

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 June 30, 2006, JCP&L's debt to total capitalization as defined under the revolving credit facility was 29%.

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 June 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 4, 2006, JCP&L Transition Funding II, a wholly owned subsidiary of JCP&L, secured pricing on the issuance of $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 will use the proceeds it receives from the issuer 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 $103 million in the first six months of 2006 compared to $83 million in the previous year. The $20 million change primarily resulted from increases of $8 million in property additions for distribution system reliability initiatives and $9 million of loans to associated companies.

During the last half of 2006, capital requirements for property additions and improvements are expected to be about $72 million. 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.

JCP&L’s capital spending for the period 2006-2010 is expected to be approximately $912 million for property additions, of which approximately $162 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. Its Risk Policy Committee, comprised of members of senior management, provides general management oversight to risk management activities throughout JCP&L. They are responsible for promoting the effective design and implementation of sound risk management programs. They also oversee compliance with corporate risk management policies and established risk management practices.

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 power purchase agreements with NUG entities that were structured pursuant to the Public Utility Regulatory Policy Act of 1978. These non-trading contracts are 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 second quarter and first six months of 2006 are summarized in the following table:

Increase (Decrease) in the Fair Value of Commodity Derivative Contracts	**Three Months Ended June 30, 2006**			**Six Months Ended June 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	$ (1,173)	$ -	$ (1,173)	$ (1,223)	$ -	$ (1,223)
New contract value when entered	-	-	-	-	-	-
Additions/change in value of existing contracts	(15)	-	(15)	(30)	-	(30)
Change in techniques/assumptions	-	-	-	-	-	-
Settled contracts	76	-	76	141	-	141
Net Liabilities - Derivative Contracts at End of Period (1)	$ (1,112)	$ -	$ (1,112)	$ (1,112)	$ -	$ (1,112)
Impact of Changes in Commodity Derivative Contracts(2)						
Income Statement effects (pre-tax)	$ (1)	$ -	$ (1)	$ (1)	$ -	$ (1)
Balance Sheet effects:						
Regulatory assets (net)	$ (62)	$ -	$ (62)	$ (112)	$ -	$ (112)

(1) Includes $1,112 million of non-hedge commodity derivative contracts (primarily with NUGs), 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 June 30, 2006 as follows:

Balance Sheet Classification	**Non-Hedge**	**Hedge**	**Total**
		(In millions)	
Non-Current-			
Other deferred charges	11	-	11
Other noncurrent liabilities	(1,123)	-	(1,123)
Net liabilities	**$ (1,112)**	**$ -**	**$ (1,112)**

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 June 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)	$ (147)	(257)	(226)	-	-	-	(630)
Prices based on models	-	-	-	(168)	(144)	(170)	(482)
Total(3)	**$ (147)**	**$ (257)**	**$ (226)**	**$ (168)**	**$ (144)**	**$ (170)**	**$ (1,112)**

(1) For the last two quarters of 2006.
(2) Broker quote sheets.
(3) Includes $1,112 million of non-hedge commodity derivative contracts (primarily with NUGs), that are offset by a regulatory asset and does not affect earnings.

JCP&L performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% adverse shift in quoted market prices in the near term on 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 June 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 $86 million and $84 million as of June 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 June 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 $2.1 billion as of June 30, 2006 and $2.2 billion as of 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 June 30, 2006, the accumulated deferred cost balance totaled approximately $638 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 4, 2006, JCP&L Transition Funding II, a wholly owned subsidiary of JCP&L, secured pricing on the issuance of $182 million of transition bonds with a weighted average interest rate of 5.5%.

On December 2, 2005, JCP&L filed a 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. A schedule for the proceeding was established, including a discovery period and evidentiary hearings scheduled for September 2006.

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 last of the quarterly reliability reports was submitted on June 12, 2006. As of June 30, 2006, there were no performance penalties issued by the NJBPU.

In a reaction 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. A final decision as to the procurement method for the Commercial Industrial Energy Price Class is expected in October 2006.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004 supporting a continuation of the current level and duration of the funding of TMI-2 decommissioning costs by its 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 those comments. A schedule for further 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. The NJBPU Staff issued a 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. JCP&L is unable to predict the outcome of this proceeding.

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 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 FERC has ordered the Presiding Judge to issue an initial decision by August 11, 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. The Companies, as part of the Responsible Pricing Alliance, intend to submit a brief on exceptions within thirty days of the initial decision.

Following submission of reply exceptions, the case is expected to 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 June 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 $54.7 million have been accrued through June 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 the result of adoption of mandatory reliability standards pursuant to the EPACT that could require additional material expenditures.

In addition to the above proceedings, FirstEnergy was named in a complaint filed in Michigan State Court by an individual who is not a customer of any FirstEnergy company. FirstEnergy's motion to dismiss the matter was denied on June 2, 2006. FirstEnergy has since filed an appeal, which is pending. A responsive pleading to this matter has been filed. Also, the complaint has been amended to include an additional party. No estimate of potential liability has been undertaken in this matter.

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 Arbitrator decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the Arbitrator issued an opinion to award approximately $16 million to the bargaining unit employees. On February 6, 2006, the federal court granted a Union motion to dismiss JCP&L's appeal of the award as premature. JCP&L will file its 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

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. 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.

SUBSEQUENT EVENTS

New Jersey Law Change

On July 8, 2006, the Governor of New Jersey signed tax legislation that increased the current New Jersey Corporate Business tax by an additional 4% surtax, which increases the effective tax from 9% to 9.36%. This increase applies to JCP&L's 2006 through 2008 tax years and is not expected to have a material impact on JCP&L's results of operations.

