

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549
FORM 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2008

OR

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

For the transition period from _____ to _____

<u>Commission File Number</u>	<u>Registrant; State of Incorporation; Address; and Telephone Number</u>	<u>I.R.S. Employer Identification No.</u>
333-21011	FIRSTENERGY CORP. (An Ohio Corporation) 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-1843785
333-145140-01	FIRSTENERGY SOLUTIONS CORP. (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	31-1560186
1-2578	OHIO EDISON COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-0437786
1-2323	THE CLEVELAND ELECTRIC ILLUMINATING COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-0150020
1-3583	THE TOLEDO EDISON COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-4375005
1-3141	JERSEY CENTRAL POWER & LIGHT COMPANY (A New Jersey Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	21-0485010
1-446	METROPOLITAN EDISON COMPANY (A Pennsylvania Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	23-0870160
1-3522	PENNSYLVANIA ELECTRIC COMPANY (A Pennsylvania Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	25-0718085



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

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
FirstEnergy Corp.	Common Stock, \$0.10 par value	New York Stock Exchange

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

Registrant	Title of Each Class
Ohio Edison Company	Common Stock, no par value per share
The Cleveland Electric Illuminating Company	Common Stock, no par value per share
The Toledo Edison Company	Common Stock, \$5.00 par value per share
Jersey Central Power & Light Company	Common Stock, \$10.00 par value per share
Metropolitan Edison Company	Common Stock, no par value per share
Pennsylvania Electric Company	Common Stock, \$20.00 par value per share

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes No
Yes No FirstEnergy Corp.
FirstEnergy Solutions Corp., Ohio Edison 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 if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes No
Yes No FirstEnergy Solutions Corp.
FirstEnergy Corp., Ohio Edison 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 (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 No
Yes No FirstEnergy Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company
FirstEnergy Solutions Corp.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

FirstEnergy Corp.
FirstEnergy Solutions Corp., Ohio Edison 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 large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer FirstEnergy Corp.
 Accelerated filer N/A
 Non-accelerated filer (do not check if a smaller reporting company) FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company
 Smaller reporting company N/A

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

Yes No FirstEnergy Corp., FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company, and Pennsylvania Electric Company

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and ask price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter.

FirstEnergy Corp., \$24,930,103,947 as of June 30, 2008; and for all other registrants, none.

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

CLASS	OUTSTANDING AS OF FEBRUARY 24, 2009
FirstEnergy Corp., \$.10 par value	304,835,407
FirstEnergy Solutions Corp., no par value	7
Ohio Edison Company, no par value	60
The Cleveland Electric Illuminating Company, no par value	67,930,743
The Toledo Edison Company, \$5 par value	29,402,054
Jersey Central Power & Light Company, \$10 par value	13,628,447
Metropolitan Edison Company, no par value	859,500
Pennsylvania Electric Company, \$20 par value	4,427,577

FirstEnergy Corp. is the sole holder of FirstEnergy Solutions Corp., 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.

Documents incorporated by reference (to the extent indicated herein):

DOCUMENT	PART OF FORM 10-K INTO WHICH DOCUMENT IS INCORPORATED
FirstEnergy Corp. Annual Report to Stockholders for the fiscal year ended December 31, 2008	Part II
Proxy Statement for 2009 Annual Meeting of Stockholders to be held May 19, 2009	Part III

This combined Form 10-K is separately filed by FirstEnergy Corp., FirstEnergy Solutions Corp., Ohio Edison 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.

OMISSION OF CERTAIN INFORMATION

FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company meet the conditions set forth in General Instruction I (1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to Form 10-K.

Forward-Looking Statements: This Form 10-K includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements.

Actual results may differ materially due to:

- the speed and nature of increased competition in the electric utility industry and legislative and regulatory changes affecting how generation rates will be determined following the expiration of existing rate plans in Ohio and Pennsylvania,
- the impact of the PUCO's regulatory process on the Ohio Companies associated with the ESP and MRO filings, including any resultant mechanism under which the Ohio Companies may not fully recover costs (including, but not limited to, costs of generation supply procured by the Ohio Companies, Regulatory Transition Charges and fuel charges), or the outcome of any competitive generation procurement process in Ohio,
- economic or weather conditions affecting future sales and margins,
- changes in markets for energy services,
- changing energy and commodity market prices and availability,
- replacement power costs being higher than anticipated or inadequately hedged,
- the continued ability of FirstEnergy's regulated utilities to collect transition and other charges or to recover increased transmission costs,
- maintenance costs being higher than anticipated,
- other legislative and regulatory changes, revised environmental requirements, including possible GHG emission regulations,
- the potential impact of the U.S. Court of Appeals' July 11, 2008 decision requiring revisions to the CAIR rules and the scope of any laws, rules or regulations that may ultimately take their place,
- 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 that certain generating units may need to be shut down) or levels of emission reductions related to the Consent Decree resolving the NSR litigation or other potential regulatory initiatives,
- adverse regulatory or legal decisions and outcomes (including, but not limited to, the revocation of necessary licenses or operating permits and oversight) by the NRC (including, but not limited to, the Demand for Information issued to FENOC on May 14, 2007),
- the timing and outcome of various proceedings before the PUCO (including, but not limited to, the ESP and MRO proceedings as well as the distribution rate cases and the generation supply plan filing for the Ohio Companies and the successful resolution of the issues remanded to the PUCO by the Ohio Supreme Court regarding the RSP and RCP, including the recovery of deferred fuel costs),
- Met-Ed's and Penelec's transmission service charge filings with the PPUC as well as the resolution of the Petitions for Review filed with the Commonwealth Court of Pennsylvania with respect to the transition rate plan for Met-Ed and Penelec,
- the continuing availability of generating units and their ability to operate at or near full capacity,
- the ability to comply with applicable state and federal reliability standards,
- the ability to accomplish or realize anticipated benefits from strategic goals (including employee workforce initiatives),
- the ability to improve electric commodity margins and to experience growth in the distribution business,
- the changing market conditions that could affect the value of assets held in the registrants' nuclear decommissioning trusts, pension trusts and other trust funds, and cause FirstEnergy to make additional contributions sooner, or in an amount that is larger than currently anticipated,
- the ability to access the public securities and other capital and credit markets in accordance with FirstEnergy's financing plan and the cost of such capital,
- changes in general economic conditions affecting the registrants,
- the state of the capital and credit markets affecting the registrants,
- interest rates and any actions taken by credit rating agencies that could negatively affect the registrants' access to financing or its costs and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees,
- the continuing decline of the national and regional economy and its impact on the registrants' major industrial and commercial customers,
- issues concerning the soundness of financial institutions and counterparties with which the registrants do business, and
- the risks and other factors discussed from time to time in the registrants' SEC filings, and other similar factors.

The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on the registrants' business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. 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.

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
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
FEV	FirstEnergy Ventures Corp., invests in certain unregulated enterprises and business ventures
FGCO	FirstEnergy Generation Corp., owns and operates non-nuclear generating facilities
FirstEnergy	FirstEnergy Corp., a public utility holding company
GPU	GPU, Inc., former parent of JCP&L, Met-Ed and Penelec, which merged with FirstEnergy on November 7, 2001
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
JCP&L Transition Funding	JCP&L Transition Funding LLC, a Delaware limited liability company and issuer of transition bonds
JCP&L Transition Funding II	JCP&L Transition Funding II LLC, a Delaware limited liability company and issuer of transition bonds
Met-Ed	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MYR	MYR Group, Inc., a utility infrastructure construction service company
NGC	FirstEnergy Nuclear Generation Corp., owns nuclear generating facilities
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
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
Pennsylvania Companies	Met-Ed, Penelec and Penn
Shelf Registrants	OE, CEI, TE, JCP&L, Met-Ed and Penelec
Shippingport	Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997
Signal Peak	A joint venture between FirstEnergy Ventures Corp. and Boich Companies, that owns mining and coal transportation operations near Roundup, Montana, formerly known as Bull Mountain
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
Utilities	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec
Waverly	The Waverly Power and Light Company, a wholly owned subsidiary of Penelec

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

ACO	Administrative Consent Order
AEP	American Electric Power Company, Inc.
ALJ	Administrative Law Judge
AMP-Ohio	American Municipal Power - Ohio
AQC	Air Quality Control
BGS	Basic Generation Service
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CBP	Competitive Bid Process
CO ₂	Carbon Dioxide
CTC	Competitive Transition Charge
DFI	Demand for Information
DOE	United States Department of Energy
DOJ	United States Department of Justice
DRA	Division of Ratepayer Advocate
ECAR	East Central Area Reliability Coordination Agreement
EIS	Energy Independence Strategy
EMP	Energy Master Plan
EPA	United States Environmental Protection Agency
EPACT	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
ERO	Electric Reliability Organization
ESP	Electric Security Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission

GLOSSARY OF TERMS Cont'd.

FMB	First Mortgage Bond
FPA	Federal Power Act
GHG	Greenhouse Gases
IRS	Internal Revenue Service
ISO	Independent System Operator
kV	Kilovolts
KWH	Kilowatt-hours
LED	Light-emitting Diode
MEW	Mission Energy Westside, Inc.
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service, Inc.
MRO	Market Rate Offer
MW	Megawatts
MWH	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NOV	Notice of Violation
NO _x	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NUGC	Non-Utility Generation Charge
OCA	Office of Consumer Advocate
OSBA	Office of Small Business Advocate
OVEC	Ohio Valley Electric Corporation
PJM	PJM Interconnection L. L. C.
PLR	Provider of Last Resort ; an electric utility's obligation to provide generation service to customers whose alternative supplier fails to deliver service
PPUC	Pennsylvania Public Utility Commission
PRP	Potentially Responsible Party
PSA	Power Supply Agreement
PUCO	Public Utilities Commission of Ohio
PUHCA	Public Utility Holding Company Act of 1935
RCP	Rate Certainty Plan
RECB	Regional Expansion Criteria and Benefits
RFP	Request for Proposal
RSP	Rate Stabilization Plan
RTC	Regulatory Transition Charge
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Service
SBC	Societal Benefits Charge
SEC	U.S. Securities and Exchange Commission
SECA	Seams Elimination Cost Adjustment
SFAS	Statement of Financial Accounting Standards
SFAS 71	SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 101	SFAS No. 101, "Accounting for Discontinuation of Application of SFAS 71"
SIP	State Implementation Plan(s) Under the Clean Air Act
SNCR	Selective Non-Catalytic Reduction
SO ₂	Sulfur Dioxide
TMI-1	Three Mile Island Unit 1
TMI-2	Three Mile Island Unit 2
TSC	Transmission Service Charge

FORM 10-K TABLE OF CONTENTS

	Page
Part I	
Item 1. Business	
The Company	1-2
Utility Regulation	2-11
Regulatory Accounting	3
Reliability Initiatives	3-4
PUCO Rate Matters	4-5
PPUC Rate Matters	6-7
NJBPU Rate Matters	7-8
FERC Rate Matters	8-11
Capital Requirements	11-13
Nuclear Operating Licenses	13-14
Nuclear Regulation	14
Nuclear Insurance	14-15
Environmental Matters	15-19
Fuel Supply	19-20
System Demand	20
Supply Plan	20
Regional Reliability	21
Competition	21
Research and Development	21
Executive Officers	22
Employees	23
FirstEnergy Web Site	23
Item 1A. Risk Factors	23-36
Item 1B. Unresolved Staff Comments	36
Item 2. Properties	36-38
Item 3. Legal Proceedings	38
Item 4. Submission of Matters to a Vote of Security Holders	38
Part II	
Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	38-39
Item 6. Selected Financial Data	39
Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations	39
Item 7A. Quantitative and Qualitative Disclosures About Market Risk	39
Item 8. Financial Statements and Supplementary Data	39
Item 9. Changes In and Disagreements with Accountants on Accounting and Financial Disclosure	39
Item 9A. Controls and Procedures	39-40
Item 9A(T). Controls and Procedures	40
Item 9B. Other Information	40
Part III	
Item 10. Directors, Executive Officers and Corporate Governance	41
Item 11. Executive Compensation	41
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	41
Item 13. Certain Relationships and Related Transactions, and Director Independence	41
Item 14. Principal Accounting Fees and Services	41
Part IV	
Item 15. Exhibits, Financial Statement Schedules	42-88

PART I

ITEM 1. BUSINESS

The Company

FirstEnergy Corp. was organized under the laws of the State of Ohio in 1996. 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. FirstEnergy's consolidated revenues are primarily derived from electric service provided by its utility operating subsidiaries and the revenues of its other principal subsidiary, FES. In addition, FirstEnergy holds all of the outstanding common stock of other direct subsidiaries including: FirstEnergy Properties, Inc., FirstEnergy Ventures Corp., FENOC, FirstEnergy Securities Transfer Company, GPU Diversified Holdings, LLC, GPU Telecom Services, Inc., GPU Nuclear, Inc. and FESC.

FES was organized under the laws of the State of Ohio in 1997. FES provides energy-related products and services to wholesale and retail customers in the MISO and PJM markets. FES also owns and operates, through its subsidiary, FGCO, FirstEnergy's fossil and hydroelectric generating facilities and owns, through its subsidiary, NGC, FirstEnergy's nuclear generating facilities. FENOC, a separate subsidiary of FirstEnergy, organized under the laws of the State of Ohio in 1998, operates and maintains NGC's nuclear generating facilities. FES purchases the entire output of the generation facilities owned by FGCO and NGC, as well as the output relating to leasehold interests of the Ohio Companies in certain of those facilities that are subject to sale and leaseback arrangements with non-affiliates, pursuant to full output, cost-of-service PSAs.

FirstEnergy's generating portfolio includes 14,173 MW of diversified capacity (FES – 13,973 MW and JCP&L – 200 MW). Within FES' portfolio, approximately 7,469 MW, or 53.5%, consists of coal-fired capacity; 3,991 MW, or 28.6%, consists of nuclear capacity; 1,599 MW, or 11.4%, consists of oil and natural gas peaking units; 451 MW, or 3.2%, consists of hydroelectric capacity; and 463 MW, or 3.3%, consists of capacity from FGCO's current 20.5% entitlement to the generation output owned by the OVEC. FirstEnergy's nuclear and non-nuclear facilities are operated by FENOC and FGCO, respectively, and, except for portions of certain facilities that are subject to the sale and leaseback arrangements with non-affiliates referred to above for which the corresponding output is available to FES through power sale agreements, are all owned directly by NGC and FGCO, respectively. The FES generating assets are concentrated primarily in Ohio, plus the bordering regions of Pennsylvania and Michigan. All FES units are dedicated to MISO except the Beaver Valley Power Station, which is designated as a PJM resource.

FES, FGCO and NGC comply with the regulations, orders, policies and practices prescribed by the SEC and the FER C. In addition, NGC and FENOC comply with the regulations, orders, policies and practices prescribed by the NRC.

The Utilities' combined service areas encompass approximately 36,100 square miles in Ohio, New Jersey and Pennsylvania. The areas they serve have a combined population of approximately 11.3 million.

OE was organized under the laws of the State of Ohio in 1930 and owns property and does business as an electric public utility in that state. OE engages in the distribution and sale of electric energy to communities in a 7,000 square mile area of central and northeastern Ohio. The area it serves has a population of approximately 2.8 million. OE complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PUCO.

OE owns all of Penn's outstanding common stock. Penn was organized under the laws of the Commonwealth of Pennsylvania in 1930 and owns property and does business as an electric public utility in that state. Penn is also authorized to do business in the State of Ohio (see Item 2 – Properties). Penn furnishes electric service to communities in 1,100 square miles of western Pennsylvania. The area it serves has a population of approximately 0.4 million. Penn complies with the regulations, orders, policies and practices prescribed by the FERC and PPUC.

CEI was organized under the laws of the State of Ohio in 1892 and does business as an electric public utility in that state. CEI engages in the distribution and sale of electric energy in an area of approximately 1,600 square miles in northeastern Ohio. The area it serves has a population of approximately 1.8 million. CEI complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PUCO.

TE was organized under the laws of the State of Ohio in 1901 and does business as an electric public utility in that state. TE engages in the distribution and sale of electric energy in an area of approximately 2,300 square miles in northwestern Ohio. The area it serves has a population of approximately 0.8 million. TE complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and PUCO.

ATSI was organized under the laws of the State of Ohio in 1998. ATSI owns transmission assets that were formerly owned by the Ohio Companies and Penn. ATSI owns major, high-voltage transmission facilities, which consist of approximately 5,821 pole miles of transmission lines with nominal voltages of 345 kV, 138 kV and 69 kV. Effective October 1, 2003, ATSI transferred operational control of its transmission facilities to MISO. With its affiliation with MISO, ATSI plans, operates, and maintains its transmission system in accordance with NERC reliability standards, and applicable regulatory agencies to ensure reliable service to customers.

JCP&L was organized under the laws of the State of New Jersey in 1925 and owns property and does business as an electric public utility in that state. JCP&L provides transmission and distribution services in 3,200 square miles of northern, western and east central New Jersey. The area it serves has a population of approximately 2.6 million. JCP&L complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and the NJBPU .

Met-Ed was organized under the laws of the Commonwealth of Pennsylvania in 1922 and owns property and does business as an electric public utility in that state. Met-Ed provides transmission and distribution services in 3,300 square miles of eastern and south central Pennsylvania. The area it serves has a population of approximately 1.3 million. Met-Ed complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and P P UC.

Penelec was organized under the laws of the Commonwealth of Pennsylvania in 1919 and owns property and does business as an electric public utility in that state. Penelec provides transmission and distribution services in 17,600 square miles of western, northern and south central Pennsylvania. The area it serves has a population of approximately 1.6 million. Penelec, as lessee of the property of its subsidiary, The Waverly Electric Light & Power Company, also serves customers in Waverly, New York and its vicinity. Penelec complies with the regulations, orders, policies and practices prescribed by the SEC, FERC and P P UC.

FESC provides legal, financial and other corporate support services to affiliated FirstEnergy companies.

Reference is made to Note 15, Segment Information, of the Notes to Consolidated Financial Statements contained in Item 8 for information regarding FirstEnergy's reportable segments.

Utility Regulation

State Regulation

Each of the Utilities' retail rates, conditions of service, issuance of securities and other matters are subject to regulation in the state in which each company operates – in Ohio by the PUCO, in New Jersey by the NJBPU and in Pennsylvania by the PPUC. In addition, under Ohio law, municipalities may regulate rates of a public utility, subject to appeal to the PUCO if not acceptable to the utility.

As a competitive retail electric supplier serving retail customers in Ohio, Pennsylvania, Maryland, Michigan, and Illinois, FES is subject to state laws applicable to competitive electric suppliers in those states, including affiliate codes of conduct that apply to FES and its public utility affiliates. In addition, if FES or any of its subsidiaries were to engage in the construction of significant new generation facilities, they would also be subject to state siting authority.

Federal Regulation

With respect to their wholesale and interstate electric operations and rates, the Utilities, ATSI, FES, FGCO and NGC are subject to regulation by the FERC. Under the FPA, the FERC regulates rates for interstate sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. The FERC regulations require ATSI, Met-Ed, JCP&L and Penelec to provide open access transmission service at FERC-approved rates, terms and conditions. Transmission service over ATSI's facilities is provided by MISO under its open access transmission tariff, and transmission service over Met-Ed's, JCP&L's and Penelec's facilities is provided by PJM under its open access transmission tariff. The FERC also regulates unbundled transmission service to retail customers.

The FERC regulates the sale of power for resale in interstate commerce by granting authority to public utilities to sell wholesale power at market-based rates upon a showing that the seller cannot exert market power in generation or transmission. FES, FGCO and NGC have been authorized by the FERC to sell wholesale power in interstate commerce and have a market-based tariff on file with the FERC. By virtue of this tariff and authority to sell wholesale power, each company is regulated as a public utility under the FPA. However, consistent with its historical practice, the FERC has granted FES, FGCO and NGC a waiver from most of the reporting, record-keeping and accounting requirements that typically apply to traditional public utilities. Along with market-based rate authority, the FERC also granted FES, FGCO and NGC blanket authority to issue securities and assume liabilities under Section 204 of the FPA. As a condition to selling electricity on a wholesale basis at market-based rates, FES, FGCO and NGC, like all other entities granted market-based rate authority, must file electronic quarterly reports with the FERC, listing its sales transactions for the prior quarter.

The nuclear generating facilities owned and leased by NGC are subject to extensive regulation by the NRC. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security and environmental and radiological aspects of those stations. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of the licenses. FENOC is the licensee for these plants and has direct compliance responsibility for NRC matters. FES controls the economic dispatch of NGC's plants. See "Nuclear Regulation" below.

Regulatory Accounting

The Utilities 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. All regulatory assets are expected to be recovered from customers under the Utilities' respective transition and regulatory plans. Based on those plans, the Utilities continue to bill and collect cost-based rates for their transmission and distribution services, which remain regulated; accordingly, it is appropriate that the Utilities continue the application of SFAS 71 to those operations.

FirstEnergy accounts for the effects of regulation through the application of SFAS 71 to its operating utilities since their rates:

- are established by a third-party regulator with the authority to set rates that bind customers;
- are cost-based; and
- can be charged to and collected from customers.

An enterprise meeting all of these criteria capitalizes costs that would otherwise be charged to expense if the rate actions of its regulator make it probable that those costs will be recovered in future revenue. SFAS 71 is applied only to the parts of the business that meet the above criteria. If a portion of the business applying SFAS 71 no longer meets those requirements, previously recorded net regulatory assets are removed from the balance sheet in accordance with the guidance in SFAS 101.

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

- restructuring the electric generation business and allowing the Utilities' customers to select a competitive electric generation supplier other than the Utilities;
- establishing or defining the PLR obligations to customers in the Utilities' service areas;
- providing the Utilities 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 Utilities' transmission and distribution systems; and
- requiring corporate separation of regulated and unregulated business activities.

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 (the PUCO, the FERC, the NERC and the U.S. – Canada Power System Outage Task Force) regarding enhancements to regional reliability. The proposed enhancements were divided into two groups: enhancements that were to be completed in 2004; and enhancements that were to be completed after 2004. In 2004, FirstEnergy completed all of the enhancements that were recommended for completion in 2004. 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 that could require additional material expenditures.

In 2005, Congress amended the Federal Power Act to provide for federally-enforceable mandatory reliability standards. The mandatory reliability standards apply to the bulk power system and impose certain operating, record-keeping and reporting requirements on the Utilities and ATSI. The NERC is charged with establishing and enforcing these reliability standards, although it has delegated day-to-day implementation and enforcement of its responsibilities to eight regional entities, including ReliabilityFirst Corporation. All of FirstEnergy's facilities are located within the ReliabilityFirst region. FirstEnergy actively participates in the NERC and ReliabilityFirst stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, it is clear that the NERC, ReliabilityFirst and the FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. The financial impact of complying with new or amended standards cannot be determined at this time. However, the 2005 amendments to the Federal Power Act provide that all prudent costs incurred to comply with the new reliability standards be recovered in rates. Still, any future inability on FirstEnergy's part to comply with the reliability standards for its bulk power system could result in the imposition of financial penalties and thus have a material adverse effect on its financial condition, results of operations and cash flows.

In April 2007, ReliabilityFirst performed a routine compliance audit of FirstEnergy's bulk-power system within the Midwest ISO region and found it to be in full compliance with all audited reliability standards. Similarly, in October 2008, ReliabilityFirst performed a routine compliance audit of FirstEnergy's bulk-power system within the PJM region and a final report is expected in early 2009. FirstEnergy does not expect any material adverse financial impact as a result of these audits.

PUCO Rate Matters

On January 4, 2006, the PUCO issued an order authorizing the Ohio Companies to recover certain increased fuel costs through a fuel rider and to defer certain other increased fuel costs to be incurred from January 1, 2006 through December 31, 2008, including interest on the deferred balances. The order also provided for recovery of the deferred costs over a twenty-five-year period through distribution rates. On August 29, 2007, the Supreme Court of Ohio concluded that the PUCO violated a provision of the Ohio Revised Code by permitting the Ohio Companies "to collect deferred increased fuel costs through future distribution rate cases, or to alternatively use excess fuel-cost recovery to reduce deferred distribution-related expenses" and remanded the matter to the PUCO for further consideration. On September 10, 2007, the Ohio Companies filed an application with the PUCO that requested the implementation of two generation-related fuel cost riders to collect the increased fuel costs that were previously authorized to be deferred. On January 9, 2008, the PUCO approved the Ohio Companies' proposed fuel cost rider to recover increased fuel costs incurred during 2008, which was approximately \$185 million. In addition, the PUCO ordered the Ohio Companies to file a separate application for an alternate recovery mechanism to collect the 2006 and 2007 deferred fuel costs. On February 8, 2008, the Ohio Companies filed an application proposing to recover \$226 million of deferred fuel costs and carrying charges for 2006 and 2007 pursuant to a separate fuel rider. Recovery of the deferred fuel costs was also addressed in the Ohio Companies' comprehensive ESP filing, which was subsequently withdrawn on December 22, 2008, and also as a part of the stipulation and recommendation which was attached to the amended application for an ESP, both as described below.

On June 7, 2007, the Ohio Companies filed an application for an increase in electric distribution rates with the PUCO and, on August 6, 2007, updated their filing to support a distribution rate increase of \$332 million. On December 4, 2007, the PUCO Staff issued its Staff Reports containing the results of its investigation into the distribution rate request. In its reports, the PUCO Staff recommended a distribution rate increase in the range of \$161 million to \$180 million, with \$108 million to \$127 million for distribution revenue increases and \$53 million for recovery of costs deferred under prior cases. During the evidentiary hearings and filing of briefs, the PUCO Staff decreased their recommended revenue increase to a range of \$117 million to \$135 million. On January 21, 2009, the PUCO granted the Ohio Companies' application to increase electric distribution rates by \$136.6 million (OE - \$68.9 million, CEI - \$29.2 million and TE - \$38.5 million). These increases went into effect for OE and TE on January 23, 2009, and will go into effect for CEI on May 1, 2009. Applications for rehearing of this order were filed by the Ohio Companies and one other party on February 20, 2009.

On May 1, 2008, Governor Strickland signed SB221, which became effective on July 31, 2008. The bill requires all utilities to file an ESP with the PUCO, which must contain a proposal for the supply and pricing of retail generation. A utility may also file an MRO with the PUCO, in which it would have to prove the following objective market criteria: 1) the utility or its transmission service affiliate belongs to a FERC approved RTO, or there is comparable and nondiscriminatory access to the electric transmission grid; 2) the RTO has a market-monitor function and the ability to mitigate market power or the utility's market conduct, or a similar market monitoring function exists with the ability to identify and monitor market conditions and conduct; and 3) a published source of information is available publicly or through subscription that identifies pricing information for traded electricity products, both on- and off-peak, scheduled for delivery two years into the future.

On July 31, 2008, the Ohio Companies filed with the PUCO a comprehensive ESP and MRO. The MRO filing outlined a CBP for providing retail generation supply if the ESP is not approved and implemented. The CBP would use a "slice-of-system" approach where suppliers bid on tranches (approximately 100 MW) of the Ohio Companies' total customer load. If the Ohio Companies proceed with the MRO option, successful bidders (including affiliates) would be required to post independent credit requirements and could be subject to significant collateral calls depending upon power price movement. The PUCO denied the MRO application on November 26, 2008. The Ohio Companies filed an application for rehearing on December 23, 2008, which the PUCO granted on January 21, 2009, for the purpose of further consideration of the matter.

The ESP proposed to phase in new generation rates for customers beginning in 2009 for up to a three-year period and resolve the Ohio Companies' collection of fuel costs deferred in 2006 and 2007, and the distribution rate request described above. On December 19, 2008, the PUCO significantly modified and approved the ESP as modified. On December 22, 2008, the Ohio Companies notified the PUCO that they were withdrawing and terminating the ESP application as allowed by the terms of SB221. The Ohio Companies further notified the PUCO that, pursuant to SB221, the Ohio Companies would continue their current rate plan in effect and filed tariffs to continue those rates.

On December 31, 2008, the Ohio Companies conducted a CBP, using an RFP format administered by an independent third party, for the procurement of electric generation for retail customers from January 5, 2009 through March 31, 2009. Four qualified wholesale bidders were selected, including FES, for 97% of the tranches offered in the RFP. The average winning bid price was equivalent to a retail rate of 6.98 cents per kilowatt-hour. Subsequent to the RFP, the remaining 3% of the Ohio Companies' wholesale energy and capacity needs were obtained through a bilateral contract with the lowest bidder in the RFP procurement. The power supply obtained through the foregoing processes provides generation service to the Ohio Companies' retail customers who choose not to shop with alternative suppliers.

Following comments by other parties on the Ohio Companies' December 22, 2008, filing which continued the current rate plan, the PUCO issued an Order on January 7, 2009, that prevented OE and TE from collecting RTC and discontinued the collection of two fuel riders for the Ohio Companies. The Ohio Companies filed an application for rehearing on January 9, 2009, and also filed an application for a new fuel rider to recover the increased costs for purchasing power during the period January 1, 2009 through March 31, 2009. On January 14, 2009, the PUCO approved the Ohio Companies' request for the new fuel rider, subject to further review, allowed current recovery of those costs for OE and TE, and allowed CEI to collect a portion of those costs currently and defer the remainder. The PUCO also ordered the Ohio Companies to file additional information in order for it to determine that the costs incurred are prudent and whether the recovery of such costs is necessary to avoid a confiscatory result. The Ohio Companies filed an application for rehearing on that order on January 26, 2009. The applications for rehearing remain pending and the Ohio Companies are unable to predict the ultimate resolution of these issues.

On January 29, 2009, the PUCO ordered its Staff to develop a proposal to establish an ESP for the Ohio Companies and further ordered that a conference be held on February 5, 2009 to discuss the Staff's proposal. The Ohio Companies, PUCO Staff, and other parties participated in that conference, and in a subsequent conference held on February 17, 2009. Following discussions with the Staff and other parties regarding the Staff's proposal, on February 19, 2009, the Ohio Companies filed an amended ESP application, including an attached Stipulation and Recommendation that was signed by the Ohio Companies, the Staff of the PUCO, and many of the intervening parties representing a diverse range of interests, which substantially reflected the terms as proposed by the Staff as modified through the negotiations of the parties. Specifically, the stipulated ESP provides that generation will be provided by FES at the average wholesale rate of the RFP process described above for April and May 2009 to the Ohio Companies for their non-shopping customers and that for the period of June 1, 2009 through May 31, 2011, retail generation prices will be based upon the outcome of a descending clock CBP on a slice-of-system basis. The PUCO may, at its discretion, phase-in a portion of any increase resulting from this CBP process by authorizing deferral of related purchased power costs, subject to specified limits. The proposed ESP further provides that the Ohio Companies will not seek a base distribution rate increase with an effective date before January 1, 2012, that CEI will agree to write-off approximately \$215 million of its Extended RTC balance, and that the Ohio Companies will collect a delivery service improvement rider at an overall average rate of \$.002 per kWh for the period of April 1, 2009 through December 31, 2011. If the Stipulated ESP is approved, one-time charges associated with implementing the ESP would be approximately \$250 million (including the CEI Extended RTC balance), or \$0.53 per share of common stock. The proposed ESP also addresses a number of other issues, including but not limited to, rate design for various customer classes, resolution of the prudence review described above and the collection of deferred costs that were approved in prior proceedings. On February 19, 2009, the PUCO attorney examiner issued an order setting this matter for hearing to begin on February 25, 2009.

PPUC Rate Matters

Met-Ed and Penelec purchase a portion of their PLR and default service requirements from FES through a fixed-price partial requirements wholesale power sales agreement. The agreement allows Met-Ed and Penelec to sell the output of NUG energy to the market and requires FES to provide energy at fixed prices to replace any NUG energy sold to the extent needed for Met-Ed and Penelec to satisfy their PLR and default service obligations. The fixed price under the agreement is expected to remain below wholesale market prices during the term of the agreement. 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 their fixed income securities. If FES ultimately determines to terminate, reduce, or significantly modify the agreement prior to the expiration of Met-Ed's and Penelec's generation rate caps in 2010, timely regulatory relief is not likely to be granted by the PPUC. See FERC Matters below for a description of the Third Restated Partial Requirements Agreement, executed by the parties on October 31, 2008, that limits the amount of energy and capacity FES must supply to Met-Ed and Penelec. In the event of a third party supplier default, the increased costs to Met-Ed and Penelec could be material.

On May 22, 2008, the PPUC approved the Met-Ed and Penelec annual updates to the TSC rider for the period June 1, 2008, through May 31, 2009. Various intervenors filed complaints against those filings. In addition, the PPUC ordered an investigation to review the reasonableness of Met-Ed's TSC, while at the same time allowing Met-Ed to implement the rider June 1, 2008, subject to refund. On July 15, 2008, the PPUC directed the ALJ to consolidate the complaints against Met-Ed with its investigation and a litigation schedule was adopted. Hearings and briefing for both companies are expected to conclude by the end of February 2009. The TSCs include a component from under-recovery of actual transmission costs incurred during the prior period (Met-Ed - \$144 million and Penelec - \$4 million) and future transmission cost projections for June 2008 through May 2009 (Met-Ed - \$258 million and Penelec - \$92 million). Met-Ed received PPUC approval for a transition approach that would recover past under-recovered costs plus carrying charges through the new TSC over thirty-one months and defer a portion of the projected costs (\$92 million) plus carrying charges for recovery through future TSCs by December 31, 2010.

On February 1, 2007, the Governor of Pennsylvania proposed an EIS. The EIS includes four pieces of proposed legislation that, according to the Governor, is designed to reduce energy costs, promote energy independence and stimulate the economy. Elements of the EIS include the installation of smart meters, funding for solar panels on residences and small businesses, conservation and demand reduction programs to meet energy growth, a requirement that electric distribution companies acquire power that results in the "lowest reasonable rate on a long-term basis," the utilization of micro-grids and a three year phase-in of rate increases. On July 17, 2007 the Governor signed into law two pieces of energy legislation. The first amended the Alternative Energy Portfolio Standards Act of 2004 to, among other things, increase the percentage of solar energy that must be supplied at the conclusion of an electric distribution company's transition period. The second law allows electric distribution companies, at their sole discretion, to enter into long term contracts with large customers and to build or acquire interests in electric generation facilities specifically to supply long-term contracts with such customers. A special legislative session on energy was convened in mid-September 2007 to consider other aspects of the EIS. As part of the 2008 state budget negotiations, the Alternative Energy Investment Act was enacted in July 2008 creating a \$650 million alternative energy fund to increase the development and use of alternative and renewable energy, improve energy efficiency and reduce energy consumption.

On October 15, 2008, the Governor of Pennsylvania signed House Bill 2200 into law which became effective on November 14, 2008 as Act 129 of 2008. The bill addresses issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters and alternative energy. Act 129 requires utilities to file with the PPUC an energy efficiency and peak load reduction plan by July 1, 2009 and a smart meter procurement and installation plan by August 14, 2009. On January 15, 2009, in compliance with Act 129, the PPUC issued its guidelines for the filing of utilities' energy efficiency and peak load reduction plans.

Major provisions of the legislation include:

- power acquired by utilities to serve customers after rate caps expire will be procured through a competitive procurement process that must include a mix of long-term and short-term contracts and spot market purchases;
- the competitive procurement process must be approved by the PPUC and may include auctions, RFPs, and/or bilateral agreements;
- utilities must provide for the installation of smart meter technology within 15 years;

- a minimum reduction in peak demand of 4.5% by May 31, 2013;
- minimum reductions in energy consumption of 1% and 3% by May 31, 2011 and May 31, 2013, respectively; and
- an expanded definition of alternative energy to include additional types of hydroelectric and biomass facilities.

Legislation addressing rate mitigation and the expiration of rate caps was not enacted in 2008 but may be considered in the legislative session which began in January 2009. While the form and impact of such legislation is uncertain, several legislators and the Governor have indicated their intent to address these issues in 2009.

On September 25, 2008, Met-Ed and Penelec filed a Voluntary Prepayment Plan with the PPUC that would provide an opportunity for residential and small commercial customers to prepay an amount on their monthly electric bills during 2009 and 2010 that would earn interest at 7.5% and be used to reduce electric rates in 2011 and 2012. Met-Ed, Penelec, OCA and OSBA have reached a settlement agreement on the Voluntary Prepayment Plan and have jointly requested that the PPUC approve the settlement. The ALJ issued a decision on January 29, 2009, recommending approval and adoption of the settlement without modification.

On February 20, 2009, Met-Ed and Penelec filed a generation procurement plan covering the period January 1, 2011 through May 31, 2013, with the PPUC. The companies' plan is designed to provide adequate and reliable service via a prudent mix of long-term, short-term and spot market generation supply, as required by Act 129. The plan proposes a staggered procurement schedule, which varies by customer class, through the use of a descending clock auction. Met-Ed and Penelec have requested PPUC approval of their plan by October 2009.

NJBPU Rate Matters

JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers, costs incurred under NUG agreements, and certain other stranded costs, exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of December 31, 2008, the accumulated deferred cost balance totaled approximately \$220 million.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004, supporting 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. JCP&L responded to additional NJBPU staff discovery requests in May and November 2007 and also submitted comments in the proceeding in November 2007. A schedule for further NJBPU proceedings has not yet been set.

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of the PUHCA pursuant to the EPACK. The NJBPU approved regulations effective October 2, 2006 that 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. These regulations are not expected to materially impact FirstEnergy or JCP&L. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. The NJBPU Staff circulated revised drafts of the proposal to interested stakeholders in November 2006 and again in February 2007. On February 1, 2008, the NJBPU accepted proposed rules for publication in the New Jersey Register on March 17, 2008. A public hearing on these proposed rules was held on April 23, 2008 and comments from interested parties were submitted by May 19, 2008.

New Jersey statutes require that the state periodically undertake a planning process, known as the EMP, to address energy related issues including energy security, economic growth, and environmental impact. The EMP is to be developed with involvement of the Governor's Office and the Governor's Office of Economic Growth, and is to be prepared by a Master Plan Committee, which is chaired by the NJBPU President and includes representatives of several State departments.

The EMP was issued on October 22, 2008, establishing five major goals:

- maximize energy efficiency to achieve a 20% reduction in energy consumption by 2020;
- reduce peak demand for electricity by 5,700 MW by 2020;
- meet 30% of the state's electricity needs with renewable energy by 2020;
- examine smart grid technology and develop additional cogeneration and other generation resources consistent with the state's greenhouse gas targets; and
- invest in innovative clean energy technologies and businesses to stimulate the industry's growth in New Jersey.

The EMP will be followed by appropriate legislation and regulation as necessary. At this time, FirstEnergy cannot determine the impact, if any, the EMP may have on its operations or those of JCP&L.

In support of the New Jersey Governor's Economic Assistance and Recovery Plan, JCP&L announced its intent to spend approximately \$98 million on infrastructure and energy efficiency projects in 2009. An estimated \$40 million will be spent on infrastructure projects, including substation upgrades, new transformers, distribution line re-closers and automated breaker operations. Approximately \$34 million will be spent implementing new demand response programs as well as expanding on existing programs. Another \$11 million will be spent on energy efficiency, specifically replacing transformers and capacitor control systems and installing new LED street lights. The remaining \$13 million will be spent on energy efficiency programs that will complement those currently being offered. Completion of the projects is dependent upon regulatory approval for full recovery of the costs associated with plan implementation.

FERC Matters

Transmission Service between MISO and PJM

On November 18, 2004, the FERC issued an order eliminating the through and out rate for transmission service between the MISO and PJM regions. The FERC's intent was to eliminate multiple transmission charges for a single transaction between the MISO and PJM regions. The FERC also ordered MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a rate mechanism to recover lost transmission revenues created by elimination of this charge (referred to as the Seams Elimination Cost Adjustment or "SECA") during a 16-month transition period. The FERC issued orders in 2005 setting the SECA for hearing. The presiding judge issued an initial decision on August 10, 2006, rejecting the compliance filings made by MISO, PJM, and the transmission owners, and directing new compliance filings. This decision is subject to review and approval by the FERC. Briefs addressing the initial decision were filed on September 11, 2006 and October 20, 2006. A final order is pending before the FERC, and in the meantime, FirstEnergy affiliates have been negotiating and entering into settlement agreements with other parties in the docket to mitigate the risk of lower transmission revenue collection associated with an adverse order. On September 26, 2008, the MISO and PJM transmission owners filed a motion requesting that the FERC approve the pending settlements and act on the initial decision. On November 20, 2008, FERC issued an order approving uncontested settlements, but did not rule on the initial decision. On December 19, 2008, an additional order was issued approving two contested settlements.

PJM Transmission Rate Design

On January 31, 2005, certain PJM transmission owners made 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. Hearings were held and numerous parties appeared and litigated various issues concerning PJM rate design; notably AEP, which proposed to create a "postage stamp", or average rate for all high voltage transmission facilities across PJM and a zonal transmission rate for facilities below 345 kV. This proposal would have the effect of shifting recovery of the costs of high voltage transmission lines to other transmission zones, including those where JCP&L, Met-Ed, and Penelec serve load. On April 19, 2007, the FERC issued an order finding that the PJM transmission owners' existing "license plate" or zonal rate design was just and reasonable and ordered that the current license plate rates for existing transmission facilities be retained. On the issue of rates for new transmission facilities, the FERC directed that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp rate. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a "beneficiary pays" basis. The FERC found that PJM's current beneficiary-pays cost allocation methodology is not sufficiently detailed and, in a related order that also was issued on April 19, 2007, directed that hearings be held for the purpose of establishing a just and reasonable cost allocation methodology for inclusion in PJM's tariff.

On May 18, 2007, certain parties filed for rehearing of the FERC's April 19, 2007 order. On January 31, 2008, the requests for rehearing were denied. On February 11, 2008, AEP appealed the FERC's April 19, 2007, and January 31, 2008, orders to the federal Court of Appeals for the D.C. Circuit. The Illinois Commerce Commission, the PUCO and Dayton Power & Light have also appealed these orders to the Seventh Circuit Court of Appeals. The appeals of these parties and others have been consolidated for argument in the Seventh Circuit.

The FERC's orders on PJM rate design will prevent the allocation of a portion of the revenue requirement of existing transmission facilities of other utilities to JCP&L, Met-Ed and Penelec. In addition, the FERC's decision to allocate the cost of new 500 kV and above transmission facilities on a PJM-wide basis will reduce the costs of future transmission to be recovered from the JCP&L, Met-Ed and Penelec zones. A partial settlement agreement addressing the "beneficiary pays" methodology for below 500 kV facilities, but excluding the issue of allocating new facilities costs to merchant transmission entities, was filed on September 14, 2007. The agreement was supported by the FERC's Trial Staff, and was certified by the Presiding Judge to the FERC. On July 29, 2008, the FERC issued an order conditionally approving the settlement subject to the submission of a compliance filing. The compliance filing was submitted on August 29, 2008, and the FERC issued an order accepting the compliance filing on October 15, 2008. The remaining merchant transmission cost allocation issues were the subject of a hearing at the FERC in May 2008. An initial decision was issued by the Presiding Judge on September 18, 2008. PJM and FERC trial staff each filed a Brief on Exceptions to the initial decision on October 20, 2008. Briefs Opposing Exceptions were filed on November 10, 2008.

Post Transition Period Rate Design

The FERC had directed MISO, PJM, and the respective transmission owners to make filings on or before August 1, 2007 to reevaluate transmission rate design within MISO, and between MISO and PJM. On August 1, 2007, filings were made by MISO, PJM, and the vast majority of transmission owners, including FirstEnergy affiliates, which proposed to retain the existing transmission rate design. These filings were approved by the FERC on January 31, 2008. As a result of the FERC's approval, the rates charged to FirstEnergy's load-serving affiliates for transmission service over existing transmission facilities in MISO and PJM are unchanged. In a related filing, MISO and MISO transmission owners requested that the current MISO pricing for new transmission facilities that spreads 20% of the cost of new 345 kV and higher transmission facilities across the entire MISO footprint (known as the RECB methodology) be retained.

On September 17, 2007, AEP filed a complaint under Sections 206 and 306 of the Federal Power Act seeking to have the entire transmission rate design and cost allocation methods used by MISO and PJM declared unjust, unreasonable, and unduly discriminatory, and to have the FERC fix a uniform regional transmission rate design and cost allocation method for the entire MISO and PJM "Super Region" that recovers the average cost of new and existing transmission facilities operated at voltages of 345 kV and above from all transmission customers. Lower voltage facilities would continue to be recovered in the local utility transmission rate zone through a license plate rate. AEP requested a refund effective October 1, 2007, or alternatively, February 1, 2008. On January 31, 2008, the FERC issued an order denying the complaint. The effect of this order is to prevent the shift of significant costs to the FirstEnergy zones in MISO and PJM. A rehearing request by AEP was denied by the FERC on December 19, 2008. On February 17, 2009, AEP appealed the FERC's January 31, 2008, and December 19, 2008, orders to the U.S. Court of Appeals for the Seventh Circuit.

Interconnection Agreement with AMP-Ohio

On May 29, 2008, TE filed with the FERC a proposed Notice of Cancellation effective midnight December 31, 2008, of the Interconnection Agreement with AMP-Ohio. AMP-Ohio protested this filing. TE also filed a Petition for Declaratory Order seeking a FERC ruling, in the alternative if cancellation is not accepted, of TE's right to file for an increase in rates effective January 1, 2009, for power provided to AMP-Ohio under the Interconnection Agreement. AMP-Ohio filed a pleading agreeing that TE may seek an increase in rates, but arguing that any increase is limited to the cost of generation owned by TE affiliates. On August 18, 2008, the FERC issued an order that suspended the cancellation of the Agreement for five months, to become effective on June 1, 2009, and established expedited hearing procedures on issues raised in the filing and TE's Petition for Declaratory Order. On October 14, 2008, the parties filed a settlement agreement and mutual notice of cancellation of the Interconnection Agreement effective midnight December 31, 2008. On October 24, 2008 the presiding judge certified the settlement agreement as uncontested and on December 22, 2008, the FERC issued an order approving the uncontested settlement agreement. This latest action terminates the litigation and the Interconnection Agreement .

Duquesne's Request to Withdraw from PJM

On November 8, 2007, Duquesne Light Company (Duquesne) filed a request with the FERC to exit PJM and to join MISO. Duquesne's proposed move would affect numerous FirstEnergy interests, including but not limited to the terms under which FirstEnergy's Beaver Valley Plant would continue to participate in PJM's energy markets. FirstEnergy, therefore, intervened and participated fully in all of the FERC dockets that were related to Duquesne's proposed move.

In November, 2008, Duquesne and other parties, including FirstEnergy, negotiated a settlement that would, among other things, allow for Duquesne to remain in PJM and provide for a methodology for Duquesne to meet the PJM capacity obligations for the 2011-2012 auction that excluded the Duquesne load. The settlement agreement was filed on December 10, 2008 and approved by the FERC in an order issued on January 29, 2009. The MISO opposed the settlement agreement pending resolution of exit fees alleged to be owed by Duquesne. The FERC did not resolve this issue in its order.

Complaint against PJM RPM Auction

On May 30, 2008, a group of PJM load-serving entities, state commissions, consumer advocates, and trade associations (referred to collectively as the RPM Buyers) filed a complaint at the FERC against PJM alleging that three of the four transitional RPM auctions yielded prices that are unjust and unreasonable under the Federal Power Act. On September 19, 2008, the FERC denied the RPM Buyers' complaint. However, the FERC did grant the RPM Buyers' request for a technical conference to review aspects of the RPM. The FERC also ordered PJM to file on or before December 15, 2008, a report on potential adjustments to the RPM program as suggested in a Bra ttle Group report. On December 12, 2008, PJM filed proposed tariff amendments that would adjust slightly the RPM program. PJM also requested that the FERC conduct a settlement hearing to address changes to the RPM and suggested that the FERC should rule on the tariff amendments only if settlement could not be reached in January, 2009. The request for settlement hearings was granted. Settlement had not been reached by January 9, 2009 and, accordingly, FirstEnergy and other parties submitted comments on PJM's proposed tariff amendments. On January 15, 2009, the Chief Judge issued an order terminating settlement talks. On February 9, 2009, PJM and a group of stakeholders submitted an offer of settlement.

On October 20, 2008, the RPM Buyers filed a request for rehearing of the FERC's September 19, 2008 order. The FERC has not yet ruled on the rehearing request.

MISO Resource Adequacy Proposal

MISO made a filing on December 28, 2007 that would create an enforceable planning reserve requirement in the MISO tariff for load-serving entities such as the Ohio Companies, Penn Power, and FES. This requirement is proposed to become effective for the planning year beginning June 1, 2009. The filing would permit MISO to establish the reserve margin requirement for load-serving entities based upon a one day loss of load in ten years standard, unless the state utility regulatory agency establishes a different planning reserve for load-serving entities in its state. FirstEnergy believes the proposal promotes a mechanism that will result in commitments from both load-serving entities and resources, including both generation and demand side resources that are necessary for reliable resource adequacy and planning in the MISO footprint. Comments on the filing were filed on January 28, 2008. The FERC conditionally approved MISO's Resource Adequacy proposal on March 26, 2008, requiring MISO to submit to further compliance filings. Rehearing requests are pending on the FERC's March 26 Order. On May 27, 2008, MISO submitted a compliance filing to address issues associated with planning reserve margins. On June 17, 2008, various parties submitted comments and protests to MISO's compliance filing. FirstEnergy submitted comments identifying specific issues that must be clarified and addressed. On June 25, 2008, MISO submitted a second compliance filing establishing the enforcement mechanism for the reserve margin requirement which establishes deficiency payments for load-serving entities that do not meet the resource adequacy requirements. Numerous parties, including FirstEnergy, protested this filing.

On October 20, 2008, the FERC issued three orders essentially permitting the MISO Resource Adequacy program to proceed with some modifications. First, the FERC accepted MISO's financial settlement approach for enforcement of Resource Adequacy subject to a compliance filing modifying the cost of new entry penalty. Second, the FERC conditionally accepted MISO's compliance filing on the qualifications for purchased power agreements to be capacity resources, load forecasting, loss of load expectation, and planning reserve zones. Additional compliance filings were directed on accreditation of load modifying resources and price responsive demand. Finally, the FERC largely denied rehearing of its March 26 order with the exception of issues related to behind the meter resources and certain ministerial matters. On November 19, 2008, MISO made various compliance filings pursuant to these orders. Issuance of orders on these compliance filings is not expected to delay the June 1, 2009, start date for MISO Resource Adequacy.

FES Sales to Affiliates

On October 24, 2008, FES, on its own behalf and on behalf of its generation-controlling subsidiaries, filed an application with the FERC seeking a waiver of the affiliate sales restrictions between FES and the Ohio Companies. The purpose of the waiver is to ensure that FES will be able to continue supplying a material portion of the electric load requirements of the Ohio Companies in January 2009 pursuant to either an ESP or MRO as filed with the PUCO. FES previously obtained a similar waiver for electricity sales to its affiliates in New Jersey, New York, and Pennsylvania. On December 23, 2008, the FERC issued an order granting the waiver request and the Ohio Companies made the required compliance filing on December 30, 2008.