METROPOLITAN EDISON COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(In thousands)			
REVENUES	$ 282,219	$ 263,136	$ 593,432	$ 558,917
EXPENSES:				
Purchased power	143,070	131,670	302,957	281,763
Other operating costs	59,575	52,648	120,654	111,118
Provision for depreciation	10,288	11,377	21,193	22,898
Amortization of regulatory assets	25,669	25,286	55,717	53,907
Deferral of new regulatory assets	(45,581)	-	(45,581)	-
General taxes	18,595	17,023	39,216	36,295
Total expenses	211,616	238,004	494,156	505,981
OPERATING INCOME	70,603	25,132	99,276	52,936
OTHER INCOME (EXPENSE):				
Interest income	8,964	9,442	17,714	18,469
Miscellaneous income	1,792	3,288	4,404	4,429
Interest expense	(12,071)	(11,398)	(23,255)	(22,621)
Capitalized interest	344	73	611	251
Total other income (expense)	(971)	1,405	(526)	528
INCOME TAXES	29,555	10,874	40,759	21,325
NET INCOME	40,077	15,663	57,991	32,139
OTHER COMPREHENSIVE INCOME:				
Unrealized gain on derivative hedges	84	84	168	168
Income tax expense related to other comprehensive income	35	35	70	70
Other comprehensive income, net of tax	49	49	98	98
TOTAL COMPREHENSIVE INCOME	$ 40,126	$ 15,712	$ 58,089	$ 32,237

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)

	June 30, 2006	December 31, 2005
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 134	$ 120
Receivables-		
Customers (less accumulated provisions of $4,069,000 and $4,352,000, respectively, for uncollectible accounts)	128,349	129,854
Associated companies	1,881	37,267
Other	7,489	8,780
Notes receivable from associated companies	31,921	27,867
Prepaid gross receipts taxes	25,361	2,072
Prepayments and other	7,115	5,840
	202,250	211,800
UTILITY PLANT:		
In service	1,885,164	1,856,425
Less - Accumulated provision for depreciation	723,799	721,566
	1,161,365	1,134,859
Construction work in progress	20,737	20,437
	1,182,102	1,155,296
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	243,179	234,854
Other	1,367	1,453
	244,546	236,307
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	860,485	864,438
Regulatory assets	358,963	309,556
Prepaid pension costs	92,472	89,005
Other	47,673	51,285
	1,359,593	1,314,284
	$ 2,988,491	$ 2,917,687
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 150,000	$ 100,000
Short-term borrowings-		
Associated companies	72,540	140,240
Other	66,000	-
Accounts payable-		
Associated companies	18,134	37,220

Other		52,754		27,507
Accrued taxes		5,866		17,911
Accrued interest		9,735		9,438
Other		21,539		24,274
		396,568		356,590
CAPITALIZATION:				
Common stockholder's equity-				
Common stock, without par value, authorized 900,000 shares-				
859,000 shares outstanding		1,283,182		1,287,093
Accumulated other comprehensive loss		(1,471)		(1,569)
Retained earnings		88,566		30,575
Total common stockholder's equity		1,370,277		1,316,099
Long-term debt and other long-term obligations		541,948		591,888
		1,912,225		1,907,987
NONCURRENT LIABILITIES:				
Accumulated deferred income taxes		369,737		344,929
Accumulated deferred investment tax credits		9,643		10,043
Nuclear fuel disposal costs		40,444		39,567
Asset retirement obligation		146,493		142,020
Retirement benefits		57,118		57,809
Other		56,263		58,742
		679,698		653,110
COMMITMENTS AND CONTINGENCIES (Note 10)				
	$	2,988,491	$	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)

	Six Months Ended June 30, 2006	2005
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 57,991	$ 32,139
Adjustments to reconcile net income to net cash from operating activities -		
Provision for depreciation	21,193	22,898
Amortization of regulatory assets	55,717	53,907
Deferred costs recoverable as regulatory assets	(50,570)	(47,798)
Deferral of new regulatory assets	(45,581)	-
Deferred income taxes and investment tax credits, net	22,463	(1,898)
Accrued compensation and retirement benefits	(4,712)	(4,519)
Cash collateral to suppliers	(2,250)	-
Decrease (increase) in operating assets -		
Receivables	38,182	110,210
Prepayments and other current assets	(24,564)	(21,205)
Increase (decrease) in operating liabilities -		
Accounts payable	6,161	(50,593)
Accrued taxes	(12,045)	(5,184)
Accrued interest	297	(887)
Other	(4,011)	1,424
Net cash provided from operating activities	58,271	88,494
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing-		
Long-term debt	-	-
Short-term borrowings, net	-	20,931
Redemptions and Repayments-		
Long-term debt	-	(37,830)
Short-term borrowings, net	(1,707)	-
Dividend Payments-		
Common stock	-	(34,000)
Net cash used for financing activities	(1,707)	(50,899)

CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions		(47,301)		(34,395)
Proceeds from nuclear decommissioning trust fund sales		116,704		55,081
Investments in nuclear decommissioning trust funds		(121,446)		(59,823)
Loan repayments from (loans to) associated companies, net		(4,054)		3,339
Other		(453)		(1,797)
Net cash used for investing activities		(56,550)		(37,595)
Net change in cash and cash equivalents		14		-
Cash and cash equivalents at beginning of period		120		120
Cash and cash equivalents at end of period	$	134	$	120

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

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Report of Independent Registered Public Accounting Firm

To the 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 June 30, 2006, and the related consolidated statements of income and comprehensive income for each of the three-month and six-month periods ended June 30, 2006 and 2005 and the consolidated statement of cash flows for the six-month period ended June 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
August 4, 2006

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 second quarter of 2006 increased to $40 million from $16 million in the second quarter of 2005. For the first six months of 2006, net income increased to $58 million from $32 million in the same period of 2005. The increase in net income for both periods reflects higher revenues and the deferral of new regulatory assets, partially offset by increased purchased power costs and other operating costs as discussed below.

Revenues

Revenues increased by $19 million, or 7.3%, in the second quarter of 2006 and $35 million, or 6.2%, in the first six months of 2006, compared with the same periods of 2005. Increases in both periods were primarily due to higher retail generation electric revenues ($15 million for the second quarter and $27 million for the first six months) which reflected higher composite unit prices in all customer classes. Higher KWH sales to commercial and industrial customers were partially offset by lower KWH sales to residential customers. Industrial KWH sales 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 14.5 percentage points, in the second quarter of 2006 and 14.2 percentage points in the first six months of 2006. For both periods, residential KWH sales decreased primarily due to the milder weather in 2006 compared with 2005.

Revenues from distribution throughput increased by $1 million in the second quarter of 2006 compared with the same period of 2005. The increase was due to higher composite unit prices and a 0.4% increase in total KWH deliveries. This relatively flat change in KWH deliveries reflected a 3.2% increase in deliveries to commercial customers primarily due to a 1.7% increase in the number of commercial customers, partially offset by milder weather in the second quarter of 2006 (a 21% decrease in heating degree days and an 8.0% decrease in cooling degree days) compared to the same period in 2005. The $1 million decrease in distribution revenues in the first six months of 2006 was primarily due to a 1.1% decrease in KWH deliveries, reflecting the milder temperatures in 2006 compared to the same period in 2005.

For both periods, transmission revenues increased primarily due to higher transmission prices, which also resulted in higher transmission expenses as discussed below. In the first six months of 2006, other revenues also increased due to a $2 million increase in the first quarter of 2006, compared to the same period in 2005, for a payment received under a contract provision associated with the prior sale of TMI Unit 1. Under the contract, additional payments are received if subsequent energy prices rise above specified levels, which occurred. This payment is credited to Met-Ed's customers, resulting in no net earnings effect.

Changes in KWH sales by customer class in the second quarter and the first six months of 2006 compared with the same periods in 2005 are summarized in the following table:

Changes in KWH Sales	**Three Months**	**Six Months**

Increase (Decrease)		
Retail Electric Generation:		
Residential	(1.0)%	(1.9)%
Commercial	4.2%	2.1%
Industrial	15.8%	14.0%
Total Retail Electric Generation Sales	**5.6%**	**3.7%**
Distribution Deliveries:		
Residential	(1.2)%	(2.1)%
Commercial	3.2%	1.2%
Industrial	(0.9)%	(2.3)%
Total Distribution Deliveries	**0.4%**	**(1.1)%**

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Expenses

Total expenses decreased by $27 million and $12 million in the second quarter and the first six 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	Six Months
	(In millions)	
Purchased power costs	$ 11	$ 21
Other operating costs	7	10
Provision for depreciation	(1)	(2)
Amortization of regulatory assets	-	2
Deferral of new regulatory assets	(46)	(46)
General taxes	2	3
Net decrease in expenses	$ (27)	$ (12)

Purchased power costs increased in the second quarter and first six months of 2006 by $11 million and $21 million, respectively, due to increased purchases to meet higher customer demand and higher composite unit prices. These increases were partially offset by increased NUG cost deferrals of $6 million in the second quarter and $4 million in the first six months of 2006. 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 of $46 million reflected the May 4, 2006 PPUC approval of Met-Ed's request to defer certain 2006 transmission-related costs. Met-Ed implemented the deferral accounting in the second quarter of 2006, which included $24 million for costs incurred in the first quarter of 2006 (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 in 2006 for expenses, construction expenditures and scheduled debt maturities, are expected to be met with a combination of cash from operations, issuance of long-term debt, and short-term credit arrangements.

Changes in Cash Position

As of June 30, 2006, Met-Ed had $134,000 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 six months of 2006 and 2005 were as follows:

Operating Cash Flows	Six Months Ended June 30, 2006	2005
	(In millions)	
Cash earnings [(1)]	$ 56	$ 55
Working capital and other	2	33
Net cash provided from operating activities	$ 58	$ 88

(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 are a useful financial measure because it provides investors and management with an additional means of evaluating its cash-based operating performance.

Reconciliation of Cash Earnings	Six Months Ended June 30, 2006	2005
	(In millions)	
Net income (GAAP)	$ 58	$ 32
Non-cash charges (credits):		
Provision for depreciation	21	23
Amortization of regulatory assets	56	54
	(51)	(48)

Deferred costs recoverable as regulatory assets				
Deferral of new regulatory assets		(46)		-
Deferred income taxes and investment tax credits, net		23		(2)
Other non-cash charges		(5)		(4)
Cash earnings (Non-GAAP)	$	56	$	55

The $1 million increase in cash earnings is described above under "Results of Operations." The $31 million working capital change primarily resulted from a $72 million decrease in cash provided from the settlement of receivables, a $7 million decrease in accrued taxes, a $3 million decrease in prepayments, a $2 million increase in cash collateral returned to suppliers, and a $4 million decrease in other accrued liabilities, partially offset by $57 million in decreased outflows for accounts payable.

Cash Flows From Financing Activities

Net cash used for financing activities was $2 million in first six months of 2006 compared to $51 million in the same period of 2005. The decrease primarily reflects a $38 million decrease in long-term debt redemptions and a $34 million decrease in common stock dividend payments to FirstEnergy in the first six months of 2006, partially offset by a $23 million decrease in short-term borrowings.

As of June 30, 2006, Met-Ed had approximately $32 million of cash and temporary investments (which included short-term notes receivable from associated companies) and $139 million of short-term borrowings. Met-Ed has authorization from the SEC, continued by FERC rules adopted as a result of EPACT's repeal of PUCHA, 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 June 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. As of June 30, 2006 the facility was drawn for $66 million. In June 2006, the facility was renewed until June 28, 2007. The annual facility fee is 0.125% on the entire finance limit.

Under the terms of Met-Ed's senior note indenture, FMBs may no longer be issued so long as the senior notes are outstanding. As of June 30, 2006, Met-Ed had the capability to issue $633 million of additional senior notes based upon FMB collateral. Met-Ed had no restrictions on the issuance of preferred stock.