On October 31, 2008, FES executed a Third Restated Partial Requirements Agreement with Met-Ed, Penelec, and Waverly effective November 1, 2008. The Third Restated Partial Requirements Agreement limits the amount of capacity and energy required to be supplied by FES in 2009 and 2010 to roughly two-thirds of these affiliates' power supply requirements. Met-Ed, Penelec, and Waverly have committed resources in place for the balance of their expected power supply during 2009 and 2010. Under the Third Restated Partial Requirements Agreement, Met-Ed, Penelec, and Waverly are responsible for obtaining additional power supply requirements created by the default or failure of supply of their committed resources. Prices for the power provided by FES were not changed in the Third Restated Partial Requirements Agreement.

Capital Requirements

Anticipated capital expenditures for the Utilities, FES and FirstEnergy's other subsidiaries for the years 2009 through 2013, excluding nuclear fuel, are shown in the following table. Such costs include expenditures for the betterment of existing facilities and for the construction of generating capacity, facilities for environmental compliance, transmission lines, distribution lines, substations and other assets.

	2008	Capital Expenditures Forecast		
	Actual ⁽¹⁾	2009	2010-2013	Total
		<i>(In millions)</i>		
OE	\$ 140	\$ 130	\$ 600	\$ 730
Penn	35	22	112	134
CEI	139	103	494	597
TE	57	48	202	250
JCP&L	177	160	812	972
Met-Ed	108	97	447	544
Penelec	129	122	484	606
ATSI	46	39	177	216
FGCO	1,037	635	1,373	2,008
NGC	115	243	1,323	1,566
Other subsidiaries	167	58	458	516
Total	\$ 2,150	\$ 1,657	\$ 6,482	\$ 8,139

⁽¹⁾ Excludes nuclear fuel, the purchase of lessor equity interests in Beaver Valley Unit 2 and Perry (\$438 million), and the acquisition of Signal Peak (\$125 million).

During the 2009-2013 period, maturities of, and sinking fund requirements for, long-term debt of FirstEnergy and its subsidiaries are:

	Long-Term Debt Redemption Schedule		
	2009	2010-2013	Total
	<i>(In millions)</i>		
FirstEnergy	\$ -	\$ 1,500	\$ 1,500
FES	42	254	296
OE	-	1	1
Penn ⁽¹⁾	1	5	6
CEI ⁽²⁾	150	300	450
JCP&L	29	133	162
Met-Ed	-	250	250
Penelec	100	59	159
Other	1	64	65
Total	\$ 323	\$ 2,566	\$ 2,889

⁽¹⁾ Penn has an additional \$63 million due to associated companies in 2010-2013.

⁽²⁾ CEI has an additional \$85 million due to associated companies in 2010-2013.

NGC's investments for additional nuclear fuel during the 2009-2013 period are estimated to be approximately \$1.3 billion, of which about \$342 million applies to 2009. During the same period, its nuclear fuel investments are expected to be reduced by approximately \$1.0 billion and \$137 million, respectively, as the nuclear fuel is consumed.

The following table displays operating lease commitments, net of capital trust cash receipts for the 2009-2013 period.

	Net Operating Lease Commitments		
	2009	2010-2013	Total
	<i>(In millions)</i>		
OE	\$ 103	\$ 390	\$ 493
CEI ⁽¹⁾	(38)	(196)	(234)
TE	41	134	175
JCP&L	8	15	23
Met-Ed	4	7	11
Penelec	4	5	9
FESC	8	34	42
FGCO	176	787	963
NGC ⁽²⁾	(103)	(413)	(516)
Total	<u>\$ 203</u>	<u>\$ 763</u>	<u>\$ 966</u>

⁽¹⁾ Reflects CEI's investment in Shippingport that purchased lease obligations bonds issued on behalf of lessors in Bruce Mansfield Units 1, 2 and 3 sale and leaseback transactions. Effective October 16, 2007, CEI and TE assigned their leasehold interests in the Bruce Mansfield Plant to FGCO.

⁽²⁾ Reflects NGC's purchase of lessor equity interests in Beaver Valley Unit 2 and Perry in the second quarter of 2008.

FirstEnergy has been notified by the lessor of certain vehicle and equipment leases of its election to terminate the lease arrangements effective November 2009. FirstEnergy is currently pursuing replacement lease arrangements with alternative lessors. In the event that replacement lease arrangements are not secured, FirstEnergy would be required to purchase the vehicles and equipment under lease at their unamortized value of approximately \$100 million upon termination of the lease.

FirstEnergy expects its existing sources of liquidity to remain sufficient to meet its anticipated obligations and those of its subsidiaries. FirstEnergy and its subsidiaries' business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest and dividend payments. During 2009 and in subsequent years, FirstEnergy expects to satisfy these requirements with a combination of cash from operations and funds from the capital markets. FirstEnergy also expects that borrowing capacity under credit facilities will continue to be available to manage working capital requirements during those periods.

FirstEnergy had approximately \$2.4 billion of short-term indebtedness as of December 31, 2008, comprised of \$2.3 billion in borrowings under the \$2.75 billion revolving line of credit described below and \$102 million of other bank borrowings. Total short-term bank lines of committed credit to FirstEnergy, FES and the Utilities as of December 31, 2008 were approximately \$4.0 billion.

FirstEnergy, along with certain of its subsidiaries, are party to a \$2.75 billion five-year revolving credit facility. FirstEnergy has the ability to request an increase in the total commitments available under this facility up to a maximum of \$3.25 billion, subject to the discretion of each lender to provide additional commitments. Commitments under the facility are available until August 24, 2012, unless the lenders agree, at the request of the borrowers, to an unlimited number of additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each borrower are subject to a specified sub-limit, as well as applicable regulatory and other limitations. The annual facility fee is 0.125%.

As of January 31, 2009, FirstEnergy had \$720 million of bank credit facilities in addition to the \$2.75 billion revolving credit facility. Also, an aggregate of \$550 million of accounts receivable financing facilities through the Ohio and Pennsylvania Companies may be accessed to meet working capital requirements and for other general corporate purposes. FirstEnergy's available liquidity as of January 31, 2009, is described in the following table.

<u>Company</u>	<u>Type</u>	<u>Maturity</u>	<u>Commitment</u>	<u>Available Liquidity as of January 31, 2009</u>
<i>(In millions)</i>				
FirstEnergy ⁽¹⁾	Revolving	Aug. 2012	\$ 2,750	\$ 405
FirstEnergy and FES	Revolving	May 2009	300	300
FirstEnergy	Bank lines	Various ⁽²⁾	120	20
FGCO	Term loan	Oct. 2009 ⁽³⁾	300	300
Ohio and Pennsylvania Companies	Receivables financing	Various ⁽⁴⁾	550	469
		Subtotal	\$ 4,020	\$ 1,494
		Cash	-	1,110
		Total	\$ 4,020	\$ 2,604

(1) FirstEnergy Corp. and subsidiary borrowers.

(2) \$100 million matures November 30, 2009; \$20 million uncommitted line of credit with no maturity date.

(3) Drawn amounts are payable within 30 days and may not be re-borrowed.

(4) \$370 million expires February 22, 2010; \$180 million expires December 18, 2009.

FirstEnergy's primary source of cash for continuing operations as a holding company is cash from the operations of its subsidiaries. During 2008, the holding company received \$995 million of cash dividends on common stock from its subsidiaries and paid \$671 million in cash dividends to common shareholders.

As of December 31, 2008, the Ohio Companies and Penn had the aggregate capability to issue approximately \$2.8 billion of additional FMBs on the basis of property additions and retired bonds under the terms of their respective mortgage indentures. The issuance of FMBs by OE, CEI and TE is 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 FMBs) supporting pollution control notes or similar obligations, or as an extension, renewal or replacement of previously outstanding secured debt. In addition, these provisions would permit OE, CEI and TE to incur additional secured debt not otherwise permitted by a specified exception of up to \$168 million, \$179 million and \$117 million, respectively, as of December 31, 2008. On June 19, 2008, FGCO established an FMB indenture. Based upon its net earnings and available bondable property additions as of December 31, 2008, FGCO had the capability to issue \$3.0 billion of additional FMBs under the terms of that indenture. Met-Ed and Penelec had the capability to issue secured debt of approximately \$376 million and \$318 million, respectively, under provisions of their senior note indentures as of December 31, 2008.

To the extent that coverage requirements or market conditions restrict the subsidiaries' abilities to issue desired amounts of FMBs or preferred stock, they may seek other methods of financing. Such financings could include the sale of preferred and/or preference stock or of such other types of securities as might be authorized by applicable regulatory authorities which would not otherwise be sold and could result in annual interest charges and/or dividend requirements in excess of those that would otherwise be incurred.

On September 22, 2008, FirstEnergy and the Shelf Registrants filed an automatically effective shelf registration statement with the SEC for an unspecified number and amount of securities to be offered thereon. The shelf registration provides FirstEnergy the flexibility to issue and sell various types of securities, including common stock, preferred stock, debt securities, warrants, share purchase contracts, and share purchase units. The Shelf Registrants may utilize the shelf registration statement to offer and sell unsecured, and in some cases, secured debt securities.

Nuclear Operating Licenses

Each of the nuclear units in the FES portfolio operates under a 40-year operating license granted by the NRC. The following table summarizes the current operating license expiration dates for FES' nuclear facilities in service.

<u>Station</u>	<u>In-Service Date</u>	<u>Current License Expiration</u>
Beaver Valley Unit 1	1976	2016
Beaver Valley Unit 2	1987	2027
Perry	1986	2026
Davis-Besse	1977	2017

In August 2007, FENOC submitted an application to the NRC to renew the operating licenses for the Beaver Valley Power Station (Units 1 and 2) for an additional 20 years. The NRC is required by statute to provide an opportunity for members of the public to request a hearing on the application. No members of the public, however, requested a hearing on the Beaver Valley license renewal application. On September 24, 2008, the NRC issued a draft supplemental Environmental Impact Statement for Beaver Valley. FENOC will continue to work with the NRC Staff as it completes its environmental and technical reviews of the license renewal application, and expects to obtain renewed licenses for the Beaver Valley Power Station in 2009. If renewed licenses are issued by the NRC, the Beaver Valley Power Station's licenses would be extended until 2036 and 2047 for Units 1 and 2, respectively. FENOC's application for operating license extensions for Beaver Valley Units 1 and 2 was accepted by the NRC on November 9, 2007. Similar applications are expected to be filed for Davis-Besse in 2010 and Perry in 2013. The NRC review process takes approximately two to three years from the docketing of an application. The license extension is for 20 years beyond the current license period.

Nuclear Regulation

On May 14, 2007, the Office of Enforcement of the NRC issued a DFI to FENOC, following FENOC's reply to an April 2, 2007 NRC request for information about two reports prepared by expert witnesses for an insurance arbitration (the insurance claim was subsequently withdrawn by FirstEnergy in December 2007) related to Davis-Besse. The NRC indicated that this information was needed for the NRC "to determine whether an Order or other action should be taken pursuant to 10 CFR 2.202, to provide reasonable assurance that FENOC will continue to operate its licensed facilities in accordance with the terms of its licenses and the Commission's regulations." FENOC was directed to submit the information to the NRC within 30 days. On June 13, 2007, FENOC filed a response to the NRC's DFI reaffirming that it accepts full responsibility for the mistakes and omissions leading up to the damage to the reactor vessel head and that it remains committed to operating Davis-Besse and FirstEnergy's other nuclear plants safely and responsibly. FENOC submitted a supplemental response clarifying certain aspects of the DFI response to the NRC on July 16, 2007. On August 15, 2007, the NRC issued a confirmatory order imposing these commitments. FENOC must inform the NRC's Office of Enforcement after it completes the key commitments embodied in the NRC's order. FENOC has conducted the employee training required by the confirmatory order and a consultant has performed follow-up reviews to ensure the effectiveness of that training. The NRC continues to monitor FENOC's compliance with all the commitments made in the confirmatory order.

Nuclear Insurance

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to \$12.5 billion (assuming 104 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to \$300 million; and (ii) \$12.2 billion provided by an industry retrospective rating plan required by the NRC pursuant thereto. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to \$118 million (but not more than \$18 million per unit per year in the event of more than one incident) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Based on their present nuclear ownership and leasehold interests, FirstEnergy's maximum potential assessment under these provisions would be \$470 million (OE-\$40 million, NGC-\$408 million, and TE-\$22 million) per incident but not more than \$70 million (OE-\$6 million, NGC-\$61 million, and TE-\$3 million) in any one year for each incident.

In addition to the public liability insurance provided pursuant to the Price-Anderson Act, FirstEnergy has also obtained insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. FirstEnergy is a member of Nuclear Electric Insurance Limited (NEIL) which provides coverage (NEIL I) for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. Under NEIL I, FirstEnergy's subsidiaries have policies, renewable yearly, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately \$2.0 billion (OE-\$168 million, NGC-\$1.7 billion, TE-\$89 million) for replacement power costs incurred during an outage after an initial 20-week waiting period. Members of NEIL I pay annual premiums and are subject to assessments if losses exceed the accumulated funds available to the insurer. FirstEnergy's present maximum aggregate assessment for incidents at any covered nuclear facility occurring during a policy year would be approximately \$18 million (OE-\$1 million, NGC-\$16 million, and TE-\$1 million).

FirstEnergy is insured as to its respective nuclear interests under property damage insurance provided by NEIL to the operating company for each plant. Under these arrangements, up to \$2.8 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. FirstEnergy pays annual premiums for this coverage and is liable for retrospective assessments of up to approximately \$61 million (OE-\$6 million, NGC-\$52 million, TE-\$2 million, Met Ed, Penelec and JCP&L-\$1 million in total) during a policy year.

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

The NRC requires nuclear power plant licensees to obtain minimum property insurance coverage of \$1.1 billion or the amount generally available from private sources, whichever is less. The proceeds of this insurance are required to be used first to ensure that the licensed reactor is in a safe and stable condition and can be maintained in that condition so as to prevent any significant risk to the public health and safety. Within 30 days of stabilization, the licensee is required to prepare and submit to the NRC a cleanup plan for approval. The plan is required to identify all cleanup operations necessary to decontaminate the reactor sufficiently to permit the resumption of operations or to commence decommissioning. Any property insurance proceeds not already expended to place the reactor in a safe and stable condition must be used first to complete those decontamination operations that are ordered by the NRC. FirstEnergy is unable to predict what effect these requirements may have on the availability of insurance proceeds.

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 FirstEnergy 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. FirstEnergy estimates capital expenditures for environmental compliance of approximately \$608 million for the period 2009-2013.

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 become both probable and reasonably estimable.

Clean Air Act Compliance

FirstEnergy is required to meet federally-approved SO₂ emissions regulations. Violations of such regulations can result in the shutdown of the generating unit involved and/or civil or criminal penalties of up to \$37,500 for each day the unit is in violation. The EPA has an interim enforcement policy for SO₂ regulations in Ohio that allows for compliance based on a 30-day averaging period. FirstEnergy believes it is currently in compliance with this policy, but cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The EPA Region 5 issued a Finding of Violation and NOV to the Bay Shore Power Plant dated June 15, 2006, alleging violations to various sections of the CAA. FirstEnergy has disputed those alleged violations based on its CAA permit, the Ohio SIP and other information provided to the EPA at an August 2006 meeting with the EPA. The EPA has several enforcement options (administrative compliance order, administrative penalty order, and/or judicial, civil or criminal action) and has indicated that such option may depend on the time needed to achieve and demonstrate compliance with the rules alleged to have been violated. On June 5, 2007, the EPA requested another meeting to discuss "an appropriate compliance program" and a disagreement regarding emission limits applicable to the common stack for Bay Shore Units 2, 3 and 4.

FirstEnergy complies with SO₂ reduction requirements under the Clean Air Act Amendments of 1990 by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NO_x reductions required by the 1990 Amendments are being achieved through combustion controls and the generation of more electricity at lower-emitting plants. In September 1998, the EPA finalized regulations requiring additional NO_x reductions at FirstEnergy's facilities. The EPA's NO_x Transport Rule imposes uniform reductions of NO_x emissions (an approximate 85% reduction in utility plant NO_x emissions from projected 2007 emissions) across a region of nineteen states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on a conclusion that such NO_x emissions are contributing significantly to ozone levels in the eastern United States. FirstEnergy believes its facilities are also complying with the NO_x budgets established under SIPs through combustion controls and post-combustion controls, including Selective Catalytic Reduction and SNCR systems, and/or using emission allowances.

In 1999 and 2000, the EPA issued an NOV and the DOJ filed a civil complaint against OE and Penn based on operation and maintenance of the W. H. Sammis Plant (Sammis NSR Litigation) and filed similar complaints involving 44 other U.S. power plants. This case and seven other similar cases are referred to as the NSR cases. OE's and Penn's settlement with the EPA, the DOJ and three states (Connecticut, New Jersey and New York) that resolved all issues related to the Sammis NSR litigation was approved by the Court on July 11, 2005. This settlement agreement, in the form of a consent decree, requires reductions of NO_x and SO₂ emissions at the Sammis, Burger, Eastlake and Mansfield 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. Capital expenditures necessary to complete requirements of the Sammis NSR Litigation consent decree are currently estimated to be \$506 million for 2009-2010 (with \$414 million expected to be spent in 2009). This amount is included in the estimated capital expenditures for environmental compliance referenced above, but excludes the potential AQC expenditures related to Burger Units 4 and 5 described below. On September 8, 2008, the Environmental Enforcement Section of the DOJ sent a letter to OE regarding its view that the company was not in compliance with the Sammis NSR Litigation consent decree because the installation of an SNCR at Eastlake Unit 5 was not completed by December 31, 2006. However, the DOJ acknowledged that stipulated penalties could not apply under the terms of the Sammis NSR Litigation consent decree because Eastlake Unit 5 was idled on December 31, 2006 pending installation of the SNCR and advised that it had exercised its discretion not to seek any other penalties for this alleged non-compliance. OE disputed the DOJ's interpretation of the consent decree in a letter dated September 22, 2008. Although the Eastlake Unit 5 issue is no longer active, OE filed a dispute resolution petition on October 23, 2008, with the United States District Court for the Southern District of Ohio, due to potential impacts on its compliance decisions with respect to Burger Units 4 and 5. On December 23, 2008, OE withdrew its dispute resolution petition and subsequently filed a motion to extend the date (from December 31, 2008 to April 15, 2009), under the Sammis NSR Litigation consent decree, to elect for Burger Units 4 and 5 to permanently shut down those units by December 31, 2010, or to repower them or to install flue gas desulfurization (FGD) by later dates. On January 30, 2009, the Court issued an order extending the election date from December 31, 2008 to March 31, 2009.

On April 2, 2007, the United States Supreme Court ruled that changes in annual emissions (in tons/year) rather than changes in hourly emissions rate (in kilograms/hour) must be used to determine whether an emissions increase triggers NSR. Subsequently, on May 8, 2007, the EPA proposed to revise the NSR regulations to utilize changes in the hourly emission rate (in kilograms/hour) to determine whether an emissions increase triggers NSR. On December 10, 2008, the EPA announced it would not finalize this proposed change to the NSR regulations.

On May 22, 2007, FirstEnergy and FGCO received a notice letter, required 60 days prior to the filing of a citizen suit under the federal CAA, alleging violations of air pollution laws at the Bruce Mansfield Plant, including opacity limitations. Prior to the receipt of this notice, the Plant was subject to a Consent Order and Agreement with the Pennsylvania Department of Environmental Protection concerning opacity emissions under which efforts to achieve compliance with the applicable laws will continue. On October 18, 2007, PennFuture filed a complaint, joined by three of its members, in the United States District Court for the Western District of Pennsylvania. On January 11, 2008, FirstEnergy filed a motion to dismiss claims alleging a public nuisance. On April 24, 2008, the Court denied the motion to dismiss, but also ruled that monetary damages could not be recovered under the public nuisance claim. In July 2008, three additional complaints were filed against FGCO in the United States District Court for the Western District of Pennsylvania seeking damages based on Bruce Mansfield Plant air emissions. In addition to seeking damages, two of the complaints seek to enjoin the Bruce Mansfield Plant from operating except in a "safe, responsible, prudent and proper manner", one being a complaint filed on behalf of twenty-one individuals and the other being a class action complaint, seeking certification as a class action with the eight named plaintiffs as the class representatives. On October 14, 2008, the Court granted FGCO's motion to consolidate discovery for all four complaints pending against the Bruce Mansfield Plant. FGCO believes the claims are without merit and intends to defend itself against the allegations made in these complaints.

On December 18, 2007, the state of New Jersey filed a CAA citizen suit alleging NSR violations at the Portland Generation Station against Reliant (the current owner and operator), Sithe Energy (the purchaser of the Portland Station from Met-Ed in 1999), GPU, Inc. and Met-Ed. Specifically, New Jersey alleges that "modifications" at Portland Units 1 and 2 occurred between 1980 and 1995 without preconstruction NSR or permitting under the CAA's prevention of significant deterioration program, and seeks injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. On March 14, 2008, Met-Ed filed a motion to dismiss the citizen suit claims against it and a stipulation in which the parties agreed that GPU, Inc. should be dismissed from this case. On March 26, 2008, GPU, Inc. was dismissed by the United States District Court. The scope of Met-Ed's indemnity obligation to and from Sithe Energy is disputed. On October 30, 2008, the state of Connecticut filed a Motion to Intervene, but the Court has yet to rule on Connecticut's Motion. On December 5, 2008, New Jersey filed an amended complaint, adding claims with respect to alleged modifications that occurred after GPU's sale of the plant. On January 14, 2009, the EPA issued a NOV to Reliant alleging new source review violations at the Portland Generation Station based on "modifications" dating back to 1986. Met-Ed is unable to predict the outcome of this matter. The EPA's January 14, 2009, NOV also alleged new source review violations at the Keystone and Shawville Stations based on "modifications" dating back to 1984. JCP&L, as the former owner of 16.67% of Keystone Station and Penelec, as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter.

On June 11, 2008, the EPA issued a Notice and Finding of Violation to MEW alleging that "modifications" at the Homer City Power Station occurred since 1988 to the present without preconstruction NSR or permitting under the CAA's prevention of significant deterioration program. MEW is seeking indemnification from Penelec, the co-owner (along with New York State Electric and Gas Company) and operator of the Homer City Power Station prior to its sale in 1999. The scope of Penelec's indemnity obligation to and from MEW is disputed. Penelec is unable to predict the outcome of this matter.

On May 16, 2008, FGCO received a request from the EPA for information pursuant to Section 114(a) of the CAA for certain operating and maintenance information regarding the Eastlake, Lakeshore, Bay Shore and Ashtabula generating plants to allow the EPA to determine whether these generating sources are complying with the NSR provisions of the CAA. On July 10, 2008, FGCO and the EPA entered into an ACO modifying that request and setting forth a schedule for FGCO's response. On October 27, 2008, FGCO received a second request from the EPA for information pursuant to Section 114(a) of the CAA for additional operating and maintenance information regarding the Eastlake, Lakeshore, Bay Shore and Ashtabula generating plants. FGCO intends to fully comply with the EPA's information requests, but, at this time, is unable to predict the outcome of this matter.

On August 18, 2008, FirstEnergy received a request from the EPA for information pursuant to Section 114(a) of the CAA for certain operating and maintenance information regarding the Avon Lake and Niles generating plants, as well as a copy of a nearly identical request directed to the current owner, Reliant Energy, to allow the EPA to determine whether these generating sources are complying with the NSR provisions of the CAA. FirstEnergy intends to fully comply with the EPA's information request, but, at this time, is unable to predict the outcome of this matter.

National Ambient Air Quality Standards

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 requires reductions of NO_x and SO₂ emissions in two phases (Phase I in 2009 for NO_x, 2010 for SO₂ and Phase II in 2015 for both NO_x and SO₂), ultimately capping SO₂ emissions in affected states to just 2.5 million tons annually and NO_x emissions to just 1.3 million tons annually. CAIR was challenged in the United States Court of Appeals for the District of Columbia and on July 11, 2008, the Court vacated CAIR "in its entirety" and directed the EPA to "redo its analysis from the ground up." On September 24, 2008, the EPA, utility, mining and certain environmental advocacy organizations petitioned the Court for a rehearing to reconsider its ruling vacating CAIR. On December 23, 2008, the Court reconsidered its prior ruling and allowed CAIR to remain in effect to "temporarily preserve its environmental values" until the EPA replaces CAIR with a new rule consistent with the Court's July 11, 2008 opinion. The future cost of compliance with these regulations may be substantial and will depend, in part, on the action taken by the EPA in response to the Court's ruling.

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, capping national mercury emissions at 38 tons by 2010 (as a "co-benefit" from implementation of SO₂ and NO_x emission caps under the EPA's CAIR program) and 15 tons per year by 2018. Several states and environmental groups appealed the CAMR to the United States Court of Appeals for the District of Columbia. On February 8, 2008, the Court vacated the CAMR, ruling that the EPA failed to take the necessary steps to "de-list" coal-fired power plants from its hazardous air pollutant program and, therefore, could not promulgate a cap-and-trade program. The EPA petitioned for rehearing by the entire Court, which denied the petition on May 20, 2008. On October 17, 2008, the EPA (and an industry group) petitioned the United States Supreme Court for review of the Court's ruling vacating CAMR. On February 6, 2009, the United States moved to dismiss its petition for certiorari. On February 23, 2009, the Supreme Court dismissed the United States' petition and denied the industry group's petition. Accordingly, the EPA could take regulatory action to promulgate new mercury emission standards for coal-fired power plants. FGCO's future cost of compliance with mercury regulations may be substantial and will depend on the action taken by the EPA and on how they are ultimately implemented.

Pennsylvania has submitted a new mercury rule for EPA approval that does not provide a cap-and-trade approach as in the CAMR, but rather follows a command-and-control approach imposing emission limits on individual sources. On January 30, 2009, the Commonwealth Court of Pennsylvania declared Pennsylvania's mercury rule "unlawful, invalid and unenforceable" and enjoined the Commonwealth from continued implementation or enforcement of that rule. It is anticipated that compliance with these regulations, if the Commonwealth Court's rulings were reversed on appeal and Pennsylvania's mercury rule was implemented, would not require the addition of mercury controls at the Bruce Mansfield Plant, FirstEnergy's only Pennsylvania coal-fired power plant, until 2015, if at all.

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, including CO₂, emitted by developed countries by 2012. The United States signed the Kyoto Protocol in 1998 but it was never submitted for ratification by the United States Senate. However, the Bush administration had 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. Also, in an April 16, 2008 speech, former President Bush set a policy goal of stopping the growth of GHG emissions by 2025, as the next step beyond the 2012 strategy. In addition, 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. President Obama has announced his Administration's "New Energy for America Plan" that includes, among other provisions, ensuring that 10% of electricity in the United States comes from renewable sources by 2012, and 25% by 2025; and implementing an economy-wide cap-and-trade program to reduce GHG emissions 80% by 2050.

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. At the international level, efforts to reach a new global agreement to reduce GHG emissions post-2012 have begun with the Bali Roadmap, which outlines a two-year process designed to lead to an agreement in 2009. At the federal level, members of Congress have introduced several bills seeking to reduce emissions of GHG in the United States, and the Senate Environment and Public Works Committee has passed one such bill. State activities, primarily the northeastern states participating in the Regional Greenhouse Gas Initiative and western states led by California, have coordinated efforts to develop regional strategies to control emissions of certain GHGs.

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate CO₂ emissions from automobiles as "air pollutants" under the CAA. Although this decision did not address CO₂ emissions from electric generating plants, the EPA has similar authority under the CAA to regulate "air pollutants" from those and other facilities. On July 11, 2008, the EPA released an Advance Notice of Proposed Rulemaking, soliciting input from the public on the effects of climate change and the potential ramifications of regulation of CO₂ under the CAA.

FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO₂ emissions could require significant capital and other expenditures. The CO₂ 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-CO₂ 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 life is drawn into a facility's cooling water system). On January 26, 2007, the United States Court of Appeals for the Second Circuit remanded portions of the rulemaking dealing with impingement mortality and entrainment back to the EPA for further rulemaking and eliminated the restoration option from the EPA's regulations. On July 9, 2007, the EPA suspended this rule, noting that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. On April 14, 2008, the Supreme Court of the United States granted a petition for a writ of certiorari to review one significant aspect of the Second Circuit Court's opinion which is whether Section 316(b) of the Clean Water Act authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. Oral argument before the Supreme Court occurred on December 2, 2008 and a decision is anticipated during the first half of 2009. FirstEnergy is studying various control options and their costs and effectiveness. Depending on the results of such studies, the outcome of the Supreme Court's review of the Second Circuit's decision, the EPA's further rulemaking and any action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

The U.S. Attorney's Office in Cleveland, Ohio has advised FGCO that it is considering prosecution under the Clean Water Act and the Migratory Bird Treaty Act for three petroleum spills at the Edgewater, Lakeshore and Bay Shore plants which occurred on November 1, 2005, January 26, 2007 and February 27, 2007. FGCO is unable to predict the outcome of this matter.

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 non-hazardous waste.

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2008, FirstEnergy had approximately \$1.7 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. As part of the application to the NRC to transfer the ownership of Davis-Besse, Beaver Valley and Perry to NGC in 2005, FirstEnergy agreed to contribute another \$80 million to these trusts by 2010. Consistent with NRC guidance, utilizing a "real" rate of return on these funds of approximately 2% over inflation, these trusts are expected to exceed the minimum decommissioning funding requirements set by the NRC. Conservatively, these estimates do not include any rate of return that the trusts may earn over the 20-year plant useful life extensions that FirstEnergy (and Exelon for TMI-1 as it relates to the timing of the decommissioning of TMI-2) seeks for these facilities.

The Utilities 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 may be liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2008, based on estimates of the total costs of cleanup, the Utilities' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately \$90 million have been accrued through December 31, 2008. Included in the total are accrued liabilities of approximately \$56 million for environmental remediation of former manufactured gas plants in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC.

Fuel Supply

FES currently has long-term coal contracts with various terms to provide approximately 21.5 million tons of coal for the year 2009, approximately 98% of its 2009 coal requirements of 22 million tons. This contract coal is produced primarily from mines located in Ohio, Pennsylvania, Kentucky, West Virginia and Wyoming. The contracts expire at various times through December 31, 2030. See "Environmental Matters" for factors pertaining to meeting environmental regulations affecting coal-fired generating units.

In July 2008, FEV entered into a joint venture with the Boich Companies, a Columbus, Ohio-based coal company, to acquire a majority stake in the Bull Mountain Mine Operations, now called Signal Peak, near Roundup, Montana. This transaction is part of FirstEnergy's strategy to secure high-quality fuel supplies at attractive prices to maximize the capacity of its fossil generating plants. In a related transaction, FirstEnergy entered into a 15-year agreement to purchase up to 10 million tons of bituminous western coal annually from the mine. FirstEnergy also entered into agreements with the rail carriers associated with transporting coal from the mine to its generating stations, and expects to begin taking delivery of the coal in late 2009 or early 2010. The joint venture has the right to resell Signal Peak coal tonnage not used at FirstEnergy facilities and has call rights on such coal above certain levels.

FirstEnergy has contracts for all uranium requirements through 2010 and a portion of uranium material requirements through 2014. Conversion services contracts fully cover requirements through 2011 and partially fill requirements through 2015. Enrichment services are contracted for all of the enrichment requirements for nuclear fuel through 2014. A portion of enrichment requirements is also contracted for through 2020. Fabrication services for fuel assemblies are contracted for both Beaver Valley units and Davis Besse through 2013 and through the current operating license period for Perry (through approximately 2026). The Davis-Besse fabrication contract also has an extension provision for services for three additional consecutive reload batches through the current operating license period (approximately 2017). In addition to the existing commitments, FirstEnergy intends to make additional arrangements for the supply of uranium and for the subsequent conversion, enrichment, fabrication, and waste disposal services.

On-site spent fuel storage facilities are expected to be adequate for Perry through 2011; facilities at Beaver Valley Units 1 and 2 are expected to be adequate through 2015 and 2010, respectively. Davis-Besse has adequate storage through the remainder of its current operating license period. After current on-site storage capacity at the plants is exhausted, additional storage capacity will have to be obtained either through plant modifications, interim off-site disposal, or permanent waste disposal facilities. FENOC is currently taking actions to extend the spent fuel storage capacity for Perry and Beaver Valley. Plant modifications to increase the storage capacity of the existing spent fuel storage pool at Beaver Valley Unit 2 will be submitted to the NRC for approval during the first half of 2009, with implementation scheduled for 2010. Dry fuel storage is also being pursued at Perry and Beaver Valley, with Perry implementation scheduled to begin in 2010.

The Federal Nuclear Waste Policy Act of 1982 provides for the construction of facilities for the permanent disposal of high-level nuclear wastes, including spent fuel from nuclear power plants operated by electric utilities. NGC has contracts with the DOE for the disposal of spent fuel for Beaver Valley, Davis-Besse and Perry. Yucca Mountain was approved in 2002 as a repository for underground disposal of spent nuclear fuel from nuclear power plants and high level waste from U.S. defense programs. The DOE submitted the license application for Yucca Mountain to the NRC on June 3, 2008. Based on the DOE's most recent published statements, the earliest date that the Yucca Mountain repository will start receiving spent fuel is 2020. FirstEnergy intends to make additional arrangements for storage capacity as a contingency for further delays with the DOE acceptance of spent fuel for disposal past 2020.

Fuel oil and natural gas are used primarily to fuel peaking units and/or to ignite the burners prior to burning coal when a coal-fired plant is restarted. Fuel oil requirements have historically been low and are forecasted to remain so; requirements are expected to average approximately 5 million gallons per year over the next five years. Due to the volatility of fuel oil prices, FirstEnergy has adopted a strategy of either purchasing fixed-priced oil for inventory or using financial instruments to hedge against price risk. Natural gas is consumed primarily by peaking units, and the demand is forecasted to range from approximately 3.5 million cubic feet (Mcf) in 2009 to 2.7 Mcf in 2010. Because of high price volatility and the unpredictability of unit dispatch, natural gas futures are purchased based on forecasted demand to hedge against price movements.

System Demand

The 2008 net maximum hourly demand for each of the Utilities was: OE-5,579 MW on June 9, 2008; Penn-1,063 MW on June 9, 2008; CEI-4,295 MW on June 9, 2008; TE-2,050 MW on June 9, 2008; JCP&L-6,299 MW on June 10, 2008; Met-Ed-3,045 MW on June 10, 2008; and Penelec-2,880 MW on June 9, 2008.

Supply Plan

Regulated Commodity Sourcing

The Utilities have a default service obligation to provide the required power supply to non-shopping customers who have elected to continue to receive service under regulated retail tariffs. The volume of these sales can vary depending on the level of shopping that occurs. Supply plans vary by state and by service territory. JCP&L's default service supply is secured through a statewide competitive procurement process approved by the NJBPU. Penn's default service supply is provided through a competitive procurement process approved by the PPUC. For the first quarter of 2009, the default service supply for the Ohio Companies was sourced 4% from the spot market and 96% through a competitive procurement process. Absent resolution of the ESP or MRO, the Ohio Companies anticipate conducting a similar CBP for the period beginning April 1, 2009. The default service supply for Met-Ed and Penelec is secured through a series of existing, long-term bilateral purchase contracts with unaffiliated suppliers, and through a FERC-approved agreement with FES. If any unaffiliated suppliers fail to deliver power to any one of the Utilities' service areas, the Utility serving that area may need to procure the required power in the market in their role as a PLR.

Unregulated Commodity Sourcing

FES has retail and wholesale competitive load-serving obligations in Ohio, New Jersey, Maryland, Pennsylvania, Michigan and Illinois serving both affiliated and non-affiliated companies. FES provides energy products and services to customers under various PLR, shopping, competitive-bid and non-affiliated contractual obligations. In 2008, FES' generation service to affiliated companies was approximately 95% of its total generation obligation. Depending upon the resolution of regulatory proceedings relating to how the Ohio Companies will obtain their supply and thereafter the results of any CBP or other procurement process implemented in accordance with PUCO requirements, FES' service to affiliated companies may decrease, making more power available to the competitive wholesale markets and potentially subjecting FES to greater volatility in the prices it receives for its power. Geographically, approximately 68% of FES' obligation is located in the MISO market area and 32% is located in the PJM market area.

FES provides energy and energy related services, including the generation and sale of electricity and energy planning and procurement through retail and wholesale competitive supply arrangements. FES controls (either through ownership, lease, affiliated power contracts or participation in OVEC) 13,973 MW of installed generating capacity. FES supplies the power requirements of its competitive load-serving obligations through a combination of subsidiary-owned generation, non-affiliated contracts and spot market transactions.

Regional Reliability

FirstEnergy's operating companies are located within MISO and PJM and operate under the reliability oversight of a regional entity known as Reliability *First*. This regional entity operates under the oversight of the NERC in accordance with a Delegation Agreement approved by the FERC. Reliability *First* began operations under the NERC on January 1, 2006. On July 20, 2006, the NERC was certified by the FERC as the ERO in the United States pursuant to Section 215 of the Federal Power Act and Reliability *First* was certified as a regional entity. Reliability *First* represents the consolidation of the ECAR, Mid-Atlantic Area Council, and Mid-American Interconnected Network reliability councils into a single regional reliability organization.

Competition

As a result of actions taken by state legislative bodies, major changes in the electric utility business have occurred in portions of the United States, including Ohio, New Jersey and Pennsylvania where FirstEnergy's utility subsidiaries operate. These changes have altered the way traditional integrated utilities conduct their business. FirstEnergy has aligned its business units to accommodate its retail strategy and participate in the competitive electricity marketplace (see Strategy and Outlook in the 2008 Annual Report of FirstEnergy). FirstEnergy's Competitive Energy Services segment participates in deregulated energy markets in Ohio, Pennsylvania, Maryland, Michigan, and Illinois through FES.

In New Jersey, JCP&L has procured electric supply to serve its BGS customers since 2002 through a statewide auction process approved by the NJBPU. The auction is designed to procure supply for BGS customers at a cost reflective of market conditions.

FirstEnergy remains focused on managing the transition to competitive markets for electricity in Ohio and Pennsylvania. On May 1, 2008, the Governor of Ohio signed SB221 into law, which became effective July 31, 2008. The new law provides two options for pricing generation in 2009 and beyond – through a negotiated rate plan or a competitive bidding process (see PUCO Rate Matters above). In Pennsylvania, all electric distribution companies will be required to secure generation for customers in competitive markets by 2011. On October 15, 2008, the Governor of Pennsylvania signed House Bill 2200 into law, which became effective on November 14, 2008, as Act 129 of 2008. The new law outlines a competitive procurement process and sets targets for energy efficiency and conservation (see PPUC Rate Matters above).

Research and Development

The Utilities participate in the funding of EPRI, which was formed for the purpose of expanding electric research and development under the voluntary sponsorship of the nation's electric utility industry - public, private and cooperative. Its goal is to mutually benefit utilities and their customers by promoting the development of new and improved technologies to help the utility industry meet present and future electric energy needs in environmentally and economically acceptable ways. EPRI conducts research on all aspects of electric power production and use, including fuels, generation, delivery, energy management and conservation, environmental effects and energy analysis. The majority of EPRI's research and development projects are directed toward practical solutions and their applications to problems currently facing the electric utility industry.

FirstEnergy also participates in other research and development initiatives with industry research consortiums and universities, including for the development of carbon capture and coal-based fuel cell technologies.

Executive Officers

Name	Age	Positions Held During Past Five Years	Dates
A. J. Alexander	57	President and Chief Executive Officer President and Chief Operating Officer	2004-present *-2004
W. D. Byrd	54	Vice President, Corporate Risk & Chief Risk Officer Director – Rates Strategy Director – Commodity Supply	2007-present 2004-2007 *-2004
L. M. Cavalier	57	Senior Vice President – Human Resources Vice President – Human Resources	2005-present *-2005
M. T. Clark	58	Executive Vice President – Strategic Planning & Operations Senior Vice President – Strategic Planning & Operations Vice President – Business Development	2008-present 2004-2008 *-2004
D. S. Elliott (B)	54	President – Pennsylvania Operations Senior Vice President	2005-present *-2005
R. R. Grigg (A)(B)	60	Executive Vice President and President-FirstEnergy Utilities Executive Vice President and Chief Operating Officer President and Chief Executive Officer – WE Generation	2008-present 2004-2008 *-2004
J. J. Hagan	58	President and Chief Nuclear Officer – FENOC Senior Vice President and Chief Operating Officer – FENOC Senior Vice President - FENOC	2007-present 2005-2007 *-2005
C. E. Jones (A)(B)	53	Senior Vice President – Energy Delivery & Customer Service (E) President – FirstEnergy Solutions Senior Vice President – Energy Delivery & Customer Service	2009-present 2007-2009 *-2007
C. D. Lasky (D)	46	Vice President – Fossil Operations Vice President – Fossil Operations & Air Quality Compliance Plant Director	2008-present 2004-2008 *-2004
G. R. Leidich	58	Executive Vice President & President – FirstEnergy Generation Senior Vice President – Operations President and Chief Nuclear Officer – FENOC	2008-present 2007-2008 *-2007
D. C. Luff	61	Senior Vice President – Governmental Affairs Vice President	2007-present *-2007
R. H. Marsh (A)(B)(D)	58	Senior Vice President and Chief Financial Officer	*-present
S. E. Morgan (C)(F)	58	President – JCP&L Vice President – Energy Delivery	2004-present *-2004
J. M. Murray (A)(G)	62	President – Ohio Operations Regional President – Toledo Edison Company Regional President – West	2005-present 2004-2005 *-2004
J. F. Pearson (A)(B)(D)	54	Vice President and Treasurer Treasurer Group Controller – Strategic Planning and Operations Group Controller – FirstEnergy Solutions	2006-present 2005-2006 2004-2005 *-2004
D. R. Schneider (D)	47	President – FirstEnergy Solutions (E) Senior Vice President – Energy Delivery & Customer Service Vice President – Energy Delivery Vice President – Commodity Operations Vice President – Fossil Operations	2009-present 2007-2009 2006-2007 2004-2006 *-2004
L.L. Vespoli (A)(B)(D)	49	Executive Vice President and General Counsel Senior Vice President and General Counsel	2008-present *-2008
H. L. Wagner (A)(B)(D)	56	Vice President, Controller and Chief Accounting Officer	*-present
T. M. Welsh	59	Senior Vice President – Assistant to CEO Senior Vice President Vice President	2007-present 2004-2007 *-2004

(A) Denotes executive officers of OE, CEI and TE.

(B) Denotes executive officers of Met-Ed and Penelec.

(C) Denotes executive officer of JCP&L

(D) Denotes executive officers of FES.

(E) Position effective February 2, 2009.

(F) Retiring, September 1, 2009.

(G) Retiring, June 1, 2009.

* Indicates position held at least since January 1, 2004.

Employees

As of January 1, 2009, FirstEnergy's subsidiaries had a total of 14,698 employees located in the United States as follows:

	<u>Total</u> <u>Employees</u>	<u>Bargaining Unit</u> <u>Employees</u>
FESC	3,355	250
OE	1,328	770
CEI	1,010	651
TE	445	321
Penn	223	165
JCP&L	1,470	1,113
Met-Ed	776	536
Penelec	994	664
ATSI	43	-
FES	219	-
FGCO	2,006	1,283
FENOC	2,829	1,031
Total	<u>14,698</u>	<u>6,784</u>

JCP&L's bargaining unit employees filed a grievance challenging JCP&L's 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties' collective bargaining agreement. At the conclusion of the June 1, 2005 hearing, the arbitration panel decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the arbitration panel issued an opinion to award approximately \$16 million to the bargaining unit employees. On February 6, 2006, a federal district Court granted a union motion to dismiss, as premature, a JCP&L appeal of the award filed on October 18, 2005. A final order identifying the individual damage amounts was issued on October 31, 2007. The award appeal process was initiated. The union filed a motion with the federal Court to confirm the award and JCP&L filed its answer and counterclaim to vacate the award on December 31, 2007. JCP&L and the union filed briefs in June and July of 2008 and oral arguments were held in the fall. The Court has yet to render its decision. JCP&L recognized a liability for the potential \$16 million award in 2005.

The union employees at the Bruce Mansfield Plant have been working without a labor contract since February 15, 2008. The parties are continuing to bargain with the assistance of a federal mediator. FirstEnergy has a strike mitigation plan ready in the event of a strike .

FirstEnergy Web Site

Each of the registrant's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are also made available free of charge on or through FirstEnergy's internet Web site at www.firstenergycorp.com. These reports are posted on the Web site as soon as reasonably practicable after they are electronically filed with the SEC. Information contained on FirstEnergy's Web site shall not be deemed incorporated into, or to be part of, this report.

ITEM 1A. RISK FACTORS

We operate in a business environment that involves significant risks, many of which are beyond our control. The following risk factors and all other information contained in this report should be considered carefully when evaluating FirstEnergy and our subsidiaries. These risk factors could affect our financial results and cause such results to differ materially from those expressed in any forward-looking statements made by or on behalf of us. Below, we have identified risks we currently consider material. However, our business, financial condition, cash flows or results of operations could be affected materially and adversely by additional risks not currently known to us or that we deem immaterial at this time. Additional information on risk factors is included in "Item 1. Business" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and in other sections of this Form 10-K that include forward-looking and other statements involving risks and uncertainties that could impact our business and financial results.

Risks Related to Business Operations

Risks Arising from the Reliability of Our Power Plants and Transmission and Distribution Equipment

Operation of generation, transmission and distribution facilities involves risk, including the potential breakdown or failure of equipment or processes, fuel supply or transportation disruptions, accidents, labor disputes or work stoppages by employees, acts of terrorism or sabotage, construction delays or cost overruns, shortages of or delays in obtaining equipment, material and labor, operational restrictions resulting from environmental limitations and governmental interventions, and performance below expected levels. In addition, weather-related incidents and other natural disasters can disrupt generation, transmission and distribution delivery systems. Because our transmission facilities are interconnected with those of third parties, the operation of our facilities could be adversely affected by unexpected or uncontrollable events occurring on the systems of such third parties.

Operation of our power plants below expected capacity levels could result in lost revenues and increased expenses, including higher maintenance costs. Unplanned outages of generating units and extensions of scheduled outages due to mechanical failures or other problems occur from time to time and are an inherent risk of our business. Unplanned outages typically increase our operation and maintenance expenses and may reduce our revenues as a result of selling fewer MWH or may require us to incur significant costs as a result of operating our higher cost units or obtaining replacement power from third parties in the open market to satisfy our forward power sales obligations. Moreover, if we were unable to perform under contractual obligations, penalties or liability for damages could result. FES, FGCO and the Ohio Companies are exposed to losses under their applicable sale-leaseback arrangements for generating facilities upon the occurrence of certain contingent events that could render those facilities worthless. Although we believe these types of events are unlikely to occur, FES, FGCO and the Ohio Companies have a maximum exposure to loss under those provisions of approximately \$1.3 billion for FES, \$800 million for OE and an aggregate of \$700 million for TE and CEI as co-lessees.

We remain obligated to provide safe and reliable service to customers within our franchised service territories. Meeting this commitment requires the expenditure of significant capital resources. Failure to provide safe and reliable service and failure to meet regulatory reliability standards due to a number of factors, including, but not limited to, equipment failure and weather, could adversely affect our operating results through reduced revenues and increased capital and operating costs and the imposition of penalties/fines or other adverse regulatory outcomes.

Changes in Commodity Prices Could Adversely Affect Our Profit Margins

We purchase and sell electricity in the competitive wholesale and retail markets. Increases in the costs of fuel for our generation facilities (particularly coal, uranium and natural gas) can affect our profit margins. Changes in the market price of electricity, which are affected by changes in other commodity costs and other factors, may impact our results of operations and financial position by increasing the amount we pay to purchase power to supply PLR and default service obligations in Ohio and Pennsylvania. In addition, the weakening global economy could lead to lower international demand for coal, oil and natural gas, which may lower fossil fuel prices and put downward pressure on electricity prices.

Electricity and fuel prices may fluctuate substantially over relatively short periods of time for a variety of reasons, including:

- changing weather conditions or seasonality;
- changes in electricity usage by our customers;
- illiquidity in wholesale power and other markets;
- transmission congestion or transportation constraints, inoperability or inefficiencies;
- availability of competitively priced alternative energy sources;
- changes in supply and demand for energy commodities;
- changes in power production capacity;
- outages at our power production facilities or those of our competitors;
- changes in production and storage levels of natural gas, lignite, coal, crude oil and refined products; and
- natural disasters, wars, acts of sabotage, terrorist acts, embargoes and other catastrophic events.

We Are Exposed to Operational, Price and Credit Risks Associated With Selling and Marketing Products in the Power Markets That We Do Not Always Completely Hedge Against

We purchase and sell power at the wholesale level under market-based tariffs authorized by the FERC, and also enter into short-term agreements to sell available energy and capacity from our generation assets. If we are unable to deliver firm capacity and energy under these agreements, we may be required to pay damages. These damages would generally be based on the difference between the market price to acquire replacement capacity or energy and the contract price of the undelivered capacity or energy. Depending on price volatility in the wholesale energy markets, such damages could be significant. Extreme weather conditions, unplanned power plant outages, transmission disruptions, and other factors could affect our ability to meet our obligations, or cause increases in the market price of replacement capacity and energy.

We attempt to mitigate risks associated with satisfying our contractual power sales arrangements by reserving generation capacity to deliver electricity to satisfy our net firm sales contracts and, when necessary, by purchasing firm transmission service. We also routinely enter into contracts, such as fuel and power purchase and sale commitments, to hedge our exposure to fuel requirements and other energy-related commodities. We may not, however, hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility, our results of operations and financial position could be negatively affected.

The Use of Derivative Contracts by Us to Mitigate Risks Could Result in Financial Losses That May Negatively Impact our Financial Results

We use a variety of non-derivative and derivative instruments, such as swaps, options, futures and forwards, to manage our commodity and financial market risks. In the absence of actively quoted market prices and pricing information from external sources, the valuation of some of these derivative instruments involves management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of some of these contracts. Also, we could recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform.

Our Risk Management Policies Relating to Energy and Fuel Prices, and Counterparty Credit Are by Their Very Nature Risk Related, and We Could Suffer Economic Losses Despite Such Policies

We attempt to mitigate the market risk inherent in our energy, fuel and debt positions. Procedures have been implemented to enhance and monitor compliance with our risk management policies, including validation of transaction and market prices, verification of risk and transaction limits, sensitivity analysis and daily portfolio reporting of various risk measurement metrics. Nonetheless, we cannot economically hedge all of our exposures in these areas and our risk management program may not operate as planned. For example, actual electricity and fuel prices may be significantly different or more volatile than the historical trends and assumptions reflected in our analyses. Also, our power plants might not produce the expected amount of power during a given day or time period due to weather conditions, technical problems or other unanticipated events, which could require us to make energy purchases at higher prices than the prices under our energy supply contracts. In addition, the amount of fuel required for our power plants during a given day or time period could be more than expected, which could require us to buy additional fuel at prices less favorable than the prices under our fuel contracts. As a result, we cannot always predict the impact that our risk management decisions may have on us if actual events lead to greater losses or costs than our risk management positions were intended to hedge.