Met-Ed, FirstEnergy, OE, Penn, CEI, TE, JCP&L, Penelec, FES and ATSI, as Borrowers, have entered into a syndicated $2 billion five-year revolving credit facility with a syndicate of banks that expires in June 2010. Borrowings under the facility are available to each Borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment expiration date, as the same may be extended. 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 $264 million as of June 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 June 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 six months of 2006 was 4.86%.

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 June 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 first six months of 2006, Met-Ed's cash used for investing activities totaled $57 million, compared with $38 million in the same period of 2005. The increase primarily resulted from a $13 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 half of 2006, capital requirements for property additions are expected to be about $29 million. Met-Ed has additional requirements of approximately $100 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.

Met-Ed's capital spending for the period 2006 through 2010 is expected to be about $360 million, of which approximately $76 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 and interest rate fluctuations. FirstEnergy's Risk Policy Committee, comprised of members of senior management, provides general oversight to risk management activities throughout the company.

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 normal purchase and normal sale exception under SFAS 133. Contracts that are not exempt from such treatment include purchase power agreements with NUG entities that were structured pursuant to the Public Utility Regulatory Policy Act of 1978. These non-trading contracts are 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 with 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 second quarter and first six months of 2006 is summarized in the following table:

Increase (Decrease) in the Fair Value of Commodity Derivative Contracts	Three Months Ended June 30, 2006			Six Months Ended June 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	$ 24	$ -	$ 24	$ 27	$ -	$ 27

New contract value when entered		-		-		-		-		-		-
Additions/change in value of existing contracts		-		-		-		4		-		4
Change in techniques/assumptions		-		-		-		-		-		-
Settled contracts		(2)		-		(2)		(9)		-		(9)
Other		1		-		1		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)	$	(2)	$	-	$	(2)
Balance Sheet effects:												
OCI (pre-tax)	$	-	$	-	$	-	$	-	$	-	$	-
Regulatory liability	$	-	$	-	$	-	$	-	$	-	$	-

(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 June 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 June 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)]	$ 5	$ 5	$ 5	$ -	$ -	$ -	$ 15
Prices based on models[(3)]	-	-	-	4	4	-	8
Total[(3)]	**$ 5**	**$ 5**	**$ 5**	**$ 4**	**$ 4**	**$ -**	**$ 23**

(1) For the last two quarters 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 June 30, 2006.

Equity Price Risk

Included in Met-Ed's nuclear decommissioning trusts are marketable equity securities carried at their market value of approximately $146 million and $142 million as of June 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 June 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 June 30, 2006 and December 31, 2005 were $359 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 September 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.

As of June 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 $335 million and $57 million, respectively. Penelec's $57 million is subject to the pending resolution of taxable income issues associated with NUG trust fund proceeds. The PPUC is reviewing a January 2006 change in Met-Ed’s and Penelec’s NUG purchase power stranded cost accounting methodology. If the PPUC orders Met-Ed and Penelec to reverse the change in accounting methodology, this would result in a pre-tax loss of $10.3 million for Met-Ed.

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 FERC has ordered the Presiding Judge to issue an initial decision by August 11, 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. The Companies, as part of the Responsible Pricing Alliance, intend to submit a brief on exceptions within thirty days of the initial decision. Following submission of reply exceptions, the case is expected to be reviewed by the FERC with a decision anticipated in the fourth quarter of 2006.

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 below. On May 4, 2006, the PPUC approved the modified request. Accordingly, Met-Ed has deferred approximately $46 million, representing transmission costs that were incurred from January 1, 2006 through June 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 deferral will be determined in the comprehensive rate filing proceeding discussed further below.

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 its 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.

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 was to replace the entire FES supply at current market power prices without corresponding regulatory authorization to increase its generation prices to customers, Met-Ed 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, 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, Met-Ed and Penelec. Hearings are scheduled for late August 2006 and a PPUC decision is expected early in the first quarter of 2007.

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 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 June 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 the result of adoption of mandatory reliability standards pursuant to the EPACT that could require additional material expenditures.

In addition to the above proceedings, FirstEnergy was named in a complaint filed in Michigan State Court by an individual who is not a customer of any FirstEnergy company. FirstEnergy's motion to dismiss the matter was denied on June 2, 2006. FirstEnergy has since filed an appeal, which is pending. A responsive pleading to this matter has been filed. Also, the complaint has been amended to include an additional party. No estimate of potential liability has been undertaken in this matter.

FirstEnergy is vigorously defending these actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be initiated against the Companies. 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

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. 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 June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(In thousands)			
REVENUES	$ 264,999	$ 262,097	$ 556,751	$ 556,026
EXPENSES:				
Purchased power	146,875	139,292	308,516	289,549
Other operating costs	48,133	62,794	86,475	116,607
Provision for depreciation	11,798	12,479	24,441	24,985
Amortization of regulatory assets	12,979	13,118	27,794	26,303
Deferral of new regulatory assets	(11,815)	-	(11,815)	-
General taxes	17,458	16,134	36,847	34,340
Total expenses	225,428	243,817	472,258	491,784
OPERATING INCOME	39,571	18,280	84,493	64,242
OTHER INCOME (EXPENSE):				
Miscellaneous income	1,627	938	3,997	1,268
Interest expense	(11,599)	(10,091)	(22,135)	(19,738)
Capitalized interest	422	264	769	389
Total other income (expense)	(9,550)	(8,889)	(17,369)	(18,081)
INCOME TAXES	14,564	3,554	28,518	18,940
NET INCOME	15,457	5,837	38,606	27,221
OTHER COMPREHENSIVE INCOME:				
Unrealized gain on derivative hedges	16	16	32	32
Unrealized loss on available for sale securities	(14)	(18)	(18)	(21)
Other comprehensive income (loss)	2	(2)	14	11
Income tax expense (benefit) related to other comprehensive income	1	(6)	7	-

Other comprehensive income, net of tax		1		4		7		11
TOTAL COMPREHENSIVE INCOME	$	15,458	$	5,841	$	38,613	$	27,232

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)