Our risk management activities, including our power sales agreements with counterparties, rely on projections that depend heavily on judgments and assumptions by management of factors such as future market prices and demand for power and other energy-related commodities. These factors become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. Even when our policies and procedures are followed and decisions are made based on these estimates, results of operations may be diminished if the judgments and assumptions underlying those calculations prove to be inaccurate.

We also face credit risks from parties with whom we contract who could default in their performance, in which cases we could be forced to sell our power into a lower-priced market or make purchases in a higher-priced market than existed at the time of executing the contract. Although we have established risk management policies and programs, including credit policies to evaluate counterparty credit risk, there can be no assurance that we will be able to fully meet our obligations, that we will not be required to pay damages for failure to perform or that we will not experience counterparty non-performance or that we will collect for voided contracts. If counterparties to these arrangements fail to perform, we may be forced to enter into alternative hedging arrangements or honor underlying commitments at then-current market prices. In that event, our financial results could be adversely affected.

Nuclear Generation Involves Risks that Include Uncertainties Relating to Health and Safety, Additional Capital Costs, the Adequacy of Insurance Coverage and Nuclear Plant Decommissioning

We are subject to the risks of nuclear generation, including but not limited to the following:

- the potential harmful effects on the environment and human health resulting from unplanned radiological releases associated with the operation of our nuclear facilities and the storage, handling and disposal of radioactive materials;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations or those of others in the United States;
- uncertainties with respect to contingencies and assessments if insurance coverage is inadequate; and
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed operation including increases in minimum funding requirements or costs of completion.

The NRC has broad authority under federal law to impose licensing security and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines and/or shut down a unit, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants, including ours. Also, a serious nuclear incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or relicensing of any domestic nuclear unit.

Our nuclear facilities are insured under NEIL policies issued for each plant. Under these policies, up to \$2.8 billion of insurance coverage is provided for property damage and decontamination and decommissioning costs. We have also obtained approximately \$2.0 billion of insurance coverage for replacement power costs. Under these policies, we can be assessed a maximum of approximately \$79 million for incidents at any covered nuclear facility occurring during a policy year that are in excess of accumulated funds available to the insurer for paying losses.

The Price-Anderson Act limits the public liability that can be assessed with respect to a nuclear power plant to \$12.5 billion (assuming 104 units licensed to operate in the United States) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to \$300.0 million; and (ii) \$12.2 billion provided by an industry retrospective rating plan. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to \$117.5 million (but not more than \$17.5 million per year) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Our maximum potential exposure under these provisions would be \$470.0 million per incident but not more than \$70.0 million in any one year.

Capital Market Performance and Other Changes May Decrease the Value of Decommissioning Trust Fund, Pension Fund Assets and Other Trust Funds Which Then Could Require Significant Additional Funding

Our financial statements reflect the values of the assets held in trust to satisfy our obligations to decommission our nuclear generation facilities and under pension and other post-retirement benefit plans. The value of certain of the assets held in these trusts do not have readily determinable market values. Changes in the estimates and assumptions inherent in the value of these assets could affect the value of the trusts. If the value of the assets held by the trusts declines by a material amount, our funding obligation to the trusts could materially increase. The recent disruption in the capital markets and its effects on particular businesses and the economy in general also affects the values of the assets that are held in trust to satisfy future obligations to decommission our nuclear plants, to pay pensions to our retired employees and to pay other funded obligations. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected return rates. Forecasting investment earnings and costs to decommission nuclear generating stations, to pay future pensions and other obligations requires significant judgment, and actual results may differ significantly from current estimates. Capital market conditions that generate investment losses or greater liability levels can negatively impact our results of operations and financial position.

We Could be Subject to Higher Costs and/or Penalties Related to Mandatory NERC/FERC Reliability Standards

As a result of the EPACT, owners, operators, and users of the bulk electric system are subject to mandatory reliability standards promulgated by NERC and approved by FERC. The standards are based on the functions that need to be performed to ensure that the bulk electric system operates reliably. Compliance with new reliability standards may subject us to higher operating costs and/or increased capital expenditures. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties.

Reliability standards that were historically subject to voluntary compliance are now mandatory and could subject us to potential civil penalties for violations which could negatively impact our business. The FERC can now impose penalties of \$1.0 million per day for failure to comply with these mandatory electric reliability standards.

In addition to direct regulation by the FERC, we are also subject to rules and terms of participation imposed and administered by various RTOs and ISOs. Although these entities are themselves ultimately regulated by the FERC, they can impose rules, restrictions and terms of service that are quasi-regulatory in nature and can have a material adverse impact on our business. For example, the independent market monitors of ISOs and RTOs may impose bidding and scheduling rules to curb the potential exercise of market power and to ensure the market functions. Such actions may materially affect our ability to sell, and the price we receive for, our energy and capacity.

We Rely on Transmission and Distribution Assets That We Do Not Own or Control to Deliver Our Wholesale Electricity. If Transmission is Disrupted Including Our Own Transmission, or Not Operated Efficiently, or if Capacity is Inadequate, Our Ability to Sell and Deliver Power May Be Hindered

We depend on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver the electricity we sell. If transmission is disrupted (as a result of weather, natural disasters or other reasons) or not operated efficiently by independent system operators, in applicable markets, or if capacity is inadequate, our ability to sell and deliver products and satisfy our contractual obligations may be hindered, or we may be unable to sell products on the most favorable terms. In addition, in certain of the markets in which we operate, we may be deemed responsible for congestion costs if we schedule delivery of power between congestion zones during periods of high demand. If we are unable to recover for such congestion costs in retail rates, our financial results could be adversely affected.

Demand for electricity within our utilities' service areas could stress available transmission capacity requiring alternative routing or curtailing electricity usage that may increase operating costs or reduce revenues with adverse impacts to results of operations. In addition, as with all utilities, potential concerns over transmission capacity could result in MISO, PJM or the FERC requiring us to upgrade or expand our transmission system, requiring additional capital expenditures.

The FERC requires wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. Although these regulations are designed to encourage competition in wholesale market transactions for electricity, it is possible that fair and equal access to transmission systems will not be available or that sufficient transmission capacity will not be available to transmit electricity as we desire. We cannot predict the timing of industry changes as a result of these initiatives or the adequacy of transmission facilities in specific markets or whether independent system operators in applicable markets will operate the transmission networks, and provide related services, efficiently.

Disruptions in Our Fuel Supplies Could Occur, Which Could Adversely Affect Our Ability to Operate Our Generation Facilities and Impact Financial Results

We purchase fuel from a number of suppliers. The lack of availability of fuel at expected prices, or a disruption in the delivery of fuel which exceeds the duration of our on-site fuel inventories, including disruptions as a result of weather, increased transportation costs or other difficulties, labor relations or environmental or other regulations affecting our fuel suppliers, could cause an adverse impact on our ability to operate our facilities, possibly resulting in lower sales and/or higher costs and thereby adversely affect our results of operations. Operation of our coal-fired generation facilities is highly dependent on our ability to procure coal. Although we have long-term contracts in place for our coal and coal transportation needs, power generators in the Midwest and the Northeast have experienced significant pressures on available coal supplies that are either transportation or supply related. If prices for physical delivery are unfavorable, our financial condition, results of operations and cash flows could be materially adversely affected.

Temperature Variations as well as Weather Conditions or other Natural Disasters Could Have a Negative Impact on Our Results of Operations and Demand Significantly Below or Above our Forecasts Could Adversely Affect our Energy Margins

Weather conditions directly influence the demand for electric power. Demand for power generally peaks during the summer months, with market prices also typically peaking at that time. Overall operating results may fluctuate based on weather conditions. In addition, we have historically sold less power, and consequently received less revenue, when weather conditions are milder. Severe weather, such as tornadoes, hurricanes, ice or snow storms, or droughts or other natural disasters, may cause outages and property damage that may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The effect of the failure of our facilities to operate as planned under these conditions would be particularly burdensome during a peak demand period.

Customer demand that we satisfy pursuant to our default service tariffs could change as a result of severe weather conditions or other circumstances over which we have no control. We satisfy our electricity supply obligations through a portfolio approach of providing electricity from our generation assets, contractual relationships and market purchases. A significant increase in demand could adversely affect our energy margins if we are required under the terms of the default service tariffs to provide the energy supply to fulfill this increased demand at capped rates, which we expect would remain below the wholesale prices at which we would have to purchase the additional supply if needed or, if we had available capacity, the prices at which we could otherwise sell the additional supply. Accordingly, any significant change in demand could have a material adverse effect on our results of operations and financial position.

We Are Subject to Financial Performance Risks Related to General Economic Cycles and also Related to Heavy Manufacturing Industries such as Automotive and Steel

Our business follows the economic cycles of our customers. Declines in demand for electricity as a result of economic downturns would be expected to reduce overall electricity sales and reduce our revenues. Economic conditions also impact the rate of delinquent customer accounts receivable, further increasing our costs. A decrease in electric generation sales volume has been, and is expected to continue to be, influenced by circumstances in automotive, steel and other heavy industries.

Increases in Customer Electric Rates and the Impact of the Economic Downturn May Lead to a Greater Amount of Uncollectible Customer Accounts

Our utility operations are impacted by the economic conditions in our service territories and those conditions could negatively impact our collections of accounts receivable which could adversely impact our financial condition, results of operations and cash flows.

The Goodwill of One or More of Our Operating Subsidiaries May Become Impaired, Which Would Result in Write-Offs of the Impaired Amounts

Goodwill could become impaired at one or more of our operating subsidiaries. The actual timing and amounts of any goodwill impairments in future years would depend on many uncertainties, including changing interest rates, utility sector market performance, our capital structure, market prices for power, results of future rate proceedings, operating and capital expenditure requirements, the value of comparable utility acquisitions and other factors.

We Face Certain Human Resource Risks Associated with the Availability of Trained and Qualified Labor to Meet Our Future Staffing Requirements

We are challenged to find ways to retain our aging skilled workforce while recruiting new talent to mitigate losses in critical knowledge and skills due to retirements. Mitigating these risks could require additional financial commitments.

Significant Increases in Our Operation and Maintenance Expenses, Including Our Health Care and Pension Costs, Could Adversely Affect Our Future Earnings and Liquidity

We continually focus on limiting, and reducing where possible, our operation and maintenance expenses. However, we expect to continue to face increased cost pressures, including health care and pension costs. We have experienced significant health care cost inflation in the last few years, and we expect our cash outlay for health care costs, including prescription drug coverage, to continue to increase despite measures that we have taken and expect to take requiring employees and retirees to bear a higher portion of the costs of their health care benefits. The measurement of our expected future health care and pension obligations and costs is highly dependent on a variety of assumptions, many of which relate to factors beyond our control. These assumptions include investment returns, interest rates, health care cost trends, benefit design changes, salary increases, the demographics of plan participants and regulatory requirements. If actual results differ materially from our assumptions, our costs could be significantly increased.

Our Business is Subject to the Risk that Sensitive Customer Data May be Compromised, Which Could Result in an Adverse Impact to Our Reputation and/or Results of Operations

Our business requires access to sensitive customer data, including personal and credit information, in the ordinary course of business. A security breach may occur, despite security measures taken by us and required of vendors. If a significant or widely publicized breach occurred, our business reputation may be adversely affected, customer confidence may be diminished, or we may become subject to legal claims, fines or penalties, any of which could have a negative impact on our business and/or results of operations.

Acts of War or Terrorism Could Negatively Impact Our Business

The possibility that our infrastructure, such as electric generation, transmission and distribution facilities, or that of an interconnected company, could be direct targets of, or indirect casualties of, an act of war or terrorism, could result in disruption of our ability to generate, purchase, transmit or distribute electricity. Any such disruption could result in a decrease in revenues and additional costs to purchase electricity and to replace or repair our assets, which could have a material adverse impact on our results of operations and financial condition.

Capital Improvements and Construction Projects May Not be Completed Within Forecasted Budget, Schedule or Scope Parameters

Our business plan calls for extensive capital investments, including the installation of environmental control equipment, as well as other initiatives. We may be exposed to the risk of substantial price increases in the costs of labor and materials used in construction. We have engaged numerous contractors and entered into a large number of agreements to acquire the necessary materials and/or obtain the required construction-related services. As a result, we are also exposed to the risk that these contractors and other counterparties could breach their obligations to us. Such risk could include our contractors' inability to procure sufficient skilled labor as well as potential work stoppages by that labor force. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices, with resulting delays in those and other projects. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than these mitigation provisions. This could have negative financial impacts such as incurring losses or delays in completing construction projects.

Changes in Technology may Significantly Affect Our Generation Business by Making Our Generating Facilities Less Competitive

We primarily generate electricity at large central facilities. This method results in economies of scale and lower costs than newer technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in technologies will reduce their costs to levels that are equal to or below that of most central station electricity production, which could have a material adverse effect on our results of operations.

We May Acquire Assets That Could Present Unanticipated Issues for our Business in the Future, Which Could Adversely Affect Our Ability to Realize Anticipated Benefits of Those Acquisitions

Asset acquisitions involve a number of risks and challenges, including: management attention; integration with existing assets; difficulty in evaluating the requirements associated with the assets prior to acquisition, operating costs, potential environmental and other liabilities, and other factors beyond our control; and an increase in our expenses and working capital requirements. Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows or realize other anticipated benefits from any such asset acquisition.

Risks Associated With Regulation

Complex and Changing Government Regulations Could Have a Negative Impact on Our Results of Operations

We are subject to comprehensive regulation by various federal, state and local regulatory agencies that significantly influence our operating environment. Changes in, or reinterpretations of, existing laws or regulations, or the imposition of new laws or regulations, could require us to incur additional costs or change the way we conduct our business, and therefore could have an adverse impact on our results of operations.

Our utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. Thus, the rates a utility is allowed to charge may or may not be set to recover its expenses at any given time. Additionally, there may also be a delay between the timing of when costs are incurred and when costs are recovered. While rate regulation is premised on providing an opportunity to earn a reasonable return on invested capital and recovery of operating expenses, there can be no assurance that the applicable regulatory commission will determine that all of our costs have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of our costs in a timely manner.

Regulatory Changes in the Electric Industry, Including a Reversal, Discontinuance or Delay of the Present Trend Toward Competitive Markets, Could Affect Our Competitive Position and Result in Unrecoverable Costs Adversely Affecting Our Business and Results of Operations

As a result of restructuring initiatives, changes in the electric utility business have occurred, and are continuing to take place throughout the United States, including Ohio, Pennsylvania and New Jersey. These changes have resulted, and are expected to continue to result, in fundamental alterations in the way utilities conduct their business.

Some states that have deregulated generation service have experienced difficulty in transitioning to market-based pricing. In some instances, state and federal government agencies and other interested parties have made proposals to delay market restructuring or even re-regulate areas of these markets that have previously been deregulated. Although we expect wholesale electricity markets to continue to be competitive, proposals to re-regulate our industry may be made, and legislative or other action affecting the electric power restructuring process may cause the process to be delayed, discontinued or reversed in the states in which we currently, or may in the future, operate. Such delays, discontinuations or reversals of electricity market restructuring in the markets in which we operate could have an adverse impact on our results of operations and financial condition.

The FERC and the U.S. Congress propose changes from time to time in the structure and conduct of the electric utility industry. If the restructuring, deregulation or re-regulation efforts result in decreased margins or unrecoverable costs, our business and results of operations would be adversely affected. We cannot predict the extent or timing of further efforts to restructure, deregulate or re-regulate our business or the industry.

The Prospect of Rising Rates Could Prompt Legislative or Regulatory Action to Restrict or Control Such Rate Increases. This In Turn Could Create Uncertainty Affecting Planning, Costs and Results of Operations and May Adversely Affect the Utilities' Ability to Recover Their Costs, Maintain Adequate Liquidity and Address Capital Requirements

Increases in utility rates, such as may follow a period of frozen or capped rates, can generate pressure on legislators and regulators to take steps to control those increases. Such efforts can include some form of rate increase moderation, reduction or freeze. The public discourse and debate can increase uncertainty associated with the regulatory process, the level of rates and revenues, and the ability to recover costs. Such uncertainty restricts flexibility and resources, given the need to plan and ensure available financial resources. Such uncertainty also affects the costs of doing business. Such costs could ultimately reduce liquidity, as suppliers tighten payment terms, and increase costs of financing, as lenders demand increased compensation or collateral security to accept such risks.

Our Profitability is Impacted by Our Affiliated Companies' Continued Authorization to Sell Power at Market-Based Rates

The FERC granted FES, FGCO and NGC authority to sell electricity at market-based rates. These orders also granted them waivers of certain FERC accounting, record-keeping and reporting requirements. The Utilities also have market-based rate authority. The FERC's orders that grant this market-based rate authority reserve the right to revoke or revise that authority if the FERC subsequently determines that these companies can exercise market power in transmission or generation, create barriers to entry or engage in abusive affiliate transactions. As a condition to the orders granting the generating companies market-based rate authority, every three years they are required to file a market power update to show that they continue to meet the FERC's standards with respect to generation market power and other criteria used to evaluate whether entities qualify for market-based rates. FES, FGCO, NGC and the Utilities renewed this authority for PJM in 2008. Their applications to renew this authorization for MISO are pending at the FERC. If any of these companies were to lose their market-based rate authority or fail to have such authority renewed, it would be required to obtain the FERC's acceptance to sell power at cost-based rates. FES, FGCO and NGC could also lose their waivers, and become subject to the accounting, record-keeping and reporting requirements that are imposed on utilities with cost-based rate schedules.

There Are Uncertainties Relating to Our Participation in Regional Transmission Organizations (RTOs)

RTO rules could affect our ability to sell power produced by our generating facilities to users in certain markets due to transmission constraints and attendant congestion costs. The prices in day-ahead and real-time energy markets and RTO capacity markets have been subject to price volatility. Administrative costs imposed by RTOs, including the cost of administering energy markets, have also increased. The rules governing the various regional power markets may also change from time to time, which could affect our costs or revenues. To the degree we incur significant additional fees and increased costs to participate in an RTO, and we are limited with respect to recovery of such costs from retail customers, we may suffer financial harm. While RTO rates for transmission service are designed to be revenue neutral, our revenues from customers to whom we currently provide transmission services may not reflect all of the administrative and market-related costs imposed under the RTO tariff. In addition, we may be allocated a portion of the cost of transmission facilities built by others due to changes in RTO transmission rate design. Finally, we may be required to expand our transmission system according to decisions made by an RTO rather than our internal planning process. As a member of an RTO, we are subject to certain additional risks, including those associated with the allocation among members of losses caused by unreimbursed defaults of other participants in that RTO's market, and those associated with complaint cases filed against the RTO that may seek refunds of revenues previously earned by its members.

MISO implemented an ancillary services market for operating reserves that would be simultaneously co-optimized with MISO's existing energy markets. The implementation of these and other new market designs has the potential to increase our costs of transmission, costs associated with inefficient generation dispatching, costs of participation in the market and costs associated with estimated payment settlements.

Because it remains unclear which companies will be participating in the various regional power markets, or how RTOs will ultimately develop and operate, or what region they will cover, we cannot fully assess the impact that these power markets or other ongoing RTO developments may have.

Energy Conservation and Energy Price Increases Could Negatively Impact our Financial Results

A number of regulatory and legislative bodies have introduced requirements and/or incentives to reduce energy consumption by certain dates. Conservation programs could impact our financial results in different ways. To the extent conservation resulted in reduced energy demand or significantly slowed the growth in demand, the value of our merchant generation and other unregulated business activities could be adversely impacted. In our regulated operations, conservation could negatively impact us depending on the regulatory treatment of the associated impacts. Should we be required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact. We could also be impacted if any future energy price increases result in a decrease in customer usage. We are unable to determine what impact, if any, conservation and increases in energy prices will have on our financial condition or results of operations.

Our Business and Activities are Subject to Extensive Environmental Requirements and Could be Adversely Affected by such Requirements

We may be forced to shut down facilities, either temporarily or permanently, if we are unable to comply with certain environmental requirements, or if we make a determination that the expenditures required to comply with such requirements are uneconomical. In fact, we are exposed to the risk that such electric generating plants would not be permitted to continue to operate if pollution control equipment is not installed by prescribed deadlines.

Costs of Compliance with Environmental Laws are Significant, and the Cost of Compliance with Future Environmental Laws, Including Limitations on GHG Emissions Could Adversely Affect Cash Flow and Profitability

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations. Compliance with these legal requirements requires us to incur costs for environmental monitoring, installation of pollution control equipment, emission fees, maintenance, upgrading, remediation and permitting at our facilities. These expenditures have been significant in the past and may increase in the future. If the cost of compliance with existing environmental laws and regulations does increase, it could adversely affect our business and results of operations, financial position and cash flows. Moreover, changes in environmental laws or regulations may materially increase our costs of compliance or accelerate the timing of capital expenditures. Because of the deregulation of generation, we may not directly recover through rates additional costs incurred for such compliance. Our compliance strategy, although reasonably based on available information, may not successfully address future relevant standards and interpretations. If we fail to comply with environmental laws and regulations, even if caused by factors beyond our control or new interpretations of longstanding requirements, that failure could result in the assessment of civil or criminal liability and fines. In addition, any alleged violation of environmental laws and regulations may require us to expend significant resources to defend against any such alleged violations.

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. Environmental advocacy groups, other organizations and some agencies in the United States are focusing considerable attention on carbon dioxide emissions from power generation facilities and their potential role in climate change. Many states and environmental groups have also challenged certain of the federal laws and regulations relating to air emissions as not being sufficiently strict. There is a growing consensus in the United States and globally that GHG emissions are a major cause of global warming and that some form of regulation will be forthcoming at the federal level with respect to GHG emissions (including carbon dioxide) and such regulation could result in the creation of substantial additional costs in the form of taxes or emission allowances. As a result, it is possible that state and federal regulations will be developed that will impose more stringent limitations on emissions than are currently in effect. Although several bills have been introduced at the state and federal level that would compel carbon dioxide emission reductions, none have advanced through the legislature. Such legislation could even make some of our electric generating units uneconomic to maintain or operate. Due to the uncertainty of control technologies available to reduce greenhouse gas emissions including CO₂, as well as the unknown nature of potential compliance obligations should climate change regulations be enacted, we cannot provide any assurance regarding the potential impacts these future regulations would have on our operations. In addition, any legal obligation that would require us to substantially reduce our emissions could require extensive mitigation efforts and, in the case of carbon dioxide legislation, would raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities. Until specific regulations are promulgated, the impact that any new environmental regulations, voluntary compliance guidelines, enforcement initiatives, or legislation may have on our results of operations, financial condition or liquidity is not determinable.

The EPA's current CAIR and CAVR require significant reductions beginning in 2009 in air emissions from coal-fired power plants and the states have been given substantial discretion in developing their own rules to implement these programs. On December 23, 2008, the United States Court of Appeals for the District of Columbia remanded CAIR to EPA but allowed the current CAIR regulations to remain in effect while EPA works to remedy flaws in the CAIR regulations identified by the court in a July 11, 2008 opinion. As a result, the ultimate requirements under CAIR may not be known for several years and may differ significantly from the current CAIR regulations. If the EPA significantly changes CAIR, or if the states elect to impose additional requirements on individual units that are already subject to CAIR, the cost of compliance could increase significantly and could have an adverse effect on future results of operations, cash flows and financial condition.

The EPA's final CAMR was vacated by the United States Court of Appeals for the District Court of Columbia on February 8, 2008 because the EPA failed to take the necessary steps to "de-list" coal-fired power plants from its hazardous air pollution program and therefore could not promulgate a cap and trade air emissions reduction program. On October 17, 2008, the EPA (and an industry group) petitioned the United States Supreme Court for review of the Court's ruling vacating CAMR. On February 6, 2009, the United States moved to dismiss its petition for certiorari. On February 23, 2009, the Supreme Court dismissed the United States' petition and denied the industry group's petition. Accordingly, the EPA could take regulatory action to promulgate new mercury emission standards for coal-fired power plants. As a result of further regulatory action by the EPA, the cost of compliance could increase significantly and could have a material adverse effect on future results of operations, cash flows and financial condition.

Various water quality regulations, the majority of which are the result of the federal Clean Water Act and its amendments, apply to our generating plants. In addition, Ohio, New Jersey and Pennsylvania have water quality standards applicable to our 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.

There is substantial uncertainty concerning the final form of federal and state regulations to implement Section 316(b) of the Clean Water Act. On January 26, 2007, the United States Court of Appeals for the Second Circuit remanded back to the EPA portions of its rulemaking pursuant to Section 316(b). The EPA subsequently suspended its rule, noting that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. On April 14, 2008, the Supreme Court of the United States granted a petition for a writ of certiorari to review one significant aspect of the Second Circuit Court's decision. Oral argument before the Supreme Court occurred on December 2, 2008 and a decision is anticipated during the first half of 2009. Depending on the outcome of the Supreme Court's review and the nature of the final regulations that may ultimately be adopted by the EPA, we may incur significant capital costs to comply with the final regulations. If either the federal or state final regulations require retrofitting of cooling water intake structures (cooling towers) at any of our power plants, and if installation of such cooling towers is not technically or economically feasible, we may be forced to take actions which could adversely impact our results of operations and financial condition.

Remediation of Environmental Contamination at Current or Formerly Owned Facilities

We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we may have generated regardless of whether the liabilities arose before, during or after the time we owned or operated the facilities. Remediation activities associated with our former MGP operations are one source of such costs. We are currently involved in a number of proceedings relating to sites where other hazardous substances have been deposited and may be subject to additional proceedings in the future. We also have current or previous ownership interests in sites associated with the production of gas and the production and delivery of electricity for which we may be liable for additional costs related to investigation, remediation and monitoring of these sites. Citizen groups or others may bring litigation over environmental issues including claims of various types, such as property damage, personal injury, and citizen challenges to compliance decisions on the enforcement of environmental requirements, such as opacity and other air quality standards, which could subject us to penalties, injunctive relief and the cost of litigation. We cannot predict the amount and timing of all future expenditures (including the potential or magnitude of fines or penalties) related to such environmental matters, although we expect that they could be material.

In some cases, a third party who has acquired assets from us has assumed the liability we may otherwise have for environmental matters related to the transferred property. If the transferee fails to discharge the assumed liability or disputes its responsibility, a regulatory authority or injured person could attempt to hold us responsible, and our remedies against the transferee may be limited by the financial resources of the transferee.

Availability and Cost of Emission Credits Could Materially Impact Our Costs of Operations

We are required to maintain, either by allocation or purchase, sufficient emission credits to support our operations in the ordinary course of operating our power generation facilities. These credits are used to meet our obligations imposed by various applicable environmental laws. If our operational needs require more than our allocated allowances of emission credits, we may be forced to purchase such credits on the open market, which could be costly. If we are unable to maintain sufficient emission credits to match our operational needs, we may have to curtail our operations so as not to exceed our available emission credits, or install costly new emissions controls. As we use the emissions credits that we have purchased on the open market, costs associated with such purchases will be recognized as operating expense. If such credits are available for purchase, but only at significantly higher prices, the purchase of such credits could materially increase our costs of operations in the affected markets.

Mandatory Renewable Portfolio Requirements Could Negatively Affect Our Costs

If federal or state legislation mandates the use of renewable and alternative fuel sources, such as wind, solar, biomass and geothermal, and such legislation would not also provide for adequate cost recovery, it could result in significant changes in our business, including renewable energy credit purchase costs, purchased power and potentially renewable energy credit costs and capital expenditures. We are unable to predict what impact, if any, these changes may have on our financial condition or results of operations.

We Are and May Become Subject to Legal Claims Arising from the Presence of Asbestos or Other Regulated Substances at Some of our Facilities

We have been named as a defendant in pending asbestos litigation involving multiple plaintiffs and multiple defendants. In addition, asbestos and other regulated substances are, and may continue to be, present at our facilities where suitable alternative materials are not available. We believe that any remaining asbestos at our facilities is contained. The continued presence of asbestos and other regulated substances at these facilities, however, could result in additional actions being brought against us.

The Continuing Availability and Operation of Generating Units is Dependent on Retaining the Necessary Licenses, Permits, and Operating Authority from Governmental Entities, Including the NRC

We are required to have numerous permits, approvals and certificates from the agencies that regulate our business. We believe the necessary permits, approvals and certificates have been obtained for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from future regulatory activities of any of these agencies and we are not assured that any such permits, approvals or certifications will be renewed.

Future Changes in Financial Accounting Standards May Affect Our Reported Financial Results

The SEC, FASB or other authoritative bodies or governmental entities may issue new pronouncements or new interpretations of existing accounting standards that may require us to change our accounting policies. These changes are beyond our control, can be difficult to predict and could materially impact how we report our financial condition and results of operations. We could be required to apply a new or revised standard retroactively, which could adversely affect our financial position. The SEC has issued a roadmap for the transition by U.S. public companies to the use of International Financial Reporting Standards (IFRS) promulgated by the International Accounting Standards Board. Under the SEC's proposed roadmap, we could be required in 2014 to prepare financial statements in accordance with IFRS. The SEC expects to make a determination in 2011 regarding the mandatory adoption of IFRS. We are currently assessing the impact that this potential change would have on our consolidated financial statements and we will continue to monitor the development of the potential implementation of IFRS.

Risks Associated With Financing and Capital Structure

Interest Rates and/or a Credit Rating Downgrade Could Negatively Affect Our Financing Costs, Our Ability to Access Capital and Our Requirement to Post Collateral

We have near-term exposure to interest rates from outstanding indebtedness indexed to variable interest rates, and we have exposure to future interest rates to the extent we seek to raise debt in the capital markets to meet maturing debt obligations and fund construction or other investment opportunities. The recent disruptions in capital and credit markets have resulted in higher interest rates on new publicly issued debt securities, increased costs for certain of our variable interest rate debt securities and failed remarketings (all of which were eventually remarketed) of variable interest rate tax-exempt debt issued to finance certain of our facilities. Continuation of these disruptions could increase our financing costs and adversely affect our results of operations. Also, interest rates could change as a result of economic or other events that our risk management processes were not established to address. As a result, we cannot always predict the impact that our risk management decisions may have on us if actual events lead to greater losses or costs than our risk management positions were intended to hedge. Although we employ risk management techniques to hedge against interest rate volatility, significant and sustained increases in market interest rates could materially increase our financing costs and negatively impact our reported results of operations.

We rely on access to bank and capital markets as sources of liquidity for cash requirements not satisfied by cash from operations. A downgrade in our credit ratings from the nationally recognized credit rating agencies, particularly to a level below investment grade, could negatively affect our ability to access the bank and capital markets, especially in a time of uncertainty in either of those markets, and may require us to post cash collateral to support outstanding commodity positions in the wholesale market, as well as available letters of credit and other guarantees. A rating downgrade would also increase the fees we pay on our various credit facilities, thus increasing the cost of our working capital. A rating downgrade could also impact our ability to grow our businesses by substantially increasing the cost of, or limiting access to, capital. Our senior unsecured debt ratings from S&P and Moody's are investment grade. The current ratings outlook from S&P and Moody's is stable.

A rating is not a recommendation to buy, sell or hold debt, inasmuch as such rating does not comment as to market price or suitability for a particular investor. The ratings assigned to our debt address the likelihood of payment of principal and interest pursuant to their terms. A rating may be subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating that may be assigned to our securities. Also, we cannot predict how rating agencies may modify their evaluation process or the impact such a modification may have on our ratings.

Our credit ratings also govern the collateral provisions of certain contract guarantees. Subsequent to the occurrence of a credit rating downgrade to below investment grade or a "material adverse event," the immediate posting of cash collateral may be required. See Note 14(B) of the Notes to the Consolidated Financial Statements for more information associated with a credit ratings downgrade leading to the posting of cash collateral.

We Must Rely on Cash from Our Subsidiaries and Any Restrictions on Our Utility Subsidiaries' Ability to Pay Dividends or Make Cash Payments to Us May Adversely Affect Our Financial Condition

We are a holding company and our investments in our subsidiaries are our primary assets. Substantially all of our business is conducted by our subsidiaries. Consequently, our cash flow is dependent on the operating cash flows of our subsidiaries and their ability to upstream cash to the holding company. Our utility subsidiaries are regulated by various state utility commissions that generally possess broad powers to ensure that the needs of utility customers are being met. Those state commissions could attempt to impose restrictions on the ability of our utility subsidiaries to pay dividends or otherwise restrict cash payments to us.

We Cannot Assure Common Shareholders that Future Dividend Payments Will be Made, or if Made, in What Amounts they May be Paid

Our Board of Directors regularly evaluates our common stock dividend policy and determines the dividend rate each quarter. The level of dividends will continue to be influenced by many factors, including, among other things, our earnings, financial condition and cash flows from subsidiaries, as well as general economic and competitive conditions. We cannot assure common shareholders that dividends will be paid in the future, or that, if paid, dividends will be at the same amount or with the same frequency as in the past.

Disruptions in the Capital and Credit Markets May Adversely Affect our Business, Including the Availability and Cost of Short-Term Funds for Liquidity Requirements, Our Ability to Meet Long-Term Commitments, our Ability to Hedge Effectively our Generation Portfolio, and the Competitiveness and Liquidity of Energy Markets; Each Could Adversely Affect our Results of Operations, Cash Flows and Financial Condition

We rely on the capital markets to meet our financial commitments and short-term liquidity needs if internal funds are not available from our operations. We also use letters of credit provided by various financial institutions to support our hedging operations. Disruptions in the capital and credit markets, as have been experienced during 2008, could adversely affect our ability to draw on our respective credit facilities. Our access to funds under those credit facilities is dependent on the ability of the financial institutions that are parties to the facilities to meet their funding commitments. Those institutions may not be able to meet their funding commitments if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time.

Longer-term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could adversely affect our access to liquidity needed for our business. Any disruption could require us to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures, changing hedging strategies to reduce collateral-posting requirements, and reducing or eliminating future dividend payments or other discretionary uses of cash.

The strength and depth of competition in energy markets depends heavily on active participation by multiple counterparties, which could be adversely affected by disruptions in the capital and credit markets. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to our business. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace those market structures with other mechanisms for the sale of power, including the requirement of long-term contracts, which could have a material adverse effect on our results of operations and cash flows.

Questions Regarding the Soundness of Financial Institutions or Counterparties Could Adversely Affect Us

We have exposure to many different financial institutions and counterparties and we routinely execute transactions with counterparties in connection with our hedging activities, including brokers and dealers, commercial banks, investment banks and other institutions and industry participants. Many of these transactions expose us to credit risk in the event that any of our lenders or counterparties are unable to honor their commitments or otherwise default under a financing agreement. We also deposit cash balances in short-term investments. Our ability to access our cash quickly depends on the soundness of the financial institutions in which those funds reside. Any delay in our ability to access those funds, even for a short period of time, could have a material adverse effect on our results of operations and financial condition.

Our Electric Utility Operating Affiliates in Ohio are Currently in the Midst of Rate Proceedings that have the Potential to Adversely Affect Our Financial Condition

As required by Amended Substitute Senate Bill 221 (SB221), Ohio's new electricity restructuring law, our Ohio utility subsidiaries filed on July 31, 2008 with the PUCO a comprehensive ESP and a n MRO. The ESP proposed, among other things, to phase in new generation rates for customers beginning in 2009 for up to a three-year period and to resolve a then pending distribution rate increase request. The MRO filing outlined a competitive bid process for providing retail generation supply at market prices in accordance with SB221 if the ESP was not approved and implemented by our Ohio utilities. The PUCO rejected the MRO filing on November 25, 2008 and we filed an application for rehearing on December 22, 2008.

The PUCO modified the ESP on December 19, 2008. We withdrew the ESP as so modified on December 22, 2008 opting instead to keep the current rate plan in effect, as we believe SB221 requires. Because our Ohio utilities do not own generating plants, they subsequently completed a competitive procurement process to ensure a reliable supply of electricity, for customers who do not shop, for the period January 5, 2009 through March 31, 2009.

Subsequent to the competitive procurement process, the PUCO ruled that our Ohio utilities could not continue certain portions of their existing tariffs. Citing inconsistencies with Ohio law and potentially serious financial consequences that could result from the PUCO's ruling, on January 9, 2009, we filed a motion to stay, as well as an application for rehearing and an application for a fuel rider. On January 9, 2009, an order was entered permitting our Ohio utilities to continue charging current rates until the PUCO rules on the pending filings. On January 14, 2009, the PUCO approved our Ohio utilities' application to recover fuel and associated purchased power costs during the period January 1, 2009 through March 31, 2009 subject to review by the PUCO, and affirmed its January 9, 2009 order regarding our Ohio utilities' ability to continue charging specific components of current rates.

Substantial recovery under the fuel rider is necessary to ensure that our Ohio utilities recover costs related to their provider-of-last-resort obligation to their customers. Without such recovery, providing generation service to their customers at rates that are well below actual costs would cause them to incur a cash shortfall of approximately \$2 million per day. This could require our Ohio Utilities to make immediate and severe reductions in operating and capital expenditures and could have other material adverse impacts on the financial condition and results of operations of not only our Ohio utilities but also FirstEnergy. Any resulting deterioration in our financial metrics could result in a downgrade of our credit ratings. On January 21, 2009, the PUCO granted our Ohio utilities' application for an increase in distribution rates in the amount of \$136.6 million in the aggregate for all three companies, as well as the application for rehearing of the MRO filing.

On February 19, 2009, the Ohio Companies filed an application for an amended ESP which substantially reflected the terms proposed by PUCO Staff to resolve the ESP proceeding, which the PUCO attorney examiner set for a hearing to begin on February 25, 2009 (see Regulatory Matters – Ohio).

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The Utilities' and FGCO's respective first mortgage indentures constitute, in the opinion of their counsel, direct first liens on substantially all of the respective Utilities' and FGCO's physical property, subject only to excepted encumbrances, as defined in the first mortgage indentures. See the "Leases" and "Capitalization" notes to the respective financial statements for information concerning leases and financing encumbrances affecting certain of the Utilities' and FGCO's properties.

FirstEnergy has access, either through ownership or lease, to the following generation sources as of February 25, 2009, shown in the table below. Except for the leasehold interests and OVEC participation referenced in the footnotes to the table, substantially all of the generating units are owned by NGC (nuclear) and FGCO (non-nuclear). See "Generation Asset Transfers" under Item 1 above.

<u>Plant-Location</u>	<u>Unit</u>	<u>Net Demonstrated Capacity (MW)</u>
Coal-Fired Units		
Ashtabula-		
Ashtabula, OH	5	244
Bay Shore-		
Toledo, OH	1-4	631
R. E. Burger-		
Shadyside, OH	3-5	406
Eastlake-Eastlake, OH	1-5	1,233
Lakeshore-		
Cleveland, OH	18	245
Bruce Mansfield-	1	830(a)
Shippingport, PA	2	830(b)
	3	830(c)
W. H. Sammis - Stratton, OH	1-7	2,220
Kyger Creek - Cheshire, OH	1-5	210(d)
Clifty Creek - Madison, IN	1-6	253(d)
Total		<u>7,932</u>
Nuclear Units		
Beaver Valley-	1	911
Shippingport, PA	2	904(e)
Davis-Besse-		
Oak Harbor, OH	1	908
Perry-		
N. Perry Village, OH	1	1,268(f)
Total		<u>3,991</u>
Oil/Gas - Fired/ Pumped Storage Units		
Richland - Defiance, OH	1-6	432
Seneca - Warren, PA	1-3	451
Sumpter - Sumpter Twp, MI	1-4	340
West Lorain - Lorain, OH	1-6	545
Yard's Creek - Blairstown Twp., NJ	1-3	200(g)
Other		282
Total		<u>2,250</u>
Total		<u><u>14,173</u></u>

- Notes: (a) Includes FGCO's leasehold interest of 93.825% (779 MW) and CEI's leasehold interest of 6.175% (51 MW), which has been assigned to FGCO.
- (b) Includes CEI's and TE's leasehold interests of 27.17% (226 MW) and 16.435% (136 MW), respectively, which have been assigned to FGCO.
- (c) Includes CEI's and TE's leasehold interests of 23.247% (193 MW) and 18.915% (157 MW), respectively, which have been assigned to FGCO.
- (d) Represents FGCO's 20.5% entitlement based on its participation in OVEC. FGCO has entered into a definitive agreement to sell 9% of its 20.5% participation in OVEC. Final closing of the transaction, which is expected in April 2009, is subject to approval by the FERC.
- (e) Includes OE's leasehold interest of 16.65% (151 MW) from non-affiliates.
- (f) Includes OE's leasehold interest of 8.11% (103 MW) from non-affiliates.
- (g) Represents JCP&L's 50% ownership interest.

The above generating plants and load centers are connected by a transmission system consisting of elements having various voltage ratings ranging from 23 kV to 500 kV. The Utilities' overhead and underground transmission lines aggregate 15,070 pole miles.

The Utilities' electric distribution systems include 118,562 miles of overhead pole line and underground conduit carrying primary, secondary and street lighting circuits. They own substations with a total installed transformer capacity of 87,624,000 kV-amperes.

The transmission facilities that are owned by ATSI are operated on an integrated basis as part of MISO and are interconnected with facilities operated by PJM. The transmission facilities of JCP&L, Met-Ed and Penelec are physically interconnected and are operated on an integrated basis as part of PJM.

FirstEnergy's distribution and transmission systems as of December 31, 2008, consist of the following:

	<u>Distribution Lines</u>	<u>Transmission Lines</u>	<u>Substation Transformer Capacity</u>
	<i>(Miles)</i>		<i>(kV-amperes)</i>
OE	30,413	555	9,718,000
Penn	5,911	44	922,000
CEI	25,321	2,144	7,841,000
TE	2,083	224	2,503,000
JCP&L	19,604	2,160	21,216,000
Met-Ed	15,057	1,421	9,962,000
Penelec	20,173	2,701	14,033,000
ATSI*	-	5,821	21,429,000
Total	<u>118,562</u>	<u>15,070</u>	<u>87,624,000</u>

* Represents transmission lines of 69kV and above located in the service areas of OE, Penn, CEI and TE.

ITEM 3. LEGAL PROCEEDINGS

Reference is made to Note 14, Commitments, Guarantees and Contingencies, of FirstEnergy's Notes to Consolidated Financial Statements contained in Item 8 for a description of certain legal proceedings involving FirstEnergy, FES, OE, CEI, TE, JCP&L, Met-Ed and Penelec.

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

None.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The information required by Item 5 regarding FirstEnergy's market information, including stock exchange listings and quarterly stock market prices, dividends and holders of common stock is included on page 1 of FirstEnergy's 2008 Annual Report to Stockholders (Exhibit 13.1). Pursuant to General Instruction I of Form 10-K, information for FES, OE, CEI, TE, JCP&L, Met-Ed and Penelec is not required to be disclosed because they are wholly owned subsidiaries.

Information regarding compensation plans for which shares of FirstEnergy common stock may be issued is incorporated herein by reference to FirstEnergy's 2009 proxy statement filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934.

The table below includes information on a monthly basis regarding purchases made by FirstEnergy of its common stock during the fourth quarter of 2008.

	Period			
	October	November	December	Fourth Quarter
Total Number of Shares Purchased ^(a)	22,317	44,129	253,936	320,382
Average Price Paid per Share	\$ 54.66	\$ 54.39	\$ 55.94	\$ 55.64
Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	-	-	-	-
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 2007 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 2007 Incentive Compensation Plan and the Executive Deferred Compensation Plan, and shares purchased as part of publicly announced plans.

ITEM 6. SELECTED FINANCIAL DATA

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by Items 6 through 8 is incorporated herein by reference to Selected Financial Data, Management's Discussion and Analysis of Financial Condition and Results of Operation, and Financial Statements included on the following pages in the 2008 Annual Report of FirstEnergy (Exhibit 13.1) and the combined 2008 Annual Report of FES, OE, CEI, TE, JCP&L, Met-Ed and Penelec (Exhibit 13.2).

	Item 6*	Item 7*	Item 7A	Item 8
FirstEnergy	1-2	3-59	38-41	62-109
FES	N/A	N/A	3-5	8-12, 91-145
OE	N/A	N/A	14-15	18-22, 91-145
CEI	N/A	N/A	24-25	28-32, 91-145
TE	N/A	N/A	35	38-42, 91-145
JCP&L	N/A	N/A	44-46	49-53, 91-145
Met-Ed	N/A	N/A	55-57	60-64, 91-145
Penelec	N/A	N/A	66-68	71-75, 91-145

*FES, OE, CEI, TE, JCP&L, Met-Ed and Penelec meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to Form 10-K.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES -- FIRSTENERGY

Evaluation of Disclosure Controls and Procedures

FirstEnergy's Chief Executive Officer and Chief Financial Officer have reviewed and evaluated such registrant's disclosure controls and procedures, as defined in the Securities Exchange Act of 1934 Rules 13a-15(e) and 15d-15(e), as of the end date covered by this report. Based upon this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that FirstEnergy's disclosure controls and procedures were effective as of December 31, 2008.

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control – Integrated Framework, management conducted an evaluation of the effectiveness of FirstEnergy's internal control over financial reporting under the supervision of FirstEnergy's Chief Executive Officer and Chief Financial Officer. Based on that evaluation, management concluded that FirstEnergy's internal control over financial reporting was effective as of December 31, 2008. The effectiveness of FirstEnergy's internal control over financial reporting, as of December 31, 2008, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report included in FirstEnergy's 2008 Annual Report to Stockholders and incorporated by reference hereto.

Changes in Internal Control over Financial Reporting

There were no changes in FirstEnergy's internal control over financial reporting during the fourth quarter of 2008 that have materially affected, or are reasonably likely to materially affect, FirstEnergy's internal control over financial reporting.

ITEM 9A(T). CONTROLS AND PROCEDURES -- FES, OE, CEI, TE, JCP&L, Met-Ed and Penelec

Evaluation of Disclosure Controls and Procedures

Each registrant's Chief Executive Officer and Chief Financial Officer have reviewed and evaluated such registrant's disclosure controls and procedures, as defined in the Securities Exchange Act of 1934 rules 13a-15(e) and 15d-15(e), as of the end date covered by this report. Based upon this evaluation, the respective Chief Executive Officer and Chief Financial Officer concluded that such registrant's disclosure controls and procedures were effective as of December 31, 2008.

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control – Integrated Framework, management conducted an evaluation of the effectiveness of each registrant's internal control over financial reporting under the supervision of such registrant's Chief Executive Officer and Chief Financial Officer. Based on that evaluation, management concluded that each registrant's internal control over financial reporting was effective as of December 31, 2008. The effectiveness of each registrant's internal control over financial reporting, as of December 31, 2008, has not been audited by such registrant's independent registered public accounting firm.

Changes in Internal Control over Financial Reporting

Related to the remediation of the material weakness described below, there were changes in internal control over financial reporting during the fourth quarter of 2008 for OE, CEI, TE and Penelec. During the fourth quarter of 2008, management of OE, CEI, TE and Penelec identified a material weakness in their accounting for unpaid dividends to FirstEnergy. This material weakness was attributable to an inadequate control to ensure that declared but unpaid dividends to FirstEnergy were not reported as cash used for financing activities on the Consolidated Statement of Cash Flows for each of the affected registrants. As a result of this material weakness, OE, CEI, TE and Penelec restated their Consolidated Statements of Cash Flows for the year ended December 31, 2007, the three months ended March 31, 2008, the six months ended June 30, 2008 and the nine months ended September 30, 2008. The Consolidated Statements of Income and Consolidated Balance Sheets were not affected by the error. In an effort to remediate the identified material weakness, management of OE, CEI, TE and Penelec has implemented a process to segregate dividend declarations with payments applicable to future reporting periods in a unique general ledger account in order to distinguish associated company dividends payable from other associated company accounts payable. Management believes that this process is fully functional, enhances the existing internal control over financial reporting and, prior to the end of the period covered by this report, remediated the material weakness in the internal controls related to the preparation and review of the Consolidated Statements of Cash Flows, which was identified in the fourth quarter of 2008.

There were no changes in internal control over financial reporting during the fourth quarter of 2008 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting for FES, JCP&L and Met-Ed.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Item 10, with respect to identification of FirstEnergy's directors and with respect to reports required to be filed under Section 16 of the Securities Exchange Act of 1934, is incorporated herein by reference to FirstEnergy's 2009 Proxy Statement filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934 and, with respect to identification of executive officers, to "Part I, Item 1. Business – Executive Officers" herein.

The Board of Directors, upon recommendation of the Corporate Governance and Audit Committees, has determined that Ernest J. Novak, Jr., an independent director, is the audit committee financial expert.

FirstEnergy makes available on its Web site at <http://www.firstenergycorp.com/ir> its Corporate Governance Policies and the charters for each of the following committees of the Board of Directors: Audit; Corporate Governance; Compensation; Finance; and Nuclear. The Corporate Governance Policies and Board committee charters are also available in print upon written request to Rhonda S. Ferguson, Corporate Secretary, FirstEnergy Corp., 76 South Main Street, Akron, OH 44308-1890.

FirstEnergy has adopted a Code of Business Conduct, which applies to all employees, including the Chief Executive Officer, the Chief Financial Officer and the Chief Accounting Officer. In addition, the Board of Directors has its own Code of Business Conduct. These Codes can be found on the Web site provided in the previous paragraph or upon written request to the Corporate Secretary.

Pursuant to Section 303A.12(a) of the New York Stock Exchange Listed Company Manual, the Company submitted the Annual CEO Certification to the NYSE on May 23, 2008.

ITEM 11. EXECUTIVE COMPENSATION

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by Items 11, 12 and 13 is incorporated herein by reference to FirstEnergy's 2009 Proxy Statement filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

A summary of the audit and audit-related fees rendered by PricewaterhouseCoopers LLP for the years ended December 31, 2008 and 2007 are as follows:

Company	Audit Fees ⁽¹⁾		Audit-Related Fees	
	200 8	200 7	200 8	200 7
	<i>(In thousands)</i>			
FES	\$ 835	\$ 1,091	\$ -	\$ 494
OE	1,155	1,014	-	-
CEI	764	719	-	-
TE	598	540	-	-
JCP&L	682	701	-	-
Met-Ed	583	528	-	-
Penelec	595	586	-	-
Other subsidiaries	607	886	-	-
Total FirstEnergy	<u>\$ 5,819</u>	<u>\$ 6,065</u>	<u>\$ -</u>	<u>\$ 494</u>

(1) Professional services rendered for the audits of FirstEnergy's annual financial statements and reviews of financial statements included in FirstEnergy's Quarterly Reports on Form 10-Q and for services in connection with statutory and regulatory filings or engagements, including comfort letters and consents for financings and filings made with the SEC.

Tax and Other Fees

There were no other fees billed to FirstEnergy for tax or other services for the years ended December 31, 2008 and 2007.

Additional information required by this item is incorporated herein by reference to FirstEnergy's 2009 Proxy Statement filed with the SEC pursuant to Regulation 14A under the Securities Exchange Act of 1934.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a)

1. Financial Statements

Included in Part II of this report and incorporated herein by reference to the 2008 Annual Report of FirstEnergy (Exhibit 13.1) and the combined 2008 Annual Report of FES, OE, CEI, TE, JCP&L, Met-Ed and Penelec (Exhibit 13.2) at the pages indicated.

	FirstEnergy	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
Management Reports	59	6	16	26	36	47	58	69
Report of Independent Registered Public Accounting Firm	60	7	17	27	37	48	59	70
Statements of Income, Three Years Ended December 31, 2008	61	8	18	28	38	49	60	71
Balance Sheets, December 31, 2008 and 2007	62	9	19	29	39	50	61	72
Statements of Capitalization, December 31, 2008 and 2007	N/A	10	20	30	40	51	62	73
Statements of Common Stockholders' Equity, Three Years Ended December 31, 2008	63	11	21	31	41	52	63	74
Statements of Cash Flows, Three Years Ended December 31, 2008	64	12	22	32	42	53	64	75
Notes to Financial Statements	65-108	91-145	91-145	91-145	91-145	91-145	91-145	91-145

2. Financial Statement Schedules

Included in Part IV of this report:

	FirstEnergy	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
Report of Independent Registered Public Accounting Firm	73	74	75	76	77	78	79	80
Schedule II -- Consolidated Valuation and Qualifying Accounts, Three Years Ended December 31, 2008	81	82	83	84	85	86	87	88

Schedules other than the schedule listed above are omitted for the reason that they are not required or are not applicable, or the required information is shown in the financial statements or notes thereto.

3. Exhibits – FirstEnergy

Exhibit Number	
3-1	Amended Articles of Incorporation of FirstEnergy Corp. (Form S-3 filed February 3, 1997, Exhibit 4(a), File No. 333-21011)
(A) 3-2	FirstEnergy Corp. Amended Code of Regulations.
4-1	Indenture, dated November 15, 2001, between FirstEnergy Corp. and The Bank of New York Mellon, as Trustee. (Form S-3 filed September 21, 2001, Exhibit 4(a), File No. 333-69856)
(A)(B) 10-1	FirstEnergy Corp. 2007 Incentive Plan, effective May 15, 2007.
(A)(B) 10-2	Amended FirstEnergy Corp. Deferred Compensation Plan for Outside Directors, amended and restated as of January 1, 2005 and ratified as of September 18, 2007.
(B) 10-3	FirstEnergy Corp. Supplemental Executive Retirement Plan, amended January 1, 1999. (1999 Form 10-K, Exhibit 10-4)
(B) 10-4	Stock Option Agreement between FirstEnergy Corp. and officers dated November 22, 2000. (2000 Form 10-K, Exhibit 10-3)
(B) 10-5	Stock Option Agreement between FirstEnergy Corp. and officers dated March 1, 2000. (2000 Form 10-K, Exhibit 10-4)

- (B) 10-6 Stock Option Agreement between FirstEnergy Corp. and director dated January 1, 2000. (2000 Form 10-K, Exhibit 10-5)
- (B) 10-7 Stock Option Agreement between FirstEnergy Corp. and two directors dated January 1, 2001. (2000 Form 10-K, Exhibit 10-6)
- (B) 10-8 Stock Option Agreements between FirstEnergy Corp. and One Director dated January 1, 2002. (2001 Form 10-K, Exhibit 10-5)
- (B) 10-9 FirstEnergy Corp. Executive Deferred Compensation Plan, amended and restated as of January 1, 2005 and ratified as of September 18, 2007. (September 2007 10-Q, Exhibit 10.2)
- (B) 10-10 Executive Incentive Compensation Plan-Tier 2. (2001 Form 10-K, Exhibit 10-7)
- (B) 10-11 Executive Incentive Compensation Plan-Tier 3. (2001 Form 10-K, Exhibit 10-8)
- (B) 10-12 Executive Incentive Compensation Plan-Tier 4. (2001 Form 10-K, Exhibit 10-9)
- (B) 10-13 Executive Incentive Compensation Plan-Tier 5. (2001 Form 10-K, Exhibit 10-10)
- (B) 10-14 Amendment to GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries, effective April 5, 2001. (2001 Form 10-K, Exhibit 10-11)
- (B) 10-15 Form of Amendment, effective November 7, 2001, to GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries, Deferred Remuneration Plan for Outside Directors of GPU, Inc., and Retirement Plan for Outside Directors of GPU, Inc. (2001 Form 10-K, Exhibit 10-12)
- (B) 10-16 GPU, Inc. Stock Option and Restricted Stock Plan for MYR Group, Inc. Employees. (2001 Form 10-K, Exhibit 10-13)
- (B) 10-17 Executive and Director Stock Option Agreement dated June 11, 2002. (2002 Form 10-K, Exhibit 10-1)
- (B) 10-18 Director Stock Option Agreement. (2002 Form 10-K, Exhibit 10-2)
- (B) 10-19 Executive Incentive Compensation Plan 2002. (2002 Form 10-K, Exhibit 10-28)
- (B) 10-20 GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries as amended and restated to reflect amendments through June 3, 1999. (1999 Form 10-K, Exhibit 10-V, File No. 1-6047, GPU, Inc.)
- (B) 10-21 Form of 1998 Stock Option Agreement under the GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries. (1997 Form 10-K, Exhibit 10-Q, File No. 1-6047, GPU, Inc.)
- (B) 10-22 Form of 1999 Stock Option Agreement under the GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries. (1999 Form 10-K, Exhibit 10-W, File No. 1-6047, GPU, Inc.)
- (B) 10-23 Form of 2000 Stock Option Agreement under the GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries. (1999 Form 10-K, Exhibit 10-W, File No. 1-6047, GPU, Inc.)
- (B) 10-24 Deferred Remuneration Plan for Outside Directors of GPU, Inc. as amended and restated effective August 8, 2000. (1999 Form 10-K, Exhibit 10-O, File No. 1-6047, GPU, Inc.)
- (B) 10-25 Retirement Plan for Outside Directors of GPU, Inc. as amended and restated as of August 8, 2000. (1999 Form 10-K, Exhibit 10-N, File No. 1-6047, GPU, Inc.)
- (B) 10-26 Forms of Estate Enhancement Program Agreements entered into by certain former GPU directors. (1999 Form 10-K, Exhibit 10-JJ, File No. 1-6047, GPU, Inc.)
- (B) 10-27 Employment Agreement for Richard R. Grigg dated February 26, 2008. (2007 Form 10-K, Exhibit 10.5)

- (B) 10-28 Stock Option Agreement between FirstEnergy Corp. and an officer dated August 20, 2004. (September 2004 Form 10-Q, Exhibit 10-42)
- (B) 10-29 Executive Bonus Plan between FirstEnergy Corp. and Officers effective November 3, 2004. (September 2004 Form 10-Q, Exhibit 10-44)
- 10-30 Consent Decree dated March 18, 2005. (Form 8-K dated March 18, 2005 by FirstEnergy Corp., Exhibit 10-1)
- (C) 10-31 Form of Guaranty Agreement dated as of December 16, 2005 between FirstEnergy Corp. and FirstEnergy Solutions Corp. in Favor of Barclays Bank PLC as Administrative Agent for the Banks. (2005 Form 10-K, Exhibit 10-1)
- (D) 10-32 Form of Guaranty Agreement dated as of April 3, 2006 by FirstEnergy Corp. in favor of the Participating Banks, Barclays Bank PLC, as administrative agent and fronting bank, and KeyBank National Association, as syndication agent, under the related Letter of Credit and Reimbursement Agreement. (March 2006 Form 10-Q, Exhibit 10-1)
- (B) 10-33 Form of Restricted Stock Agreement between FirstEnergy Corp. and A. J. Alexander, dated February 27, 2006. (March 2006 Form 10-Q, Exhibit 10-6)
- (B) 10-34 Form of Restricted Stock Unit Agreement (Performance Adjusted) between FirstEnergy Corp. and A.J. Alexander, dated March 1, 2006. (March 2006 Form 10-Q, Exhibit 10-7)
- (B) 10-35 Form of Restricted Stock Unit Agreement (Performance Adjusted) between FirstEnergy Corp. and named executive officers, dated March 1, 2006. (March 2006 Form 10-Q, Exhibit 10-8)
- (B) 10-36 Form of Restricted Stock Unit Agreement (Performance Adjusted) between FirstEnergy Corp. and R.H. Marsh, dated March 1, 2006. (March 2006 Form 10-Q, Exhibit 10-9)
- 10-37 Confirmation dated March 1, 2007 between FirstEnergy Corp. and Morgan Stanley and Co., International Limited. (March 2007 Form 10-Q, Exhibit 10.1)
- 10-38 Form of U.S. \$250,000,000 Credit Agreement, dated as of March 2, 2007, between FirstEnergy Corp., as Borrower, and Morgan Stanley Senior Funding, Inc., as Lender. (March 2007 Form 10-Q, Exhibit 10.2)
- 10-39 Form of Guaranty dated as of March 2, 2007, between FirstEnergy Corp., as Guarantor, and Morgan Stanley Senior Funding, Inc., as Lender under a U.S. \$250,000,000 Credit Agreement dated as of March 2, 2007, with FirstEnergy Solutions Corp., as Borrower. (March 2007 Form 10-Q, Exhibit 10.2)
- (B) 10-40 FirstEnergy Corp. Supplemental Executive Retirement Plan as amended September 18, 2007. (September 2007 Form 10-Q, Exhibit 10.2)
- (B) 10-41 Employment Agreement between FirstEnergy Corp. and Gary R. Leidich, dated February 26, 2008. (2007 Form 10-K, Exhibit 10-88)
- (B) 10-42 Form of Restricted Stock Unit Agreement for Gary R. Leidich (per Employment Agreement dated February 26, 2008). (2007 Form 10-K, Exhibit 10-90)
- (B) 10-43 Form of Restricted Stock Agreement Amendment for Gary R. Leidich dated February 26, 2008. (2007 Form 10-K, Exhibit 10-91)
- (B) 10-44 Form of Restricted Stock Unit Agreement for Richard R. Grigg (per Employment Agreement dated February 26, 2008). (2007 Form 10-K, Exhibit 10-92)
- (B) 10-45 Form of Restricted Stock Unit Agreement for named executive officers dated March 3, 2008. (2007 Form 10-K, Exhibit 10-93)
- (B) 10-46 Form of 2007 Incentive Compensation Plan Performance Share Award for the performance period January 1, 2008 to December 31, 2010. (2007 Form 10-K, Exhibit 10-94)

- 10-47 U.S. \$300,000,000 Credit Agreement, dated as of October 8, 2008, among FirstEnergy Generation Corp., as Borrower, FirstEnergy Corp. and FirstEnergy Solutions Corp., as Guarantors, Credit Suisse and the other Banks parties thereto from time to time, as Banks and Credit Suisse, as Administrative Agent. (September 2008 Form 10-Q, Exhibit 10.1)
- (A)(B) 10-48 Form of 2009-2011 Performance Share Award Agreement effective January 1, 2009
- (A)(B) 10-49 Form of Performance-Adjusted Restricted Stock Unit Award Agreement as of March 2, 2009
- (A) 12-1 Consolidated ratios of earnings to fixed charges.
- (A) 13-1 FirstEnergy 2008 Annual Report to Stockholders. (Only those portions expressly incorporated by reference in this Form 10-K are to be deemed "filed" with the SEC.)
- (A) 21 List of Subsidiaries of the Registrant at December 31, 2008.
- (A) 23-1 Consent of Independent Registered Public Accounting Firm.
- (A) 31-1 Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
- (A) 31-2 Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
- (A) 32 Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. §1350.
- (A) Provided herein in electronic format as an exhibit.
- (B) Management contract or compensatory plan contract or arrangement filed pursuant to Item 601 of Regulation S-K.
- (C) Four substantially similar agreements, each dated as of the same date, were executed and delivered by the registrant and its affiliates with respect to four other series of pollution control revenue refunding bonds issued by the Ohio Water Development Authority, the Ohio Air Quality Authority and Beaver County Industrial Development Authority, Pennsylvania, relating to pollution control notes of FirstEnergy Nuclear Generation Corp.
- (D) Three substantially similar agreements, each dated as of the same date, were executed and delivered by the registrant and its affiliates with respect to three other series of pollution control revenue refunding bonds issued by the Ohio Water Development Authority and the Beaver County Industrial Development Authority relating to pollution control notes of FirstEnergy Generation Corp. and FirstEnergy Nuclear Generation Corp.

3. Exhibits – FES

- 3-1 Articles of Incorporation of FirstEnergy Solutions Corp., as amended August 31, 2001. (Form S-4 filed August 6, 2007, Exhibit 3.1)
- 3-2 Code of Regulations of FirstEnergy Solutions Corp. (Form S-4 filed August 6, 2007, Exhibit 3.4)
- 10-1 Form of 6.85% Exchange Certificate due 2034. (Form S-4 filed August 6, 2007, Exhibit 4.1)
- 10-2 Guaranty of FirstEnergy Solutions Corp., dated as of July 1, 2007. (Form 8-K/A filed August 2, 2007 by FirstEnergy Corp. (333-21011), Exhibit 10-9)
- 10-3 Indenture of Trust, Open-End Mortgage and Security Agreement, dated as of July 1, 2007, between the applicable Lessor and The Bank of New York Trust Company, N.A., as Indenture Trustee. (Form 8-K/A filed August 2, 2007 by FirstEnergy Corp. (333-21011), Exhibit 10-3)
- 10-4 6.85% Lessor Note due 2034. (Form 8-K/A filed August 2, 2007 by FirstEnergy Corp. (333-21011), Exhibit 10-3)

- 10-5 Registration Rights Agreement, dated as of July 13, 2007, among FirstEnergy Generation Corp., FirstEnergy Solutions Corp., The Bank of New York Trust Company, N.A., as Pass Through Trustee, Morgan Stanley & Co. Incorporated, and Credit Suisse Securities (USA) LLC, as representatives of the several initial purchasers named in the Purchase Agreement. (Form 8-K/A filed August 2, 2007 by FirstEnergy Corp. (333-21011), Exhibit 10-14)
- 10-6 Participation Agreement, dated as of June 26, 2007, among FirstEnergy Generation Corp., as Lessee, FirstEnergy Solutions Corp., as Guarantor, the applicable Lessor, U.S. Bank Trust National Association, as Trust Company, the applicable Owner Participant, The Bank of New York Trust Company, N.A., as Indenture Trustee, and The Bank of New York Trust Company, N.A., as Pass Through Trustee. (Form 8-K/A filed August 2, 2007 by FirstEnergy Corp. (333-21011), Exhibit 10-1)
- 10-7 Trust Agreement, dated as of June 26, 2007, between the applicable Owner Participant and U.S. Bank Trust National Association, as Owner Trustee. (Form 8-K/A filed August 2, 2007 by FirstEnergy Corp. (333-21011), Exhibit 10-2)
- 10-8 Pass Through Trust Agreement, dated as of June 26, 2007, among FirstEnergy Generation Corp., FirstEnergy Solutions Corp., and The Bank of New York Trust Company, N.A., as Pass Through Trustee. (Form 8-K/A filed August 2, 2007 by FirstEnergy Corp. (333-21011), Exhibit 10-12)
- 10-9 Bill of Sale and Transfer, dated as of July 1, 2007, between FirstEnergy Generation Corp. and the applicable Lessor. (Form 8-K/A filed August 2, 2007 by FirstEnergy Corp. (333-21011), Exhibit 10-5)
- 10-10 Facility Lease Agreement, dated as of July 1, 2007, between FirstEnergy Generation Corp. and the applicable Lessor. (Form 8-K/A filed August 2, 2007 by FirstEnergy Corp. (333-21011), Exhibit 10-6)
- 10-11 Site Lease, dated as of July 1, 2007, between FirstEnergy Generation Corp. and the applicable Lessor. (Form 8-K/A filed August 2, 2007 by FirstEnergy Corp. (333-21011), Exhibit 10-7)
- 10-12 Site Sublease, dated as of July 1, 2007, between FirstEnergy Generation Corp. and the applicable Lessor. (Form 8-K/A filed August 2, 2007 by FirstEnergy Corp. (333-21011), Exhibit 10-8)
- 10-13 Support Agreement, dated as of July 1, 2007, between FirstEnergy Generation Corp. and the applicable Lessor. (Form 8-K/A filed August 2, 2007 by FirstEnergy Corp. (333-21011), Exhibit 10-10)
- 10-14 Second Amendment to the Bruce Mansfield Units 1, 2, and 3 Operating Agreement, dated as of July 1, 2007, between FirstEnergy Generation Corp., The Cleveland Electric Illuminating Company and The Toledo Edison Company. (Form 8-K/A filed August 2, 2007 by FirstEnergy Corp. (333-21011), Exhibit 10-11)
- 10-15 OE Fossil Purchase and Sale Agreement by and between Ohio Edison Company (Seller) and FirstEnergy Generation Corp. (Purchaser). (June 2005 Form 10-Q filed by FirstEnergy Corp. (333-21011), Exhibit 10.2)
- 10-16 CEI Fossil Purchase and Sale Agreement by and between The Cleveland Electric Illuminating Company (Seller) and FirstEnergy Generation Corp. (Purchaser). (June 2005 Form 10-Q, Exhibit 10.6)
- 10-17 TE Fossil Purchase and Sale Agreement by and between The Toledo Edison Company (Seller) and FirstEnergy Generation Corp. (Purchaser). (June 2005 Form 10-Q, Exhibit 10.2)
- 10-18 Agreement, dated August 26, 2005, by and between FirstEnergy Generation Corp. and Bechtel Power Corporation. (September 2005 Form 10-Q, Exhibit 10-2)
- 10-19 CEI Fossil Note, dated October 24, 2005, of FirstEnergy Generation Corp. (Form S-4/A filed August 20, 2007, Exhibit 10.15)

- 10-20 CEI Fossil Security Agreement, dated October 24, 2005, by and between FirstEnergy Generation Corp. and The Cleveland Electric Illuminating Company. (Form S-4/A filed August 20, 2007, Exhibit 10.16)
- 10-21 OE Fossil Note, dated October 24, 2005, of FirstEnergy Generation Corp. (Form S-4/A filed August 20, 2007, Exhibit 10.17)
- 10-22 OE Fossil Security Agreement, dated October 24, 2005, by and between FirstEnergy Generation Corp. and Ohio Edison Company. (Form S-4/A filed August 20, 2007, Exhibit 10.18)
- 10-23 Amendment No. 1 to OE Fossil Security Agreement, dated as of June 30, 2007, between FirstEnergy Generation Corp. and Ohio Edison Company. (Form S-4/A filed August 20, 2007, Exhibit 10.19)
- 10-24 PP Fossil Note, dated October 24, 2005, of FirstEnergy Generation Corp. (Form S-4/A filed August 20, 2007, Exhibit 10.20)
- 10-25 PP Fossil Security Agreement, dated October 24, 2005, by and between FirstEnergy Generation Corp. and Pennsylvania Power Company. (Form S-4/A filed August 20, 2007, Exhibit 10.21)
- 10-26 Amendment No. 1 to PP Fossil Security Agreement, dated as of June 30, 2007, between FirstEnergy Generation Corp. and Pennsylvania Power Company. (Form S-4/A filed August 20, 2007, Exhibit 10.22)
- 10-27 TE Fossil Note, dated October 24, 2005, of FirstEnergy Generation Corp. (Form S-4/A filed August 20, 2007, Exhibit 10.23)
- 10-28 TE Fossil Security Agreement, dated October 24, 2005, by and between FirstEnergy Generation Corp. and The Toledo Edison Company. (Form S-4/A filed August 20, 2007, Exhibit 10.24)
- 10-29 CEI Nuclear Note, dated December 16, 2005, of FirstEnergy Nuclear Generation Corp. (Form S-4/A filed August 20, 2007, Exhibit 10.25)
- 10-30 CEI Nuclear Security Agreement, dated December 16, 2005, by and between FirstEnergy Nuclear Generation Corp. and The Cleveland Electric Illuminating Company. (Form S-4/A filed August 20, 2007, Exhibit 10.26)
- 10-31 OE Nuclear Note, dated December 16, 2005, of FirstEnergy Nuclear Generation Corp. (Form S-4/A filed August 20, 2007, Exhibit 10.27)
- 10-32 PP Nuclear Note, dated December 16, 2005, of FirstEnergy Nuclear Generation Corp. (Form S-4/A filed August 20, 2007, Exhibit 10.28)
- 10-33 TE Nuclear Note, dated December 16, 2005, of FirstEnergy Nuclear Generation Corp. (Form S-4/A filed August 20, 2007, Exhibit 10.29)
- 10-34 TE Nuclear Security Agreement, dated December 16, 2005, by and between FirstEnergy Nuclear Generation Corp. and The Toledo Edison Company. (Form S-4/A filed August 20, 2007, Exhibit 10.30)
- 10-35 Mansfield Power Supply Agreement, dated August 10, 2006, among The Cleveland Electric Illuminating Company, The Toledo Edison Company and FirstEnergy Generation Corp. (Form S-4/A filed August 20, 2007, Exhibit 10.31)
- 10-36 Nuclear Power Supply Agreement, dated August 10, 2006, between FirstEnergy Nuclear Generation Corp. and FirstEnergy Solutions Corp. (Form S-4/A filed August 20, 2007, Exhibit 10.32)
- 10-37 Revised Power Supply Agreement, dated December 8, 2006, among FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company. (Form S-4/A filed August 20, 2007, Exhibit 10.34)

- 10-38 GENCO Power Supply Agreement, dated January 1, 2007, between FirstEnergy Generation Corp. and FirstEnergy Solutions Corp. (Form S-4/A filed August 20, 2007, Exhibit 10.36)
- 10-39 Form of U.S. \$250,000,000 Credit Agreement, dated as of March 2, 2007, between FirstEnergy Solutions Corp., as Borrower, and Morgan Stanley Senior Funding, Inc., as Lender. (March 2007 Form 10-Q filed by FirstEnergy Corp., Exhibit 10-2)
- 10-40 Form of Guaranty dated as of March 2, 2007, between FirstEnergy Corp., as Guarantor, and Morgan Stanley Senior Funding, Inc., as Lender under the U.S. \$250,000,000 Credit Agreement, dated as of March 2, 2007, with FirstEnergy Solutions Corp., as Borrower. (March 2007 Form 10-Q filed by FirstEnergy Corp., Exhibit 10-23)
- 10-41 Guaranty, dated as of March 26, 2007, by FirstEnergy Generation Corp. on behalf of FirstEnergy Solutions Corp. (Form S-4/A filed August 20, 2007, Exhibit 10.39)
- 10-42 Guaranty, dated as of March 26, 2007, by FirstEnergy Solutions Corp. on behalf of FirstEnergy Generation Corp. (Form S-4/A filed August 20, 2007, Exhibit 10.40)
- 10-43 Guaranty, dated as of March 26, 2007, by FirstEnergy Solutions Corp. on behalf of FirstEnergy Nuclear Generation Corp. (Form S-4/A filed August 20, 2007, Exhibit 10.41)
- 10-44 Guaranty, dated as of March 26, 2007, by FirstEnergy Nuclear Generation Corp. on behalf of FirstEnergy Solutions Corp. (Form S-4/A filed August 20, 2007, Exhibit 10.42)
- (B) 10-45 Form of Guaranty Agreement dated as of December 16, 2005 between FirstEnergy Corp. and FirstEnergy Solutions Corp. in Favor of Barclays Bank PLC as Administrative Agent for the Banks. (2005 Form 10-K, Exhibit 10-58)
- (B) 10-46 Form of Trust Indenture dated as of December 1, 2005 between Ohio Water Development Authority and JP Morgan Trust Company related to issuance of FirstEnergy Nuclear Generation Corp. pollution control revenue refunding bonds. (2005 Form 10-K, Exhibit 10-59)
- 10-47 GENCO Power Supply Agreement dated as of October 14, 2005 between FirstEnergy Generation Corp. (Seller) and FirstEnergy Solutions Corp. (Buyer). (2005 Form 10-K, Exhibit 10-60)
- 10-48 Nuclear Power Supply Agreement dated as of October 14, 2005 between FirstEnergy Nuclear Generation Corp. (Seller) and FirstEnergy Solutions Corp. (Buyer). (2005 Form 10-K, Exhibit 10-61)
- (B) 10-49 Form of Letter of Credit and Reimbursement Agreement Dated as of December 16, 2005 among FirstEnergy Nuclear Generation Corp., and the Participating Banks and Barclays Bank PLC. (2005 Form 10-K, Exhibit 10-62)
- (B) 10-50 Form of Waste Water Facilities and Solid Waste Facilities Loan Agreement between Ohio Water Development Authority and FirstEnergy Nuclear Generation Corp., dated as of December 1, 2005. (2005 Form 10-K, Exhibit 10-63)
- 10-51 Nuclear Sale/Leaseback Power Supply Agreement dated as of October 14, 2005 between Ohio Edison Company and the Toledo Edison Company (Sellers) and FirstEnergy Nuclear Generation Corp. (Buyer). (2005 Form 10-K, Exhibit 10-64)
- 10-52 Mansfield Power Supply Agreement dated as of October 14, 2005 between Cleveland Electric Illuminating Company and The Toledo Edison Company (Sellers) and FirstEnergy Generation Corp. (Buyer). (2005 Form 10-K, Exhibit 10-65)
- 10-53 Power Supply Agreement dated as of October 31, 2005 between FirstEnergy Solutions Corp. (Seller) and the FirstEnergy Operating Companies – Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (Buyers). (2005 Form 10-K, Exhibit 10-66)

- 10-54 Electric Power Supply Agreement dated as of October 3, 2005 between FirstEnergy Solutions Corp. (Seller) and Pennsylvania Power Company (Buyer). (2005 Form 10-K, Exhibit 10-67)
- (C) 10-55 Form of Letter of Credit and Reimbursement Agreement dated as of April 3, 2006 among FirstEnergy Generation Corp., the Participating Banks, Barclays Bank PLC, as administrative agent and fronting bank, and KeyBank National Association, as syndication agent. (March 2006 Form 10-Q, Exhibit 10-2)
- (C) 10-56 Form of Trust Indenture dated as of April 1, 2006 between the Ohio Water Development Authority and The Bank of New York Trust Company, N.A. as Trustee securing pollution control revenue refunding bonds issued on behalf of FirstEnergy Generation Corp. (March 2006 Form 10-Q, Exhibit 10-3)
- (C) 10-57 Form of Waste Water Facilities Loan Agreement between the Ohio Water Development Authority and FirstEnergy Generation Corp. dated as of April 1, 2006. (March 2006 Form 10-Q, Exhibit 10-4)
- (D) 10-58 Form of Trust Indenture dated as of December 1, 2006 between the Ohio Water Development Authority and The Bank of New York Trust Company, N.A. as Trustee securing State of Ohio Pollution Control Revenue Refunding Bonds (FirstEnergy Nuclear Generation Corp. Project). (2006 Form 10-K, Exhibit 10-77)
- (D) 10-59 Form of Waste Water Facilities and Solid Waste Facilities Loan Agreement between the Ohio Water Development Authority and FirstEnergy Nuclear Generation Corp. dated as of December 1, 2006. (2006 Form 10-K, Exhibit 10-80)
- 10-60 Consent Decree dated March 18, 2005. (Form 8-K filed March 18, 2005 by FirstEnergy Corp., Exhibit 10.1)
- 10-61 Amendment to Agreement for Engineering, Procurement and Construction of Air Quality Control Systems by and between FirstEnergy Generation Corp. and Bechtel Power Corporation dated September 14, 2007. (September 2007 Form 10-Q, Exhibit 10.1)
- 10-62 Asset Purchase Agreement by and between Calpine Corporation, as Seller, and FirstEnergy Generation Corp., as Buyer, dated as of January 28, 2008. (2007 Form 10-K, Exhibit 10-48)
- 10-63 U.S. \$300,000,000 Credit Agreement, dated as of October 8, 2008, among FirstEnergy Generation Corp., as Borrower, FirstEnergy Corp. and FirstEnergy Solutions Corp., as Guarantors, Credit Suisse and the other Banks parties thereto from time to time, as Banks and Credit Suisse, as Administrative Agent. (September 2008 Form 10-Q, Exhibit 10.1)
- (A) 12-2 Consolidated ratios of earnings to fixed charges.
- (A) 13-2 FES 2008 Annual Report to Stockholders. (Only those portions expressly incorporated by reference in this Form 10-K are to be deemed "filed" with the SEC.)
- (A) 31-1 Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
- (A) 31-2 Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
- (A) 32 Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. §1350.
- (A) Provided herein in electronic format as an exhibit.
- (B) Four substantially similar agreements, each dated as of the same date, were executed and delivered by the registrant and its affiliates with respect to four other series of pollution control revenue refunding bonds issued by the Ohio Water Development Authority, the Ohio Air Quality Authority and Beaver County Industrial Development Authority, Pennsylvania, relating to pollution control notes of FirstEnergy Nuclear Generation Corp.

- (C) Three substantially similar agreements, each dated as of the same date, were executed and delivered by the registrant and its affiliates with respect to three other series of pollution control revenue refunding bonds issued by the Ohio Water Development Authority and the Beaver County Industrial Development Authority relating to pollution control notes of FirstEnergy Generation Corp. and FirstEnergy Nuclear Generation Corp.
- (D) Seven substantially similar agreements, each dated as of the same date, were executed and delivered by the registrant and its affiliates with respect to one other series of pollution control revenue refunding bonds issued by the Ohio Water Development Authority, three other series of pollution control bonds issued by the Ohio Air Quality Development Authority and the three other series of pollution control bonds issued by the Beaver County Industrial Development Authority, relating to pollution control notes of FirstEnergy Generation Corp. and FirstEnergy Nuclear Generation Corp.

3. Exhibits – OE

- 2-1 Agreement and Plan of Merger, dated as of September 13, 1996, between Ohio Edison Company and Centerior Energy Corporation. (Form 8-K filed September 17, 1996, Exhibit 2-1)
- 3-1 Amended and Restated Articles of Incorporation of Ohio Edison Company, Effective December 18, 2007. (2007 Form 10-K, Exhibit 3-4)
- 3-2 Amended and Restated Code of Regulations of Ohio Edison Company, dated December 14, 2007. (2007 Form 10-K, Exhibit 3-5)
- 4-1 General Mortgage Indenture and Deed of Trust dated as of January 1, 1998 between Ohio Edison Company and the Bank of New York, as Trustee, as amended and supplemented by Supplemental Indentures: (Registration No. 333-05277, Exhibit 4(g))
- 4-1(a) February 1, 2003 (2003 Form 10-K, File No. 1-2578, Exhibit 4-4)
- 4-1(b) March 1, 2003 (2003 Form 10-K, File No. 1-2578, Exhibit 4-5)
- 4-1(c) August 1, 2003 (2003 Form 10-K, File No. 1-2578, Exhibit 4-6)
- 4-1(d) June 1, 2004 (2004 Form 10-K, File No. 1-2578, Exhibit 4-4)
- 4-1(e) December 1, 2004 (2004 Form 10-K, File No. 1-2578, Exhibit 4-4)
- 4-1(f) April 1, 2005 (June 2005 Form 10-Q, File No. 1-2578, Exhibit 4-4)
- 4-1(g) April 15, 2005 (June 2005 Form 10-Q, File No. 1-2578, Exhibit 4-5)
- 4-1(h) June 1, 2005 (June 2005 Form 10-Q, File No. 1-2578, Exhibit 4-6)
- 4-1(i) October 1, 2008 (Form 8-K filed October 22, 2008, Exhibit 4.1)
- 4-2 Indenture dated as of April 1, 2003 between Ohio Edison Company and The Bank of New York, as Trustee. (2003 Form 10-K, Exhibit 4-3)
- 4-2(a) Officer's Certificate (including the forms of the 6.40% Senior Notes due 2016 and the 6.875% Senior Notes due 2036), dated June 21, 2006. (Form 8-K filed June 27, 2006, Exhibit 4)
- 10-1 Administration Agreement between the CAPCO Group dated as of September 14, 1967. (Registration No. 2-43102, Exhibit 5(c)(2))
- 10-2 Amendment No. 1 dated January 4, 1974 to Administration Agreement between the CAPCO Group dated as of September 14, 1967. (Registration No. 2-68906, Exhibit 5(c)(3))
- 10-3 Amendment No. 4 dated as of July 1, 1985 to the Bond Guaranty dated as of October 1, 1973, as amended, by the CAPCO Companies to National City Bank as Bond Trustee. (1985 Form 10-K, Exhibit 10-30)
- 10-4 Amendment No. 5 dated as of May 1, 1986, to the Bond Guaranty by the CAPCO Companies to National City Bank as Bond Trustee. (1986 Form 10-K, Exhibit 10-33)
- 10-5 Amendment No. 6A dated as of December 1, 1991, to the Bond Guaranty dated as of October 1, 1973, by The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company to National City Bank, as Bond Trustee. (1991 Form 10-K, Exhibit 10-33)

- 10-6 Amendment No. 6B dated as of December 30, 1991, to the Bond Guaranty dated as of October 1, 1973 by The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company to National City Bank, as Bond Trustee. (1991 Form 10-K, Exhibit 10-34)
- (B) 10-7 Ohio Edison System Executive Supplemental Life Insurance Plan. (1995 Form 10-K, Exhibit 10-44)
- (B) 10-8 Ohio Edison System Executive Incentive Compensation Plan. (1995 Form 10-K, Exhibit 10-45)
- (B) 10-9 Ohio Edison System Restated and Amended Supplemental Executive Retirement Plan. (1995 Form 10-K, Exhibit 10-47)
- (B) 10-10 Form of Amendment, effective November 7, 2001, to GPU, Inc. 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries, Deferred Remuneration Plan for Outside Directors of GPU, Inc., and Retirement Plan for Outside Directors of GPU, Inc. (2001 Form 10-K, Exhibit 10-26)
- (B) 10-11 GPU, Inc. Stock Option and Restricted Stock Plan for MYR Group, Inc. Employees. (2001 Form 10-K, Exhibit 10-27)
- (B) 10-12 Severance pay agreement between Ohio Edison Company and A. J. Alexander. (1995 Form 10-K, Exhibit 10-50)
- (C) 10-13 Participation Agreement dated as of March 16, 1987 among Perry One Alpha Limited Partnership, as Owner Participant, the Original Loan Participants listed in Schedule 1 Hereto, as Original Loan Participants, PNPP Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Ohio Edison Company, as Lessee. (1986 Form 10-K, Exhibit 28-1)
- (C) 10-14 Amendment No. 1 dated as of September 1, 1987 to Participation Agreement dated as of March 16, 1987 among Perry One Alpha Limited Partnership, as Owner Participant, the Original Loan Participants listed in Schedule 1 thereto, as Original Loan Participants, PNPP Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company (now The Bank of New York), as Indenture Trustee, and Ohio Edison Company, as Lessee. (1991 Form 10-K, Exhibit 10-46)
- (C) 10-15 Amendment No. 3 dated as of May 16, 1988 to Participation Agreement dated as of March 16, 1987, as amended among Perry One Alpha Limited Partnership, as Owner Participant, PNPP Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee, and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-47)
- (C) 10-16 Amendment No. 4 dated as of November 1, 1991 to Participation Agreement dated as of March 16, 1987 among Perry One Alpha Limited Partnership, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1991 Form 10-K, Exhibit 10-47)
- (C) 10-17 Amendment No. 5 dated as of November 24, 1992 to Participation Agreement dated as of March 16, 1987, as amended, among Perry One Alpha Limited Partnership, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company as Lessee. (1992 Form 10-K, Exhibit 10-49)
- (C) 10-18 Amendment No. 6 dated as of January 12, 1993 to Participation Agreement dated as of March 16, 1987 among Perry One Alpha Limited Partnership, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-50)

- (C) 10-19 Amendment No. 7 dated as of October 12, 1994 to Participation Agreement dated as of March 16, 1987 as amended, among Perry One Alpha Limited Partnership, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-54)
- (C) 10-20 Facility Lease dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee, with Perry One Alpha Limited Partnership, Lessor, and Ohio Edison Company, Lessee. (1986 Form 10-K, Exhibit 28-2)
- (C) 10-21 Amendment No. 1 dated as of September 1, 1987 to Facility Lease dated as of March 16, 1997 between The First National Bank of Boston, as Owner Trustee, Lessor and Ohio Edison Company, Lessee. (1991 Form 10-K, Exhibit 10-49)
- (C) 10-22 Amendment No. 2 dated as of November 1, 1991, to Facility Lease dated as of March 16, 1987, between The First National Bank of Boston, as Owner Trustee, Lessor and Ohio Edison Company, Lessee. (1991 Form 10-K, Exhibit 10-50)
- (C) 10-23 Amendment No. 3 dated as of November 24, 1992 to Facility Lease dated as March 16, 1987 as amended, between The First National Bank of Boston, as Owner Trustee, with Perry One Alpha Limited partnership, as Owner Participant and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-54)
- (C) 10-24 Amendment No. 4 dated as of January 12, 1993 to Facility Lease dated as of March 16, 1987 as amended, between, The First National Bank of Boston, as Owner Trustee, with Perry One Alpha Limited Partnership, as Owner Participant, and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-59)
- (C) 10-25 Amendment No. 5 dated as of October 12, 1994 to Facility Lease dated as of March 16, 1987 as amended, between, The First National Bank of Boston, as Owner Trustee, with Perry One Alpha Limited Partnership, as Owner Participant, and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-60)
- (C) 10-26 Letter Agreement dated as of March 19, 1987 between Ohio Edison Company, Lessee, and The First National Bank of Boston, Owner Trustee under a Trust dated March 16, 1987 with Chase Manhattan Realty Leasing Corporation, required by Section 3(d) of the Facility Lease. (1986 Form 10-K, Exhibit 28-3)
- (C) 10-27 Ground Lease dated as of March 16, 1987 between Ohio Edison Company, Ground Lessor, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with the Owner Participant, Tenant. (1986 Form 10-K, Exhibit 28-4)
- (C) 10-28 Trust Agreement dated as of March 16, 1987 between Perry One Alpha Limited Partnership, as Owner Participant, and The First National Bank of Boston. (1986 Form 10-K, Exhibit 28-5)
- (C) 10-29 Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of March 16, 1987 with Perry One Alpha Limited Partnership, and Irving Trust Company, as Indenture Trustee. (1986 Form 10-K, Exhibit 28-6)
- (C) 10-30 Supplemental Indenture No. 1 dated as of September 1, 1987 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of March 16, 1987 between The First National Bank of Boston as Owner Trustee and Irving Trust Company (now The Bank of New York), as Indenture Trustee. (1991 Form 10-K, Exhibit 10-55)
- (C) 10-31 Supplemental Indenture No. 2 dated as of November 1, 1991 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee and The Bank of New York, as Indenture Trustee. (1991 Form 10-K, Exhibit 10-56)

- (C) 10-32 Tax Indemnification Agreement dated as of March 16, 1987 between Perry One, Inc. and PARock Limited Partnership as General Partners and Ohio Edison Company, as Lessee. (1986 Form 10-K, Exhibit 28-7)
- (C) 10-33 Amendment No. 1 dated as of November 1, 1991 to Tax Indemnification Agreement dated as of March 16, 1987 between Perry One, Inc. and PARock Limited Partnership and Ohio Edison Company. (1991 Form 10-K, Exhibit 10-58)
- (C) 10-34 Amendment No. 2 dated as of January 12, 1993 to Tax Indemnification Agreement dated as of March 16, 1987 between Perry One, Inc. and PARock Limited Partnership and Ohio Edison Company. (1994 Form 10-K, Exhibit 10-69)
- (C) 10-35 Amendment No. 3 dated as of October 12, 1994 to Tax Indemnification Agreement dated as of March 16, 1987 between Perry One, Inc. and PARock Limited Partnership and Ohio Edison Company. (1994 Form 10-K, Exhibit 10-70)
- (C) 10-36 Partial Mortgage Release dated as of March 19, 1987 under the Indenture between Ohio Edison Company and Bankers Trust Company, as Trustee, dated as of the 1st day of August 1930. (1986 Form 10-K, Exhibit 28-8)
- (C) 10-37 Assignment, Assumption and Further Agreement dated as of March 16, 1987 among The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Perry One Alpha Limited Partnership, The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company and Toledo Edison Company. (1986 Form 10-K, Exhibit 28-9)
- (C) 10-38 Additional Support Agreement dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Perry One Alpha Limited Partnership, and Ohio Edison Company. (1986 Form 10-K, Exhibit 28-10)
- (C) 10-39 Bill of Sale, Instrument of Transfer and Severance Agreement dated as of March 19, 1987 between Ohio Edison Company, Seller, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Perry One Alpha Limited Partnership. (1986 Form 10-K, Exhibit 28-11)
- (C) 10-40 Easement dated as of March 16, 1987 from Ohio Edison Company, Grantor, to The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Perry One Alpha Limited Partnership, Grantee. (1986 Form 10-K, Exhibit 28-12)
- 10-41 Participation Agreement dated as of March 16, 1987 among Security Pacific Capital Leasing Corporation, as Owner Participant, the Original Loan Participants listed in Schedule 1 Hereto, as Original Loan Participants, PNPP Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Ohio Edison Company, as Lessee. (1986 Form 10-K, Exhibit 28-13)
- 10-42 Amendment No. 1 dated as of September 1, 1987 to Participation Agreement dated as of March 16, 1987 among Security Pacific Capital Leasing Corporation, as Owner Participant, The Original Loan Participants Listed in Schedule 1 thereto, as Original Loan Participants, PNPP Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Ohio Edison Company, as Lessee. (1991 Form 10-K, Exhibit 10-65)
- 10-43 Amendment No. 4 dated as of November 1, 1991, to Participation Agreement dated as of March 16, 1987 among Security Pacific Capital Leasing Corporation, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1991 Form 10-K, Exhibit 10-66)

- 10-44 Amendment No. 5 dated as of November 24, 1992 to Participation Agreement dated as of March 16, 1987 as amended among Security Pacific Capital Leasing Corporation, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-71)
- 10-45 Amendment No. 6 dated as of January 12, 1993 to Participation Agreement dated as of March 16, 1987 as amended among Security Pacific Capital Leasing Corporation, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-80)
- 10-46 Amendment No. 7 dated as of October 12, 1994 to Participation Agreement dated as of March 16, 1987 as amended among Security Pacific Capital Leasing Corporation, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-81)
- 10-47 Facility Lease dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee, with Security Pacific Capital Leasing Corporation, Lessor, and Ohio Edison Company, as Lessee. (1986 Form 10-K, Exhibit 28-14)
- 10-48 Amendment No. 1 dated as of September 1, 1987 to Facility Lease dated as of March 16, 1987 between The First National Bank of Boston as Owner Trustee, Lessor and Ohio Edison Company, Lessee. (1991 Form 10-K, Exhibit 10-68)
- 10-49 Amendment No. 2 dated as of November 1, 1991 to Facility Lease dated as of March 16, 1987 between The First National Bank of Boston as Owner Trustee, Lessor and Ohio Edison Company, Lessee. (1991 Form 10-K, Exhibit 10-69)
- 10-50 Amendment No. 3 dated as of November 24, 1992 to Facility Lease dated as of March 16, 1987, as amended, between, The First National Bank of Boston, as Owner Trustee, with Security Pacific Capital Leasing Corporation, as Owner Participant and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-75)
- 10-51 Amendment No. 4 dated as of January 12, 1993 to Facility Lease dated as of March 16, 1987 as amended between, The First National Bank of Boston, as Owner Trustee, with Security Pacific Capital Leasing Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-76)
- 10-52 Amendment No. 5 dated as of October 12, 1994 to Facility Lease dated as of March 16, 1987 as amended between, The First National Bank of Boston, as Owner Trustee, with Security Pacific Capital Leasing Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-87)
- 10-53 Letter Agreement dated as of March 19, 1987 between Ohio Edison Company, as Lessee, and The First National Bank of Boston, as Owner Trustee under a Trust, dated as of March 16, 1987, with Security Pacific Capital Leasing Corporation, required by Section 3(d) of the Facility Lease. (1986 Form 10-K, Exhibit 28-15)
- 10-54 Ground Lease dated as of March 16, 1987 between Ohio Edison Company, Ground Lessor, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Perry One Alpha Limited Partnership, Tenant. (1986 Form 10-K, Exhibit 28-16)
- 10-55 Trust Agreement dated as of March 16, 1987 between Security Pacific Capital Leasing Corporation, as Owner Participant, and The First National Bank of Boston. (1986 Form 10-K, Exhibit 28-17)

- 10-56 Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Security Pacific Capital Leasing Corporation, and Irving Trust Company, as Indenture Trustee. (1986 Form 10-K, Exhibit 28-18)
- 10-57 Supplemental Indenture No. 1 dated as of September 1, 1987 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee and Irving Trust Company (now The Bank of New York), as Indenture Trustee. (1991 Form 10-K, Exhibit 10-74)
- 10-58 Supplemental Indenture No. 2 dated as of November 1, 1991 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee and The Bank of New York, as Indenture Trustee. (1991 Form 10-K, Exhibit 10-75)
- 10-59 Tax Indemnification Agreement dated as of March 16, 1987 between Security Pacific Capital Leasing Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1986 Form 10-K, Exhibit 28-19)
- 10-60 Amendment No. 1 dated as of November 1, 1991 to Tax Indemnification Agreement dated as of March 16, 1987 between Security Pacific Capital Leasing Corporation and Ohio Edison Company. (1991 Form 10-K, Exhibit 10-77)
- 10-61 Amendment No. 2 dated as of January 12, 1993 to Tax Indemnification Agreement dated as of March 16, 1987 between Security Pacific Capital Leasing Corporation and Ohio Edison Company. (1994 Form 10-K, Exhibit 10-96)
- 10-62 Amendment No. 3 dated as of October 12, 1994 to Tax Indemnification Agreement dated as of March 16, 1987 between Security Pacific Capital Leasing Corporation and Ohio Edison Company. (1994 Form 10-K, Exhibit 10-97)
- 10-63 Assignment, Assumption and Further Agreement dated as of March 16, 1987 among The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Security Pacific Capital Leasing Corporation, The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company and Toledo Edison Company. (1986 Form 10-K, Exhibit 28-20)
- 10-64 Additional Support Agreement dated as of March 16, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Security Pacific Capital Leasing Corporation, and Ohio Edison Company. (1986 Form 10-K, Exhibit 28-21)
- 10-65 Bill of Sale, Instrument of Transfer and Severance Agreement dated as of March 19, 1987 between Ohio Edison Company, Seller, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Security Pacific Capital Leasing Corporation, Buyer. (1986 Form 10-K, Exhibit 28-22)
- 10-66 Easement dated as of March 16, 1987 from Ohio Edison Company, Grantor, to The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of March 16, 1987, with Security Pacific Capital Leasing Corporation, Grantee. (1986 Form 10-K, Exhibit 28-23)
- 10-67 Refinancing Agreement dated as of November 1, 1991 among Perry One Alpha Limited Partnership, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee, The Bank of New York, as Collateral Trust Trustee, The Bank of New York, as New Collateral Trust Trustee and Ohio Edison Company, as Lessee. (1991 Form 10-K, Exhibit 10-82)

- 10-68 Refinancing Agreement dated as of November 1, 1991 among Security Pacific Leasing Corporation, as Owner Participant, PNPP Funding Corporation, as Funding Corporation, PNPP II Funding Corporation, as New Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee, The Bank of New York, as Collateral Trust Trustee, The Bank of New York as New Collateral Trust Trustee and Ohio Edison Company, as Lessee. (1991 Form 10-K, Exhibit 10-83)
- 10-69 Ohio Edison Company Master Decommissioning Trust Agreement for Perry Nuclear Power Plant Unit One, Perry Nuclear Power Plant Unit Two, Beaver Valley Power Station Unit One and Beaver Valley Power Station Unit Two dated July 1, 1993. (1993 Form 10-K, Exhibit 10-94)
- (D) 10-70 Participation Agreement dated as of September 15, 1987, among Beaver Valley Two Pi Limited Partnership, as Owner Participant, the Original Loan Participants listed in Schedule 1 Thereto, as Original Loan Participants, BVPS Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Ohio Edison Company as Lessee. (1987 Form 10-K, Exhibit 28-1)
- (D) 10-71 Amendment No. 1 dated as of February 1, 1988, to Participation Agreement dated as of September 15, 1987, among Beaver Valley Two Pi Limited Partnership, as Owner Participant, the Original Loan Participants listed in Schedule 1 Thereto, as Original Loan Participants, BVPS Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Ohio Edison Company, as Lessee. (1987 Form 10-K, Exhibit 28-2)
- (D) 10-72 Amendment No. 3 dated as of March 16, 1988 to Participation Agreement dated as of September 15, 1987, as amended, among Beaver Valley Two Pi Limited Partnership, as Owner Participant, BVPS Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-99)
- (D) 10-73 Amendment No. 4 dated as of November 5, 1992 to Participation Agreement dated as of September 15, 1987, as amended, among Beaver Valley Two Pi Limited Partnership, as Owner Participant, BVPS Funding Corporation, BVPS II Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-100)
- (D) 10-74 Amendment No. 5 dated as of September 30, 1994 to Participation Agreement dated as of September 15, 1987, as amended, among Beaver Valley Two Pi Limited Partnership, as Owner Participant, BVPS Funding Corporation, BVPS II Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-118)
- (D) 10-75 Facility Lease dated as of September 15, 1987, between The First National Bank of Boston, as Owner Trustee, with Beaver Valley Two Pi Limited Partnership, Lessor, and Ohio Edison Company, Lessee. (1987 Form 10-K, Exhibit 28-3)
- (D) 10-76 Amendment No. 1 dated as of February 1, 1988, to Facility Lease dated as of September 15, 1987, between The First National Bank of Boston, as Owner Trustee, with Beaver Valley Two Pi Limited Partnership, Lessor, and Ohio Edison Company, Lessee. (1987 Form 10-K, Exhibit 28-4)
- (D) 10-77 Amendment No. 2 dated as of November 5, 1992, to Facility Lease dated as of September 15, 1987, as amended, between The First National Bank of Boston, as Owner Trustee, with Beaver Valley Two Pi Limited Partnership, as Owner Participant, and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-103)
- (D) 10-78 Amendment No. 3 dated as of September 30, 1994 to Facility Lease dated as of September 15, 1987, as amended, between The First National Bank of Boston, as Owner Trustee, with Beaver Valley Two Pi Limited Partnership, as Owner Participant, and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-122)