	June 30, 2006	December 31, 2005
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 49	$ 35
Receivables-		
Customers (less accumulated provisions of $4,044,000 and $4,184,000, respectively, for uncollectible accounts)	119,103	129,960
Associated companies	2,173	18,626
Other	9,625	12,800
Notes receivable from associated companies	21,090	17,624
Prepaid gross receipts taxes	22,626	-
Prepayments and other	3,874	7,936
	178,540	186,981
UTILITY PLANT:		
In service	2,095,438	2,043,885
Less - Accumulated provision for depreciation	793,523	784,494
	1,301,915	1,259,391
Construction work in progress	27,761	30,888
	1,329,676	1,290,279
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	115,252	113,368
Non-utility generation trusts	97,866	96,761
Other	531	918
	213,649	211,047
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	877,651	882,344
Prepaid pension costs	92,307	89,637
Other	37,150	38,289
	1,007,108	1,010,270
	$ 2,728,973	$ 2,698,577
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Short-term borrowings-		
Associated companies	$ 220,801	$ 261,159
Other	67,000	-
Accounts payable-		
Associated companies	16,256	33,770
Other	46,783	38,277
Accrued taxes	17,148	27,905

Accrued interest		9,094		8,905
Other		17,796		19,756
		394,878		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		1,197,889		1,202,551
Accumulated other comprehensive loss		(302)		(309)
Retained earnings		64,429		25,823
Total common stockholder's equity		1,367,828		1,333,877
Long-term debt and other long-term obligations		476,904		476,504
		1,844,732		1,810,381
NONCURRENT LIABILITIES:				
Regulatory liabilities		135,494		162,937
Accumulated deferred income taxes		119,912		106,871
Retirement benefits		105,980		102,046
Asset retirement obligation		74,574		72,295
Other		53,403		54,275
		489,363		498,424
COMMITMENTS AND CONTINGENCIES (Note 10)				
	$	2,728,973	$	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)

	Six Months Ended June 30,	
	2006	**2005**
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 38,606	$ 27,221
Adjustments to reconcile net income to net cash from operating activities -		
Provision for depreciation	24,441	24,985
Amortization of regulatory assets	27,794	26,303
Deferral of new regulatory assets	(11,815)	-
Deferred costs recoverable as regulatory assets	(54,092)	(35,946)
Deferred income taxes and investment tax credits, net	13,206	2,647
Accrued retirement benefit obligations	1,264	1,905
Accrued compensation, net	(371)	(2,386)
Decrease (increase) in operating assets -		
Receivables	30,485	79,602
Prepayments and other current assets	(18,565)	(22,107)
Increase (decrease) in operating liabilities -		
Accounts payable	(9,008)	(20,333)
Accrued taxes	(10,756)	10,728
Accrued interest	190	(34)
Other	8,817	4,365
Net cash provided from operating activities	40,196	96,950
CASH FLOWS FROM FINANCING ACTIVITIES:		
New Financing -		
Short-term borrowings, net	26,642	-
Redemptions and Repayments -		
Long-term debt	-	(3,521)
Short-term borrowings, net	-	(36,608)
Dividend Payments -		
Common stock	-	(30,000)
Net cash provided from (used for) financing activities	26,642	(70,129)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Property additions	(60,747)	(33,683)

Loan repayments from (loans to) associated companies, net	(3,466)	7,011
Proceeds from nuclear decommissioning trust fund sales	51,536	24,127
Investments in nuclear decommissioning trust funds	(51,536)	(24,127)
Other, net	(2,611)	(150)
Net cash used for investing activities	(66,824)	(26,822)
Net increase (decrease) in cash and cash equivalents	14	(1)
Cash and cash equivalents at beginning of period	35	36
Cash and cash equivalents at end of period	$ 49	$ 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 June 30, 2006, and the related consolidated statements of income and comprehensive income for each of the three-month and six-month periods ended June 30, 2006 and 2005 and the consolidated statement of cash flows for the six-month period ended June 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
August 4, 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 second quarter of 2006 increased to $15 million, compared to $6 million in the second quarter of 2005. In the first six months of 2006, net income increased to $39 million, compared to $27 million in the first six months of 2005. The increase in net income for both periods resulted from lower other operating costs, deferral of new regulatory assets, and higher revenues which were partially offset by higher purchased power costs, general taxes and interest expense, as discussed below.

Revenues

Revenues increased by $3 million in the second quarter of 2006 and $1 million in the first six months of 2006, compared to the same periods of 2005. Increases in both periods were due primarily to higher retail generation revenues partially offset by lower transmission and distribution revenues. Retail generation revenues increased by $12 million in the second quarter of 2006 and $23 million for the first six months of 2006 primarily due to higher KWH sales to industrial customers and higher composite unit prices in all customer classes. Industrial sales increased $8 million for the second quarter of 2006 and $15 million for the first six months of 2006 primarily due to the return of customers to Penelec from alternative suppliers. Generation service provided by alternative suppliers as a percent of total industrial sales in Penelec's service area decreased by 12.1 percentage points and 13.2 percentage points in the second quarter and the first six months of 2006, respectively. The higher composite unit prices also increased generation revenues from residential customers by $1 million and $3 million and from commercial customers by $3 million and $5 million in the second quarter and first six months of 2006, respectively.

Distribution revenues decreased by $1 million in the second quarter of 2006 and by $3 million in the first six months of 2006, compared with the same periods of 2005. The decreases were primarily due to 1.1% and 1.9% decreases in KWH deliveries in the second quarter and first six months of 2006, respectively. Reduced KWH deliveries reflected milder temperatures in both periods of 2006 compared with the same periods of 2005. Those reductions were partially offset by slightly higher composite unit prices during the periods. Transmission revenues decreased by $8 million in the second quarter of 2006 and $20 million in the first six months of 2006 due to lower transmission load requirements and lower prices. The decreased loads for the first six months of 2006 (and related lower congestion revenues) resulted from milder temperatures, as demonstrated by a 40.4% decrease in cooling degree days and a 14.4% decrease in heating degree days compared to the same period in 2005, which resulted in decreased transmission expenses discussed further below. For the first six months of 2006, other revenues also increased 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 second quarter and first six months of 2006 compared to the respective periods in 2005 are summarized in the following table:

	Three	Six

Changes in KWH Sales	**Months**	**Months**
Increase (Decrease)		
Retail Electric Generation:		
Residential	(1.9)%	(2.1)%
Commercial	-	(0.7)%
Industrial	14.8%	14.9%
Total Retail Electric Generation Sales	**3.8%**	**3.3%**
Distribution Deliveries:		
Residential	(2.1)%	(2.2)%
Commercial	(1.0)%	(1.7)%
Industrial	(0.5)%	(1.8)%
Total Distribution Deliveries	**(1.1)%**	**(1.9)%**

Expenses

Total expenses decreased by $19 million or 7.5% in the second quarter of 2006 and $20 million or 4.0% in the first six 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	Six Months
	(In millions)	
Increase (Decrease)		
Purchased power costs	$ 8	$ 19
Other operating costs	(15)	(30)
Provision for depreciation	(1)	(1)
Amortization of regulatory assets	-	1
Deferral of new regulatory assets	(12)	(12)
General taxes	1	3
Net decrease in expenses	$ (19)	$ (20)

Purchased power costs increased by $8 million or 5.4% in the second quarter and $19 million or 6.6% in the first six months of 2006 compared to the same periods in 2005. The increases in both periods were primarily attributable to higher unit costs from non-affiliated suppliers and increased KWH purchased to meet retail generation sales requirements. These increases were partially offset by increased NUG expense deferrals of $4 million in both the second quarter and in the first six months of 2006. Other operating costs decreased due to lower transmission expenses resulting from lower congestion charges. Expenses were further reduced due to higher levels of construction activities in the second quarter of 2006 compared to a higher level of maintenance activities in the same period of 2005 for energy delivery operations and reliability initiatives. The deferral of new regulatory assets of $12 million reflected the May 4, 2006 PPUC approval of Penelec's request to defer certain 2006 transmission-related costs. Penelec implemented the deferral accounting in the second quarter of 2006, which included $4 million for costs incurred in the first quarter of 2006 (see Regulatory Matters for further discussion). For both periods, general taxes increased primarily due to higher Pennsylvania gross receipt taxes.

<u>Capital Resources and Liquidity</u>

Penelec's cash requirements in 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 June 30, 2006, Penelec had $49,000 of cash and cash equivalents compared with $35,000 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 six months of 2006 and 2005 were as follows:

Operating Cash Flows	**Six Months Ended June 30, 2006**	**2005**
	(In millions)	
Cash earnings [(1)]	$ 39	$ 45
Working capital and other	1	52
Net cash provided from operating activities	$ 40	$ 97

[(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 are a useful financial measure because it provides investors and management with an additional means of evaluating its cash-based operating performance.

Reconciliation of Cash Earnings	Six Months Ended June 30, 2006	2005
	(In millions)	
Net income (GAAP)	$ 39	$ 27
Non-cash charges (credits):		
Provision for depreciation	24	25
Amortization of regulatory assets	28	26
Deferral of new regulatory assets	(12)	-
Deferred costs recoverable as regulatory assets	(54)	(36)
Deferred income taxes and investment tax credits, net	13	3
Other non-cash items	1	-
Cash earnings (Non-GAAP)	$ 39	$ 45

The $6 million decrease in cash earnings is described above under “Results of Operations.” The $51 million decrease from working capital primarily resulted from a decrease of $49 million in cash provided from the settlement of receivables and a $21 million decrease in accrued taxes, partially offset by decreased outflows of $11 million for accounts payable and $4 million for prepayments.

Cash Flows From Financing Activities

Net cash provided from financing activities was $27 million in the first six months of 2006 compared to net cash used for financing activities of $70 million in the first six months of 2005. The change reflects a $63 million increase in short-term borrowings, a $30 million reduction in common stock dividend payments to FirstEnergy and a $4 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 $288 million of short-term indebtedness as of June 30, 2006. Penelec has authorization from the SEC, continued by FERC rules adopted as a result of EPACT's repeal of PUHCA, 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 June 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 June 30, 2006 the facility was drawn for $67 million. In June 2006, the facility was renewed until July 28, 2007. 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 June 30, 2006, Penelec had the ability to issue $50 million of additional senior notes based upon FMB collateral. Penelec has no restrictions on the issuance of preferred stock.

Penelec, FirstEnergy, OE, Penn, CEI, TE, JCP&L, Met-Ed, FES and ATSI, as Borrowers, have entered into a syndicated $2 billion five-year revolving credit facility which expires in June 2010. Borrowings under the facility are available to each Borrower separately and mature on the earlier of 364 days from the date of borrowing or the commitment termination date, as the same may be extended. Penelec's borrowing limit under the facility is $250 million.

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 $258 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%. As of June 30, 2006, Penelec’s debt to total capitalization as defined under the revolving credit facility was 36%.

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 six months of 2006 was 4.86%.

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 six months of 2006, net cash used for investing activities totaled $67 million compared to $27 million in the first six months of 2005. The increase primarily resulted from $27 million in increased property additions and a $10 million increase in loans to associated companies. Expenditures for property additions primarily support Penelec’s energy delivery operations and reliability initiatives.

During the last half of 2006, capital requirements for property additions are expected to be approximately $46 million. Penelec’s capital spending for the period 2006-2010 is expected to be approximately $496 million, of which approximately $110 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 and interest rate fluctuations. FirstEnergy’s Risk Policy Committee, comprised of members of senior management, provides general oversight to risk management activities throughout the Company.