- (D) 10-79 Ground Lease and Easement Agreement dated as of September 15, 1987, between Ohio Edison Company, Ground Lessor, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of September 15, 1987, with Beaver Valley Two Pi Limited Partnership, Tenant. (1987 Form 10-K, Exhibit 28-5)
- (D) 10-80 Trust Agreement dated as of September 15, 1987, between Beaver Valley Two Pi Limited Partnership, as Owner Participant, and The First National Bank of Boston. (1987 Form 10-K, Exhibit 28-6)
- (D) 10-81 Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987, between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987, with Beaver Valley Two Pi Limited Partnership, and Irving Trust Company, as Indenture Trustee. (1987 Form 10-K, Exhibit 28-7)
- (D) 10-82 Supplemental Indenture No. 1 dated as of February 1, 1988 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with Beaver Valley Two Pi Limited Partnership and Irving Trust Company, as Indenture Trustee. (1987 Form 10-K, Exhibit 28-8)
- (D) 10-83 Tax Indemnification Agreement dated as of September 15, 1987, between Beaver Valley Two Pi Inc. and PARock Limited Partnership as General Partners and Ohio Edison Company, as Lessee. (1987 Form 10-K, Exhibit 28-9)
- (D) 10-84 Amendment No. 1 dated as of November 5, 1992 to Tax Indemnification Agreement dated as of September 15, 1987, between Beaver Valley Two Pi Inc. and PARock Limited Partnership as General Partners and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-128)
- (D) 10-85 Amendment No. 2 dated as of September 30, 1994 to Tax Indemnification Agreement dated as of September 15, 1987, between Beaver Valley Two Pi Inc. and PARock Limited Partnership as General Partners and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-129)
- (D) 10-86 Tax Indemnification Agreement dated as of September 15, 1987, between HG Power Plant, Inc., as Limited Partner and Ohio Edison Company, as Lessee. (1987 Form 10-K, Exhibit 28-10)
- (D) 10-87 Amendment No. 1 dated as of November 5, 1992 to Tax Indemnification Agreement dated as of September 15, 1987, between HG Power Plant, Inc., as Limited Partner and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-131)
- (D) 10-88 Amendment No. 2 dated as of September 30, 1994 to Tax Indemnification Agreement dated as of September 15, 1987, between HG Power Plant, Inc., as Limited Partner and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-132)
- (D) 10-89 Assignment, Assumption and Further Agreement dated as of September 15, 1987, among The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of September 15, 1987, with Beaver Valley Two Pi Limited Partnership, The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company and Toledo Edison Company. (1987 Form 10-K, Exhibit 28-11)
- (D) 10-90 Additional Support Agreement dated as of September 15, 1987, between The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of September 15, 1987, with Beaver Valley Two Pi Limited Partnership, and Ohio Edison Company. (1987 Form 10-K, Exhibit 28-12)
- (E) 10-91 Participation Agreement dated as of September 15, 1987, among Chrysler Consortium Corporation, as Owner Participant, the Original Loan Participants listed in Schedule 1 Thereto, as Original Loan Participants, BVPS Funding Corporation as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee and Ohio Edison Company, as Lessee. (1987 Form 10-K, Exhibit 28-13)

- (E) 10-92 Amendment No. 1 dated as of February 1, 1988, to Participation Agreement dated as of September 15, 1987, among Chrysler Consortium Corporation, as Owner Participant, the Original Loan Participants listed in Schedule 1 Thereto, as Original Loan Participants, BVPS Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee, and Ohio Edison Company, as Lessee. (1987 Form 10-K, Exhibit 28-14)
- (E) 10-93 Amendment No. 3 dated as of March 16, 1988 to Participation Agreement dated as of September 15, 1987, as amended, among Chrysler Consortium Corporation, as Owner Participant, BVPS Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee, and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-114)
- (E) 10-94 Amendment No. 4 dated as of November 5, 1992 to Participation Agreement dated as of September 15, 1987, as amended, among Chrysler Consortium Corporation, as Owner Participant, BVPS Funding Corporation, BVPS II Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-115)
- (E) 10-95 Amendment No. 5 dated as of January 12, 1993 to Participation Agreement dated as of September 15, 1987, as amended, among Chrysler Consortium Corporation, as Owner Participant, BVPS Funding Corporation, BVPS II Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-139)
- (E) 10-96 Amendment No. 6 dated as of September 30, 1994 to Participation Agreement dated as of September 15, 1987, as amended, among Chrysler Consortium Corporation, as Owner Participant, BVPS Funding Corporation, BVPS II Funding Corporation, The First National Bank of Boston, as Owner Trustee, The Bank of New York, as Indenture Trustee and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-140)
- (E) 10-97 Facility Lease dated as of September 15, 1987, between The First National Bank of Boston, as Owner Trustee, with Chrysler Consortium Corporation, Lessor, and Ohio Edison Company, as Lessee. (1987 Form 10-K, Exhibit 28-15)
- (E) 10-98 Amendment No. 1 dated as of February 1, 1988, to Facility Lease dated as of September 15, 1987, between The First National Bank of Boston, as Owner Trustee, with Chrysler Consortium Corporation, Lessor, and Ohio Edison Company, Lessee. (1987 Form 10-K, Exhibit 28-16)
- (E) 10-99 Amendment No. 2 dated as of November 5, 1992 to Facility Lease dated as of September 15, 1987, as amended, between The First National Bank of Boston, as Owner Trustee, with Chrysler Consortium Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-118)
- (E) 10-100 Amendment No. 3 dated as of January 12, 1993 to Facility Lease dated as of September 15, 1987, as amended, between The First National Bank of Boston, as Owner Trustee, with Chrysler Consortium Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1992 Form 10-K, Exhibit 10-119)
- (E) 10-101 Amendment No. 4 dated as of September 30, 1994 to Facility Lease dated as of September 15, 1987, as amended, between The First National Bank of Boston, as Owner Trustee, with Chrysler Consortium Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-145)
- (E) 10-102 Ground Lease and Easement Agreement dated as of September 15, 1987, between Ohio Edison Company, Ground Lessor, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of September 15, 1987, with Chrysler Consortium Corporation, Tenant. (1987 Form 10-K, Exhibit 28-17)
- (E) 10-103 Trust Agreement dated as of September 15, 1987, between Chrysler Consortium Corporation, as Owner Participant, and The First National Bank of Boston. (1987 Form 10-K, Exhibit 28-18)

- (E) 10-104 Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987, between The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of September 15, 1987, with Chrysler Consortium Corporation and Irving Trust Company, as Indenture Trustee. (1987 Form 10-K, Exhibit 28-19)
- (E) 10-105 Supplemental Indenture No. 1 dated as of February 1, 1988 to Trust Indenture, Mortgage, Security Agreement and Assignment of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with Chrysler Consortium Corporation and Irving Trust Company, as Indenture Trustee. (1987 Form 10-K, Exhibit 28-20)
- (E) 10-106 Tax Indemnification Agreement dated as of September 15, 1987, between Chrysler Consortium Corporation, as Owner Participant, and Ohio Edison Company, Lessee. (1987 Form 10-K, Exhibit 28-21)
- (E) 10-107 Amendment No. 1 dated as of November 5, 1992 to Tax Indemnification Agreement dated as of September 15, 1987, between Chrysler Consortium Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-151)
- (E) 10-108 Amendment No. 2 dated as of January 12, 1993 to Tax Indemnification Agreement dated as of September 15, 1987, between Chrysler Consortium Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-152)
- (E) 10-109 Amendment No. 3 dated as of September 30, 1994 to Tax Indemnification Agreement dated as of September 15, 1987, between Chrysler Consortium Corporation, as Owner Participant, and Ohio Edison Company, as Lessee. (1994 Form 10-K, Exhibit 10-153)
- (E) 10-110 Assignment, Assumption and Further Agreement dated as of September 15, 1987, among The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of September 15, 1987, with Chrysler Consortium Corporation, The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company, and Toledo Edison Company. (1987 Form 10-K, Exhibit 28-22)
- (E) 10-111 Additional Support Agreement dated as of September 15, 1987, between The First National Bank of Boston, as Owner Trustee under a Trust Agreement, dated as of September 15, 1987, with Chrysler Consortium Corporation, and Ohio Edison Company. (1987 Form 10-K, Exhibit 28-23)
- 10-112 Operating Agreement for Bruce Mansfield Units Nos. 1, 2 and 3 dated as of June 1, 1976, and executed on September 15, 1987, by and between the CAPCO Companies. (1987 Form 10-K, Exhibit 28-25)
- 10-113 OE Nuclear Capital Contribution Agreement by and between Ohio Edison Company and FirstEnergy Nuclear Generation Corp. (June 2005 Form 10-Q, Exhibit 10.1)
- 10-114 OE Fossil Purchase and Sale Agreement by and between Ohio Edison Company (Seller) and FirstEnergy Generation Corp. (Purchaser). (June 2005 Form 10-Q, Exhibit 10.2)
- 10-115 OE Fossil Security Agreement, dated October 24, 2005, by and between FirstEnergy Generation Corp. and Ohio Edison Company. (Form S-4/A filed August 20, 2007 by FirstEnergy Solutions Corp., Exhibit 10.18)
- 10-116 Consent Decree dated March 18, 2005. (Form 8-K filed March 18, 2005 by FirstEnergy Corp., Exhibit 10.1)
- 10-117 Nuclear Sale/Leaseback Power Supply Agreement dated as of October 14, 2005 between Ohio Edison Company and The Toledo Edison Company (Sellers) and FirstEnergy Nuclear Generation Corp. (Buyer). (2005 Form 10-K, Exhibit 10-64)
- 10-118 Power Supply Agreement dated as of October 31, 2005 between FirstEnergy Solutions Corp. (Seller) and the FirstEnergy Operating Companies – Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company (Buyers). (2005 Form 10-K, Exhibit 10-65)

- 10-119 Revised Power Supply Agreement, dated December 8, 2006, among FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company. (Form S-4/A dated August 20, 2007, Exhibit 10.34)
- (A) 12-3 Consolidated ratios of earnings to fixed charges.
- (A) 13-2 OE 2008 Annual Report to Stockholders. (Only those portions expressly incorporated by reference in this Form 10-K are to be deemed "filed" with the SEC.)
- (A) 23-2 Consent of Independent Registered Public Accounting Firm.
- (A) 31-1 Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
- (A) 31-2 Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
- (A) 32 Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. §1350.
 - (A) Provided herein in electronic format as an exhibit.
 - (B) Management contract or compensatory plan contract or arrangement filed pursuant to Item 601 of Regulation S-K.
 - (C) Substantially similar documents have been entered into relating to three additional Owner Participants.
 - (D) Substantially similar documents have been entered into relating to five additional Owner Participants.
 - (E) Substantially similar documents have been entered into relating to two additional Owner Participants.

3. Exhibits – Common Exhibits for CEI and TE

- 2-1 Agreement and Plan of Merger between Ohio Edison Company and Centerior Energy dated as of September 13, 1996. (Form S-4, Exhibit (2)-1, File No. 333-21011)
- 2-2 Merger Agreement by and among Centerior Acquisition Corp., FirstEnergy Corp and Centerior Energy Corp. (Form S-4, Exhibit (2)-3, File No. 333-21011)
- 10-1 CAPCO Administration Agreement dated November 1, 1971, as of September 14, 1967, among the CAPCO Group members regarding the organization and procedures for implementing the objectives of the CAPCO Group. (Amendment No. 1, Exhibit 5(p), File No. 2-42230)
- 10-2 Amendment No. 1, dated January 4, 1974, to CAPCO Administration Agreement among the CAPCO Group members. (File No. 2-68906, Exhibit 5(c)(3) filed by Ohio Edison Company)
- 10-3 Agreement for the Termination or Construction of Certain Agreement By and Among the CAPCO Group members, dated December 23, 1993 and effective as of September 1, 1980. (1993 Form 10-K, Exhibit 10b(4), File Nos. 1-9130, 1-2323 and 1-3583)
- 10-4 Second Amendment to the Bruce Mansfield Units 1, 2, and 3 Operating Agreement, dated as of July 1, 2007, between FirstEnergy Generation Corp., The Cleveland Electric Illuminating Company and The Toledo Edison Company. (Form 8-K/A filed August 2, 2007 by FirstEnergy Corp., Exhibit 10-11)
- 10-5 Amendment No. 6A dated as of December 1, 1991, to the Bond Guaranty dated as of October 1, 1973, by The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company to National City Bank, as Bond Trustee. (1991 Form 10-K filed by Ohio Edison Company, Exhibit 10-33)

- 10-6 Amendment No. 6B dated as of December 30, 1991, to the Bond Guaranty dated as of October 1, 1973 by The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company to National City Bank, as Bond Trustee. (1991 Form 10-K filed by Ohio Edison Company, Exhibit 10-34)
- 10-7 Form of Collateral Trust Indenture among CTC Beaver Valley Funding Corporation, The Cleveland Electric Illuminating Company, The Toledo Edison Company and Irving Trust Company, as Trustee. (File No. 33-18755, Exhibit 4(a))
- 10-8 Form of Supplemental Indenture to Collateral Trust Indenture constituting Exhibit 10-10 above, including form of Secured Lease Obligation bond. (File No. 33-18755, Exhibit 4(b))
- 10-9 Form of Collateral Trust Indenture among Beaver Valley II Funding Corporation, The Cleveland Electric Illuminating Company and The Toledo Edison Company and The Bank of New York, as Trustee. (File No. 33-46665, Exhibit (4) (a))
- 10-10 Form of Supplemental Indenture to Collateral Trust Indenture constituting Exhibit 10-12 above, including form of Secured Lease Obligation Bond. (File No. 33-46665, Exhibit (4)(b))
- 10-11 Form of Collateral Trust Indenture among CTC Mansfield Funding Corporation, Cleveland Electric, Toledo Edison and IBJ Schroder Bank & Trust Company, as Trustee. (File No. 33-20128, Exhibit 4(a))
- 10-12 Form of Supplemental Indenture to Collateral Trust Indenture constituting Exhibit 10-14 above, including forms of Secured Lease Obligation bonds. (File No. 33-20128, Exhibit 4(b))
- 10-13 Form of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the limited partnership Owner Participant named therein, Lessor, and The Cleveland Electric Illuminating Company and The Toledo Edison Company, Lessee. (File No. 33-18755, Exhibit 4(c))
- 10-14 Form of Amendment No. 1 to Facility Lease constituting Exhibit 10-16 above. (File No. 33-18755, Exhibit 4(e))
- 10-15 Form of Facility Lease dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the corporate Owner Participant named therein, Lessor, and The Cleveland Electric Illuminating Company and The Toledo Edison Company, Lessees. (File No. 33-18755, Exhibit 4(d))
- 10-16 Form of Amendment No. 1 to Facility Lease constituting Exhibit 10-18 above. (File No. 33-18755, Exhibit 4(f))
- 10-17 Form of Facility Lease dated as of September 30, 1987 between Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Lessor, and The Cleveland Electric Illuminating Company and The Toledo Edison Company, Lessees. (File No. 33-20128, Exhibit 4 (c))
- 10-18 Form of Amendment No. 1 to the Facility Lease constituting Exhibit 10-20 above. (File No. 33-20128, Exhibit 4(f))
- 10-19 Form of Participation Agreement dated as of September 15, 1987 among the limited partnership Owner Participant named therein, the Original Loan Participants listed in Schedule 1 thereto, as Original Loan Participants, CTC Beaver Valley Fund Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee, and The Cleveland Electric Illuminating Company and The Toledo Edison Company, as Lessees. (File No. 33-18755, Exhibit 28(a))
- 10-20 Form of Amendment No. 1 to Participation Agreement constituting Exhibit 10-22 above (File No. 33-18755, Exhibit 28(c))

- 10-21 Form of Participation Agreement dated as of September 15, 1987 among the corporate Owner Participant named therein, the Original Loan Participants listed in Schedule 1 thereto, as Owner Loan Participants, CTC Beaver Valley Funding Corporation, as Funding Corporation, The First National Bank of Boston, as Owner Trustee, Irving Trust Company, as Indenture Trustee, and The Cleveland Electric Illuminating Company and The Toledo Edison Company, as Lessees. (File No. 33-18755, Exhibit 28(b))
- 10-22 Form of Amendment No. 1 to Participation Agreement constituting Exhibit 10-24 above (File No. 33-18755, Exhibit 28(d))
- 10-23 Form of Participation Agreement dated as of September 30, 1987 among the Owner Participant named therein, the Original Loan Participants listed in Schedule II thereto, as Owner Loan Participants, CTC Mansfield Funding Corporation, Meridian Trust Company, as Owner Trustee, IBJ Schroder Bank & Trust Company, as Indenture Trustee, and The Cleveland Electric Illuminating Company and The Toledo Edison Company, as Lessees. (File No. 33-0128, Exhibit 28(a))
- 10-24 Form of Amendment No. 1 to the Participation Agreement constituting Exhibit 10-26 above (File No. 33-20128, Exhibit 28(b))
- 10-25 Form of Ground Lease dated as of September 15, 1987 between Toledo Edison, Ground Lessor, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the Owner Participant named therein, Tenant. (File No. 33-18755, Exhibit 28(e))
- 10-26 Form of Site Lease dated as of September 30, 1987 between Toledo Edison, Lessor, and Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Tenant. (File No. 33-20128, Exhibit 28(c))
- 10-27 Form of Site Lease dated as of September 30, 1987 between The Cleveland Electric Illuminating Company, Lessor, and Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Tenant. (File No. 33-20128, Exhibit 28(d))
- 10-28 Form of Amendment No. 1 to the Site Leases constituting Exhibits 10-29 and 10-30 above (File No. 33-20128, Exhibit 4(f))
- 10-29 Form of Assignment, Assumption and Further Agreement dated as of September 15, 1987 among The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the Owner Participant named therein, The Cleveland Electric Illuminating Company, Duquesne, Ohio Edison Company, Pennsylvania Power Company and The Toledo Edison Company. (File No. 33-18755, Exhibit 28(f))
- 10-30 Form of Additional Support Agreement dated as of September 15, 1987 between The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the Owner Participant named therein and The Toledo Edison Company. (File No. 33-18755, Exhibit 28(g))
- 10-31 Form of Support Agreement dated as of September 30, 1987 between Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, The Toledo Edison Company, The Cleveland Electric Illuminating Company, Duquesne, Ohio Edison Company and Pennsylvania Power Company. (File No. 33-20128, Exhibit 28(e))
- 10-32 Form of Indenture, Bill of Sale, Instrument of Transfer and Severance Agreement dated as of September 30, 1987 between The Toledo Edison Company, Seller, and The First National Bank of Boston, as Owner Trustee under a Trust Agreement dated as of September 15, 1987 with the Owner Participant named therein, Buyer. (File No. 33-18755, Exhibit 28(h))

- 10-33 Form of Bill of Sale, Instrument of Transfer and Severance Agreement dated as of September 30, 1987 between The Toledo Edison Company, Seller, and Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Buyer. (File No. 33-20128, Exhibit 28(f))
- 10-34 Form of Bill of Sale, Instrument of Transfer and Severance Agreement dated as of September 30, 1987 between The Cleveland Electric Illuminating Company, Seller, and Meridian Trust Company, as Owner Trustee under a Trust Agreement dated as of September 30, 1987 with the Owner Participant named therein, Buyer. (File No. 33-20128, Exhibit 28(g))
- 10-35 Forms of Refinancing Agreement, including exhibits thereto, among the Owner Participant named therein, as Owner Participant, CTC Beaver Valley Funding Corporation, as Funding Corporation, Beaver Valley II Funding Corporation, as New Funding Corporation, The Bank of New York, as Indenture Trustee, The Bank of New York, as New Collateral Trust Trustee, and The Cleveland Electric Illuminating Company and The Toledo Edison Company, as Lessees. (File No. 33-46665, Exhibit (28)(e)(i))
- 10-36 Form of Amendment No. 2 to Facility Lease among Citicorp Lescaman, Inc., The Cleveland Electric Illuminating Company and The Toledo Edison Company. (Form S-4 filed March 10, 1998, Exhibit 10(a), File No. 333-47651)
- 10-37 Form of Amendment No. 3 to Facility Lease among Citicorp Lescaman, Inc., The Cleveland Electric Illuminating Company and The Toledo Edison Company. (Form S-4 filed March 10, 1998, Exhibit 10(b), File No. 333-47651)
- 10-38 Form of Amendment No. 2 to Facility Lease among US West Financial Services, Inc., The Cleveland Electric Illuminating Company and The Toledo Edison Company. (Form S-4 filed March 10, 1998, Exhibit 10(c), File No. 333-47651)
- 10-39 Form of Amendment No. 3 to Facility Lease among US West Financial Services, Inc., The Cleveland Electric Illuminating Company and The Toledo Edison Company. (Form S-4 filed March 10, 1998, Exhibit 10(d), File No. 333-47651)
- 10-40 Form of Amendment No. 2 to Facility Lease among Midwest Power Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company. (Form S-4 filed March 10, 1998 by The Cleveland Electric Illuminating Company, Exhibit 10(e), File No. 333-47651)
- 10-41 Centerior Energy Corporation Equity Compensation Plan. (Form S-8 filed May 26, 1995 by Centerior Energy Corporation, Exhibit 99, File No. 33-59635)
- 10-42 Revised Power Supply Agreement, dated December 8, 2006, among FirstEnergy Solutions Corp., Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company. (Form S-4/A filed August 20, 2007 by FirstEnergy Solutions Corp., Exhibit 10.34)

3. Exhibits – CEI

- 3-1 Amended and Restated Articles of Incorporation of The Cleveland Electric Illuminating Company, Effective December 21, 2007. (2007 Form 10-K, Exhibit 3.3)
- 3-2 Amended and Restated Code of Regulations of The Cleveland Electric Illuminating Company, dated December 14, 2007. (2007 Form 10-K, Exhibit 3.4)
- (B) 4-1 Mortgage and Deed of Trust between The Cleveland Electric Illuminating Company and Guaranty Trust Company of New York (now The Chase Manhattan Bank (National Association)), as Trustee, dated July 1, 1940. (File No. 2-4450, Exhibit 7(a))

Supplemental Indentures between The Cleveland Electric Illuminating Company and the Trustee, supplemental to Exhibit 4-1, dated as follows:
 - 4-1(a) July 1, 1940 (File No. 2-4450, Exhibit 7(b))
 - 4-1(b) August 18, 1944 (File No. 2-9887, Exhibit 4(c))
 - 4-1(c) December 1, 1947 (File No. 2-7306, Exhibit 7(d))

4-1(d) September 1, 1950 (File No. 2-8587, Exhibit 7(c))
 4-1(e) June 1, 1951 (File No. 2-8994, Exhibit 7(f))
 4-1(f) May 1, 1954 (File No. 2-10830, Exhibit 4(d))
 4-1(g) March 1, 1958 (File No. 2-13839, Exhibit 2(a)(4))
 4-1(h) April 1, 1959 (File No. 2-14753, Exhibit 2(a)(4))
 4-1(i) December 20, 1967 (File No. 2-30759, Exhibit 2(a)(4))
 4-1(j) January 15, 1969 (File No. 2-30759, Exhibit 2(a)(5))
 4-1(k) November 1, 1969 (File No. 2-35008, Exhibit 2(a)(4))
 4-1(l) June 1, 1970 (File No. 2-37235, Exhibit 2(a)(4))
 4-1(m) November 15, 1970 (File No. 2-38460, Exhibit 2(a)(4))
 4-1(n) May 1, 1974 (File No. 2-50537, Exhibit 2(a)(4))
 4-1(o) April 15, 1975 (File No. 2-52995, Exhibit 2(a)(4))
 4-1(p) April 16, 1975 (File No. 2-53309, Exhibit 2(a)(4))
 4-1(q) May 28, 1975 (Form 8-A filed June 5, 1975, Exhibit 2(c), File No. 1-2323)
 4-1(r) February 1, 1976 (1975 Form 10-K, Exhibit 3(d)(6), File No. 1-2323)
 4-1(s) November 23, 1976 (File No. 2-57375, Exhibit 2(a)(4))
 4-1(t) July 26, 1977 (File No. 2-59401, Exhibit 2(a)(4))
 4-1(u) September 7, 1977 (File No. 2-67221, Exhibit 2(a)(5))
 4-1(v) May 1, 1978 (June 1978 Form 10-Q, Exhibit 2(b), File No. 1-2323)
 4-1(w) September 1, 1979 (September 1979 Form 10-Q, Exhibit 2(a), File No. 1-2323)
 4-1(x) April 1, 1980 (September 1980 Form 10-Q, Exhibit 4(a)(2), File No. 1-2323)
 4-1(y) April 15, 1980 (September 1980 Form 10-Q, Exhibit 4(b), File No. 1-2323)
 4-1(z) May 28, 1980 (Amendment No. 1, Exhibit 2(a)(4), File No. 2-67221)
 4-1(aa) June 9, 1980 (September 1980 Form 10-Q, Exhibit 4(d), File No. 1-2323)
 4-1(bb) December 1, 1980 (1980 Form 10-K, Exhibit 4(b)(29), File No. 1-2323)
 4-1(cc) July 28, 1981 (September 1981 Form 10-Q, Exhibit 4(a), File No. 1-2323)
 4-1(dd) August 1, 1981 (September 1981 Form 10-Q, Exhibit 4(b), File No. 1-2323)
 4-1(ee) March 1, 1982 (Amendment No. 1, Exhibit 4(b)(3), File No. 2-76029)
 4-1(ff) July 15, 1982 (September 1982 Form 10-Q, Exhibit 4(a), File No. 1-2323)
 4-1(gg) September 1, 1982 (September 1982 Form 10-Q, Exhibit 4(a)(1), File No. 1-2323)
 4-1(hh) November 1, 1982 (September 1982 Form 10-Q, Exhibit (a)(2), File No. 1-2323)
 4-1(ii) November 15, 1982 (1982 Form 10-K, Exhibit 4(b)(36), File No. 1-2323)
 4-1(jj) May 24, 1983 (June 1983 Form 10-Q, Exhibit 4(a), File No. 1-2323)
 4-1(kk) May 1, 1984 (June 1984 Form 10-Q, Exhibit 4, File No. 1-2323)
 4-1(ll) May 23, 1984 (Form 8-K dated May 22, 1984, Exhibit 4, File No. 1-2323)
 4-1(mm) June 27, 1984 (Form 8-K dated June 11, 1984, Exhibit 4, File No. 1-2323)
 4-1(nn) September 4, 1984 (1984 Form 10-K, Exhibit 4b(41), File No. 1-2323)
 4-1(oo) November 14, 1984 (1984 Form 10 K, Exhibit 4b(42), File No. 1-2323)
 4-1(pp) November 15, 1984 (1984 Form 10-K, Exhibit 4b(43), File No. 1-2323)
 4-1(qq) April 15, 1985 (Form 8-K dated May 8, 1985, Exhibit 4(a), File No. 1-2323)
 4-1(rr) May 28, 1985 (Form 8-K dated May 8, 1985, Exhibit 4(b), File No. 1-2323)
 4-1(ss) August 1, 1985 (September 1985 Form 10-Q, Exhibit 4, File No. 1-2323)
 4-1(tt) September 1, 1985 (Form 8-K dated September 30, 1985, Exhibit 4, File No. 1-2323)
 4-1(uu) November 1, 1985 (Form 8-K dated January 31, 1986, Exhibit 4, File No. 1-2323)
 4-1(vv) April 15, 1986 (March 1986 Form 10-Q, Exhibit 4, File No. 1-2323)
 4-1(ww) May 14, 1986 (June 1986 Form 10-Q, Exhibit 4(a), File No. 1-2323)
 4-1(xx) May 15, 1986 (June 1986 Form 10-Q, Exhibit 4(b), File No. 1-2323)
 4-1(yy) February 25, 1987 (1986 Form 10-K, Exhibit 4b(52), File No. 1-2323)
 4-1(zz) October 15, 1987 (September 1987 Form 10-Q, Exhibit 4, File No. 1-2323)
 4-1(aaa) February 24, 1988 (1987 Form 10-K, Exhibit 4b(54), File No. 1-2323)
 4-1(bbb) September 15, 1988 (1988 Form 10-K, Exhibit 4b(55), File No. 1-2323)
 4-1(ccc) May 15, 1989 (File No. 33-32724, Exhibit 4(a)(2)(i))
 4-1(ddd) June 13, 1989 (File No. 33-32724, Exhibit 4(a)(2)(ii))
 4-1(eee) October 15, 1989 (File No. 33-32724, Exhibit 4(a)(2)(iii))
 4-1(fff) January 1, 1990 (1989 Form 10-K, Exhibit 4b(59), File No. 1-2323)
 4-1(ggg) June 1, 1990 (September 1990 Form 10-Q, Exhibit 4(a), File No. 1-2323)
 4-1(hhh) August 1, 1990 (September 1990 Form 10-Q, Exhibit 4(b), File No. 1-2323)
 4-1(iii) May 1, 1991 (June 1991 Form 10-Q, Exhibit 4(a), File No. 1-2323)
 4-1(jjj) May 1, 1992 (File No. 33-48845, Exhibit 4(a)(3))
 4-1(kkk) July 31, 1992 (File No. 33-57292, Exhibit 4(a)(3))
 4-1(lll) January 1, 1993 (1992 Form 10-K, Exhibit 4b(65), File No. 1-2323)
 4-1(mmm) February 1, 1993 (1992 Form 10-K, Exhibit 4b(66), File No. 1-2323)
 4-1(nnn) May 20, 1993 (Form 8-K dated July 14, 1993, Exhibit 4(a), File No. 1-2323)

- 4-1(ooo) June 1, 1993 (Form 8-K dated July 14, 1993, Exhibit 4(b), File No. 1-2323)
- 4-1(ppp) September 15, 1994 (September 1994 Form 10-Q, Exhibit 4(a), File No. 1-2323)
- 4-1(qqq) May 1, 1995 (September 1995 Form 10-Q, Exhibit 4(a), File No. 1-2323)
- 4-1(rrr) May 2, 1995 (September 1995 Form 10-Q, Exhibit 4(b), File No. 1-2323)
- 4-1(sss) June 1, 1995 (September 1995 Form 10-Q, Exhibit 4(c), File No. 1-2323)
- 4-1(ttt) July 15, 1995 (1995 Form 10-K, Exhibit 4b(73), File No. 1-2323)
- 4-1(uuu) August 1, 1995 (1995 Form 10-K, Exhibit 4b(74), File No. 1-2323)
- 4-1(vvv) June 15, 1997 (Form S-4, Exhibit 4(a), File No. 333-35931)
- 4-1(www) October 15, 1997 (Form S-4, Exhibit 4(a), File No. 333-47651)
- 4-1(xxx) June 1, 1998 (Form S-4, Exhibit 4b(77), File No. 333-72891)
- 4-1(yyy) October 1, 1998 (Form S-4, Exhibit 4b(78), File No. 333-72891)
- 4-1(zzz) October 1, 1998 (Form S-4, Exhibit 4b(79), File No. 333-72891)
- 4-1(aaaa) February 24, 1999 (Form S-4, Exhibit 4b(80), File No. 333-72891)
- 4-1(bbbb) September 29, 1999 (1999 Form 10-K, Exhibit 4b(81), File No. 1-2323)
- 4-1(cccc) January 15, 2000 (1999 Form 10-K, Exhibit 4b(82), File No. 1-2323)
- 4-1(dddd) May 15, 2002 (2002 Form 10-K, Exhibit 4b(83), File No. 1-2323)
- 4-1(eeee) October 1, 2002 (2002 Form 10-K, Exhibit 4b(84), File No. 1-2323)
- 4-1(ffff) Supplemental Indenture dated as of September 1, 2004 (September 2004 Form 10-Q, Exhibit 4-1(85), File No. 1-2323)
- 4-1(gggg) Supplemental Indenture dated as of October 1, 2004 (September 2004 Form 10-Q, Exhibit 4-1(86), File No. 1-2323)
- 4-1(hhhh) Supplemental Indenture dated as of April 1, 2005 (June 2005 Form 10-Q, Exhibit 4.1, File No. 1-2323)
- 4-1(iiii) Supplemental Indenture dated as of July 1, 2005 (June 2005 Form 10-Q, Exhibit 4.2, File No. 1-2323)
- 4-1(jjjj) Eighty-Ninth Supplemental Indenture, dated as of November 1, 2008 (relating to First Mortgage Bonds, 8.875% Series due 2018). (Form 8-K filed November 19, 2008, Exhibit 4.1)
- 4-2 Form of Note Indenture between The Cleveland Electric Illuminating Company and The Chase Manhattan Bank, as Trustee dated as of October 24, 1997. (Form S-4 filed March 10, 1998, File No. 333-47651, Exhibit 4(b))
- 4-2(a) Form of Supplemental Note Indenture between The Cleveland Electric Illuminating Company and The Chase Manhattan Bank, as Trustee dated as of October 24, 1997. (Form S-4 filed March 10, 1998, File No. 333-47651, Exhibit 4(c))
- 4-3 Indenture dated as of December 1, 2003 between The Cleveland Electric Illuminating Company and JPMorgan Chase Bank, as Trustee. (2003 Form 10-K, Exhibit 4-1, File No. 1-02323)
- 4-3(a) Officer's Certificate (including the form of 5.95% Senior Notes due 2036), dated as of December 11, 2006. (Form 8-K filed December 12, 2006, Exhibit 4)
- 4-3(b) Officer's Certificate (including the form of 5.70% Senior Notes due 2017), dated as of March 27, 2007. (Form 8-K filed March 28, 2007, Exhibit 4)
- 10-1 Administration Agreement between the CAPCO Group dated as of September 14, 1967. (Registration No. 2-43102, Exhibit 5(c)(2))
- 10-2 Amendment No. 1 dated January 4, 1974 to Administration Agreement between the CAPCO Group dated as of September 14, 1967. (Registration No. 2-68906, Exhibit 5(c)(3))
- 10-3 CEI Nuclear Purchase and Sale Agreement by and between The Cleveland Electric Illuminating Company and FirstEnergy Nuclear Generation Corp. (June 2005 Form 10-Q, Exhibit 10.1)
- 10-4 CEI Fossil Purchase and Sale Agreement by and between The Cleveland Electric Illuminating Company (Seller) and FirstEnergy Generation Corp. (Purchaser). (June 2005 Form 10-Q, Exhibit 10.2)
- 10-5 CEI Fossil Security Agreement, dated October 24, 2005, by and between FirstEnergy Generation Corp. and The Cleveland Electric Illuminating Company. (Form S-4/A filed August 20, 2007 by FirstEnergy Solutions Corp., Exhibit 10.16)

- 10-6 CEI Nuclear Security Agreement, dated December 16, 2005, by and between FirstEnergy Nuclear Generation Corp. and The Cleveland Electric Illuminating Company. (Form S-4/A filed August 20, 2007 by FirstEnergy Solutions Corp., Exhibit 10.26)
- 10-7 Nuclear Sale/Leaseback Power Supply Agreement dated as of October 14, 2005 between Ohio Edison Company and The Toledo Edison Company (Sellers) and FirstEnergy Nuclear Generation Corp. (Buyer). (2005 Form 10-K, Exhibit 10-64)
- 10-8 Power Supply Agreement dated as of October 31, 2005 between FirstEnergy Solutions Corp. (Seller) and the FirstEnergy Operating Companies – Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company (Buyers). (2005 Form 10-K, Exhibit 10-66)
- 10-9 Mansfield Power Supply Agreement dated as of October 14, 2005 between The Cleveland Electric Illuminating Company and The Toledo Edison Company (Sellers) and FirstEnergy Generation Corp. (Buyer). (2005 Form 10-K, Exhibit 10-65)
- (A) 12-4 Consolidated ratios of earnings to fixed charges.
- (A) 13-2 CEI 2008 Annual Report to Stockholders. (Only those portions expressly incorporated by reference in this Form 10-K are to be deemed “filed” with the SEC.)
- (A) 23-3 Consent of Independent Registered Public Accounting Firm
- (A) 31-1 Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
- (A) 31-2 Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
- (A) 32 Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. §1350.
 - (A) Provided herein in electronic format as an exhibit.
 - (B) Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, CEI has not filed as an exhibit to this Form 10-K any instrument with respect to long-term debt if the total amount of securities authorized thereunder does not exceed 10% of the total assets of CEI, but hereby agrees to furnish to the Commission on request any such instruments.

3. Exhibits – TE

- 3-1 Amended and Restated Articles of Incorporation of The Toledo Edison Company, effective December 18, 2007. (2007 Form 10-K, Exhibit 3c)
- 3-2 Amended and Restated Code of Regulations of The Toledo Edison Company, dated December 14, 2007. (2007 Form 10-K, Exhibit 3d)
- (B) 4-1 Indenture, dated as of April 1, 1947, between The Toledo Edison Company and The Chase National Bank of the City of New York (now The Chase Manhattan Bank (National Association)), as Trustee. (File No. 2-26908, Exhibit 2 (b))

Supplemental Indentures between The Toledo Edison Company and the Trustee, supplemental to Exhibit 4-1, dated as follows:

 - 4-1(a) September 1, 1948 (File No. 2-26908, Exhibit 2(d))
 - 4-1(b) April 1, 1949 (File No. 2-26908, Exhibit 2(e))
 - 4-1(c) December 1, 1950 (File No. 2-26908, Exhibit 2(f))
 - 4-1(d) March 1, 1954 (File No. 2-26908, Exhibit 2(g))
 - 4-1(e) February 1, 1956 (File No. 2-26908, Exhibit 2(h))
 - 4-1(f) May 1, 1958 (File No. 2-59794, Exhibit 5(g))
 - 4-1(g) August 1, 1967 (File No. 2-26908, Exhibit 2(c))
 - 4-1(h) November 1, 1970 (File No. 2-38569, Exhibit 2(c))
 - 4-1(i) August 1, 1972 (File No. 2-44873, Exhibit 2(c))
 - 4-1(j) November 1, 1973 (File No. 2-49428, Exhibit 2(c))
 - 4-1(k) July 1, 1974 (File No. 2-51429, Exhibit 2(c))

4-1(l)	October 1, 1975 (File No. 2-54627, Exhibit 2(c))
4-1(m)	June 1, 1976 (File No. 2-56396, Exhibit 2(c))
4-1(n)	October 1, 1978 (File No. 2-62568, Exhibit 2(c))
4-1(o)	September 1, 1979 (File No. 2-65350, Exhibit 2(c))
4-1(p)	September 1, 1980 (File No. 2-69190, Exhibit 4(s))
4-1(q)	October 1, 1980 (File No. 2-69190, Exhibit 4(c))
4-1(r)	April 1, 1981 (File No. 2-71580, Exhibit 4(c))
4-1(s)	November 1, 1981 (File No. 2-74485, Exhibit 4(c))
4-1(t)	June 1, 1982 (File No. 2-77763, Exhibit 4(c))
4-1(u)	September 1, 1982 (File No. 2-87323, Exhibit 4(x))
4-1(v)	April 1, 1983 (March 1983 Form 10-Q, Exhibit 4(c), File No. 1-3583)
4-1(w)	December 1, 1983 (1983 Form 10-K, Exhibit 4(x), File No. 1-3583)
4-1(x)	April 1, 1984 (File No. 2-90059, Exhibit 4(c))
4-1(y)	October 15, 1984 (1984 Form 10-K, Exhibit 4(z), File No. 1-3583)
4-1(z)	October 15, 1984 (1984 Form 10-K, Exhibit 4(aa), File No. 1-3583)
4-1(aa)	August 1, 1985 (File No. 33-1689, Exhibit 4(dd))
4-1(bb)	August 1, 1985 (File No. 33-1689, Exhibit 4(ee))
4-1(cc)	December 1, 1985 (File No. 33-1689, Exhibit 4(c))
4-1(dd)	March 1, 1986 (1986 Form 10-K, Exhibit 4b(31), File No. 1-3583)
4-1(ee)	October 15, 1987 (September 30, 1987 Form 10-Q, Exhibit 4, File No. 1-3583)
4-1(ff)	September 15, 1988 (1988 Form 10-K, Exhibit 4b(33), File No. 1-3583)
4-1(gg)	June 15, 1989 (1989 Form 10-K, Exhibit 4b(34), File No. 1-3583)
4-1(hh)	October 15, 1989 (1989 Form 10-K, Exhibit 4b(35), File No. 1-3583)
4-1(ii)	May 15, 1990 (June 30, 1990 Form 10-Q, Exhibit 4, File No. 1-3583)
4-1(jj)	March 1, 1991 (June 30, 1991 Form 10-Q, Exhibit 4(b), File No. 1-3583)
4-1(kk)	May 1, 1992 (File No. 33-48844, Exhibit 4(a)(3))
4-1(ll)	August 1, 1992 (1992 Form 10-K, Exhibit 4b(39), File No. 1-3583)
4-1(mm)	October 1, 1992 (1992 Form 10-K, Exhibit 4b(40), File No. 1-3583)
4-1(nn)	January 1, 1993 (1992 Form 10-K, Exhibit 4b(41), File No. 1-3583)
4-1(oo)	September 15, 1994 (September 1994 Form 10-Q, Exhibit 4(b), File No. 1-3583)
4-1(pp)	May 1, 1995 (September 1995 Form 10-Q, Exhibit 4(d), File No. 1-3583)
4-1(qq)	June 1, 1995 (September 1995 Form 10-Q, Exhibit 4(e), File No. 1-3583)
4-1(rr)	July 14, 1995 (September 1995 Form 10-Q, Exhibit 4(f), File No. 1-3583)
4-1(ss)	July 15, 1995 (September 1995 Form 10-Q, Exhibit 4(g), File No. 1-3583)
4-1(tt)	August 1, 1997 (1998 Form 10-K, Exhibit 4b(47), File No. 1-3583)
4-1(uu)	June 1, 1998 (1998 Form 10-K, Exhibit 4b (48), File No. 1-3583)
4-1(vv)	January 15, 2000 (1999 Form 10-K, Exhibit 4b(49), File No. 1-3583)
4-1(ww)	May 1, 2000 (2000 Form 10-K, Exhibit 4b(50), File No. 1-3583)
4-1(xx)	September 1, 2000 (2002 Form 10-K, Exhibit 4b(51), File No. 1-3583)
4-1(yy)	October 1, 2002 (2002 Form 10-K, Exhibit 4b(52), File No. 1-3583)
4-1(zz)	April 1, 2003 (2003 Form 10-K, Exhibit 4b(53), File No. 1-3583)
4-1(aaa)	September 1, 2004 (September 2004 10-Q, Exhibit 4.2.56, File No. 1-3583)
4-1(bbb)	April 1, 2005 (June 2005 10-Q, Exhibit 4.1, File No. 1-3583)
4-2	Indenture dated as of November 1, 2006, between The Toledo Edison Company and The Bank of New York Trust Company, N.A. (2006 Form 10-K, Exhibit 4-2)
4-2(a)	Officer's Certificate (including the form of 6.15% Senior Notes due 2037), dated November 16, 2006. (Form 8-K filed November 16, 2006, Exhibit 4)
10-1	TE Nuclear Purchase and Sale Agreement by and between The Toledo Edison Company (Seller) and FirstEnergy Nuclear Generation Corp. (Purchaser). (June 2005 Form 10-Q, Exhibit 10.1)
10-2	TE Fossil Purchase and Sale Agreement by and between The Toledo Edison Company (Seller) and FirstEnergy Generation Corp. (Purchaser). (June 2005 Form 10-Q, Exhibit 10.2)
10-3	TE Fossil Security Agreement, dated October 24, 2005, by and between FirstEnergy Generation Corp. and The Toledo Edison Company. (Form S-4/A filed August 20, 2007 by FirstEnergy Solutions Corp., Exhibit 10.24)

- 10-4 Nuclear Sale/Leaseback Power Supply Agreement dated as of October 14, 2005 between Ohio Edison Company and The Toledo Edison Company (Sellers) and FirstEnergy Nuclear Generation Corp. (Buyer). (2005 Form 10-K, Exhibit 10-64)
- 10-5 Power Supply Agreement dated as of October 31, 2005 between FirstEnergy Solutions Corp. (Seller) and the FirstEnergy Operating Companies – Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company (Buyers). (2005 Form 10-K, Exhibit 10-6)
- 10-6 Mansfield Power Supply Agreement dated as of October 14, 2005 between The Cleveland Electric Illuminating Company and The Toledo Edison Company (Sellers) and FirstEnergy Generation Corp. (Buyer). (2005 Form 10-K, Exhibit 10-65)
- (A) 12-5 Consolidated ratios of earnings to fixed charges.
- (A) 13-2 TE 2008 Annual Report to Stockholders. (Only those portions expressly incorporated by reference in this Form 10-K are to be deemed “filed” with the SEC.)
- (A) 23-4 Consent of Independent Registered Public Accounting Firm
- (A) 31-1 Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
- (A) 31-2 Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
- (A) 32 Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. §1350.
- (A) Provided herein in electronic format as an exhibit.
- (B) Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, TE has not filed as an exhibit to this Form 10-K any instrument with respect to long-term debt if the total amount of securities authorized thereunder does not exceed 10% of the total assets of TE, but hereby agrees to furnish to the Commission on request any such instruments.

3. Exhibits – JCP&L

- 3-1 Amended and Restated Certificate of Incorporation of Jersey Central Power & Light Company, filed February 14, 2008. (2007 Form 10-K, Exhibit 3-D)
- 3-2 Amended and Restated Bylaws of Jersey Central Power & Light Company, dated January 9, 2008. (2007 Form 10-K, Exhibit 3-E)
- 4-1 Senior Note Indenture, dated as of July 1, 1999, between Jersey Central Power & Light Company and The Bank of New York Mellon Trust Company, N.A., as successor trustee to United States Trust Company of New York. (Registration No. 333-78717, Exhibit 4-A)
- 4-1(a) First Supplemental Indenture, dated October 31, 2007, between Jersey Central Power & Light Company, The Bank of New York, as resigning trustee, and The Bank of New York Trust Company, N.A., as successor trustee. (Registration No. 333-146968, Exhibit 4-2)
- 4-1(b) Form of Jersey Central Power & Light Company 6.40% Senior Note due 2036. (Form 8-K filed May 12, 2006, Exhibit 10-1)
- 4-1(c) Form of 7.35% Senior Notes due 2019. (Form 8-K filed January 27, 2009, Exhibit 4.1)
- 10-1 Indenture dated as of August 10, 2006 between JCP&L Transition Funding II LLC as Issuer and The Bank of New York as Trustee. (Form 8-K filed August 10, 2006, Exhibit 4-1)
- 10-2 2006-A Series Supplement dated as of August 10, 2006 between JCP&L Transition Funding II LLC as Issuer and The Bank of New York as Trustee. (Form 8-K filed August 10, 2006, Exhibit 4-2)

- 10-3 Bondable Transition Property Sale Agreement dated as of August 10, 2006 between JCP&L Transition Funding II LLC as Issuer and Jersey Central Power & Light Company as Seller. (Form 8-K filed August 10, 2006, Exhibit 10-1)
- 10-4 Bondable Transition Property Service Agreement dated as of August 10, 2006 between JCP&L Transition Funding II LLC as Issuer and Jersey Central Power & Light Company as Servicer. (Form 8-K filed August 10, 2006, Exhibit 10-2)
- 10-5 Administration Agreement dated as of August 10, 2006 between JCP&L Transition Funding II LLC as Issuer and FirstEnergy Service Company as Administrator. (Form 8-K filed August 10, 2006, Exhibit 10-3)
- (A) 12-6 Consolidated ratios of earnings to fixed charges.
- (A) 13-2 JCP&L 2008 Annual Report to Stockholders. (Only those portions expressly incorporated by reference in this Form 10-K are to be deemed "filed" with SEC.)
- (A) 23-5 Consent of Independent Registered Public Accounting Firm
- (A) 31-1 Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
- (A) 31-2 Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
- (A) 32 Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. §1350.
- (A) Provided herein electronic format as an exhibit.

3. Exhibits - Met-Ed

- 3-1 Amended and Restated Articles of Incorporation of Metropolitan Edison Company, effective December 19, 2007. (2007 Form 10-K, Exhibit 3.9)
- 3-2 Amended and Restated Bylaws of Metropolitan Edison Company, dated December 14, 2007. (2007 Form 10-K, Exhibit 3.10)
- 4-1 Indenture of Metropolitan Edison Company, dated November 1, 1944, between Metropolitan Edison Company and United States Trust Company of New York, Successor Trustee, as amended and supplemented by fourteen supplemental indentures dated February 1, 1947 through May 1, 1960. (Metropolitan Edison Company's Instruments of Indebtedness Nos. 1 to 14 inclusive, and 16, filed as part of Amendment No. 1 to 1959 Annual Report of GPU on Form U5S, File Nos. 30-126 and 1-3292)
- 4-1(a) Supplemental Indenture of Metropolitan Edison Company, dated December 1, 1962. (Registration No. 2-59678, Exhibit 2-E(1))
- 4-1(b) Supplemental Indenture of Metropolitan Edison Company, dated March 20, 1964. (Registration No. 2-59678, Exhibit 2-E(2))
- 4-1(c) Supplemental Indenture of Metropolitan Edison Company, dated July 1, 1965. (Registration No. 2-59678, Exhibit 2-E(3))
- 4-1(d) Supplemental Indenture of Metropolitan Edison Company, dated June 1, 1966. (Registration No. 2-24883, Exhibit 2-B-4))
- 4-1(e) Supplemental Indenture of Metropolitan Edison Company, dated March 22, 1968. (Registration No. 2-29644, Exhibit 4-C-5)
- 4-1(f) Supplemental Indenture of Metropolitan Edison Company, dated September 1, 1968. (Registration No. 2-59678, Exhibit 2-E(6))
- 4-1(g) Supplemental Indenture of Metropolitan Edison Company, dated August 1, 1969. (Registration No. 2-59678, Exhibit 2-E(7))
- 4-1(h) Supplemental Indenture of Metropolitan Edison Company, dated November 1, 1971. (Registration No. 2-59678, Exhibit 2-E(8))
- 4-1(i) Supplemental Indenture of Metropolitan Edison Company, dated May 1, 1972. (Registration No. 2-59678, Exhibit 2-E(9))
- 4-1(j) Supplemental Indenture of Metropolitan Edison Company, dated December 1, 1973. (Registration No. 2-59678, Exhibit 2-E(10))

- 4-1(k) Supplemental Indenture of Metropolitan Edison Company, dated October 30, 1974. (Registration No. 2-59678, Exhibit 2-E(11))
- 4-1(l) Supplemental Indenture of Metropolitan Edison Company, dated October 31, 1974. (Registration No. 2-59678, Exhibit 2-E(12))
- 4-1(m) Supplemental Indenture of Metropolitan Edison Company, dated March 20, 1975. (Registration No. 2-59678, Exhibit 2-E(13))
- 4-1(n) Supplemental Indenture of Metropolitan Edison Company, dated September 25, 1975. (Registration No. 2-59678, Exhibit 2-E(15))
- 4-1(o) Supplemental Indenture of Metropolitan Edison Company, dated January 12, 1976. (Registration No. 2-59678, Exhibit 2-E(16))
- 4-1(p) Supplemental Indenture of Metropolitan Edison Company, dated March 1, 1976. (Registration No. 2-59678, Exhibit 2-E(17))
- 4-1(q) Supplemental Indenture of Metropolitan Edison Company, dated September 28, 1977. (Registration No. 2-62212, Exhibit 2-E(18))
- 4-1(r) Supplemental Indenture of Metropolitan Edison Company, dated January 1, 1978. (Registration No. 2-62212, Exhibit 2-E(19))
- 4-1(s) Supplemental Indenture of Metropolitan Edison Company, dated September 1, 1978. (Registration No. 33-48937, Exhibit 4-A(19))
- 4-1(t) Supplemental Indenture of Metropolitan Edison Company, dated June 1, 1979. (Registration No. 33-48937, Exhibit 4-A(20))
- 4-1(u) Supplemental Indenture of Metropolitan Edison Company, dated January 1, 1980. (Registration No. 33-48937, Exhibit 4-A(21))
- 4-1(v) Supplemental Indenture of Metropolitan Edison Company, dated September 1, 1981. (Registration No. 33-48937, Exhibit 4-A(22))
- 4-1(w) Supplemental Indenture of Metropolitan Edison Company, dated September 10, 1981. (Registration No. 33-48937, Exhibit 4-A(23))
- 4-1(x) Supplemental Indenture of Metropolitan Edison Company, dated December 1, 1982. (Registration No. 33-48937, Exhibit 4-A(24))
- 4-1(y) Supplemental Indenture of Metropolitan Edison Company, dated September 1, 1983. (Registration No. 33-48937, Exhibit 4-A(25))
- 4-1(z) Supplemental Indenture of Metropolitan Edison Company, dated September 1, 1984. (Registration No. 33-48937, Exhibit 4-A(26))
- 4-1(aa) Supplemental Indenture of Metropolitan Edison Company, dated March 1, 1985. (Registration No. 33-48937, Exhibit 4-A(27))
- 4-1(bb) Supplemental Indenture of Metropolitan Edison Company, dated September 1, 1985. (Registration No. 33-48937, Exhibit 4-A(28))
- 4-1(cc) Supplemental Indenture of Metropolitan Edison Company, dated June 1, 1988. (Registration No. 33-48937, Exhibit 4-A(29))
- 4-1(dd) Supplemental Indenture of Metropolitan Edison Company, dated April 1, 1990. (Registration No. 33-48937, Exhibit 4-A(30))
- 4-1(ee) Amendment dated May 22, 1990 to Supplemental Indenture of Metropolitan Edison Company, dated April 1, 1990. (Registration No. 33-48937, Exhibit 4-A(31))
- 4-1(ff) Supplemental Indenture of Metropolitan Edison Company, dated September 1, 1992. (Registration No. 33-48937, Exhibit 4-A(32)(a))
- 4-1(gg) Supplemental Indenture of Metropolitan Edison Company, dated December 1, 1993. (1993 Annual Report of GPU on Form U5S, Exhibit C-58, File No. 30-126)
- 4-1(hh) Supplemental Indenture of Metropolitan Edison Company, dated July 15, 1995. (1995 Form 10-K, Exhibit 4-B-35, File No. 1-446)
- 4-1(ii) Supplemental Indenture of Metropolitan Edison Company, dated August 15, 1996. (1996 Form 10-K, Exhibit 4-B-35, File No. 1-446)
- 4-1(jj) Supplemental Indenture of Metropolitan Edison Company, dated May 1, 1997. (1997 Form 10-K, Exhibit 4-B-36, File No. 1-446)
- 4-1(kk) Supplemental Indenture of Metropolitan Edison Company, dated July 1, 1999. (1999 Form 10-K, Exhibit 4-B-38, File No. 1-446)
- 4-1(ll) Supplemental Indenture of Metropolitan Edison Company, dated May 1, 2001. (2001 Form 10-K, Exhibit 4-5, File No. 1-446)
- 4-1(mm) Supplemental Indenture of Metropolitan Edison Company, dated March 1, 2003. (2003 Form 10-K, Exhibit 4-10, File No. 1-446)

- 4-2 Senior Note Indenture between Metropolitan Edison Company and United States Trust Company of New York, dated July 1, 1999. (1999 Annual Report of GPU on Form U5S, Exhibit C-154, File No. 30-126)

- 4-2(a) Form of Metropolitan Edison Company 7.70% Senior Notes due 2019. (Form 8-K filed January 21, 2009, Exhibit 4.1)
- (A) 12-7 Consolidated ratios of earnings to fixed charges.
- (A) 13-2 Met-Ed 2008 Annual Report to Stockholders (Only those portions expressly incorporated by reference in this Form 10-K are to be deemed "filed" with SEC.)
- (A) 23-6 Consent of Independent Registered Public Accounting Firm
- (A) 31-1 Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
- (A) 31-2 Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
- (A) 32 Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. §1350.
- (A) Provided herein electronic format as an exhibit.