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 purchase power agreements with NUG entities that were structured pursuant to the Public Utility Regulatory Policy Act of 1978. These non-trading contracts are 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 with 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 second quarter and first six months of 2006 is summarized in the following table:

Increase (Decrease) in the Fair Value of Commodity Derivative Contracts	Three Months Ended June 30, 2006			Six Months Ended June 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	$	30	$	-	$	30	$	27	$	-	$	27
New contract value when entered		-		-		-		-		-		-
Additions/change in value of existing contracts		-		-		-		2		-		2
Change in techniques/assumptions		-		-		-		-		-		-
Settled contracts		(4)		-		(4)		(3)		-		(3)
Other		(14)		-		(14)		(14)		-		(14)
Net Assets - Derivative Contracts at End of Period [1]	$	12	$	-	$	12	$	12	$	-	$	12
Impact of Changes in Commodity Derivative Contracts[3]												
Income Statement effects (pre-tax)	$	(4)	$	-	$	(4)	$	(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 increase in value of existing contracts, settled contracts and changes in techniques/assumptions.

Derivatives are included on the Consolidated Balance Sheet as of June 30, 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 June 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	$ 2	$ -	$ -	$ -	$ 8
Prices based on models(3)	-	-	-	2	2	-	4
Total(3)	**$ 3**	**$ 3**	**$ 2**	**$ 2**	**$ 2**	**$ -**	**$ 12**

(1) For the last two quarters of 2006.
(2) Broker quote sheets.
(3) Includes $11 million from a non-hedge commodity derivative contract that is offset by a regulatory liability and does not affect earnings.

Penelec performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% adverse shift in quoted market prices in the near term on both of Penelec's trading and non-trading derivative instruments would not have had a material effect on its consolidated financial position or cash flows as of June 30, 2006. Penelec estimates that if energy commodity prices experienced an adverse 10% change, net income for the next 12 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 $64 million and $62 million as of June 30, 2006 and December 31, 2005, respectively. A hypothetical

10% decrease in prices quoted by stock exchanges would result in a $6 million reduction in fair value as of June 30, 2006.

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. Penelec’s net regulatory liabilities were approximately $135 million and $163 million as of June 30, 2006 and December 31, 2005, respectively, and are included under Noncurrent Liabilities on the Consolidated Balance Sheets.

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 September 30, 2004 as the date for Met-Ed's and Penelec's NUG trust fund refunds. The PPUC order also denied their accounting treatment request regarding the CTC rate/shopping credit swap by requiring Met-Ed and Penelec to treat the stipulated CTC rates that were in effect from January 1, 2002 on a retroactive basis. On October 22, 2003, Met-Ed and Penelec filed an Objection with the Commonwealth Court asking that the Court reverse this PPUC finding; a Commonwealth Court judge subsequently denied their Objection on October 27, 2003 without explanation. On October 31, 2003, Met-Ed and Penelec filed an Application for Clarification of the Court order with the 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.

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 FERC has ordered the Presiding Judge to issue an initial decision by August 11, 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. The Companies, as part of the Responsible Pricing Alliance, intend to submit a brief on exceptions within thirty days of the initial decision. Following submission of reply exceptions, the case is expected to be reviewed by the FERC with a decision anticipated in the fourth quarter of 2006.

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 below. On May 4, 2006, the PPUC approved the modified request. Accordingly, Penelec deferred approximately $12 million, representing transmission costs that were incurred from January 1, 2006 through June 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 below.

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.

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, 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.

Penelec made a comprehensive rate filing with the PPUC on April 10, 2006 that addresses a number of transmission, distribution and supply issues. If Penelec's preferred approach involving accounting deferrals is approved, the filing would increase annual revenues by $157 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. 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, 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. The filing contemplates 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 are scheduled for late August 2006 and a PPUC decision is expected early in the first quarter of 2007.

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 Penelec.

Environmental Matters

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

Penelec has been named a PRP at waste disposal sites, which may require cleanup under the Comprehensive Environmental Response, Compensation and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site are liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of June 30, 2006, based on estimates of the total costs of cleanup, Penelec's proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay.

Other Legal Proceedings

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to Penelec's normal business operations pending against Penelec. The other material items not otherwise discussed below are described in Note 10(C) to the consolidated financial statements.

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 the result of adoption of mandatory reliability standards pursuant to the EPACT that could require additional material expenditures.

In addition to the above proceedings, FirstEnergy was named in a complaint filed in Michigan State Court by an individual who is not a customer of any FirstEnergy company. FirstEnergy's motion to dismiss the matter was denied on June 2, 2006. FirstEnergy has since filed an appeal, which is pending. A responsive pleading to this matter has been filed. Also, the complaint has been amended to include an additional party. No estimate of potential liability has been undertaken in this matter.

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

New Accounting Standards and Interpretations

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. Penelec 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. Penelec is currently evaluating the impact of this Statement.

SUBSEQUENT EVENTS

Pennsylvania Law Change

On July 12, 2006, the Governor of Pennsylvania signed House Bill 859, which increases the net operating loss deduction allowed for the corporate net income tax from $2 million to $3 million, or the greater of 12.5% of taxable income. As a result, Penelec expects to recognize a net operating loss benefit of $2.2 million (net of federal tax benefit) in the third quarter of 2006.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Management's Discussion and Analysis of Results of Operation and Financial Condition - Market Risk Information" in Item 2 above.

ITEM 4. CONTROLS AND PROCEDURES

(a) EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The applicable registrant's chief executive officer and chief financial officer have reviewed and evaluated the registrant's disclosure controls and procedures. The term disclosure controls and procedures means controls and other procedures of a registrant that are designed to ensure that information required to be disclosed by the registrant in the reports that it files or submits under the Securities Exchange Act of 1934 (15 U.S.C. 78a et seq.) is recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under that Act is accumulated and communicated to the registrant's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Based on that evaluation, those officers have concluded that the applicable registrant's disclosure controls and procedures are effective and were designed to bring to their attention material information relating to the registrant and its consolidated subsidiaries by others within those entities.