3. Exhibits - Penelec

- 3-1 Amended and Restated Articles of Incorporation of Pennsylvania Electric Company, effective December 19, 2007. (2007 Form 10-K, Exhibit 3.11)
- 3-2 Amended and Restated Bylaws of Pennsylvania Electric Company, dated December 14, 2007. (2007 Form 10-K, Exhibit 3.12)
- 4-1 Mortgage and Deed of Trust of Pennsylvania Electric Company, dated January 1, 1942, between Pennsylvania Electric Company and United States Trust Company of New York, Successor Trustee, and indentures supplemental thereto dated March 7, 1942 through May 1, 1960 – (Pennsylvania Electric Company's Instruments of Indebtedness Nos. 1-20, inclusive, filed as a part of Amendment No. 1 to 1959 Annual Report of GPU on Form U5S, File Nos. 30-126 and 1-3292)
- 4-1(a) Supplemental Indentures to Mortgage and Deed of Trust of Pennsylvania Electric Company, dated May 1, 1961 through December 1, 1977. (Registration No. 2-61502, Exhibit 2-D(1) to 2-D(19))
- 4-1(b) Supplemental Indenture of Pennsylvania Electric Company, dated June 1, 1978. (Registration No. 33-49669, Exhibit 4-A(2))
- 4-1(c) Supplemental Indenture of Pennsylvania Electric Company dated June 1, 1979. (Registration No. 33-49669, Exhibit 4-A(3))
- 4-1(d) Supplemental Indenture of Pennsylvania Electric Company, dated September 1, 1984. (Registration No. 33-49669, Exhibit 4-A(4))
- 4-1(e) Supplemental Indenture of Pennsylvania Electric Company, dated December 1, 1985. (Registration No. 33-49669, Exhibit 4-A(5))
- 4-1(f) Supplemental Indenture of Pennsylvania Electric Company, dated December 1, 1986. (Registration No. 33-49669, Exhibit 4-A(6))
- 4-1(g) Supplemental Indenture of Pennsylvania Electric Company, dated May 1, 1989. (Registration No. 33-49669, Exhibit 4-A(7))
- 4-1(h) Supplemental Indenture of Pennsylvania Electric Company, dated December 1, 1990. (Registration No. 33-45312, Exhibit 4-A(8))
- 4-1(i) Supplemental Indenture of Pennsylvania Electric Company, dated March 1, 1992. (Registration No. 33-45312, Exhibit 4-A(9))
- 4-1(j) Supplemental Indenture of Pennsylvania Electric Company, dated June 1, 1993. (1993 Annual Report of GPU on Form U5S, Exhibit C-73, File No. 30-126)
- 4-1(k) Supplemental Indenture of Pennsylvania Electric Company, dated November 1, 1995. (1995 Form 10-K, Exhibit 4-C-11, File No. 1-3522)
- 4-1(l) Supplemental Indenture of Pennsylvania Electric Company, dated August 15, 1996. (1996 Form 10-K, Exhibit 4-C-12, File No. 1-3522)
- 4-1(m) Supplemental Indenture of Pennsylvania Electric Company, dated May 1, 2001. (2001 Form 10-K, Exhibit 4-C-16)

- 4-2 Senior Note Indenture between Pennsylvania Electric Company and United States Trust Company of New York, dated April 1, 1999. (1999 Form 10-K, Exhibit 4-C-13, File No. 1-3522)
- 4-2(a) Form of Pennsylvania Electric Company 6.05% Senior Notes due 2017. (Form 8-K filed August 31, 2007, Exhibit 4.1)
- (A) 12-8 Consolidated ratios of earnings to fixed charges.
- (A) 13-2 Penelec 2008 Annual Report to Stockholders. (Only those portions expressly incorporated by reference in this Form 10-K are to be deemed "filed" with SEC)
- (A) 23-7 Consent of Independent Registered Public Accounting Firm.
- (A) 31-1 Certification of chief executive officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
- (A) 31-2 Certification of chief financial officer, as adopted pursuant to Rule 13a-15(e)/15d-15(e).
- (A) 32 Certification of chief executive officer and chief financial officer, pursuant to 18 U.S.C. §1350.
- (A) Provided here in electronic format as an exhibit.

3. Exhibits - Common Exhibits for FES, Met-Ed and Penelec

- 10-1 Notice of Termination Tolling Agreement dated as of April 7, 2006; Restated Partial Requirements Agreement, dated January 1, 2003, by and among, Metropolitan Edison Company, Pennsylvania Electric Company, The Waverly Electric Power and Light Company and FirstEnergy Solutions Corp., as amended by a First Amendment to Restated Requirements Agreement, dated August 29, 2003 and by a Second Amendment to Restated Requirements Agreement, dated June 8, 2004 ("Partial Requirements Agreement"). (March 2006 Form 10-Q filed by Metropolitan Edison Company, Exhibit 10-5)
- 10-2 Third Restated Partial Requirements Agreement, among Metropolitan Edison Company, Pennsylvania Electric Company, a Pennsylvania corporation, The Waverly Electric Power and Light Company and FirstEnergy Solutions Corp., dated November 1, 2008. (September 2008 Form 10-Q filed by Metropolitan Edison Company, Exhibit 10-2)

3. Exhibits - Common Exhibits for FirstEnergy, FES, OE, CEI, TE, JCP&L, Met-Ed and Penelec

- 10-1 \$2,750,000,000 Credit Agreement dated as of August 24, 2006 among FirstEnergy Corp., FirstEnergy Solutions Corp., American Transmission Systems, Inc., 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, as Borrowers, the banks party thereto, the fronting banks party thereto and the swing line lenders party thereto. (Form 8-K filed August 24, 2006, Exhibit 10-1)
- 10-2 Consent and Amendment to \$2,750,000,000 Credit Agreement dated November 2, 2007. (2007 Form 10-K, Exhibit 10-2)

**Report of Independent Registered Public Accounting Firm
on
Financial Statement Schedule**

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

Our audits of the consolidated financial statements and of the effectiveness of internal control over financial reporting referred to in our report dated February 24, 2009 appearing in the 2008 Annual Report to Stockholders of FirstEnergy Corp. (which report and consolidated financial statements are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedule listed in Item 15(a)(2) of this Form 10-K. In our opinion, this financial statement schedule presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 24, 2009

**Report of Independent Registered Public Accounting Firm
on
Financial Statement Schedule**

To the Stockholder and Board of Directors of
FirstEnergy Solutions Corp.:

Our audits of the consolidated financial statements referred to in our report dated February 24, 2009 appearing in the 2008 Annual Report to Stockholders of FirstEnergy Solutions Corp. (which report and consolidated financial statements are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedule listed in Item 15(a)(2) of this Form 10-K. In our opinion, this financial statement schedule presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 24, 2009

**Report of Independent Registered Public Accounting Firm
on
Financial Statement Schedule**

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

Our audits of the consolidated financial statements referred to in our report dated February 24, 2009 appearing in the 2008 Annual Report to Stockholders of Ohio Edison Company (which report and consolidated financial statements are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedule listed in Item 15(a)(2) of this Form 10-K. In our opinion, this financial statement schedule presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 24, 2009

**Report of Independent Registered Public Accounting Firm
on
Financial Statement Schedule**

To the Stockholder and Board of Directors of
The Cleveland Electric Illuminating Company:

Our audits of the consolidated financial statements referred to in our report dated February 24, 2009 appearing in the 2008 Annual Report to Stockholders of The Cleveland Electric Illuminating Company (which report and consolidated financial statements are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedule listed in Item 15(a)(2) of this Form 10-K. In our opinion, this financial statement schedule presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 24, 2009

**Report of Independent Registered Public Accounting Firm
on
Financial Statement Schedule**

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

Our audits of the consolidated financial statements referred to in our report dated February 24, 2009 appearing in the 2008 Annual Report to Stockholders of The Toledo Edison Company (which report and consolidated financial statements are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedule listed in Item 15(a)(2) of this Form 10-K. In our opinion, this financial statement schedule presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 24, 2009

**Report of Independent Registered Public Accounting Firm
on
Financial Statement Schedule**

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

Our audits of the consolidated financial statements referred to in our report dated February 24, 2009 appearing in the 2008 Annual Report to Stockholders of Jersey Central Power & Light Company (which report and consolidated financial statements are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedule listed in Item 15(a)(2) of this Form 10-K. In our opinion, this financial statement schedule presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 24, 2009

**Report of Independent Registered Public Accounting Firm
on
Financial Statement Schedule**

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

Our audits of the consolidated financial statements referred to in our report dated February 24, 2009 appearing in the 2008 Annual Report to Stockholders of Metropolitan Edison Company (which report and consolidated financial statements are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedule listed in Item 15(a)(2) of this Form 10-K. In our opinion, this financial statement schedule presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 24, 2009

**Report of Independent Registered Public Accounting Firm
on
Financial Statement Schedule**

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

Our audits of the consolidated financial statements referred to in our report dated February 24, 2009 appearing in the 2008 Annual Report to Stockholders of Pennsylvania Electric Company (which report and consolidated financial statements are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the financial statement schedule listed in Item 15(a)(2) of this Form 10-K. In our opinion, this financial statement schedule presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 24, 2009

FIRSTENERGY CORP.

**CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006**

Description	Beginning Balance	Additions		Deductions	Ending Balance
		Charged to Income	Charged to Other Accounts <i>(In thousands)</i>		
Year Ended December 31, 2008:					
Accumulated provision for uncollectible accounts – customers	\$ 35,567	\$ 48,297	\$ 31,308(a)	\$ 87,325(b)	\$ 27,847
– other	\$ 21,924	\$ 11,339	\$ 3,189(a)	\$ 27,285(b)	\$ 9,167
Loss carryforward tax valuation reserve	\$ 30,616	\$ 1,435	\$ (4,757)	\$ -	\$ 27,294
Year Ended December 31, 2007:					
Accumulated provision for uncollectible accounts – customers	\$ 43,214	\$ 53,522	\$ 50,165(a)	\$ 111,334(b)	\$ 35,567
– other	\$ 23,964	\$ 4,933	\$ 406(a)	\$ 7,379(b)	\$ 21,924
Loss carryforward tax valuation reserve	\$ 415,531	\$ 8,819	\$ (393,734)	\$ -	\$ 30,616
Year Ended December 31, 2006:					
Accumulated provision for uncollectible accounts – customers	\$ 37,733	\$ 60,461	\$ 34,259(a)	\$ 89,239(b)	\$ 43,214
– other	\$ 26,566	\$ 3,956	\$ 2,554(a)	\$ 9,112(b)	\$ 23,964
Loss carryforward tax valuation reserve	\$ 402,142	\$ -	\$ 13,389	\$ -	\$ 415,531

(a) Represents recoveries and reinstatements of accounts previously written off.

(b) Represents the write-off of accounts considered to be uncollectible.

FIRSTENERGY SOLUTIONS CORP.

**CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006**

Description	Beginning Balance	Additions		Deductions	Ending Balance
		Charged to Income	Charged to Other Accounts <i>(In thousands)</i>		
Year Ended December 31, 2008:					
Accumulated provision for uncollectible accounts – customers	\$ 8,072	\$ (2,174)	\$ 110(a)	\$ 109(b)	\$ 5,899
– other	\$ 9	\$ 4,374	\$ 2,541(a)	\$ 109(b)	\$ 6,815
Year Ended December 31, 2007:					
Accumulated provision for uncollectible accounts – customers	\$ 7,938	\$ 94	\$ 532(a)	\$ 492(b)	\$ 8,072
– other	\$ 5,593	\$ 9	\$ -(a)	\$ 5,593(b)	\$ 9
Year Ended December 31, 2006:					
Accumulated provision for uncollectible accounts – customers	\$ 11,531	\$ 2,244	\$ 789(a)	\$ 6,626(b)	\$ 7,938
– other	\$ 5,599	\$ 15	\$ 7(a)	\$ 28(b)	\$ 5,593

(a) Represents recoveries and reinstatements of accounts previously written off.

(b) Represents the write-off of accounts considered to be uncollectible.

OHIO EDISON COMPANY

**CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006**

Description	Beginning Balance	Additions		Deductions	Ending Balance
		Charged to Income	Charged to Other Accounts <i>(In thousands)</i>		
Year Ended December 31, 2008:					
Accumulated provision for uncollectible accounts – customers	\$ 8,032	\$ 12,179	\$ 10,027(a)	\$ 24,173(b)	\$ 6,065
– other	\$ 5,639	\$ 16,618	\$ 394(a)	\$ 22,644(b)	\$ 7
Year Ended December 31, 2007:					
Accumulated provision for uncollectible accounts – customers	\$ 15,033	\$ 10,513	\$ 30,234(a)	\$ 47,748(b)	\$ 8,032
– other	\$ 1,985	\$ 4,117	\$ (240) (a)	\$ 223(b)	\$ 5,639
Year Ended December 31, 2006:					
Accumulated provision for uncollectible accounts – customers	\$ 7,619	\$ 22,466	\$ 11,817(a)	\$ 26,869(b)	\$ 15,033
– other	\$ 4	\$ 2,218	\$ 473(a)	\$ 710(b)	\$ 1,985

(a) Represents recoveries and reinstatements of accounts previously written off.

(b) Represents the write-off of accounts considered to be uncollectible.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006

Description	Beginning Balance	Additions		Deductions	Ending Balance
		Charged to Income	Charged to Other Accounts <i>(In thousands)</i>		
Year Ended December 31, 2008:					
Accumulated provision for uncollectible accounts – customers	\$ 7,540	\$ 11,323	\$ 9,179(a)	\$ 22,126(b)	\$ 5,916
– other	\$ 433	\$ (183)	\$ 30(a)	\$ 269(b)	\$ 11
Year Ended December 31, 2007:					
Accumulated provision for uncollectible accounts – customers	\$ 6,783	\$ 17,998	\$ 7,842(a)	\$ 25,083(b)	\$ 7,540
– other	\$ -	\$ 431	\$ 124(a)	\$ 122(b)	\$ 433
Year Ended December 31, 2006:					
Accumulated provision for uncollectible accounts – customers	\$ 5,180	\$ 14,890	\$ 10,067(a)	\$ 23,354(b)	\$ 6,783
– other	\$ -	\$ 22	\$ 138(a)	\$ 160(b)	\$ -

(a) Represents recoveries and reinstatements of accounts previously written off.

(b) Represents the write-off of accounts considered to be uncollectible.

THE TOLEDO EDISON COMPANY

**CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006**

<u>Description</u>	<u>Beginning Balance</u>	<u>Additions</u>		<u>Deductions</u>	<u>Ending Balance</u>
		<u>Charged to Income</u>	<u>Charged to Other Accounts</u>		
Year Ended December 31, 2008:					
Accumulated provision for uncollectible accounts	\$ 615	\$ (247)	\$ 121(a)	\$ 286(b)	\$ 203
Year Ended December 31, 2007:					
Accumulated provision for uncollectible accounts	\$ 430	\$ 361	\$ 13(a)	\$ 189	\$ 615
Year Ended December 31, 2006:					
Accumulated provision for uncollectible accounts	\$ -	\$ 440	\$ 118(a)	\$ 128(b)	\$ 430

(a) Represents recoveries and reinstatements of accounts previously written off.

(b) Represents the write-off of accounts considered to be uncollectible.

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006

Description	Beginning Balance	Additions		Deductions	Ending Balance
		Charged to Income	Charged to Other Accounts <i>(In thousands)</i>		
Year Ended December 31, 2008:					
Accumulated provision for uncollectible accounts – customers	\$ 3,691	\$ 10,377	\$ 3,504(a)	\$ 14,342(b)	\$ 3,230
– other	\$ -	\$ 44	\$ 24(a)	\$ 23(b)	\$ 45
Year Ended December 31, 2007:					
Accumulated provision for uncollectible accounts – customers	\$ 3,524	\$ 8,563	\$ 4,049(a)	\$ 12,445(b)	\$ 3,691
– other	\$ -	\$ -	\$ -(a)	\$ -(b)	\$ -
Year Ended December 31, 2006:					
Accumulated provision for uncollectible accounts – customers	\$ 3,830	\$ 4,945	\$ 4,643(a)	\$ 9,894(b)	\$ 3,524
– other	\$ 204	\$ (201)	\$ 866(a)	\$ 869(b)	\$ -

(a) Represents recoveries and reinstatements of accounts previously written off.

(b) Represents the write-off of accounts considered to be uncollectible.

METROPOLITAN EDISON COMPANY

**CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006**

Description	Beginning Balance	Additions		Deductions	Ending Balance
		Charged to Income	Charged to Other Accounts <i>(In thousands)</i>		
Year Ended December 31, 2008:					
Accumulated provision for uncollectible accounts – customers	\$ 4,327	\$ 9,004	\$ 3,729(a)	\$ 13,444(b)	\$ 3,616
– other	\$ 1	\$ 19	\$ 21(a)	\$ 41(b)	\$ -
Year Ended December 31, 2007:					
Accumulated provision for uncollectible accounts – customers	\$ 4,153	\$ 9,971	\$ 3,548(a)	\$ 13,345(b)	\$ 4,327
– other	\$ 2	\$ 245	\$ 18	\$ 264	\$ 1
Year Ended December 31, 2006:					
Accumulated provision for uncollectible accounts – customers	\$ 4,352	\$ 7,070	\$ 4,108(a)	\$ 11,377(b)	\$ 4,153
– other	\$ -	\$ 15	\$ 36(a)	\$ 49(b)	\$ 2

(a) Represents recoveries and reinstatements of accounts previously written off.

(b) Represents the write-off of accounts considered to be uncollectible.

PENNSYLVANIA ELECTRIC COMPANY

**CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006**

<u>Description</u>	<u>Beginning Balance</u>	<u>Additions</u>		<u>Deductions</u>	<u>Ending Balance</u>
		<u>Charged to Income</u>	<u>Charged to Other Accounts</u>		
<i>(In thousands)</i>					
Year Ended December 31, 2008:					
Accumulated provision for uncollectible accounts – customers	\$ 3,905	\$ 7,589	\$ 4,758(a)	\$ 13,131(b)	\$ 3,121
– other	\$ 105	\$ 57	\$ 36(a)	\$ 133(b)	\$ 65
Year Ended December 31, 2007:					
Accumulated provision for uncollectible accounts – customers	\$ 3,814	\$ 8,351	\$ 3,958(a)	\$ 12,218(b)	\$ 3,905
– other	\$ 3	\$ 181	\$ 3(a)	\$ 82(b)	\$ 105
Year Ended December 31, 2006:					
Accumulated provision for uncollectible accounts – customers	\$ 4,184	\$ 6,381	\$ 4,368(a)	\$ 11,119(b)	\$ 3,814
– other	\$ 2	\$ 105	\$ 173(a)	\$ 277(b)	\$ 3

(a) Represents recoveries and reinstatements of accounts previously written off.

(b) Represents the write-off of accounts considered to be uncollectible.

SIGNATURES

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

FIRSTENERGY CORP.

BY: /s/Anthony J. Alexander

Anthony J. Alexander

President and Chief Executive Officer

Date: February 24, 2009

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ George M. Smart
George M. Smart
Chairman of the Board

/s/ Anthony J. Alexander
Anthony J. Alexander
President and Chief Executive Officer
and Director (Principal Executive Officer)

/s/ Richard H. Marsh
Richard H. Marsh
Senior Vice President and Chief Financial
Officer (Principal Financial Officer)

/s/ Harvey L. Wagner
Harvey L. Wagner
Vice President, Controller and Chief Accounting
Officer (Principal Accounting Officer)

/s/ Paul T. Addison
Paul T. Addison
Director

/s/ Ernest J. Novak, Jr.
Ernest J. Novak, Jr.
Director

/s/ Michael J. Anderson
Michael J. Anderson
Director

/s/ Catherine A. Rein
Catherine A. Rein
Director

/s/ Carol A. Cartwright
Carol A. Cartwright
Director

/s/ Wes M. Taylor
Wes M. Taylor
Director

/s/ William T. Cottle
William T. Cottle
Director

/s/ Jesse T. Williams, Sr.
Jesse T. Williams, Sr.
Director

/s/ Robert B. Heisler, Jr.
Robert B. Heisler, Jr.
Director

Date: February 24, 2009

SIGNATURES

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

FIRSTENERGY SOLUTIONS CORP.

BY: /s/ Donald R. Schneider
Donald R. Schneider
President

Date: February 24, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ Donald R. Schneider
Donald R. Schneider
President
(Principal Executive Officer)

/s/ Richard H. Marsh
Richard H. Marsh
Senior Vice President and Chief
Financial Officer and Director
(Principal Financial Officer)

/s/ Anthony J. Alexander
Anthony J. Alexander
Director

/s/ Harvey L. Wagner
Harvey L. Wagner
Vice President and Controller
(Principal Accounting Officer)

/s/ Gary R. Leidich
Gary R. Leidich
Director

Date: February 24, 2009

SIGNATURES

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

OHIO EDISON COMPANY

BY: /s/ Richard R. Grigg
Richard R. Grigg
President

Date: February 24, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ Anthony J. Alexander
Anthony J. Alexander
Director

/s/ Richard R. Grigg
Richard R. Grigg
President and Director
(Principal Executive Officer)

/s/ Richard H. Marsh
Richard H. Marsh
Senior Vice President and Chief
Financial Officer and Director
(Principal Financial Officer)

/s/ Harvey L. Wagner
Harvey L. Wagner
Vice President and Controller
(Principal Accounting Officer)

Date: February 24, 2009

SIGNATURES

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

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

BY: /s/ Richard R. Grigg

Richard R. Grigg
President

Date: February 24, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ Anthony J. Alexander

Anthony J. Alexander
Director

/s/ Richard R. Grigg

Richard R. Grigg
President and Director
(Principal Executive Officer)

/s/ Richard H. Marsh

Richard H. Marsh
Senior Vice President and Chief
Financial Officer and Director
(Principal Financial Officer)

/s/ Harvey L. Wagner

Harvey L. Wagner
Vice President and Controller
(Principal Accounting Officer)

Date: February 24, 2009

SIGNATURES

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

THE TOLEDO EDISON COMPANY

BY: /s/ Richard R. Grigg
Richard R. Grigg
President

Date: February 24, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ Anthony J. Alexander
Anthony J. Alexander
Director

/s/ Richard R. Grigg
Richard R. Grigg
President and Director
(Principal Executive Officer)

/s/ Richard H. Marsh
Richard H. Marsh
Senior Vice President and Chief
Financial Officer and Director
(Principal Financial Officer)

/s/ Harvey L. Wagner
Harvey L. Wagner
Vice President and Controller
(Principal Accounting Officer)

Date: February 24, 2009

SIGNATURES

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

JERSEY CENTRAL POWER & LIGHT COMPANY

BY: /s/ Stephen E. Morgan

Stephen E. Morgan
President

Date: February 24, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ Stephen E. Morgan

Stephen E. Morgan
President and Director
(Principal Executive Officer)

/s/ Paulette R. Chatman

Paulette R. Chatman
Controller
(Principal Financial and Accounting Officer)

/s/ Richard R. Grigg

Richard R. Grigg
Director

/s/ Gelorma E. Persson

Gelorma E. Persson
Director

/s/ Charles E. Jones

Charles E. Jones
Director

/s/ Jesse T. Williams, Sr.

Jesse T. Williams, Sr.
Director

/s/ Mark A. Julian

Mark A. Julian
Director

Date: February 24, 2009

SIGNATURES

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

METROPOLITAN EDISON COMPANY

BY: /s/ Richard R. Grigg
Richard R. Grigg
President

Date: February 24, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ Richard R. Grigg
Richard R. Grigg
President and Director
(Principal Executive Officer)

/s/ Richard H. Marsh
Richard H. Marsh
Senior Vice President and Chief
Financial Officer
(Principal Financial Officer)

/s/ Ronald P. Lantzy
Ronald P. Lantzy
Regional President and Director

/s/ Harvey L. Wagner
Harvey L. Wagner
Vice President and Controller
(Principal Accounting Officer)

/s/ Randy Scilla
Randy Scilla
Assistant Treasurer and Director

Date: February 24, 2009

SIGNATURES

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

PENNSYLVANIA ELECTRIC COMPANY

BY: /s/ Richard R. Grigg
Richard R. Grigg
President

Date: February 24, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ Richard R. Grigg
Richard R. Grigg
President and Director
(Principal Executive Officer)

/s/ Richard H. Marsh
Richard H. Marsh
Senior Vice President and Chief
Financial Officer
(Principal Financial Officer)

/s/ James R. Napier, Jr.
James R. Napier, Jr.
Regional President and Director

/s/ Harvey L. Wagner
Harvey L. Wagner
Vice President and Controller
(Principal Accounting Officer)

/s/ Randy Scilla
Randy Scilla
Assistant Treasurer and Director

Date: February 24, 2009

FirstEnergy Corp.

AMENDED
CODE OF REGULATIONS

5/18/04

SHAREHOLDER MEETINGS

1. **Time and Place of Meetings.** All meetings of the shareholders for the election of directors or for any other purpose will be held at such time and place, within or without the State of Ohio, as may be designated by the Board of Directors or, in the absence of a designation by the Board of Directors, the Chairman of the Board of Directors, if any (the "Chairman"), the President, or the Secretary, and stated in the notice of meeting. The Board of Directors may postpone and reschedule any previously scheduled annual or special meeting of the shareholders.

2. **Annual Meeting.** An annual meeting of the shareholders will be held at such date and time as may be designated from time to time by the Board of Directors, at which meeting the shareholders will elect directors to succeed those directors whose terms expire at such meeting and will transact such other business as may be brought properly before the meeting in accordance with Regulation 9.

3. **Special Meetings.** (a) Special meetings of shareholders may be called by the Chairman or the President or by a majority of the Board of Directors acting with or without a meeting or by any person or persons who hold not less than 50% of all the shares outstanding and entitled to be voted on any proposal to be submitted at said meeting. Special meetings of the holders of shares that are entitled to call a special meeting by virtue of any Preferred Stock Designation may call such meetings in the manner and for the purposes provided in the applicable terms of such Preferred Stock Designation. For purposes of this Code of Regulations, "Preferred Stock Designation" has the meaning ascribed to such term in the Articles of Incorporation of the Corporation, as may be amended from time to time.

(b) Upon written request by any person or persons entitled to call a meeting of shareholders delivered in person or by certified mail to the Chairman, the President or the Secretary, such officer shall forthwith cause notice of the meeting to be given to the shareholders entitled to notice of such meeting in accordance with Regulation 4. If such notice shall not be given within 60 days after the delivery or mailing of such request, the person or persons requesting the meeting may fix the time of the meeting and give, or cause to be given, notice in the manner provided in Regulation 4.

4. **Notice of Meetings.** Except to the full extent that notice is legally permitted (now or hereafter) to be given by any other form of media, including any form of electronic or other communications, written notice of every meeting of the shareholders called in accordance with these Regulations, stating the time, place and purposes for which the meeting is called, will be given by or at the direction of the Chairman, the President, a Vice President, the Secretary or an Assistant Secretary (or in case of their refusal, by the person or persons entitled to call the meeting under Regulation 3). Such notice will be given not less than 7 nor more than 60 calendar days before the date of the meeting to each shareholder of record entitled to notice of such meeting. If such notice is mailed, it shall be addressed to the shareholders at their respective addresses as they appear on the records of the Corporation, and notice shall be deemed to have been given on the day so mailed. Notice of adjournment of a meeting need not be given if the time and place to which it is adjourned are fixed and announced at such meeting.

5. **Inspectors.** Inspectors of election may be appointed to act at any meeting of shareholders in accordance with Ohio law.

6. **Quorum.** To constitute a quorum at any meeting of shareholders, there shall be present in person or by proxy shareholders of record entitled to exercise not less than a majority of the voting power of the Corporation in respect of any one of the purposes for which the meeting is called, unless a greater or lesser number is expressly provided for with respect to a particular class or series of capital stock by the terms of any applicable Preferred Stock Designation. Except as may be otherwise provided in any Preferred Stock Designation, the holders of a majority of the voting power of the Corporation represented in person or by proxy at a meeting of shareholders, whether or not a quorum be present, may adjourn the meeting from time to time. For purposes of this Code of Regulations, "voting power of the Corporation" has the meaning ascribed to such term in the Articles of Incorporation of the Corporation, as may be amended from time to time.

7. **Voting.** Except as otherwise expressly provided by law, the Articles of Incorporation or this Code of Regulations, at any meeting of shareholders at which a quorum is present, a majority of the votes cast, whether in person or by proxy, on any matter properly brought before such meeting in accordance with Regulation 9 will be the act of the shareholders. An abstention shall not represent a vote cast. Every proxy must be duly executed and filed with the Secretary. A shareholder may revoke any proxy that is not irrevocable by attending the meeting and voting in person or by filing with the Secretary written notice of revocation or a later appointment. The vote upon any question brought before a meeting of the shareholders may be by voice vote, unless otherwise required by law, the Articles of Incorporation or this Code of Regulations or unless the presiding officer otherwise determines.

8. **Record Dates.** In order that the Corporation may determine the shareholders entitled to notice of or to vote at any meeting of shareholders or any adjournment thereof, the Board of Directors may fix a record date, which will not be less than 7 nor more than 60 calendar days before the date of such meeting. If no record date is fixed by the Board of Directors, the record date for determining shareholders entitled to notice of or to vote at a meeting of shareholders will be the date next preceding the day on which notice is given, or, if notice is waived, at the date next preceding the day on which the meeting is held.

9. **Order of Business.** (a) The Chairman, or such other officer of the Corporation designated by a majority of the total number of directors that the Corporation would have if there were no vacancies on the Board of Directors (such number being referred to as the "Whole Board"), will call meetings of shareholders to order and will act as presiding officer thereof. Unless otherwise determined by the Board of Directors prior to the meeting, the presiding officer of the meeting of shareholders will also determine the order of business and have the authority in his or her sole discretion to regulate the conduct of any such meeting including, without limitation, by imposing restrictions on the persons (other than shareholders of the Corporation or their duly appointed proxies) who may attend any such shareholders' meeting, by ascertaining whether any shareholder or his proxy may be excluded from any meeting of shareholders based upon any determination by the presiding officer, in his sole discretion, that any such person has unduly disrupted or is likely to disrupt the proceedings of the meeting, and by determining the circumstances in which any person may make a statement or ask questions at any meeting of shareholders.

(b) At an annual meeting of the shareholders, only such business will be conducted or considered as is properly brought before the meeting. To be properly brought before an annual meeting, business must be (i) specified in the notice of meeting (or any supplement thereto) given by or at the direction of the Chairman, the President, a Vice President, the Secretary or an Assistant Secretary in accordance with Regulation 4, (ii) otherwise properly brought before the meeting by the presiding officer or by or at the direction of a majority of the Whole Board, or (iii) otherwise properly requested to be brought before the meeting by a shareholder of the Corporation in accordance with Regulation 9(c).

(c) For business to be properly requested by a shareholder to be brought before an annual meeting, the shareholder must (i) be a shareholder of the Corporation of record at the time of the giving of the notice for such annual meeting provided for in this Code of Regulations, (ii) be entitled to vote at such meeting, and (iii) have given timely notice thereof in writing to the Secretary. To be timely, a shareholder's notice must be delivered to or mailed and received at the principal executive offices of the Corporation not less than 30 nor more than 60 calendar days prior to the annual meeting; provided, however, that in the event public announcement of the date of the annual meeting is not made at least 70 calendar days prior to the date of the annual meeting, notice by the shareholder to be timely must be so received not later than the close of business on the 10th calendar day following the day on which public announcement is first made of the date of the annual meeting. A shareholder's notice to the Secretary must set forth as to each matter the shareholder proposes to bring before the annual meeting (A) a description in reasonable detail of the business desired to be brought before the annual meeting and the reasons for conducting such business at the annual meeting, (B) the name and address, as they appear on the Corporation's books, of the shareholder proposing such business and of the beneficial owner, if any, on whose behalf the proposal is made, (C) the class and number of shares of the Corporation that are owned beneficially and of record by the shareholder proposing such business and by the beneficial owner, if any, on whose behalf the proposal is made, and (D) any material interest of such shareholder proposing such business and the beneficial owner, if any, on whose behalf the proposal is made in such business. Notwithstanding the foregoing provisions of this Code of Regulations, a shareholder must also comply with all applicable requirements of the Securities Exchange Act of 1934, as amended, and the rules and regulations thereunder with respect to the matters set forth in this Regulation 9(c). For purposes of this Regulation 9(c) and Regulation 14, "public announcement" means disclosure in a press release reported by the Dow Jones News Service, Associated Press, or comparable national news service or in a document publicly filed by the Corporation with the Securities and Exchange Commission pursuant to Sections 13, 14, or 15(d) of the Securities Exchange Act of 1934, as amended, or publicly filed by the Corporation with any national securities exchange or quotation service through which the Corporation's stock is listed or traded, or furnished by the Corporation to its shareholders. Nothing in this Regulation 9(c) will be deemed to affect any rights of shareholders to request inclusion of proposals in the Corporation's proxy statement pursuant to Rule 14a-8 under the Securities Exchange Act of 1934, as amended.

(d) At a special meeting of shareholders, only such business may be conducted or considered as is properly brought before the meeting. To be properly brought before a special meeting, business must be (i) specified in the notice of the meeting (or any supplement thereto) given by or at the direction of the Chairman, the President, a Vice President, the Secretary or an Assistant Secretary (or in case of their failure to give any required notice, the other persons entitled to give notice) in accordance with Regulation 4 or (ii) otherwise brought before the meeting by the presiding officer or by or at the direction of a majority of the Whole Board.

(e) The determination of whether any business sought to be brought before any annual or special meeting of the shareholders is properly brought before such meeting in accordance with this Regulation 9 will be made by the presiding officer of such meeting. If the presiding officer determines that any business is not properly brought before such meeting, he or she will so declare to the meeting and any such business will not be conducted or considered.

DIRECTORS

10. **Function and Qualification.** (a) Except where the law, the Articles of Incorporation, or this Code of Regulations requires action to be authorized or taken by the shareholders, all of the authority of the Corporation shall be exercised by or under the direction of the Board of Directors.

(b) In order to qualify for service as a director of the Corporation, within 90 days following election to the Board of Directors in accordance with Regulations 11, 12 and 14, each director will become and will remain the beneficial owner of not less than 100 shares of Common Stock of the Corporation, except where such ownership would be inconsistent with or prohibited by (i) any applicable law, rule, regulation, order or decree of any governmental authority or (ii) any policy, contract, commitment or arrangement authorized by the Corporation.

11. **Number, Election and Terms of Directors.** Except as may be otherwise provided in any Preferred Stock Designation, the number of the directors of the Corporation will not be less than nine nor more than 16 as may be determined from time to time only (i) by a vote of a majority of the Whole Board, or (ii) by the affirmative vote of the holders of at least 80% of the voting power of the Corporation, voting together as a single class. Except as may be otherwise provided in any Preferred Stock Designation, at each annual meeting of the shareholders of the Corporation, the directors shall be elected by plurality vote of all votes cast at such meeting and shall hold office for a term expiring at the following annual meeting of shareholders and until their successors shall have been elected; provided, that any director elected for a longer term before the annual meeting of shareholders to be held in 2005 shall hold office for the entire term for which he or she was originally elected. Except as may be otherwise provided in any Preferred Stock Designation, directors may be elected by the shareholders only at an annual meeting of shareholders. No decrease in the number of directors constituting the Board of Directors may shorten the term of any incumbent director. Election of directors of the Corporation need not be by written ballot unless requested by the presiding officer or by the holders of a majority of the voting power of the Corporation present in person or represented by proxy at a meeting of the shareholders at which directors are to be elected.

12. **Newly Created Directorships and Vacancies.** Except as may be otherwise provided in any Preferred Stock Designation, any vacancy (including newly created directorships resulting from any increase in the number of directors and any vacancies on the Board of Directors resulting from death, resignation, disqualification, removal or other cause) may be filled only (i) by the affirmative vote of a majority of the remaining directors then in office, even though less than a quorum of the Board of Directors, or by a sole remaining director or (ii) by the affirmative vote of the shareholders after a vote to increase the number of directors at a meeting called for that purpose in accordance with this Code of Regulations. Any director elected in accordance with the preceding sentence to fill a vacancy that does not result from a newly created directorship will hold office for the remainder of the full term of the director that he or she is replacing. Any director elected in accordance with the first sentence of Regulation 12 will hold office until such director's successor has been elected.

13. **Removal.** Except as may be otherwise provided in any Preferred Stock Designation, any director or the entire Board of Directors may be removed only upon the affirmative vote of the holders of at least 80% of the voting power of the Corporation, voting together as a single class.

14. **Nominations of Directors; Election.** (a) Except as may be otherwise provided in any Preferred Stock Designation, only persons who are nominated in accordance with this Regulation 14 will be eligible for election at a meeting of shareholders to be members of the Board of Directors of the Corporation.

(b) Nominations of persons for election as directors of the Corporation may be made only at an annual meeting of shareholders (i) by or at the direction of the Board of Directors or a committee thereof or (ii) by any shareholder who is a shareholder of record at the time of giving of notice provided for in this Regulation 14, who is entitled to vote for the election of directors at such meeting, and who complies with the procedures set forth in this Regulation 14. All nominations by shareholders must be made pursuant to timely notice in proper written form to the Secretary.

(c) To be timely, a shareholder's notice must be delivered to or mailed and received at the principal executive offices of the Corporation not less than 30 nor more than 60 calendar days prior to the annual meeting of shareholders; provided, however, that in the event that public announcement of the date of the annual meeting is not made at least 70 calendar days prior to the date of the annual meeting, notice by the shareholder to be timely must be so received not later than the close of business on the 10th calendar day following the day on which public announcement is first made of the date of the annual meeting. To be in proper written form, such shareholder's notice must set forth or include: (i) the name and address, as they appear on the Corporation's books, of the shareholder giving the notice and of the beneficial owner, if any, on whose behalf the nomination is made; (ii) a representation that the shareholder giving the notice is a holder of record of stock of the Corporation entitled to vote at such annual meeting and intends to appear in person or by proxy at the annual meeting to nominate the person or persons specified in the notice; (iii) the class and number of shares of stock of the Corporation owned beneficially and of record by the shareholder giving the notice and by the beneficial owner, if any, on whose behalf the nomination is made; (iv) a description of all arrangements or understandings between or among any of (A) the shareholder giving the notice, (B) the beneficial owner on whose behalf the notice is given, (C) each nominee, and (D) any other person or persons (naming such person or persons) pursuant to which the nomination or nominations are to be made by the shareholder giving the notice; (v) such other information regarding each nominee proposed by the shareholder giving the notice as would be required to be included in a proxy statement filed pursuant to the proxy rules of the Securities and Exchange Commission had the nominee been nominated, or intended to be nominated, by the Board of Directors; and (vi) the signed consent of each nominee to serve as a director of the Corporation if so elected. The presiding officer of any annual meeting may, if the facts warrant, determine that a nomination was not made in accordance with this Regulation 14, and if he or she should so determine, he or she will so declare to the meeting, and the defective nomination will be disregarded. Notwithstanding the foregoing provisions of this Regulation 14, a shareholder must also comply with all applicable requirements of the Securities Exchange Act of 1934, as amended, and the rules and regulations thereunder with respect to the matters set forth in this Regulation 14.

15. **Resignation.** Any director may resign at any time by giving written notice of his resignation to the Chairman or the Secretary. Any resignation will be effective upon actual receipt by any such person or, if later, as of the date and time specified in such written notice.

16. **Regular Meetings.** Regular meetings of the Board of Directors may be held immediately after the annual meeting of the shareholders and at such other time and place either within or without the State of Ohio as may from time to time be determined by a majority of the Whole Board. Notice of regular meetings of the Board of Directors need not be given.

17. **Special Meetings.** Special meetings of the Board of Directors may be called by the Chairman or the President on one day's notice to each director by whom such notice is not waived, given either personally or by mail, telephone, telegram, telex, facsimile or similar medium of communication, and will be called by the Chairman or the President, in like manner and on like notice, on the written request of not less than one-third of the Whole Board. Special meetings of the Board of Directors may be held at such time and place either within or without the State of Ohio as is determined by a majority of the Whole Board or specified in the notice of any such meeting.

18. **Quorum and Vote.** At all meetings of the Board of Directors, one-third of the total number of directors then in office will constitute a quorum for the transaction of business. Except for the designation of committees as hereinafter provided and except for actions required by this Code of Regulations to be taken by a majority of the Whole Board, the act of a majority of the directors present at any meeting at which a quorum is present will be the act of the Board of Directors. If a quorum is not present at any meeting of the Board of Directors, the directors present thereat may adjourn the meeting from time to time to another time or place, without notice other than announcement at the meeting, until a quorum is present.

19. **Participation in Meetings by Communications Equipment.** Meetings of the Board of Directors or of any committee of the Board of Directors may be held through any means of communications equipment if all persons participating can hear each other, and such participation will constitute presence in person at such meeting.

20. **Committees.** The Board of Directors may from time to time create an executive committee or any other committee or committees of directors to act in the intervals between meetings of the Board of Directors and may delegate to such committee or committees any of its authority other than that of filling vacancies among the Board of Directors or in any committee of the Board of Directors. No committee shall consist of less than three directors. The Board of Directors may appoint one or more directors as alternate members of any such committee to take the place of absent committee members at meetings of such committee. Unless otherwise ordered by the Board of Directors, a majority of the members of any committee appointed by the Board of Directors pursuant to this Regulation 20 shall constitute a quorum at any meeting thereof, and the act of a majority of the members present at a meeting at which a quorum is present shall be the act of such committee. Action may be taken by any such committee without a meeting by a writing or writings signed by all of its members. Any such committee may prescribe its own rules for calling and holding meetings and its method of procedure, subject to any rules prescribed by the Board of Directors, and will keep a written record of all action taken by it.

21.Compensation. The Board of Directors may establish the compensation and expense reimbursement policies for directors in exchange for membership on the Board of Directors and on committees of the Board of Directors, attendance at meetings of the Board of Directors or committees of the Board of Directors, and for other services by directors to the Corporation or any of its subsidiaries. No director that is also an officer or employee of the Corporation shall receive compensation as a director.

22.Bylaws. The Board of Directors may adopt Bylaws for the conduct of its meetings and those of any committees of the Board of Directors that are not inconsistent with the Articles of Incorporation or this Code of Regulations.

OFFICERS

23.Generally. The Corporation may have a Chairman, elected by the directors from among their number, and shall have a President, a Secretary and a Treasurer. The Corporation may also have one or more Vice Chairmen and Vice Presidents and such other officers and assistant officers as the Board of Directors may deem appropriate. If the Board of Directors so desires, it may elect a Chief Executive Officer to manage the affairs of the Corporation, subject to the direction and control of the Board of Directors. All of the officers shall be elected by the Board of Directors. Notwithstanding the foregoing, by specific action, the Board of Directors may authorize the Chairman or the President to appoint any person to any office other than Chairman, President, Secretary, or Treasurer. Any number of offices may be held by the same person, and no two offices must be held by the same person. Any of the offices may be left vacant from time to time as the Board of Directors may determine. In case of the absence or disability of any officer of the Corporation or for any other reason deemed sufficient by a majority of the Board of Directors, the Board of Directors may delegate the absent or disabled officer's powers or duties to any other officer or to any director.

24. Authority and Duties of Officers. The officers of the Corporation shall have such authority and shall perform such duties as are customarily incident to their respective offices, or as may be specified from time to time by the Board of Directors, the Chairman or the President regardless of whether such authority and duties are customarily incident to such office.

25. Compensation. The compensation of all officers and agents of the Corporation who are also members of the Board of Directors of the Corporation will be fixed by the Board of Directors or by a committee of the Board of Directors. The Board of Directors may fix, or delegate the power to fix, the compensation of the other officers and agents of the Corporation to the Chief Executive Officer or any other officer of the Corporation.

26. **Succession.** The officers of the Corporation will hold office until their successors are elected. Any officer may be removed at any time by the affirmative vote of a majority of the Whole Board. Any vacancy occurring in any office of the Corporation may be filled by the Board of Directors or by the Chairman or President as provided in Regulation 23.

STOCK

27. **Transfer and Registration of Shares.** The Board of Directors shall have authority to make such rules and regulations as they deem expedient concerning the issuance, transfer and registration of shares and may appoint transfer agents and registrars thereof.

28. **Substituted Certificates.** Any person claiming a certificate for shares to have been lost, stolen or destroyed shall make an affidavit or affirmation of that fact, shall give the Corporation and its transfer agent or agents a bond of indemnity or other assurance satisfactory to the Board of Directors or a committee thereof or to the President or a Vice President and the Secretary or the Treasurer, whereupon a new certificate may be executed and delivered of the same class and series or type and for the same number of shares as the one alleged to have been lost, stolen or destroyed.

29. **Voting Of Shares Held by the Corporation.** Unless otherwise ordered by the Board of Directors, the President in person or by proxy or proxies appointed by him will have full power and authority on behalf of the Corporation to vote, act and consent with respect to any shares issued by other corporations that the Corporation may own.

30. **Owners of Shares.** The Corporation will be entitled to treat the person in whose name shares are registered on the books of the Corporation as the absolute owner thereof, and will not be bound to recognize any equitable or other claim to, or interest in, such share on the part of any other person, whether or not the Corporation has knowledge or notice thereof, except as expressly provided by applicable law.

INDEMNIFICATION AND INSURANCE

31. **Indemnification.** The Corporation shall indemnify, to the full extent then permitted by law, any person who was or is a party or is threatened to be made a party to any threatened, pending or completed action, suit or proceeding, whether civil, criminal, administrative or investigative, by reason of the fact that he is or was a member of the Board of Directors or an officer, employee or agent of the Corporation, or is or was serving at the request of the Corporation as a director, trustee, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise. The Corporation shall pay, to the full extent then required by law, expenses, including attorney's fees, incurred by a member of the Board of Directors in defending any such action, suit or proceeding as they are incurred, in advance of the final disposition thereof, and may pay, in the same manner and to the full extent then permitted by law, such expenses incurred by any other person. The indemnification and payment of expenses provided hereby shall not be exclusive of, and shall be in addition to, any other rights granted to those seeking indemnification under any law, the Articles of Incorporation, any agreement, vote of shareholders or disinterested members of the Board of Directors, or otherwise, both as to action in official capacities and as to action in another capacity while he or she is a member of the Board of Directors, or an officer, employee or agent of the Corporation, and shall continue as to a person who has ceased to be a member of the Board of Directors, trustee, officer, employee or agent and shall inure to the benefit of the heirs, executors and administrators of such a person.

32. **Insurance.** The Corporation may, to the full extent then permitted by law and authorized by the Board of Directors, purchase and maintain insurance or furnish similar protection, including but not limited to trust funds, letters of credit or self-insurance, on behalf of or for any persons described in Regulation 31 against any liability asserted against and incurred by any such person in any such capacity, or arising out of his status as such, whether or not the Corporation would have the power to indemnify such person against such liability. Insurance may be purchased from or maintained with a person in which the Corporation has a financial interest.

33. **Agreements.** The Corporation, upon approval by the Board of Directors, may enter into agreements with any persons whom the Corporation may indemnify under this Code of Regulations or under law and undertake thereby to indemnify such persons and to pay the expenses incurred by them in defending any action, suit or proceeding against them, whether or not the Corporation would have the power under law or this Code of Regulations to indemnify any such person.

GENERAL

34. **Fiscal Year.** The fiscal year of the Corporation will end on the thirty-first day of December in each calendar year or such other date as may be fixed from time to time by the Board of Directors.

35. **Seal.** The Board of Directors may adopt a corporate seal and use the same by causing it or a facsimile thereof to be impressed or affixed or reproduced or otherwise.

36. **Amendments.** Except as otherwise provided by law or by the Articles of Incorporation or this Code of Regulations, these Regulations or any of them may be amended in any respect or repealed at any time at any meeting of shareholders, provided that any amendment or supplement proposed to be acted upon at any such meeting has been described or referred to in the notice of such meeting. Notwithstanding the foregoing sentence or anything to the contrary contained in the Articles of Incorporation or this Code of Regulations, Regulations 1, 3(a), 9, 11, 12, 13, 14, 31 and 36 may not be amended or repealed by the shareholders, and no provision inconsistent therewith may be adopted by the shareholders, without the affirmative vote of the holders of at least 80% of the voting power of the Corporation, voting together as a single class. Notwithstanding the foregoing provisions of this Regulation 36, no amendment to Regulations 31, 32 or 33 will be effective to eliminate or diminish the rights of persons specified in those Regulations existing at the time immediately preceding such amendment.

{24002-1}

2009-2011 Performance Share Award Agreement Template

This Performance Share Award Agreement (the "Award Agreement") with the Participant is effective as of the 1st day of January 2009 ("Grant Date"), and is not in lieu of salary or any other compensation for services. The Performance Period for this Award is January 1, 2009 through December 31, 2011. For the purposes of this Award Agreement, the term "Company" means FirstEnergy Corp., its successors and/or its Subsidiaries, singularly or collectively.

SECTION ONE - AWARD

As of the Grant Date, in accordance with the FirstEnergy Corp. 2007 Incentive Plan (the "Plan") and the terms and conditions of this Award Agreement, the Company grants to the Participant an award of Performance Shares. The Performance Shares will be placed into a Performance Share account until paid out or forfeited.

Until the Performance Period ends pursuant to the terms and conditions described in this Award Agreement, the Performance Share account of the Participant will be credited with an amount per each Performance Share (the "Dividend Equivalent") equal to the amount per share of any cash dividends declared by the Board with a record date on or after the Grant Date on the outstanding common stock of the Company. Such Dividend Equivalents will be credited in the form of an additional number of Performance Shares (which Performance Shares, from the time of crediting, will be deemed to be in addition to and part of the base number of Performance Shares awarded by this Award Agreement for all purposes hereunder). The additional number of Performance Shares will be equal to the aggregate amount of Dividend Equivalents credited on this Award on the respective dividend payment date divided by the average of the high and low prices per share of common stock on the respective dividend payment date. The Performance Shares attributable to the Dividend Equivalents will be either paid out or forfeited, as appropriate, under the same terms and conditions under this Award Agreement that apply to the other Performance Shares.

The value of the Participant's account at the end of the three-year Performance Period will be based on the average of the high and low prices of common stock for the month of December 2011 and may be adjusted upward or downward based upon the total shareholder return ("TSR") of common stock relative to an energy services company index during the same three-year period. If the TSR rating is at or above the 90th percentile, the payout will be 200% of the account value. If the TSR is at the 50th percentile, the payout will be 100% of the account value. If the TSR is at the 40th percentile, the payout will be 50% of the account value. Payouts for a ranking above the 40th percentile and below the 90th percentile will be interpolated. For a TSR ranking below the 40th percentile, no payout will be made.

The payout under this Award will be made between February 15 and March 15, 2012 if the payout is on account of the completion of the Performance Period and satisfaction of the TSR ranking, as specified above, or, if earlier, on the payment date as specified in Section Two below (all payment dates are referred to as "Payment Date"). The payout will be made in cash; however, the Participant may elect to defer receipt of any payout under the provisions of the FirstEnergy Corp. Executive Deferred Compensation Plan. The election to defer shall be made in a manner as required under administrative rules established by the Company and shall be made in a manner that complies with Section 409A of the Internal Revenue Code ("Section 409A").

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SECTION TWO - GENERAL TERMS

Forfeiture

The Participant shall forfeit all or a portion of the Award and any rights hereunder to receive the Award upon the occurrence of any of the following events before the expiration of the Performance Period:

<u>Event of Participant</u>	<u>Effect on Award</u>	<u>Further Information</u>	<u>Payment Form and Time</u>
Termination due to retirement (including early retirement)	Account balance prorated based on full months of service during Performance Period.	As provided under 9.5 of the Plan.	Single lump sum between February 15 and March 15, 2012.
Termination due to Disability	Account balance prorated based on full months of service during Performance Period.	As provided under 9.5 of the Plan.	Single lump sum between February 15 and March 15, 2012.
Death	Account balance prorated based on full months of service during Performance Period.	Payout made to beneficiary as provided under Article 15 of the Plan or by will or by the laws of descent and distribution.	Single lump sum as soon as practicable after the Participant's death but by the earlier of March 15 following the calendar year of death or the end of the 90 day period commencing on the date of death.
Termination for Cause	Award immediately forfeited.	Termination for Cause as provided under 2.7 of the Plan.	N/A
Termination in which the Participant qualifies for and receives benefits under the FirstEnergy Severance Plan, if offered	Account balance prorated based on full months of service during Performance Period.	Refer to the FirstEnergy Severance Plan.	Single lump sum between February 15 and March 15, 2012.

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<u>Event of Participant</u>	<u>Effect on Award</u>	<u>Further Information</u>	<u>Payment Form and Time</u>
Other Termination (including resignation)	Award immediately forfeited.		N/A
Transfer out of an executive eligible position and employed by the Company on December 31, 2011	Account balance prorated based on full months in an executive eligible position during Performance Period.	If the Participant terminates prior to December 31, 2011, the Participant may still be entitled to a prorated account balance as described above.	Single lump sum between February 15 and March 15, 2012.

Prorated awards will be calculated using the average high and low prices of common stock for the month of December 2011 or, in the case of death, a thirty day period ending immediately before the date of death and the most recent quarterly TSR factor.

In the event of a Change in Control, this Award will be fully vested and will be paid in a single lump sum as soon as practicable but by the earlier of March 15 following the year in which the Change in Control occurs or the end of the 90-day period commencing on the date of the consummation of the Change in Control but subject to such other terms as determined by the Committee. For purposes of this Award, the term "Change in Control" means a change in control that satisfies both a Change in Control as defined in the Plan and a "change in control event" as defined in Treasury Regulation Section 1.409A-3(i)(5).

Withholding Tax

The Company shall have the right to deduct, withhold or require the Participant to surrender a cash amount sufficient to satisfy all federal, state and local taxes required by law to be withheld in connection with the payment of benefits under this Award.

Shareholder Rights

The Participant shall have no rights as a shareholder of the Company, including voting rights, with respect to the Award.

Effect on the Employment Relationship

This grant of Performance Shares is voluntary and made on a one-time basis and does not constitute a commitment to make any future awards. Nothing by this Award or in this Award Agreement guarantees employment with the Company, nor does this Award or Award Agreement confer any special rights or privileges to the Participant as to the terms of employment.

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Administration

1. This Award is governed by the laws of the State of Ohio without giving effect to the principles of the conflicts of laws.
2. The administration of this Award and the Plan will be performed in accordance with Article 3 of the Plan.
3. All determinations and decisions made by the Committee, the Board, or any delegate of the Committee as to the provisions of the Plan shall be final, conclusive, and binding on all persons.
4. The terms of this Award Agreement are governed at all times by the official text of the Plan and in no way alter or modify the Plan.
5. If a term is capitalized but not defined in this Award Agreement, it has the meaning given to it in the Plan.
6. To the extent a conflict exists between the terms of this Award Agreement and the provisions of the Plan, the provisions of the Plan shall govern.
7. The terms and conditions of this Award Agreement may be modified by the Committee:
 - (a) in any case permitted by the terms of the Plan or this Award Agreement;
 - (b) with the written consent of the Participant; or
 - (c) without the consent of the Participant, if the amendment is either not materially adverse to the interests of the Participant or is necessary or appropriate in the view of the Committee to conform with, or to take into account, applicable law, including either exemption from or compliance with any applicable tax law.

409A

It is intended that this Award and the compensation and benefits hereunder be exempt from Section 409A, and this Award shall be so construed and administered. In the event that the Committee reasonably determines that any compensation or benefits payable under this Award Agreement may be subject to taxation under Section 409A, the Committee shall have the authority to adopt, prospectively or retroactively, such amendments to this Award Agreement or to take any other actions it determines necessary or appropriate to (a) exempt the compensation and benefits payable under this Award from Section 409A or (b) comply with the requirements of Section 409A. The Committee, in its sole discretion, shall determine to what extent, if any, this Award Agreement must be amended, modified, or reformed. In no event, however, shall any provision of this Award Agreement be construed to require the Company to provide any gross-up for the tax consequences of any provisions of, or payments under, this Award and the Company shall have no responsibility for tax consequences to Participant (or the Participant's beneficiary) resulting from the terms or operation of this Award.

Notwithstanding any other provision in this Award Agreement to the contrary, if the Award is deemed to be subject to the requirements of Section 409A and not exempt from such coverage:

1. A Participant shall not be treated as having a termination of employment unless the Participant has a "separation from service" as defined in regulations under, and for purposes of, Section 409A.

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2. If a Participant is a "specified employee," as determined under the Company's policy for determining specified employees on the date of a "separation from service," all payments under this Award Agreement that would otherwise be paid or provided during the first six (6) months following such separation from service (other than payments, benefits, or reimbursements that are treated as separation pay under Section 1.409A-1(b)(9)(v) of the Treasury Regulations, short-term deferrals under Section 1.409A-1(b)(4) of the Treasury Regulations or other payments exempted under the Treasury Regulations for Section 409A) shall be accumulated through and paid or provided (together with interest at the applicable federal rate under Section 7872(f)(2)(A) of the Internal Revenue Code of 1986, as amended, in effect on the date of the separation from service) as soon as practicable following the six (6) month anniversary of such separation from service but not later than the end of the taxable year in which the six (6) month anniversary occurs. Notwithstanding the foregoing, payments delayed pursuant to this paragraph shall commence as soon as practicable following the date of death of the Participant prior to the end of the 6 month period but in no event later than ninety (90) days following the date of death.

SECTION THREE - TRANSFER OF AWARD

The Performance Shares are not transferable during the life of the Participant. Only the Participant shall have the right to receive payout of the Award, unless the Participant is deceased, at which time the payout may be paid to the Participant's beneficiary (as designated under Article 15 of the Plan), or pursuant to the Participant's will or the laws of descent and distribution.

I acknowledge receipt of this Performance Share Award and I accept and agree with the terms and conditions stated above.

FirstEnergy Corp.

By _____

(Signature of Participant)

(Date)

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**FirstEnergy Corp.
Performance-Adjusted Restricted Stock Unit Award Agreement**

This Restricted Stock Unit Award Agreement (the "Award Agreement") is entered into as of March 2, 2009 (the "Grant Date") between FirstEnergy Corp. and the Participant. For the purposes of this Award Agreement, the term "Company" means FirstEnergy Corp., its successors and/or its Subsidiaries, singularly or collectively.

SECTION ONE - AWARD

As of the Grant Date, in accordance with the FirstEnergy Corp. 2007 Incentive Plan (the "Plan") and the terms and conditions of this Award Agreement, the Company grants to the Participant the right to receive, at the end of the Period of Restriction (as defined below) a number of shares of common stock of the Company equal to number of restricted stock units set forth above (the "Restricted Stock Units"), subject to adjustment based on the Company's performance as described below.

Dividend Equivalents

Until the expiration of the Period of Restriction pursuant to the terms and conditions of this Award Agreement, the Participant will be credited on the books and records of the Company with an amount per each Restricted Stock Unit (the "Dividend Equivalent") equal to the amount per share of any cash dividends declared by the Board with a record date on or after the Grant Date on the outstanding common stock of the Company. Such Dividend Equivalents will be credited in the form of an additional number of Restricted Stock Units (which Restricted Stock Units, from the time of crediting, will be deemed to be in addition to and part of the base number of Restricted Stock Units awarded by this Award Agreement for all purposes hereunder). The additional number of Restricted Stock Units will be equal to the aggregate amount of Dividend Equivalents credited on this Award on the respective dividend payment date divided by the average of the high and low prices per share of common stock on the respective dividend payment date. The Restricted Stock Units attributable to the Dividend Equivalents will be either delivered or forfeited, as appropriate, under the same terms and conditions under this Award Agreement that apply to the other Restricted Stock Units.

SECTION TWO - GENERAL TERMS

This Award Agreement is subject to the Plan and the following terms and conditions:

Period of Restriction

For the purposes of this Award Agreement, "Period of Restriction" means the period beginning on the Grant Date set forth above and ending on the earliest of:

- a) 5:00 p.m. Akron time on March 2, 2012;
- b) The date of the Participant's death;
- c) The date that the Participant's employment is terminated due to Disability; or
- d) The date of a Change in Control.

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Notwithstanding that the Period of Restriction ends upon a termination of employment due to Disability, Restricted Stock Units awarded pursuant to this Award Agreement shall be subject to limited restrictions after a termination due to Disability as provided in this Award Agreement.

Performance Adjustment

If the Payment Date (as defined below under "Delivery of Common Stock") is March 2, 2012, the actual number of shares issuable under the Restricted Stock Units awarded pursuant to this Award Agreement may be adjusted upward or downward by fifty percent (50%) from the number of Shares issuable under the Restricted Stock Units (as set forth in Section One of this Award Agreement), based on the Company's performance against three key metrics. The Committee has identified the three performance metrics as Earnings Per Share, Safety, and Operational Performance Index.

The Company's performance against the three performance metrics will be evaluated, with respect to each performance metric, by comparing the average of the Company's actual annual performance over the three years beginning in the year of grant of this Award to the average of the annual target performance levels established over the same period to determine whether the Company has exceeded, met or fallen below the target performance level for that particular performance metric. The annual target performance level relating to each metric for each year will be set by the Committee in February of that year. The following guidelines will be used to adjust the number of shares issuable under the Restricted Stock Units awarded pursuant to this Award Agreement:

- If the Company's average annual performance meets or exceeds the average of the target performance levels established by the Committee with respect to all three of the performance metrics identified above, the number of Shares issuable under the Restricted Stock Units (as set forth in Section One of this Award Agreement) will be increased by fifty percent (50%).
- If the Company's average annual performance falls below the average of the target performance levels established by the Committee with respect to all three of the performance metrics identified above, the number of Shares issuable under the Restricted Stock Units (as set forth in Section One of this Award Agreement) will be decreased by fifty percent (50%).
- If the Company's average annual performance meets or exceeds the average of the target performance levels established by the Committee with respect to one or more of the performance metrics identified above, but falls below the average of the target performance levels with respect to one or more of the other performance metrics, the number of Shares issuable under the Restricted Stock Units (as set forth in Section One of this Award Agreement) will not be adjusted.

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Delivery of Common Stock

The date that shares of common stock shall be issued to the Participant (the "Payment Date") shall be as follows for each specified event:

- As soon as practicable, but not later than ninety (90) days, after March 2, 2012 if the payment is on account of the expiration of the Period of Restriction set forth in paragraph a) of the subsection entitled "Period of Restriction" above; the Participant's termination of employment upon retirement (as defined under the then established rules of the Company or any of its Subsidiaries, as the case may be); the Participant's termination of employment due to Disability as set forth in paragraph c) of the subsection entitled "Period of Restriction" above; the Participant's involuntary termination under conditions in which the Participant qualifies for and receives an employer severance benefit that is offered, and executes an agreement to release the Company in full against any and all claims as required by (and per the timing requirements in) the arrangement or plan providing the employer severance benefit; or if the Participant continues to be employed by the Company but ceases to be employed in an executive position during the three-year Period of Restriction; or, if earlier,
- As soon as practicable, but not later than ninety (90) days, after the expiration of the Period of Restriction due to the Participant's death or the date of a Change in Control pursuant to paragraph b) or d) of the subsection entitled "Period of Restriction" above. If the Payment Date is pursuant to paragraph d), the Participant will receive a payout equal to the number of Shares equal to the full number of Restricted Stock Units granted in this Award Agreement.

As soon as practicable after the Payment Date, the Company shall deliver to the Participant Shares of common stock under the Restricted Stock Units. The Company will deliver a number of Shares equal to the number of Restricted Stock Units awarded under this Award Agreement, as adjusted, less any Shares sold to cover the tax obligations in accordance with the subsection entitled "Withholding Tax" below; provided that, no fractional Shares will be delivered and any fractional Shares to which the Participant would otherwise be entitled will be rounded up to the next full Share. All Shares delivered will be registered in the name of the Participant and will be transferred to and held in book entry form in a dividend reinvestment account in the name of the Participant.

Change in Control

For purposes of this Award, the term "Change in Control" means a change in control that satisfies both a Change in Control as defined in the Plan and a "change in control event" as defined in Treasury Regulation Section 1.409A-3(i)(5).

Withholding Tax

The Company shall sell Shares on the open market in an amount sufficient to satisfy all federal, state, and local taxes required by law to be withheld in connection with the delivery of Shares of common stock granted under this Award Agreement.

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Forfeiture

The Participant shall forfeit all of the Restricted Stock Units and any right under this Award Agreement to receive Shares of common stock upon the occurrence of any of the following events before the expiration of the Period of Restriction:

- Termination of employment with the Company for any reason; provided, however, that no forfeiture shall occur if termination of employment occurs upon or after a Change in Control.
- Any attempt to sell, transfer, pledge, assign or otherwise alienate or hypothecate the Restricted Stock Units or the right to receive the common stock issuable under the Restricted Stock Units in violation of this Award Agreement.

Notwithstanding the above, if the Participant dies, has a termination of employment upon retirement, (as defined under the then established rules of the Company or any of its Subsidiaries, as the case may be), has a termination of employment due to Disability, is involuntarily terminated under conditions in which the Participant qualifies for and receives an employer severance benefit that is offered, and executes an agreement to release the Company in full against any and all claims as required by (and per the timing requirements in) the arrangement or plan providing the employer severance benefit; or if the Participant continues to be employed by the Company until March 2, 2012 but ceases to be employed in an executive position during the three-year Period of Restriction, the Restricted Stock Units awarded to the Participant under this Award Agreement will be forfeited and/or payable as follows:

- If the Participant dies, terminates employment as described above or ceases to be employed in an executive position prior to a full month after the Grant Date, all Restricted Stock Units earned will be forfeited upon the death or termination.
- If the Participant dies, terminates employment as described above or ceases to be employed in an executive position after the lapse of a full month or more after the Grant Date, the Participant will be entitled to a prorated number of Restricted Stock Units. The proration will be calculated by multiplying the number of Restricted Stock Units awarded by the number of full months served after the Grant Date, divided by thirty-six months. The prorated Restricted Stock Units will then be adjusted upward or downward by the performance factors in accordance with the provisions under the subsection "Performance Adjustment" (as determined by the Committee), except that no adjustment is made upon death. All fractional shares will be rounded up to the next full share. The remaining portion of Restricted Stock Units awarded will be forfeited.

Upon the occurrence of any of the above forfeiture events (for which no exception has been made as set forth above) before the expiration of the Period of Restriction, the Restricted Stock Units that are to be forfeited as described above (either in full or in part), shall be forfeited by the Participant to the Company. At the time of such forfeiture, the Participant's interest in the Restricted Stock Units and the common stock issuable under the Restricted Stock Units shall terminate, unless such forfeiture is waived in the sole discretion of the Committee.

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Shareholder Rights

The Participant shall have no rights as a shareholder of the Company, including voting rights, with respect to the Restricted Stock Units until the issuance of common stock upon expiration of the Period of Restriction.

Effect on the Employment Relationship

The grant of Restricted Stock Units is voluntary and made on a one-time basis and does not constitute a commitment to make any future awards. Nothing by this Award or in this Award Agreement guarantees employment with the Company or any Subsidiary, nor does this Award or Award Agreement confer any special rights or privileges to the Participant as to the terms of employment.

Adjustments

In the event of any merger, reorganization, consolidation, recapitalization, separation, liquidation, stock dividend, stock split, combination, distribution, or other change in corporate structure of the Company affecting the common stock, the Committee will adjust the number and class of securities granted under this Award Agreement in a manner determined by the Committee, in its sole discretion, to be appropriate to prevent dilution or enlargement of the Restricted Stock Units granted under this Award Agreement.

Administration

1. This Award Agreement is governed by the laws of the State of Ohio without giving effect to the principles of conflicts of laws.
2. The administration of this Award Agreement and the Plan will be performed in accordance with Article 3 of the Plan.
3. All determinations and decisions made by the Committee, the Board, or any delegate of the Committee as to the provisions of the Plan shall be final, conclusive, and binding on all persons.
4. The terms of this Award Agreement are governed at all times by the official text of the Plan and in no way alter or modify the Plan.
5. If a term is capitalized but not defined in this Award Agreement, it has the meaning given to it in the Plan.
6. To the extent a conflict exists between the terms of this Award Agreement and the provisions of the Plan, the provisions of the Plan shall govern.
7. The terms and conditions of this Award may be modified by the Committee:
 - (a) in any case permitted by the terms of the Plan or this Award Agreement;
 - (b) with the written consent of the Participant; or
 - (c) without the consent of the Participant if the amendment is either not materially adverse to the interests of the Participant or is necessary or appropriate in the view of the Committee to conform with, or to take into account, applicable law, including either exemption from or compliance with any applicable tax law.

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409A

It is intended that this Award Agreement and the compensation and benefits hereunder either be exempt from, or comply with, Section 409A of the Internal Revenue Code ("Section 409A"), and this Award Agreement shall be so construed and administered. In the event that the Committee reasonably determines that any compensation or benefits payable under this Award Agreement may be subject to taxation under Section 409A, the Committee shall have the authority to adopt, prospectively or retroactively, such amendments to this Award Agreement or to take any other actions it determines necessary or appropriate to (a) exempt the compensation and benefits payable under this Award Agreement from Section 409A or (b) comply with the requirements of Section 409A. The Committee, in its sole discretion, shall determine to what extent, if any, this Award must be amended, modified or reformed. In no event, however, shall this section or any other provisions of this Award Agreement be construed to require the Company to provide any gross-up for the tax consequences of any provisions of, or payments under, this Award Agreement and the Company shall have no responsibility for tax consequences to Participant (or the Participant's beneficiary) resulting from the terms or operation of this Award Agreement.

Notwithstanding any other provision in this Award Agreement to the contrary, in the event a benefit payable under this Award Agreement is subject to the requirements of Section 409A:

1. A Participant shall not be treated as having a termination of employment unless the Participant has a "separation from service" as defined in regulations under, and for purposes of, Section 409A.
2. If a Participant is a "specified employee," as determined under the Company's policy for determining specified employees on the date of a "separation from service," all payments under this Award Agreement that would otherwise be paid or provided during the first six (6) months following such separation from service (other than payments, benefits, or reimbursements that are treated as separation pay under Section 1.409A-1(b)(9)(v) of the Treasury Regulations, short-term deferrals under Section 1.409A-1(b)(4) of the Treasury Regulations or other payments exempted under the Treasury Regulations for Section 409A) shall be accumulated through and paid or provided (together with interest at the applicable federal rate under Section 7872(f)(2)(A) of the Internal Revenue Code of 1986, as amended, in effect on the date of the separation from service) as soon as practicable following the six (6) month anniversary of such separation from service but not later than the end of the taxable year in which the six (6) month anniversary occurs. Notwithstanding the foregoing, payments delayed pursuant to this paragraph shall commence as soon as practicable following the date of death of the Participant prior to the end of the 6 month period but in no event later than ninety (90) days following the date of death.

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SECTION THREE - TRANSFER OF AWARD

Neither the Restricted Stock Units nor the right to receive the common stock issuable under the Restricted Stock Units are transferable during the life of the Participant. Only the Participant shall have the right to receive the common stock issuable under this Award Agreement, unless the Participant is deceased, at which time the common stock issuable under this Award Agreement may be issued to the Participant's beneficiary (as designated under Article 15 of the Plan), or pursuant to the Participant's will or the laws of descent and distribution.

FirstEnergy Corp.

By _____
Corporate Secretary

I acknowledge receipt of this Restricted Stock Unit Award Agreement and I accept and agree with the terms and conditions stated above.

(Signature of Participant)

(Date)

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FIRSTENERGY CORP.
DEFERRED COMPENSATION PLAN
FOR OUTSIDE DIRECTORS

Effective December 31, 1997
Amended and Restated January 1, 2005

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TABLE OF CONTENTS

	<u>Page</u>
ARTICLE 1 – GENERAL	1
1.1 Preamble	1
1.2 Purpose	1
1.3 Payment Method	1
1.4 Status under Laws	1
1.5 Definitions	2
ARTICLE 2 – DEFERRALS	7
2.1 Written Election to Defer Fees	7
2.2 Election Upon Becoming a Director	7
2.3 Election Irrevocable	7
2.4 Transfers from Other Plans	7
ARTICLE 3 – ACCOUNTS AND INVESTMENT FUNDS	8
3.1 Deferred Fee Account	8
3.2 Transfer Account	8
3.3 Other Accounts and Subaccounts	9
3.4 Investment Funds	9
3.5 Credits to Investment Funds	9
3.6 Reporting	10
ARTICLE 4 – PAYMENT TO DIRECTOR	15
4.1 Distribution Election – Separation from Service	11
4.2 Accelerated Distribution	12
4.3 Withdrawal	12
4.4 Financial Hardship Distributions	13
4.5 Special Circumstance	14
4.6 Small Accounts	14
ARTICLE 5 – BENEFICIARY	15
5.1 Beneficiary Designation	15
5.2 Distribution Election	15
5.3 Change of Beneficiary	15
5.4 Payment of Benefit upon Death	15
ARTICLE 6 – ASSIGNMENT	16
ARTICLE 7 – ADMINISTRATION	16
7.1 Administrator	16
7.2 Powers of Administrator	17
7.3 Delegation	17

	<u>Page</u>
ARTICLE 8 – CLAIMS	17
8.1 Claim	17
8.2 Initial Claim Review	17
8.3 Review of Claim	18
8.4 Review of Claims on and after a Change in Control	20
ARTICLE 9 – AMENDMENT, TERMINATION AND PARTICIPATION	20
9.1 Amendment by Board	20
9.2 Termination by the Company	21
9.3 Automatic Cessation of Bonus Credit and Dividends	21
9.4 Distribution of Benefits on Plan Termination	21
9.5 Participation by Affiliates	22
ARTICLE 10 – UNFUNDED PLAN	23
10.1 Bookkeeping Entries	23
10.2 Trusts, Insurance Contracts or Other Investment	23
ARTICLE 11 – MISCELLANEOUS	23
11.1 Severability	23
11.2 Liability for Benefits	23
11.3 Applicable Law	24
11.4 Not a Contract	24
11.5 Successors	24
11.6 Distribution under Terms of the Trust or in the Event of Taxation	24
11.7 Insurance	25
11.8 Legal Representation	25
11.9 Code Section 409A	26
ATTACHMENT 2.4-A	27
ATTACHMENT 2.4-B	28
ATTACHMENT 2.4-C	29

FIRSTENERGY CORP.
DEFERRED COMPENSATION PLAN
FOR OUTSIDE DIRECTORS

ARTICLE 1 — GENERAL

1.1 Preamble

The FirstEnergy Corp. Deferred Compensation Plan for Outside Directors (the "Plan") was initially established on December 31, 1997 as the FirstEnergy Corp. Deferred Compensation Plan for Directors. The Ohio Edison Company Deferred Compensation Plan for Directors was merged into the Plan effective as of December 31, 1997 and the Centerior Energy Corporation Deferred Compensation Plan for Directors was merged into the Plan effective as of January 1, 2000. The Plan was restated as of November 7, 2001. This restatement of the Plan is effective as of January 1, 2005 in order to comply with Code Section 409A and supersedes all prior versions of this Plan and all prior arrangements and understandings regarding the deferral of fees by Directors.

1.2 Purpose

The purpose of this Plan is to provide a benefit to Directors by giving them the opportunity to defer certain fees in accordance with the provisions of the Plan. The Plan is also intended to advance the interests of the Company and its Affiliates by providing a benefit which attracts and retains the services of qualified persons who are not employees of the Company or its Affiliates to serve as Directors.

1.3 Payment Method

Payment of an equity retainer is in the form of Company common stock, which can be deferred into a Deferred Stock Fund. Cash retainers, meeting fees, chairperson fees, and any additional annual cash retainer paid to a non-employee Chairman of the Board, will be paid in cash, but can be paid in stock or deferred into a Deferred Fee Account based on an annual election made by the Director.

1.4 Status under Laws

The Plan does not provide benefits to employees of the Company or any Affiliate and, accordingly, is not subject to the provisions of the Employee Retirement Income Security Act of 1974. The Plan shall be unfunded for purposes of the Code and is not intended to qualify under Code Section 401(a).

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

1.5 Definitions

As used in the Plan, the following terms shall have the following meanings:

- (a) "Accounts" means bookkeeping accounts maintained on behalf of each Participant and includes a Participant's Deferred Fee Account, Transfer Account and such other accounts as may be established in accordance with the directions of the Committee.
- (b) "Administrator" means the Committee or such other person or persons appointed in accordance with Section 7.1 .
- (c) "Affiliate" means a member of the affiliated group of corporations as defined in Code Section 414(b) and (c) except that in applying Code Section 1563 "50 percent" shall be substituted for "80 percent" that includes the Company. An Affiliate may elect to participate in this Plan in accordance with Section 9.5 and such election may be approved by the Company.
- (d) "Appeals Committee" means the committee appointed to review claims denied by the Administrator and to have such other discretionary powers and duties as provided by Section 8.3 .
- (e) "Beneficiary" means one or more persons, trust, estates or other entities, designated in accordance with Article 5 , that are entitled to receive benefits under this Plan upon the death of a Participant. A Beneficiary is a general unsecured creditor of the Company or of the Affiliate which maintains the Accounts and provides any benefits under this Plan.
- (f) "Board" means the board of directors of the Company.
- (g) "Bonus Credit" means an amount credited to a Participant's Account as provided in Section 3.5(b)(1).
- (h) "Change in Control" means any of the following:

(1) The acquisition by any Person (as such term is used in Section 13(d)(3) or 14(d)(2) of the Securities Exchange Act of 1934 (the "Exchange Act"), as amended) of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of fifty percent (50%) or more (twenty five percent (25%) if such Person proposes any individual for election to the Board or any member of the Board is a representative of such Person) of either (i) the then outstanding shares of common stock of the Company (the "Outstanding Company Common Stock") or (ii) the combined voting power of the then outstanding voting securities of the Company entitled to vote generally in the election of Directors (the "Outstanding Company Voting Securities"); provided, however, that the following acquisitions shall not constitute a Change in Control: (i) any acquisition directly from the Company (excluding an acquisition by virtue of the exercise of a conversion privilege); (ii) any acquisition by the Company; (iii) any acquisition by any employee benefit plan (or related trust) sponsored or maintained by the Company or any corporation controlled by the Company; or (iv) any acquisition by any corporation pursuant to a reorganization, merger or consolidation (collectively "Reorganization") if, following such Reorganization the conditions described in clauses (i), (ii), and (iii) of paragraph (3) of this Subsection (h) are satisfied; or

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

(2) Individuals who, as of the date hereof, constitute the Board (the "Incumbent Board") cease for any reason to constitute at least a majority of the Board; provided, however, that any individual becoming a director subsequent to the date hereof whose election, or nomination for election by the Company's shareholders, was approved by a vote of at least a majority of the directors then comprising the Incumbent Board shall be considered as though such individual were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as a result of either an actual or threatened election contest (within the meaning of solicitations subject to as such terms are used in Rule 14a 12(c) of Regulation 14A promulgated under the Exchange Act or any such successor rule) or other actual or threatened solicitation of proxies or consent by or on behalf of a Person other than the Board; or

(3) Consummation of a Reorganization, merger, or consolidation or sale or other disposition of all or substantially all of the assets of the Company, in each case, unless, following such Reorganization (i) more than seventy-five percent (75%) of, respectively, the then outstanding shares of common stock of the corporation resulting from such Reorganization, merger or consolidation or acquiring such assets and the combined voting power of the then outstanding voting securities of such corporation entitled to vote generally in the election of directors is then beneficially owned, directly or indirectly, by all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the Outstanding Company Common Stock and Outstanding Company Voting Securities immediately prior to such Reorganization, merger, consolidation or sale or other disposition of assets in substantially the same proportions as their ownership, immediately prior to such Reorganization of the Outstanding Company Common Stock and Outstanding Company Voting Securities, as the case may be, (ii) no Person (excluding the Company, any holding company formed by the Company to become the parent of the Company, any employee benefit plan (or related trust) of the Company or such corporation resulting from such Reorganization and any Person beneficially owning, immediately prior to such Reorganization directly or indirectly, twenty-five percent (25%) or more of, respectively, the Outstanding Company Common Stock, or Outstanding Company Voting Securities, as the case may be) beneficially owns, directly or indirectly, twenty-five percent (25%) or more of, respectively, the then outstanding shares of common stock of the corporation resulting from such Reorganization or the combined voting power of the then outstanding voting securities of such corporation entitled to vote generally in the election of directors and (iii) at least a majority of the members of the board of directors of the corporation resulting from such Reorganization were members of the Incumbent Board at the time of the execution of the initial agreement providing for such Reorganization; or

(4) Approval by the shareholders of the Company of (i) a complete liquidation or dissolution of the Company. A Change in Control may occur only with respect to the Company. A change in ownership of common stock of an Affiliate or subsidiary, change in membership of a board of directors of an Affiliate or subsidiary, the sale of assets of an Affiliate or subsidiary, or any other event described in this Subsection (h) that occurs only with respect to an Affiliate or subsidiary does not constitute a Change in Control.

(i) "Code" means the Internal Revenue Code of 1986, as amended and any regulations or other guidance promulgated thereunder.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

- (j) "Committee" means the Compensation Committee of the Board.
- (k) "Company" means FirstEnergy Corp., an Ohio corporation.
- (l) "Corporate Secretary" means the Corporate Secretary of FirstEnergy Corp.
- (m) "Default" means a failure by the Company or Affiliate to contribute to the Trust, within thirty (30) days of receipt of written notice from its trustee, any of the following amounts:

(1) The full amount of any insufficiency in assets of the Trust or any subtrust of the Trust that is required to pay any Plan benefit payable by the trustee pursuant to directions by the Administrator or disputed by the Administrator after a Special Circumstance and determined by the trustee to be payable; or

(2) Any contribution which is then required to be made by the Company or Affiliate to the Trust or any subtrust of the Trust.

If, after the occurrence of a Default, the Company or Affiliate at any time cures such Default by contributing to the Trust all amounts which are then required under paragraphs (1) and (2) above, it shall then cease to be deemed that a Default has occurred or that a Special Circumstance has occurred by reason of such Default.

(n) "Deferred Fee Account" means a bookkeeping account established by the Company or an Affiliate which maintains record of deferred Director's Fees including expenses and earnings, gains and losses. All amounts credited to a Director's Deferred Fee Account shall constitute a general, unsecured liability of the Company or of the Affiliate for which the Director serves when Director's Fees are deferred.

(o) "Deferred Stock Fund" means an Investment Fund which is deemed to be invested in FirstEnergy Corp. common stock.

(p) "Director" means a member of the Board, a member of the board of directors of any Affiliate and any individual designated as a Director by the Committee incident to a merger of or acquisition by the Company of an Affiliate. A Director may not be an employee of the Company or any Affiliate.

(q) "Director's Fees" means the equity retainer fees, cash retainer fees, meeting fees, chairperson fees, and any additional annual cash retainer for a non-employee Chairman of the Board, payable for services as a Director whether payable in cash or in equity instruments.

(r) "Disability" means a period of disability during which the Participant is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or which has lasted or can be expected to last for a continuous period of not less than twelve (12) months. A Participant shall not be considered to be Disabled unless he or she furnishes proof of the existence of Disability in the form and manner as required by the Administrator.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

(s) "Financial Hardship" means a severe financial hardship to the Participant resulting from a sudden and unexpected illness or accident of the Participant, the Participant's spouse, or of a Participant's dependent (as defined in Code Section 152 without regard to sections 152(b)(1), (b)(2) and (d)(1)(B)), loss of the Participant's property due to casualty, or other extraordinary and unforeseeable circumstances arising as a result of events beyond the control of the Participant. Financial Hardship shall be determined by the Administrator on the basis of information supplied by the Participant to the Administrator.

(t) "Investment Fund" means an investment fund in which Accounts may be deemed to be invested. An Investment Fund may be any open-ended fund, closed-end fund, a fund which is deemed to be invested in a particular stock or other investment, or a fund which credits a fixed or variable interest rate determined by the Committee.

(u) "Participant" means a Director or former Director who is owed a benefit under this Plan. A Participant is a general unsecured creditor of the Company or of the Affiliate which maintains the Accounts and provides any benefits under this Plan.

(v) "Plan" means the FirstEnergy Corp. Deferred Compensation Plan for Outside Directors.

(w) "Plan Year" means the period beginning on each January 1 and ending on the following December 31.

(x) "Potential Change in Control" means any of the following:

(1) Any Person (as defined in Section 13(d)(3) of the Exchange Act) other than a trustee or other fiduciary holding securities under an employee benefit plan of the Company, delivers to the Company a statement containing the information required by Schedule 13 D under the Exchange Act, or any amendment to any such statement (or the Company becomes aware that any such statement or amendment has been filed with the Securities and Exchange Commission pursuant to applicable Rules under the Exchange Act), that shows that such Person has acquired, directly or indirectly, the beneficial ownership of (i) more than twenty percent (20%) of any class of equity security of the Company entitled to vote as single class in the election or removal from office of directors, or (ii) more than twenty percent (20%) of the voting power of any group of classes of equity securities of the Company entitled to vote as a single class in the election or removal from office of directors;

(2) The Company becomes aware that preliminary or definitive copies of a proxy statement and information statement or other information have been filed with the Securities and Exchange Commission pursuant to Rule 14a-6, Rule 14c-5, or Rule 14f-1 under the Exchange Act relating to a Potential Change in Control of the Company;

(3) Any Person delivers to the Company pursuant to Rule 14d-3 under the Exchange Act a Tender Offer Statement relating to Voting Securities of the Company (or the Company becomes aware that any such statement has been filed with the Securities and Exchange Commission pursuant to applicable Rules under the Exchange Act);

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

- (4) Any Person (other than the Company) publicly announces an intention to take actions which if consummated would constitute a Change in Control;
- (5) The Company enters into an agreement or arrangement, the consummation of which would result in the occurrence of a Change in Control;
- (6) The Board approves a proposal, which if consummated would constitute a Change in Control; or
- (7) The Board adopts a resolution to the effect that, for purposes of this Plan, a Potential Change in Control has occurred.

Notwithstanding the foregoing, a Potential Change in Control shall not be deemed to occur as a result of any event described in paragraphs (1) through (6) above, if a number of directors (who were serving on the Board immediately prior to such event and who continue to serve on the Board) equal to a majority of the members of the Board as constituted prior to such event determines that the event shall not constitute a Potential Change in Control.

If a Potential Change in Control ceases to exist for any reason except for the occurrence of a Change in Control, it shall then cease to be deemed that a Potential Change in Control has occurred as a result of any event described in paragraphs (1) through (7) above, or that a Special Circumstance has occurred by reason of such Potential Change in Control.

A Potential Change in Control may occur only with respect to the Company. A change in ownership of common stock of an Affiliate or subsidiary, change in membership of a board of directors of an Affiliate or subsidiary, the sale of assets of an Affiliate or subsidiary, or any other event described in this Subsection (x) that occurs only with respect to an Affiliate or subsidiary does not constitute a Change in Control.

(y) "Retirement" means (i) with respect to amounts that were vested and accrued as of December 31, 2004 including earnings, gains and losses credited thereon after that date, a Separation from Service on or after the attainment of age sixty-nine (69), and (ii) with respect to amounts that accrue and vest after December 31, 2004 including earnings, gains and losses credited thereon after that date, a Separation from Service on or after the attainment of age fifty-five (55).

(z) "Separation" means (i) with respect to amounts that were accrued and vested as of December 31, 2004 including earnings, gains and losses credited thereon after that date, a Separation from Service prior to age sixty-nine (69); and (ii) with respect to amounts that accrue and vest after December 31, 2004 including earnings, gains and losses credited thereon after that date, a Separation from Service prior to age fifty-five (55).

(aa) "Separation from Service" means the expiration of all contracts under which the Director performs services for the Company and any Affiliate where expiration constitutes a good faith and complete termination of the contractual relationship.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

(bb) "Special Circumstance" means a Change in Control, a Potential Change in Control, or a Default.

(cc) "Transfer Account" means a bookkeeping account established by the Company or an Affiliate which maintains record of deferred Directors' Fees transferred from another plan including expenses and earnings. All amounts credited to a Directors' Transfer Account shall constitute a general, unsecured liability of the Company or of the Affiliate for which the Director serves.

(dd) "Trust" means the FirstEnergy Corp. Trust for Outside Directors.

(ee) "Year of Service" means a period of time commencing on a date during a calendar year and ending on the day immediately preceding such date in the subsequent calendar year throughout which an individual serves as a Director. A Year of Service shall commence for specified purposes such as vesting of the Bonus Credit under Section 3.5(b)(2) on the date as set forth in the Plan.

ARTICLE 2 — DEFERRALS

2.1 Written Election to Defer Fees

A Director may elect, by notice to the Company, either in writing or through electronic means approved by the Committee, given on or before December 31, to defer receipt of all or any specified part of his or her Director's Fees earned for services performed during the calendar year next following his or her election to defer.

2.2 Election Upon Becoming a Director

Any person who becomes a Director and who was not a Director on the preceding December 31 may elect, by notice to the Company, either in writing or through electronic means approved by the Committee, given within thirty (30) days after becoming a Director, to defer receipt of all or any specified part of his or her Director's Fees earned for services performed subsequent to such election and for the balance of that calendar year.

2.3 Election Irrevocable

An election to defer Director's Fees shall be irrevocable as of December 31 preceding the Plan Year for which an election is made or, in the event of an election made upon becoming a Director pursuant to Section 2.2, as of the thirtieth (30th) day after become a Director.

2.4 Transfers from Other Plans

If permitted by the Committee and the provisions of this Plan, a Director may transfer his or her benefits from another nonqualified plan to this Plan as provided in this Section.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

(a) An individual who was a member of a board of directors of a corporation which is merged into the Company, who was not an employee of such corporation, who is not an employee of the Company or any Affiliate, and who is either selected to serve as a member of the Board or designated as a Director with respect to the Company for purposes of this Plan by the Committee may elect to transfer his or her benefit under a nonqualified plan sponsored by the corporation merged into the Company. Any account balance transferred shall be credited to a Transfer Account established and maintained under this Plan and shall be a liability of the Company. Any other benefit transferred shall be identified in Attachment 2.4.

(b) An individual who was a member of a board of directors of a corporation which is merged into an Affiliate or which is acquired and becomes an Affiliate, who was not an employee of such corporation, who is not an employee of the Company or any Affiliate and who is either a member of the board of directors of an Affiliate after such merger or acquisition or designated as a Director with respect to an Affiliate for purposes of this Plan by the Committee may elect to transfer his or her benefit under a nonqualified plan sponsored by the corporation merged into an Affiliate or acquired by the Company. Any account balance transferred shall be credited to a Transfer Account established and maintained under this Plan and shall be a liability of the Affiliate into which the corporation is merged or which the corporation becomes. Any other benefit transferred shall be identified in Attachment 2.4.

(c) Any balance transferred shall become payable under the terms and conditions of this Plan; provided however, that the Director's beneficiary elections made under the plan from which the benefit is transferred shall continue to be effective under this Plan unless such designation is amended or changed under the terms of this Plan.

(d) Provisions regarding such transfers and terms of participation in this Plan by the Director for whom a benefit is transferred shall be established by the Committee and shall be set forth in Attachment 2.4 of this Plan.

ARTICLE 3 — ACCOUNTS AND INVESTMENT FUNDS

3.1 Deferred Fee Account

Any Director's Fees earned and deferred while serving as a member of the Board shall be credited by the Company to the Participant's Deferred Fee Account established and maintained by the Company as of the date the Director's Fees would otherwise be payable. Any Director's Fees earned while serving as a member of the board of directors of an Affiliate shall be credited by the Affiliate to the Participant's Deferred Fee Account established and maintained by such Affiliate as of the date the Director's Fees would otherwise be payable.

3.2 Transfer Account

Any account balances transferred to this Plan pursuant to Section 2.4 shall be credited to the Participant's Transfer Account established and maintained by the Company or the applicable Affiliate.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

3.3 Other Accounts and Subaccounts

The Committee may establish such other Accounts and subaccounts as it may deem necessary for the administration of the Plan including subaccounts where the Participant has specified different methods of payment, or where necessary to maintain the vested portion of a Participant's Account. Such Accounts and subaccounts shall be credited in accordance with procedures adopted by the Committee.

3.4 Investment Funds

A Participant's Accounts shall be adjusted for gains and losses as if the Accounts held assets and such assets were invested in one or more Investment Funds selected by the Committee. The Investment Funds in which a Participant is deemed to be invested shall be determined in accordance with Section 3.5. The Committee shall have sole discretion in the selection, number and types of Investment Funds for this Plan and may change or eliminate Investment Funds from time to time in its sole discretion except that no change may be made that would constitute a material modification to the Plan under Code Section 409A.

3.5 Credits to Investment Funds

The Committee shall credit Director's Fees deferred under this Plan and transferred from another plan to Investment Funds in accordance with this Section unless other rules for transferred amounts are set forth in Attachment 2.4.

(a) Rules and Limitations Regarding Deferrals and Transfers:

(1) Equity Retainer Fees and Transfers Distributable only in Stock. Equity retainer fees that are deferred under this Plan and any account balance transferred directly to this Plan from another plan in accordance with Section 2.4 where such account balance may only be distributed in stock from the other plan upon an event permitting distribution and such stock has been or is to be exchanged for Company common stock under a plan of merger with the Company shall be credited to the Deferred Stock Fund.

(2) All Other Deferred Director's Fees and Transfers. Unless and until another procedure is established by the Committee for designation of Investment Funds, a Participant may direct that all deferred Director's Fees and transfers except those Director's Fees and transfers identified in Section 3.5(a)(1) shall be deemed to be invested in any one or more of the Investment Funds selected by the Committee. In the event a Participant does not direct the Investment Funds in which his or her Accounts are deemed to be invested, the deferrals and transfers shall be deemed to be invested in an Investment Fund that reflects the investment performance of a money market fund selected by the Committee.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

(b) Rules and Limitations Regarding Bonus Credit:

(1) Bonus Credit. At the time Director's Fees are initially deferred under this Plan and credited for investment into the Deferred Stock Fund, such Director's Fees except equity retainer fees shall be increased by a Bonus Credit equal to twenty percent (20%) of such Director's Fees credited to the Deferred Stock Fund. Any account balance transferred to this Plan from another plan in accordance with Section 2.4 that may be credited to the Deferred Stock Fund shall not be increased by the Bonus Credit.

(2) Vesting of Bonus Credit. A Participant shall be fully vested in his or her Bonus Credit and all associated earnings, gains and losses if he or she has three (3) Years of Service from the date the Bonus Credit is credited to the Participant's Account. In addition, a Participant shall be fully vested in his or her Bonus Credit and all associated earnings, gains and losses if he or she has a Separation from Service due to death, Retirement, or Disability. Furthermore, a Participant shall be fully vested in the Bonus Credit and all associated earnings, gains and losses upon a Special Circumstance or where such Participant has a Separation due to ineligibility to stand for reelection due to circumstances unrelated to the Participant's performance as a Director.

(3) Forfeiture of Bonus Credit. If a Participant incurs a Separation for any reason other than the events set forth in paragraph (2) above, takes an accelerated distribution under Section 4.2 or withdraws a portion of his Deferred Stock Fund under Section 4.3, any unvested Bonus Credit attributable to Director's Fees to be distributed shall be forfeited.

(c) Rules and Limitations Regarding Transfers Among Investment Funds:

(1) Deferred Stock Fund. No amount credited to the Deferred Stock Fund may be transferred and credited to any other Investment Fund, and no amount credited to an Investment Fund other than the Deferred Stock Fund may be transferred and credited to the Deferred Stock Fund.

(2) All Other Investment Funds. Any amount credited to an Investment Fund other than the Deferred Stock Fund may be transferred and credited to any other Investment Fund except the Deferred Stock Fund at the direction of the Participant. Any such direction from a Participant will become effective as of the date it is received by the Committee.

(d) Investment Fund Performance. The earnings, gains and losses of each Investment Fund shall be determined by the Committee, in its reasonable discretion, based on the performance of the Investment Funds themselves. The balance of a Participant's Accounts shall be credited or debited on a daily basis based on the performance of each Investment Fund in which a Participant's Accounts are deemed to be invested, such performance and the crediting of such performance being determined by the Committee in its sole discretion.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

(e) Committee Procedures. The Committee may establish such rules and procedures as it determines to be appropriate for the crediting of deferrals and transfers to Investment Funds, for transfers among Investment Funds and for crediting earnings, gains and losses of an Investment Fund.

3.6 Reporting

The Company shall provide a statement to each Director who has any amount credited to his or her Accounts at least annually.

ARTICLE 4 — PAYMENT TO DIRECTOR

4.1 Distribution Election—Separation from Service

A Participant's Accounts shall be distributed upon a Separation from Service in accordance with the Plan and Participants' elections on file with the Committee. A Participant's Accounts allocated to Investment Funds other than the Deferred Stock Fund shall be paid to the Participant in cash, and the Participant's Deferred Stock Fund shall be paid in the form of Company common stock.

(a) Time of Election. At the time a Participant makes his or her deferral election pursuant to either Section 2.1 or 2.2 herein, such Participant shall also make an election as to the time of distribution and form of payment of benefits by the Plan with respect to that year's deferrals.

Notwithstanding the above, distribution elections made with respect to deferrals made between January 1, 2005 and December 31, 2007 may be changed no later than December 31, 2007 in accordance with IRS Notice 2006-79 and Code Section 409A.

(b) Form of Payment. A Participant may elect to receive benefits under this Plan in a lump sum or in substantially equal annual installments over a period not to exceed ten (10) years. In the absence of an election, such Participant's Accounts shall be distributed in a lump sum payment in the calendar year next following the Participant's Separation, Retirement, death or Disability but not later than January 31 of such calendar year.

(c) Time of Payment. A Participant may elect to receive benefits under this Plan in the later of:

(1) the taxable year of the Participant next following the year in which the Participant has a Separation from Service; or

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

(2) the taxable year of the Participant specified by the Participant, but not later than the taxable year next following the year the Participant attains age seventy-two (72).

(3)

Payments under subsection (c)(1) and (2) shall be made no later than January 31 of the taxable year elected by the Participant.