(b) CHANGES IN INTERNAL CONTROLS

During the quarter ended June 30, 2006, there were no changes in the registrants' internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the registrants' internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information required for Part II, Item 1 is incorporated by reference to the discussions in Notes 10 and 11 of the Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

ITEM 1A. RISK FACTORS

See Item 1A RISK FACTORS in Part I of the Form 10-K for the year ended December 31, 2005 for a discussion of the risk factors of FirstEnergy and the subsidiary registrants. For the quarter ended June 30, 2006, there have been no material changes to these risk factors.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

(c) FirstEnergy

The table below includes information on a monthly basis regarding purchases made by FirstEnergy of its common stock.

	Period			
	April 1-30, **2006**	**May 1-31, 2006**	**June 1-30, 2006**	**Second Quarter**
Total Number of Shares Purchased [a]	132,910	481,150	470,009	1,084,069
Average Price Paid per Share	$ 49.82	$ 52.26	$ 53.10	$ 52.33
Total Number of Shares Purchased As Part of Publicly Announced Plans or Programs [b]	-	-	-	-
Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs	-	-	-	-

[a] Share amounts reflect purchases on the open market to satisfy FirstEnergy's obligations to deliver common stock under its Executive and Director Incentive Compensation Plan, Deferred Compensation Plan for Outside Directors, Executive Deferred Compensation Plan, Savings Plan and Stock Investment Plan. In addition, such amounts reflect shares tendered by employees to pay the exercise price or withholding taxes upon exercise of stock options granted

under the Executive and Director Incentive Compensation Plan.

(b) On June 20, 2006, FirstEnergy Corp. announced that its Board of Directors has authorized a share repurchase program for up to 12 million shares of common stock. At management's discretion, shares may be acquired 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 purchase any shares and the program may be terminated at any time.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

(a) The annual meeting of FirstEnergy shareholders was held on May 16, 2006.

(b) At this meeting, the following persons were elected to FirstEnergy's Board of Directors for one-year terms:

	Number of Votes	
	For	**Withheld**
Anthony J. Alexander	193,156,658	90,938,042
Dr. Carol A. Cartwright	164,744,513	119,350,187
William T. Cottle	183,961,100	100,133,600
Robert B. Heisler, Jr.	268,681,345	15,413,355
Russell W. Maier	186,309,666	97,785,034
George M. Smart	183,516,902	100,577,798
Wes M. Taylor	186,519,704	97,574,996
Jesse T. Williams, Sr.	185,540,843	98,553,857

The term of office for the following Directors continued after the shareholders meeting and expires in 2007: Paul T. Addison, Ernest J. Novak, Jr., Catherine A. Rein and Robert C. Savage. The following Directors retired from the Board effective May 16, 2006: Robert N. Pokelwaldt, Paul J. Powers and Dr. Patricia K. Woolf.

(c) (i) At this meeting, the appointment of PricewaterhouseCoopers LLP, an independent registered public accounting firm, as auditor for the year 2006 was ratified:

Number of Votes		
For	Against	Abstentions
278,799,686	2,661,331	2,633,683

(ii) At this meeting, a shareholder proposal recommending that the Board of Directors adopt simple majority shareholder voting and make it applicable to the greatest number of governance issues practicable was approved (approval required a favorable vote of a majority of the votes cast):

Number of Votes			
For	Against	Abstentions	Broker Non-Votes
184,910,522	67,099,919	4,832,226	27,252,033

Based on this result, the Board of Directors will further review this proposal and consider the appropriate steps to take in response.

(iii) At this meeting, a shareholder proposal urging the Board of Directors to seek shareholder approval of future severance agreements with senior executives that provide benefits in an amount exceeding 2.99 times the sum of the executives' base salary plus bonus was not approved (approval required a favorable vote of a majority of the votes cast):

Number of Votes			
For	Against	Abstentions	Broker Non-Votes
123,673,866	128,388,870	4,780,131	27,251,833

ITEM 6. EXHIBITS

Exhibit Number

FirstEnergy

12	Fixed charge ratios
15	Letter from independent registered public accounting firm
31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-(e).
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-(e).
32.1	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350.

OE

12	Fixed charge ratios
15	Letter from independent registered public accounting firm
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Penn

15	Letter from independent registered public accounting firm
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32.1	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350.

CEI

31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-(e).
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-(e).
32.1	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350.

TE

31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-(e).
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-(e).
32.1	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350.

JCP&L

12	Fixed charge ratios
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-(e).
31.3	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-(e).
32.2	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350.

Met-Ed

12	Fixed charge ratios
31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-(e).
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-(e).
32.1	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350.

Penelec

12	Fixed charge ratios
15	Letter from independent registered public accounting firm
31.1	Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-(e).
31.2	Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-(e).
32.1	Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. Section 1350.

Pursuant to reporting requirements of respective financings, FirstEnergy, OE, JCP&L, Met-Ed and Penelec are required to file fixed charge ratios as an exhibit to this Form 10-Q. CEI, TE and Penn do not have similar financing reporting requirements and have not filed their respective fixed charge ratios.

Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, neither FirstEnergy, OE, CEI, TE, Penn, JCP&L, Met-Ed nor Penelec have filed as an exhibit to this Form 10-Q any instrument with respect to long-term debt if the respective total amount of securities authorized thereunder does not exceed 10% of their respective total assets of FirstEnergy and its subsidiaries on a consolidated basis, or respectively, OE, CEI, TE, Penn, JCP&L, Met-Ed or Penelec but hereby agree to furnish to the Commission on request any such documents.

SIGNATURE

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

August 7, 2006

FIRSTENERGY CORP.
Registrant

OHIO EDISON COMPANY
Registrant

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
Registrant

THE TOLEDO EDISON COMPANY
Registrant

PENNSYLVANIA POWER COMPANY
Registrant

JERSEY CENTRAL POWER & LIGHT COMPANY
Registrant

METROPOLITAN EDISON COMPANY
Registrant

PENNSYLVANIA ELECTRIC COMPANY
Registrant

/s/ Harvey L. Wagner
Harvey L. Wagner
Vice President, Controller

and Chief Accounting Officer

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