(d) Amendment of Grandfathered Distribution Election. Solely with respect to Accounts that are accrued and vested as of December 31, 2004 and deemed earnings, gains and losses credited thereon after that date, a Participant may change the form and/or time of payment of his or her Account by filing a new superseding election with the Company at any time prior to the 120 day period ending on the day prior to the day on which the Participant is entitled to distribution under this Plan. If a Participant requests any change in the date of the distribution of his Deferred Stock Fund, the request must be approved by the Committee.

(e) Amendment of Other Distribution Elections. Solely with respect to Account balances that accrue and/or vest after December 31, 2004 including deemed earnings, gains and losses credited thereon after that date, a Participant may change his or her elections regarding the time and/or form of benefit payment provided:

(1) Such election is submitted to the Committee in writing at least twelve (12) months prior to the date any amount is to be distributed from the Plan;

(2) Such election shall not take effect until twelve (12) months after it is submitted to the Committee in writing; and

(3) The payment of any benefits under this Plan shall not commence until at least five (5) years from the date such payment would otherwise have been made.

(f) Distribution Election of Transfer Amounts. Any elections made with respect to benefits transferred from another nonqualified plan shall be paid and distributed in accordance with the elections made by the Participant under such plan and such election shall continue to be in effect under this Plan unless the Participant submits new elections to the Committee under the provisions and procedures of this Plan. If such Transfer Amount is subject to the provisions of Code Section 409A, the elections in effect on the date of transfer shall be irrevocable.

(g) Unvested Bonus Credit. As of January 1, 2005, the unvested portion of the Bonus Credit shall be segregated from vested Bonus Credit amounts and distribution of such vested Bonus Credit shall be made according to the distribution election in effect with respect to the Participant's Deferred Stock Fund that was accrued and vested on December 31, 2004. This election may be changed in accordance with subsection (e) above.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

4.2 Accelerated Distribution

Solely with respect to Account balances that were accrued and vested as of December 31, 2004 and deemed earnings, gains and losses credited thereon after that date, a Participant may at any time request an accelerated distribution of his or her Accounts, subject to a ten percent (10%) penalty and, if applicable, forfeiture of the Bonus Credit and associated deemed earnings described above if the Bonus Credit is not fully vested as provided by Section 3.5(b)(2). The ten percent (10%) penalty is imposed after any forfeiture of the Bonus Credit and associated deemed earnings. Such a request must be made in writing, in a form and manner specified by the Administrator. If the request is approved by the Administrator, the Company will distribute to the Participant the entire balance of his or her Accounts minus any forfeitures and minus the ten percent (10%) penalty as a lump sum within ninety (90) days after the end of the month in which the Administrator receives the request. Such distribution shall completely discharge the Company and the applicable Affiliate from all liability with respect to the Participant's Accounts. When a Participant elects to receive a distribution pursuant to this Section, such Participant shall not be permitted to elect to defer in the Plan Year following the year in which the Participant receives such distribution.

4.3 Withdrawal

(a) Solely with respect to Account balances that were accrued and vested as of December 31, 2004 and deemed earnings, gains and losses credited thereon after that date, a Participant who has deferred Director's Fees under this Plan for five (5) full years may request to withdraw a portion of the amounts credited to his or her Accounts subject to forfeiture of the Bonus Credit and associated deemed earnings and losses as provided by Section 3.5(b)(3). The requisite full years of deferral to request a withdrawal need not be consecutive but may be intermittent. Amounts credited to the Deferred Stock Fund will be distributed only after amounts credited to all other Investment Funds are distributed. Such request must be made in writing in a form and manner specified by the Administrator and must specify the amount to be withdrawn and the future date or dates to be paid. The date(s) must be no earlier than the first of a month in the second calendar year following the calendar year in which the request was made. The request will be irrevocable after December 31 of the calendar year in which it is made unless, prior to payment, the Participant separates from the Board or the board of directors of an Affiliate, or a Special Circumstance occurs. In these instances, the request will become null and void and the Account Balance will be paid as elected by the Participant pursuant to Section 4.2 or as provided in Section 4.5. If the request is approved by the Administrator, the Company will distribute to the Director the balance of his or her Accounts except the portion credited to the Deferred Stock Fund as a lump sum within ninety (90) days after the end of the month in which the Administrator receives the request and will distribute to the Director the balance of his or Accounts credited to the Deferred Stock Fund minus any forfeitures in Company common stock in an administratively reasonable period of time.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

(b) Solely with respect to Account balances that accrue and/or vest after December 31, 2004 including deemed earnings, gains and losses credited thereon after that date, a Participant may, at the time such Participant makes a deferral election pursuant to Sections 2.1 or 2.2, elect to withdraw all or a portion of such deferred Director's Fees plus deemed earnings, gains and losses and vested Bonus Credit on a specified date provided such date is no earlier than the second January 1 following the Plan Year to which the deferral election applies. A Participant may elect to withdraw amounts allocated to Investment Funds other than the Deferred Stock Fund, amounts allocated to the Deferred Stock Fund, or all Investment Funds. The Account balance for a Plan Year that is allocated to the Investment Funds other than the Deferred Stock Fund shall be distributed prior to a distribution from the Deferred Stock Fund. Distributions pursuant to this Subsection (b) shall be made in a single lump sum within ninety (90) days after the date selected by the Participant. In the event a Participant receives a distribution from the Deferred Stock Fund and the associated Bonus Credit is not yet vested, such Bonus Credit shall be forfeited as of the date the Deferred Stock Fund is distributed to the Participant.

4.4 Financial Hardship Distributions

Notwithstanding any other provision of the Plan and solely with respect to Account balances that accrue and/or vest after December 31, 2004 including deemed earnings, gains and losses credited thereon after that date, payment from the Participant's Account may be made to the Participant, in the sole discretion of the Administrator, by reason of Financial Hardship. Such payment shall not exceed the amount necessary to satisfy such emergency plus amounts necessary to pay taxes reasonably anticipated as a result of the distribution after taking into account the extent to which such hardship is or may be relieved through reimbursement or compensation by insurance or otherwise or by liquidation of the Participant's assets, to the extent such liquidation would not itself cause severe financial hardship. If such a distribution is made, the Participant's deferral elections for the Plan Year in which the distribution is made shall be void and such Participant shall not be eligible to defer Director's Fees until the next Plan Year. Payment shall be made in a single lump sum within thirty (30) days after the date the Financial Hardship is approved by the Administrator. Distributions shall be made first from the Investment Funds other than the Deferred Stock Fund and then from the Deferred Stock Fund, excluding the Bonus Credit.

4.5 Special Circumstance

Solely with respect to deferrals that were accrued and vested as of December 31, 2004 and deemed earnings, gains and losses credited thereon after that date, in the instance of a Special Circumstance, all balances in Investment Funds other than the Deferred Stock Fund shall be paid out immediately in cash as a lump sum and the balance of the Deferred Stock Fund shall be distributed in Company common stock in an administratively reasonable period of time. A Participant may elect to receive distribution from this Plan in a distribution payment otherwise permitted by this Plan if such election is made more than 120 days prior to the Special Circumstance.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

Solely with respect to Account balances that accrue and/or vest after December 31, 2004 and deemed earnings, gains and losses credited thereon after that date, in the event of a Change in Control that would also qualify as a change in control event under Code Section 409A (a)(2)(A)(v), all balances in Investment Funds shall be paid out pursuant to the Participants' elections not more than ninety (90) days after the Change in Control. This paragraph shall only apply if all other plans, programs and arrangements sponsored by the Company or its Affiliates that must be aggregated pursuant to Code Section 409A are terminated and liquidated within twelve (12) months of the Change in Control.

4.6 Small Accounts

Notwithstanding anything herein to the contrary, if, on the date of the Participant's Separation, Retirement, death or Disability, such Participant's Account balance with respect to amounts that accrue and/or vest after December 31, 2004 including deemed earnings, gains and losses credited thereon after that date (plus any amounts that are aggregated with this Plan under Code Section 409A) are worth less than the then-current Code Section 402(g)(1)(B) limit, such Accounts shall be paid in a lump sum in the next following calendar year, but not later than January 31 of such calendar year, regardless of any elections the Participant may have made.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

ARTICLE 5 — BENEFICIARY

5.1 Beneficiary Designation

Each Participant shall have the right, at any time, to designate his or her Beneficiary(ies) to receive any benefits payable under the Plan upon his or her death. A Participant shall designate his or her Beneficiary by completing and signing a Beneficiary designation form and returning it to the Committee.

5.2 Distribution Election

The Participant shall designate, in his or her initial deferral election made after becoming a Director, the time and the manner of payment to the Beneficiary, which may be either (a) in a lump sum as soon as practicable after the date of death, but not later than ninety (90) days after Participant's date of death; (b) in a lump sum in the calendar year following the date of the Participant's death but not later than January 31 of such calendar year; or (c) in one or more annual payments the last of which may occur no later than January 1 of the fifth year following the year in which the death occurred. In the absence of an election, benefits shall be paid to the Beneficiary pursuant to (a) above. Such election may be changed by a Participant at any time and will become effective twelve (12) months after the date it is received by the Committee.

Amounts credited to the Deferred Stock Fund shall be distributed in Company common stock. In the event the Participant designates distribution in the form of two or more annual payments, a pro rata portion shall be distributed from each Investment Fund in which the Participant's Accounts are credited.

5.3 Change of Beneficiary

A Participant shall have the right to file a new Beneficiary designation form. Upon acceptance of a new Beneficiary designation form, all Beneficiary designations previously filed shall be cancelled as of the date of the new Beneficiary designation form.

5.4 Payment of Benefit upon Death

Upon the death of a Participant prior to the distribution of the entire balance credited to the Participant's Accounts, benefits shall be paid to the Beneficiary or Beneficiaries designated by the Participant in writing filed with the Administrator. In the event that a Participant fails to designate a Beneficiary or, if all designated Beneficiaries predecease the Participant or die prior to complete distribution of the Participant's benefits, then the Participant's benefits under this Plan shall be distributed to his or her surviving spouse. If the Participant has no surviving spouse, the benefits remaining under the Plan to be paid shall be paid to the executor or personal representative of the Participant's estate.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

ARTICLE 6 — ASSIGNMENT

Except to the extent that a Participant may designate a Beneficiary to receive any payment to be made following his or her death and except by will or the laws of descent and distribution, no rights or benefits under this Plan shall be assignable or transferable, or subject to encumbrance or charge of any nature.

ARTICLE 7 — ADMINISTRATION

7.1 Administrator

Unless another Administrator is selected by the Board or until a Change in Control, this Plan shall be administered by the Committee. Except as otherwise provided by action of the Board or the terms of the Plan: (a) a majority of the members of the Committee shall constitute a quorum for the transaction of business, and (b) all resolutions or other actions taken by the Committee at a meeting shall be by the vote of the majority of the Committee members present, or, without a meeting, by an instrument in writing signed by all members of the Committee. A Committee member may not vote on any matter which directly affects only his or her benefit under the Plan.

Upon and after the occurrence of a Change in Control, however, the "Administrator" shall be at least three (3) independent third parties selected by the individual who, immediately prior to such event, was the Company's Chief Executive Officer or, if not so identified, the Company's highest ranking officer (the "Ex-CEO"); provided, however, the Committee, as constituted immediately prior to a Change in Control, shall continue to act as the Administrator for this Plan until the date on which the independent third parties selected by the Ex-CEO accept the responsibilities as the Administrator of this Plan. Upon and after a Change in Control, the Administrator shall have all discretionary authorities and powers granted to the Administrator under this Plan including the discretionary authority to determine all questions arising in connection with the administration of the Plan and the interpretation of the Plan except benefit entitlement determinations upon appeal. Upon and after the occurrence of a Change in Control, the Company must: (1) pay all reasonable administrative expenses and fees of the Administrator; (2) indemnify the Administrator against any costs, expenses and liabilities including, without limitation, attorney's fees and expenses arising in connection with the performance of the Administrator hereunder, except with respect to matters resulting from the gross negligence or willful misconduct of the Administrator or its employees or agents; and (3) supply full and timely information to the Administrator on all matters relating to the Plan, the Participants and their Beneficiaries, the Account balances of the Participants, the date and circumstances of the Retirement, Disability, death or Separation from Service of the Participants, and such other pertinent information as the Administrator may reasonably require. Upon and after a Change in Control, a person serving as a member of the committee acting as Administrator may only be removed (and a replacement may only be appointed) by the Ex-CEO.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

7.2 Powers of Administrator

The Administrator shall have the full discretion and authority to administer the Plan including the discretion and authority to construe, interpret, and apply this Plan, and to render nondiscriminatory rulings or determinations. All questions regarding the Plan, as well as any dispute over accounting or administrative procedures or interpretation of the Plan, shall be resolved at the sole discretion of the Administrator. Constructions, interpretations, and decisions of the Administrator shall be conclusive and binding on all persons. The Administrator shall also have the discretion and authority to make, amend, interpret, and enforce all appropriate rules and regulations for the administration of this Plan. Any individual serving on a committee acting as Administrator who is a Participant shall not vote or act on any matter relating solely to himself or herself. When making a determination or calculation, the Administrator shall be entitled to rely on information furnished by a Participant or the Company.

7.3 Delegation

The Committee may delegate all or any duties, discretions and responsibilities under this Plan to the Corporate Secretary.

ARTICLE 8 — CLAIMS

8.1 Claim

Any person claiming a benefit ("Claimant") under the Plan shall present the request in writing to the Administrator.

8.2 Initial Claim Review

In the case of a claims regarding Disability, the Administrator will make a benefit determination within forty-five (45) days of its receipt of an application for benefits. This period may be extended up to an additional thirty (30) days, if the Administrator provides the Claimant with a written notice of the extension within the initial forty-five (45)-day period. The extension notice will explain the reason for the extension and the date by which the Administrator expects a decision will be made. The Administrator may obtain a second thirty (30)-day extension by providing you written notice of such second extension within the thirty (30)-day extension. The second extension notice must include an explanation of the special circumstances necessitating the second extension and the date by which the Administrator's decision will be made. If the extension is necessary because additional information is needed to decide the claim, the extension notice will describe the required information. The Claimant will have forty-five (45) days after receiving the extension notice to provide the required information.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

In the case of all other claims, the Administrator will make a benefit determination within ninety (90) days of its receipt of an application for benefits. This period may be extended up to an additional ninety (90) days, if the Administrator provides the Claimant with a written notice of the extension within the initial ninety (90)-day period. The extension notice will explain the reason for the extension and the date by which the Administrator expects a decision will be made.

The Administrator will notify the Claimant in writing, delivered in person or mailed by first-class mail to the Claimant's last known address, if any part of a claim for benefits under the Plan has been denied. The notice of a denial of any claim will include:

- (a) the specific reason for the denial;
- (b) reference to specific provisions of the Plan upon which the denial is based;
- (c) a description of any internal rule, guidelines, protocol or similar criterion relied on in making the denial (or a statement that such internal criterion will be provided free of charge upon request);
- (d) a description of any additional material or information deemed necessary by the Administrator for the Claimant to perfect the claim, and an explanation of why such material or information is necessary; and
- (e) an explanation of the claims review procedure under the Plan.

If the notice described above is not furnished and if the claim has not been granted within the time specified above for payment of the claim, the claim will be deemed denied and will be subject to review as set forth in Section 8.3 .

8.3 Review of Claim

If a claim for benefits is denied, in whole or in part, the Claimant may request to have the claim reviewed. The Claimant will have one hundred eighty (180) days in which to request a review of a claim regarding Disability, and will have sixty (60) days in which to request a review of all other claims. The request must be in writing and delivered to the Appeals Committee. If no such review is requested, the initial decision of the Appeals Committee will be considered final and binding.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

The request for review must specify the reason the Claimant believes the denial should be reversed. He or she may submit additional written comments, documents, records, and other information relating to and in support of the claim; all information submitted will be reviewed whether or not it was available for the initial review. The Claimant may request reasonable access to and copies of, all documents, records, and other information relevant to the Claimant's claim for benefits. A member of the Appeals Committee may not participate in the review of his or her own claim. In addition, if the Claimant requests a review, a member of the Committee who is a subordinate of the original decision maker shall not participate in the review of the claim. The review will not defer to the initial adverse determination. If the denial was based in whole or in part on a medical judgment, the Appeals Committee will consult with an appropriate health care professional who was not consulted in the initial determination of his or her claim and who is not the subordinate of someone consulted in the initial determination. Names of the health care professionals will be available on request.

Upon receipt of a request for review, the Appeals Committee may schedule a hearing within thirty (30) days of its receipt of such request, subject to availability of the Claimant and the availability of the Appeals Committee, at a time and place convenient for all parties at which time the Claimant may appear before the person or committee designated by the Appeals Committee to hear appeals for a full and fair review of the Administrator's initial decision. The Claimant may indicate in writing at the time the Appeals Committee attempts to schedule the hearing, that he or she wishes to waive the right to a hearing. If the Claimant does not waive his or her right to a hearing, he or she must notify the Appeals Committee in writing, at least fifteen (15) days in advance of the date established for such hearing, of his or her intention to appear at the appointed time and place. The Claimant must also specify any persons who will accompany him or her to the hearing, or such other persons will not be admitted to the hearing. If written notice is not timely provided, the hearing will be automatically canceled. The Claimant or the Claimant's duly authorized representative may review all pertinent documents relating to the claim in preparation for the hearing and may submit issues, documents, affidavits, arguments, and comments in writing prior to or during the hearing.

The Appeals Committee will notify the Claimant of its decision following the reviews. In the case of a claim regarding Disability, the Appeals Committee will render its final decision within forty-five (45) days of receipt of an appeal or such shorter period as may be required by law. If the Appeals Committee determines that an extension of the time for processing the claim is needed, it will notify the Claimant of the reasons for the extension and the date by which the Appeals Committee expects a decision will be made. The extended date may not exceed ninety (90) days after the date of the filing of the appeal.

In the case of all other claims, the Appeals Committee will render its final decision within sixty (60) days of receipt of an appeal. If the Appeals Committee determines that an extension of the time for processing the claim is needed, it will notify the Claimant of the reasons for the extension and the date by which the Appeals Committee expects a decision will be made. The extended date may not exceed one hundred twenty (120) days after the date of the filing of the appeal

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

If after the review the claim continues to be denied, the Claimant will be provided a notice of the denial of the appeal which will contain the following information:

- (a) The specific reasons for the denial of the appeal;
- (b) A reference to the specific provisions of the Plan on which the denial was based;
- (c) A statement that the Claimant is entitled to receive, upon request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to the claim for benefits;
- (d) A statement disclosing any internal rule, guidelines, protocol or similar criterion relied on in making the denial (or a statement that such information would be provided free of charge upon request); and
- (e) A statement describing the Claimant's right to bring a civil suit under Federal law and a statement concerning other voluntary alternative dispute resolutions options.

8.4 Review of Claims on and after a Change in Control.

Upon and after the occurrence of a Change in Control, the Appeals Committee, as constituted immediately prior to a Change in Control, shall continue to act as the Appeals Committee. The Appeals Committee shall have responsibility and the discretionary authority to review denied claims. In the event any member of the Appeals Committee resigns or is unable to perform the duties of a member of the Appeals Committee, successors to such members shall be selected by the Ex-CEO. Upon and after a Change in Control, the Appeals Committee shall have all discretionary authorities and powers granted the Appeals Committee under this Plan including the discretionary authority to determine all questions arising in connection with the review of a denied claim as provided in this Section. Upon and after the occurrence of a Change in Control, the Company must: (1) pay all reasonable administrative expenses and fees of the Appeals Committee; (2) indemnify the Appeals Committee against any costs, expenses and liabilities including, without limitation, attorney's fees and expenses arising in connection with the performance of the Appeals Committee hereunder, except with respect to matters resulting from the gross negligence or willful misconduct of the Appeals Committee or its employees or agents; and (3) supply full and timely information to the Appeals Committee on all matters relating to the Plan, the Participants and their Beneficiaries, the Account balances of the Participants, the date and circumstances of the Retirement, Disability, death, Separation or Separation from Service of the Participants, and such other pertinent information as the Appeals Committee may reasonably require. Upon and after a Change in Control, a member of the Appeals Committee may only be removed (and a replacement may only be appointed) by the Ex-CEO.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

ARTICLE 9 — AMENDMENT, TERMINATION AND PARTICIPATION

9.1 Amendment by Board

Prior to a Special Circumstance and solely with respect to amounts deferred and vested as of December 31, 2004 and earnings, gains and losses credited thereon after that date, the Board may from time to time, amend, suspend, terminate or reinstate any or all of the provisions of this Plan, retroactive or otherwise, except that no amendment, suspension, termination or reinstatement shall adversely affect the Accounts or benefits under this Plan of any Participant as they existed immediately before the amendment, suspension, termination, merger or reinstatement or the manner of payments, unless the Participant shall have consented in writing. In addition, no amendment, suspension, termination or reinstatement shall be made that would constitute a material modification of the Plan under Code Section 409A after October 2, 2004.

Prior to a Special Circumstance and solely with respect to amounts that accrue and/or vest after December 31, 2004 and earnings, gains and losses credited thereon after that date, the Board may from time to time amend, suspend, or reinstate any or all of the provisions of this Plan, retroactive or otherwise, provided such amendment, suspension or reinstatement does not violate Code Section 409A nor adversely affect the Accounts or benefits under this Plan of any Participant as they existed immediately before the amendment, suspension or reinstatement or the manner of payments, unless the Participant shall have consented in writing.

9.2 Termination by the Company

Prior to a Special Circumstance, the Board may at any time terminate this Plan and/or transfer its liabilities under this Plan to a similar plan it may establish. Upon the termination of this Plan, amounts credited to the Accounts of Participants and benefits transferred shall continue to be payable to those Participants in accordance with the terms of this Plan except as provided in Section 9.4 herein. Upon termination of this Plan, if the Board should transfer its liabilities to another plan, such transfer of liabilities shall not adversely affect the Accounts or benefits of any Participant as they existed immediately prior to a transfer authorized by the Board or the manner of payments, unless the Participant shall have consented in writing. In addition, any transfer of liabilities of this Plan shall not affect the liability of the Company or any Affiliate responsible to pay the benefit represented by the Account Balance.

9.3 Automatic Cessation of Bonus Credit and Dividends

Unless the Plan is terminated by the Company prior to the following, the crediting of the 20% Bonus Credit and dividend equivalent features of this Plan with respect to Company common stock will automatically cease on May 17, 2014 or earlier if the maximum share reserve of 500,000 shares of Company common stock is reached, unless shareholders reapprove these features the earlier of the prior date or prior to the depletion of the maximum share reserve.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

9.4 Distribution of Benefits on Plan Termination

In the event the Board elects to terminate the Plan as provided under Section 9.2:

(a) With respect to Accounts that accrued and vested as of December 31, 2004 and notwithstanding any other provisions of the Plan, if the Plan is terminated, no subsequent Director's fees may be deferred under this Plan as of the January 1 next following the date of termination. Upon termination, if the liabilities of this Plan are not transferred to another plan, the Director's Accounts shall continue to be credited with deemed earnings as provided in Section 3.4, and the entire balance in the Account Balance shall become payable to the Participant in accordance with the provisions of this Plan and deferral elections regarding the time and form of payment in effect at the date of termination.

(b) Solely with respect to Account balances that accrue and/or vest after December 31, 2004, including deemed earnings, gains and losses credited thereon after that date, no right to the payment of benefits shall arise as a result of a Plan Termination;

(c) The Board may, in its discretion, provide by amendment to the Plan a right to the payment of all such Account balances as a result of the liquidation and termination of the Plan where:

(1) The termination and liquidation does not occur proximate to a downturn in the financial health of the Company and the participating Affiliates;

(2) The Plan and all arrangements required to be aggregated with the Plan under Code Section 409A are terminated and liquidated;

(3) no payments, other than those that would be payable under the terms of the Plan and the aggregated arrangements if the termination and liquidation had not occurred, are made within twelve (12) months of the date the Company takes all necessary action to irrevocably terminate and liquidate the Plan;

(4) All payments are made within twenty-four (24) months of the date the Company takes all necessary action to irrevocably terminate and liquidate the Plan; and

(5) The Company and the Affiliates do not adopt a new arrangement that would be aggregated with any terminated arrangement under Code Section 409A, at any time within three (3) years following the date the Company takes all necessary action to irrevocably terminate and liquidate the Plan.

(d) Similarly, the Company may, in its discretion, provide by amendment to liquidate and terminate the Plan where the termination and liquidation occurs within twelve (12) months of a corporate dissolution taxed under Code Section 331, or with the approval of a bankruptcy court pursuant to 11 United States Code Section 503(b)(1)(A), provided that all amounts deferred under the Plan are included in the Participants' gross incomes in the latest of the following years (or, if earlier, the taxable year in which the amount is actually or constructively received):

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

- (1) The calendar year in which the termination occurs;
- (2) The calendar year in which the amount is no longer subject to a substantial risk of forfeiture; or
- (3) The first calendar year in which the payment is administratively practicable.

9.5 Participation by Affiliates

Affiliates may participate in this Plan as provided in this Section.

(a) An Affiliate may adopt this Plan with the consent of the Company. The Affiliate shall be liable for the payment of any benefit of a Participant whose benefits under the Plan relate to Director's Fees deferred while serving on the board of directors of the Affiliate or which are transferred to this Plan by the Participant. Neither the Company nor any other Affiliate shall have any liability for such benefits.

(b) Each Affiliate, by adopting the Plan, appoints the Company as its agent and fully empowers the Company to act on behalf of all Affiliates as it may deem appropriate in maintaining or terminating the Plan. The adoption by the Company of any amendment to the Plan or the termination of all or any part of the Plan will constitute and represent, without further action on the part of any Affiliate, the approval, adoption, ratification or confirmation by each Affiliate of any such amendment or termination and each Affiliate shall be bound by such amendment or termination.

(c) An Affiliate may cease participation in the Plan only upon approval by the Company and only in accordance with such terms and conditions that may be required by the Company.

ARTICLE 10 — UNFUNDED PLAN

10.1 Bookkeeping Entries

The Accounts maintained for purposes of this Plan shall constitute bookkeeping records of the Company or the applicable Affiliate and shall not constitute any allocation of any assets of the Company or Affiliate or be deemed to create any trust or special deposit with respect to any of the assets of the Company or any Affiliate. Neither the Company nor any Affiliate shall be under any obligation to any Participant to acquire, segregate or reserve any funds or other assets for purposes relating to this Plan. No Participant shall have any rights whatsoever in or with respect to any funds or other assets owned or held by the Company or any Affiliate. The rights of a Participant under this Plan are solely those of a general creditor of the Company or any Affiliate to the extent of the amount credited to his or her Accounts with the Company or the applicable Affiliate and this Plan is a mere promise to pay benefits to the Participants.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

10.2 Trusts, Insurance Contracts or Other Investment

The Company or the Affiliates may, in their respective discretion, establish one or more trusts, purchase one or more insurance contracts or otherwise invest or segregate funds for purposes relating to this Plan, but the assets of such trusts, rights and assets of such insurance contracts or otherwise invested or held in segregated funds shall at all times remain subject to the claims of the general creditors of the Company and any Affiliate as provided in such trust or contract except to the extent and at the time any payment is made to a Participant under this Plan.

ARTICLE 11— MISCELLANEOUS

11.1 Severability

The invalidity or unenforceability of any particular provision of this Plan shall not affect any other provision, and the Plan shall be construed in all respects as if invalid or unenforceable provisions were omitted.

11.2 Liability for Benefits

Except as otherwise agreed in writing, liability for the payment of a Participant's benefit under this Plan shall be borne solely by the Company or the participating Affiliate for which the Participant served as a Director during the accrual or increase in the benefit. No liability for the payment of any benefit shall be incurred by reason of Plan sponsorship or participation except for benefits incurred by the Company for its Directors and for benefits incurred by an Affiliate for its Directors. Nothing in this Section shall be interpreted as prohibiting the Company or any participating Affiliate from expressly agreeing in writing to the assumption of liability or the guarantee of payment of any benefit under this Plan.

11.3 Applicable Law

This Plan shall be construed and governed in accordance with the laws of the State of Ohio without giving effect to principles of conflicts of laws.

11.4 Not a Contract

The terms and conditions of this Plan shall not be deemed to constitute a contract for services between the Company or any Affiliate and the Participant. A Director is retained on an "at will" relationship that can be terminated at any time for any reason, or no reason, with or without cause, and with or without notice, unless expressly provided in a written agreement. Nothing in this Plan shall be deemed to give a Participant the right to be retained as a Director of the Company and any Affiliate.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

11.5 Successors

The provisions of this Plan shall bind and inure to the benefit of the successors and assigns of the Company and each Affiliate.

11.6 Distribution under Terms of the Trust or in the Event of Taxation

(a) If the Trust terminates in accordance with its terms and benefits accrued and vested as of December 31, 2004 are distributed from the Trust to a Participant in accordance therewith, the Participant's benefits accrued and vested as of December 31, 2004 and deemed earnings, gains and losses thereon credited after that date under this Plan shall be reduced to the extent of such distributions.

(b) If, for any reason, all or any portion of a Participant's benefits attributable to deferrals accrued and vested as of December 31, 2004 and earnings, gains and losses thereon credited after that date under this Plan becomes taxable to the Participant prior to receipt, a Participant may petition the Committee before a Special Circumstance, or the trustee of the Trust after a Special Circumstance, for a distribution of that portion of his or her benefit that has become taxable. Upon the grant of such a petition, which grant shall not be unreasonably withheld (and, after a Special Circumstance, shall be granted), the Company or applicable Affiliate shall distribute to the Participant immediately available funds in an amount equal to the taxable portion of his or her benefit. If the petition is granted, the tax liability distribution shall be made within ninety (90) days of the date when the Participant's petition is granted. Such a distribution shall affect and reduce the benefits to be paid under this Plan.

(c) If this Plan fails to meet the requirements of Code Section 409A and causes any amounts deferred and/or which became vested after December 31, 2004 to be included in a Participant's income prior to distribution, the Participant shall be paid the amount required to be included in income as a result of the failure to comply with Code Section 409A and the Participant's benefits under this Plan shall be reduced to the extent of such distributions.

11.7 Insurance

The Company and the Affiliates, on their own behalf or on behalf of the trustee of the Trust, and, in their sole discretion, may apply for and procure insurance on the life of the Participant, in such amounts and in such forms as the Trust may choose. The Company, the Affiliates or the trustee of the Trust, as the case may be, shall be the sole owner and beneficiary of any such insurance. The Participant shall have no interest whatsoever in any such policy or policies, and at the request of the Company or an Affiliate shall submit to medical examinations and supply such information and execute such documents as may be required by the insurance company or companies to whom the Company or Affiliate have applied for insurance.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

11.8 Legal Representation

The Company and each Affiliate is aware that upon the occurrence of a Change in Control, the Board or the board of directors of an Affiliate (which might then be composed of new members) or a shareholder of the Company or an Affiliate, or of any successor corporation might then cause or attempt to cause the Company, an Affiliate or successor to refuse to comply with its obligations under the Plan and might cause or attempt to cause the Company or an Affiliate to institute, or may institute, litigation seeking to deny Participants the benefits intended under the Plan. In these circumstances, the purpose of the Plan could be frustrated. Accordingly, if, following a Change in Control, it should appear to any Participant that the Company, an Affiliate or any successor corporation has failed to comply with any of its obligations under the Plan or, if the Company, an Affiliate or any other person takes any action to declare the Plan void or unenforceable or institutes any litigation or other legal action designed to deny, diminish or to recover from any Participant the benefits intended to be provided, then the Company and the applicable Affiliate irrevocably authorize such Participant to retain legal counsel of his or her choice at the expense of the Company and the Affiliate (which shall be jointly and severally liable) to represent such Participant in connection with the initiation or defense of any litigation or other legal action, whether by or against the Company, an Affiliate or any director, officer, shareholder or other person affiliated with the Company, an Affiliate or any successor thereto in any jurisdiction. The Company and the Affiliate shall pay all attorney fees and all expenses and costs that are incurred by the Participant during the twenty-year period commencing on the date of the Change in Control and that relate to the collection of benefits under this Plan or to defending against the recovery of any benefits paid by this Plan. If the Participant elects to pay such fees, expenses and costs, then the Company and the Affiliate shall reimburse the Participant. The reimbursement of an eligible fee, expense or cost shall be made on or before the last day of the Participant's taxable year following the taxable year in which the expense was incurred. The amount paid or reimbursed during a Participant's taxable year shall not affect the payments made in any other taxable year of the Participant. The right to payment or reimbursement of such legal fees, expenses and costs is not subject to liquidation or exchange for another benefit.

11.9 Code Section 409A

Notwithstanding anything to the contrary in the provisions of this Plan regarding the benefits payable hereunder and the time and form thereof, this Plan is intended to meet any applicable requirements of Code Section 409A and this Plan shall be construed and administered in accordance with Section 409A of the Code, Department of Treasury regulations and other interpretive guidance issued thereunder, including without limitation any such regulations or other guidance that may be issued after the Effective Date. In the event that the Company determines that any provision of this Plan or the operation thereof may violate Section 409A of the Code and related Department of Treasury guidance, the Company may in its sole discretion adopt such amendments to this Plan and appropriate policies and procedures, including amendments and policies with retroactive effect, or take such other actions, as the Company determines necessary or appropriate to comply with the requirements of Section 409A of the Code.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

ATTACHMENT 2.4-A

Ohio Edison Company Deferred Compensation Plan for Directors

Merger of Plans. Effective as of December 31, 1997, the Ohio Edison Deferred Compensation Plan for Directors ("Ohio Edison Plan") was merged into this Plan.

Definition of Director. The individuals who made deferral elections under the Ohio Edison Plan shall be considered "Directors" for purposes of this Plan even if they have not served on the Board or any board of directors of any Affiliate.

Prior Elections to Defer. Any election to defer director's fees made under the Ohio Edison Plan prior to December 31, 1997 shall, to the extent such deferred fees and any earnings and losses credited to such deferred fees have not been paid to the Director or to his or her Beneficiary prior to such date, be treated as having been made under this Plan and shall be subject to all of the rights and limitations imposed on elections made under this Plan.

Transfer of Account Balance. With respect to any Director who had a balance in his or her account under the Ohio Edison Plan immediately prior to December 31, 1997, the balance of such account shall be transferred to a Transfer Account under this Plan as of December 31, 1997 and shall be administered in accordance with this Plan. Such Directors shall be permitted to designate how such transferred account balances shall be deemed invested as permitted under this Plan.

Liability for Payment. All liabilities of the Ohio Edison Plan shall be paid by the Company.

Transfer of Liabilities and Payment of Accounts. If any account under the Ohio Edison Plan is in pay status or is otherwise payable to an Participant as of such date, it shall continue to be payable to that person under the same terms and conditions as were provided under the Ohio Edison Plan. The balance of any account under the Ohio Edison Plan shall become payable under the terms and conditions of this Plan; provided, however, that the Director's deferral elections, commencement date elections, and beneficiary elections made under the Ohio Edison Plan shall continue to be effective under this Plan unless amended or changed by the Director under the terms of this Plan.

Crediting of Service. All service as a director of the Ohio Edison Company or any affiliate of Ohio Edison Company shall count as Years of Service under this Plan.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

ATTACHMENT 2.4-B

Centerior Energy Corporation Deferred Compensation Plan for Directors

Merger of Plans. Effective as of January 1, 2000, the Centerior Energy Corporation Deferred Compensation Plan for Directors (the "Centerior Plan") was merged into this Plan.

Definition of Director. The individuals who made deferral elections under the Centerior Plan shall be considered "Directors" for purposes of this Plan even if they have not served on the Board or any board of directors of any Affiliate.

Prior Elections to Defer. Any election to defer director's fees made under the Centerior Plan prior to January 1, 2000 shall, to the extent such deferred fees and any earnings and losses credited to such deferred fees have not been paid to the Director or to his or her Beneficiary prior to such date, be treated as having been made under this Plan and shall be subject to all of the rights and limitations imposed on elections made under this Plan.

Transfer of Account Balance. With respect to any Director who had a balance in his or her account under the Centerior Plan immediately prior to January 1, 2000, the balance of such account shall be transferred to a Transfer Account under this Plan as of January 1, 2000 and shall be administered in accordance with this Plan. Such Directors shall be permitted to designate how such transferred account balances shall be deemed invested as permitted under this Plan.

Liability for Payment. All liabilities of the Centerior Plan shall be paid by the Company.

Transfer of Liabilities and Payment of Accounts. If any account under the Centerior Plan is in pay status or is otherwise payable to an Participant as of such date, it shall continue to be payable to that person under the same terms and conditions as were provided under the Centerior Plan. The balance of any account under the Centerior Plan shall become payable under the terms and conditions of this Plan; provided, however, that the Director's deferral elections, commencement date elections, and beneficiary elections made under the Centerior Plan shall continue to be effective under this Plan unless amended or changed by the Director under the terms of this Plan.

Crediting of Service. All service as a director of Centerior Energy Corporation or any affiliate of Centerior Energy Corporation shall count as Years of Service under this Plan.

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

ATTACHMENT 2.4-C

Deferred Remuneration Plan for Outside Directors of GPU, Inc.

And

Deferred Stock Unit Plan for Outside Directors of GPU, Inc.

And

Deferred Remuneration Plan for Outside Directors of
Jersey Central Power & Light

Transfers from GPU Plans. Any individual who participated in the Deferred Remuneration Plan for Outside Directors of GPU, Inc., Deferred Stock Unit Plan for Outside Directors of GPU, Inc., or the Deferred Remuneration Plan for Outside Directors of Jersey Central Power & Light (collectively the "GPU Plans") and who was selected as a member of the board of directors for the Company or Jersey Central Power & Light after November 7, 2001, may elect to transfer his or her account under each GPU Plan to this Plan.

Prior Elections. Any election to defer director's fees made under any GPU Plan prior to November 7, 2001 shall, to the extent such deferred fees and any earnings credited to such deferred fees have not been paid to the director or to his or her beneficiary prior to such date, be treated as having been made under this Plan and shall be subject to all of the rights and limitations imposed on elections made under this Plan.

Transfer of Account Balance. Any Director who had a balance in his or her account under a GPU Plan immediately prior to November 7, 2001 may elect to transfer such account's balance to a Transfer Account under this Plan as of November 7, 2001. The Committee shall establish subaccounts within the Transfer Account to reflect and administer Pre-Retirement and Retirement Accounts transferred from the GPU Plans. From the date of the election, the Transfer Account shall be deemed to be invested in the Moody's Investment Fund. The Moody's Investment Fund is an Investment Fund established by the Committee pursuant to Section 3.4 of the Plan and, the balance transferred from a GPU Plan shall be adjusted in the same manner as the balances of Accounts of all other Participants that are deemed to be invested in the Moody's Investment Fund. In the event the Committee modifies the interest rate or the measurement period, amends any feature of the Moody's Investment Fund, or eliminates the Moody's Investment Fund, such modification, amendment or elimination shall apply to all Participants including any Director that transfers his or her account balance from a GPU Plan to this Plan. After January 1, 2002, a Director that transfers his or her account balance from a GPU Plan may direct the Investment Funds in which his or her Transfer Account is deemed invested as permitted by Section 3.5 .

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

Liability for Payment. Liabilities of the GPU Plans transferred to the Company shall be paid by the Company. Any liability of the GPU Plans transferred to an Affiliate shall be paid by the Affiliate.

Payment of Accounts. An account balance of a GPU Plan shall be transferred to this Plan as of the later of the date of the Director's election or November 7, 2001. If any account under a GPU Plan is in pay status or is otherwise payable to an Participant as of such date, it shall continue to be payable to that person under the same terms and conditions as were provided under the applicable GPU Plan. The balance of any account under a GPU Plan shall become payable under the terms and conditions of this Plan; provided, however, that the Director's deferral elections, commencement date elections, and beneficiary elections made under the GPU Plan shall continue to be effective under this Plan unless amended or changed under the terms of this Plan.

Crediting of Service and Years of Deferral. All service as a director with GPU, Inc. or any affiliate of GPU, Inc. shall count as Years of Service under this Plan. A full year during which a Director deferred fees under a GPU Plan shall count as a full year of deferral under this Plan for purposes of withdrawals under Section 4.4 .

DEFERRED COMPENSATION PLAN FOR OUTSIDE DIRECTORS 7/31/2007

**FirstEnergy Corp.
2007 Incentive Plan**

Amendment and Restatement
Effective May 15, 2007

{EXHIBIT 10.4.DOC;1}

Contents

	<u>Page</u>
Article 1. Establishment, Purpose, and Duration	1
Article 2. Definitions	1
Article 3. Administration	8
Article 4. Shares Subject to This Plan and Maximum Awards	9
Article 5. Eligibility and Participation	12
Article 6. Stock Options	12
Article 7. Stock Appreciation Rights	14
Article 8. Restricted Stock and Restricted Stock Units	16
Article 9. Performance Shares	18
Article 10. Cash-Based Awards and Other Stock-Based Awards	19
Article 11. Transferability of Awards	20
Article 12. Performance Measures	20
Article 13. Nonemployee Director Awards	22
Article 14. Dividend Equivalents	22
Article 15. Beneficiary Designation	22
Article 16. Rights of Participants	23
Article 17. Change in Control	23
Article 18. Amendment, Modification, Suspension and Termination	24
Article 19. Withholding	26
Article 20. Successors	26
Article 21. General Provisions	26

{EXHIBIT 10.4.DOC;1}

FirstEnergy Corp. 2007 Incentive Plan

Article 1. Establishment, Purpose, and Duration

1.1 Establishment . FirstEnergy Corp., an Ohio corporation (the "Company"), hereby amends and restates in its entirety the FirstEnergy Corp. Executive and Director Incentive Compensation Plan, renamed as the "FirstEnergy Corp. 2007 Incentive Plan" (the "Plan"), as set forth in this document.

This Plan permits the grant of Nonqualified Stock Options, Incentive Stock Options, Stock Appreciation Rights, Restricted Stock, Restricted Stock Units, Performance Shares, Cash-Based Awards and Other Stock-Based Awards.

1.2 Purpose of This Plan . The purpose of the Plan is to promote the success of the Company and its Subsidiaries by providing incentives to key employees and Directors that will link their personal interests to the long-term financial success of the Company and its Subsidiaries, and to increase shareholder value. The Plan is designed to provide flexibility to the Company and its Subsidiaries in their ability to motivate, attract and retain the services of employees and Directors whose judgment, interest, efforts and special skills will help enable the Company to succeed. The Plan is intended to permit the preservation of the maximum deductibility of all Awards within the structure of Code Section 162(m).

1.3 Duration of This Plan . This amended and restated Plan shall become effective upon shareholder approval (the "Effective Date"). After this Plan is terminated, no Awards may be granted but Awards previously granted shall remain outstanding subject to this Plan's terms and conditions. Incentive Stock Options cannot be granted more than ten (10) years after the earlier of the date of adoption of this Plan by the Board and the Effective Date.

Article 2. Definitions

As used in this Plan, the following capitalized terms shall have the following meanings:

2.1 "Annual Award Limit" and "Annual Award Limits" have the meanings set forth in Section 4.3.

2.2 "Award" means, individually or collectively, a grant of Nonqualified Stock Options, Incentive Stock Options, Stock Appreciation Rights, Restricted Stock, Restricted Stock Units, Performance Shares, Cash-Based Awards , or Other Stock-Based Awards under and subject to the terms of this Plan.

2.3 “**Award Agreement**” means either: (a) a written agreement entered into by the Company and a Participant setting forth the terms of an Award, or (b) a written or electronic statement issued by the Company to a Participant describing the terms of an Award, including any amendment or modification thereof. The Committee may provide for the use of electronic, Internet, or other non-paper Award Agreements, and the use of electronic, Internet, or other non-paper means for the acceptance thereof and actions thereunder by a Participant.

2.4 “**Beneficial Owner**” or “**Beneficial Ownership**” shall have the meaning ascribed to such term in Rule 13d-3 of the General Rules and Regulations under the Exchange Act.

2.5 “**Board**” or “**Board of Directors**” means the Board of Directors of the Company.

2.6 “**Cash-Based Award**” means an Award, denominated in cash, granted to a Participant as described in Article 10.

2.7 “**Cause**” shall mean:

- (a) the willful and continued failure by a Participant to substantially perform his/her duties (other than any such failure resulting from the Participant’s Disability), after a written demand for substantial performance is delivered to the Participant that specifically identifies the manner in which the Company or any of its Subsidiaries, as the case may be, believes that the Participant has not substantially performed his/her duties, and the Participant has failed to remedy the situation within ten (10) business days of receiving such notice; or
- (b) the Participant’s conviction for committing a felony or a crime involving an act of moral turpitude, dishonesty or misfeasance; or
- (c) the willful engaging by the Participant in gross misconduct materially and demonstrably injurious to the Company or any of its Subsidiaries. However, no act, or failure to act, on the Participant’s part shall be considered “willful” unless done, or omitted to be done, by the Participant not in good faith and without reasonable belief that his/her action or omission was in the best interest of the Company or any of its Subsidiaries; or
- (d) a material breach by a Participant of any agreement between the Participant and the Company.

2.8 “Change in Control” shall mean:

- (a) An acquisition by any Person of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Exchange Act) immediately after which such Person has beneficial ownership of fifty percent (50%) (twenty-five percent (25%) if such Person proposes any individual for election to the Board or any member of the Board is the representative of such Person) or more of either: (i) the then-outstanding shares of common stock of the Company (the “Outstanding Company Common Stock”), or (ii) the combined voting power of the then-outstanding voting securities of the Company entitled to vote generally in the election of Directors (the “Outstanding Company Voting Securities”); provided, however, that the following acquisitions shall not constitute a Change in Control:
 - (i) Any acquisition directly from the Company (excluding an acquisition by virtue of the exercise of a conversion privilege);
 - (ii) Any acquisition by the Company;
 - (iii) Any acquisition by an employee benefit plan (or related trust) sponsored or maintained by the Company or any corporation controlled by the Company; or
 - (iv) Any acquisition by any corporation pursuant to a reorganization, merger, or consolidation (collectively “Reorganization”) if, following such Reorganization, the conditions described in (c)(i), (c)(ii), and (c)(iii) of this Section are satisfied.
- (b) Individuals who, as of the Effective Date, constitute the Board (the “Incumbent Board”) cease for any reason to constitute at least a majority of the Board; provided, however, that any individual becoming a Director subsequent to the date of adoption whose election, or nomination for election by the Company’s shareholders, is approved by a vote of at least a majority of the Directors then comprising the Incumbent Board shall be considered as a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as a result of either an actual or threatened election contest (within the meaning of solicitations subject to Rule 14a-12(c) of Regulation 14A promulgated under the Exchange Act or any successor rule) or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board; or

- (c) Consummation of a Reorganization, or sale or other disposition of all or substantially all of the assets of the Company in one transaction or a series of related transactions, in each case, unless, following such Reorganization, or sale or other disposition of assets:
- (i) More than seventy-five percent (75%) of, respectively, the then-outstanding shares of common stock of the corporation resulting from such Reorganization or acquisition of such assets and the combined voting power of the then-outstanding voting securities of such resulting or acquiring corporation entitled to vote generally in the election of Directors is then beneficially owned, directly or indirectly, by all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the Outstanding Company Common Stock and Outstanding Company Voting Securities immediately prior to such Reorganization, or sale or other disposition of assets in substantially the same proportions as their ownership, immediately prior to such Reorganization, or sale or other disposition of assets, of the Outstanding Company Common Stock and Outstanding Company Voting Securities, as the case may be;
 - (ii) No Person (excluding the Company, any employee benefit plan (or related trust) of the Company or such corporation resulting from such Reorganization, or sale or other disposition of assets, and any Person beneficially owning, immediately prior to such Reorganization, or sale or other disposition of assets, directly or indirectly, twenty-five percent (25%) or more of the Outstanding Company Common Stock or Outstanding Company Voting Securities, as the case may be) beneficially owns, directly or indirectly, twenty-five percent (25%) or more of, respectively, the then-outstanding shares of common stock of the corporation resulting from such Reorganization or acquisition of such assets, or the combined voting power of the then-outstanding voting securities of such resulting or acquiring corporation that are entitled to vote generally in the election of directors; and
 - (iii) At least a majority of the members of the board of directors of the corporation resulting from such Reorganization or acquisition of such assets were members of the Incumbent Board at the time of the execution of the initial agreement providing for such Reorganization, or sale or other disposition of assets; or
- (d) Approval by the shareholders of the Company of a complete liquidation or dissolution of the Company.

{EXHIBIT 10.4.DOC;1}

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However, in no event will a Change in Control be deemed to have occurred, with respect to a Participant, if the Participant is part of a purchasing group which consummates the Change in Control transaction. The Participant shall be deemed "part of a purchasing group" for purposes of the preceding sentence if the Participant is an equity participant or has agreed to become an equity participant in the purchasing company or group (excluding passive ownership of less than five percent (5%) of the voting securities of the purchasing company or ownership of equity participation in the purchasing company or group which is otherwise not deemed to be significant, as determined prior to the Change in Control by a majority of the nonemployee continuing members of the Board of Directors).

In addition, a Change in Control may occur only with respect to the Company. A change in ownership of common stock of an affiliate or subsidiary, change in membership of a board of directors of an affiliate or subsidiary, the sale of assets of an affiliate or subsidiary, or any other event described in this subsection that occurs only with respect to an affiliate or subsidiary does not constitute a Change in Control.

2.9 "Code" means the Internal Revenue Code of 1986, as amended from time to time. References to Code Sections shall be deemed to include references to any applicable regulations thereunder and any successor provision with the same or similar purpose.

2.10 "Committee" means the Compensation Committee of the Board or a subcommittee thereof, or any other committee designated by the Board to administer this Plan. The Committee members shall be appointed from time to time by, and shall serve at the discretion of, the Board. If the Committee does not exist or cannot function for any reason, the Board may take any action under the Plan that would otherwise be the responsibility of the Committee.

2.11 "Company" means FirstEnergy Corp., an Ohio corporation, and any successor thereto as provided in Article 20.

2.12 "Covered Employee" means any Employee who is or may become a "covered employee," as defined in Code Section 162(m), and who is designated, as an individual Employee or as a member of a class of Employees, by the Committee.

2.13 "Director" means a member of the Board.

2.14 "Disability" means, as of any date, a Participant's qualification for, and receipt of, benefits under the Company's then-existing long-term disability plan or program.

2.15 "Effective Date" has the meaning set forth in Section 1.3.

2.16 “**Employee**” means any individual performing services for the Company, or a Subsidiary and designated as an employee of the Company, or its Subsidiaries on the payroll records thereof. An Employee shall not include any individual during any period he or she is classified or treated by the Company or Subsidiary as an independent contractor, a consultant or an employee of an employment, consulting, or temporary agency or any entity other than the Company or a Subsidiary, without regard to whether such individual is subsequently determined to have been, or is subsequently retroactively reclassified as, a common law employee of the Company or Subsidiary during such period by a court, agency or otherwise.

2.17 “**Exchange Act**” means the Securities Exchange Act of 1934, as amended from time to time, or any successor thereto.

2.18 “**Exercise Price**” means the price at which a Share may be purchased by a Participant pursuant to an Option or the price established at the time of grant of an SAR pursuant to Article 7 which is used to determine the amount of any payment due upon exercise of the Option or SAR, as the case may be.

2.19 “**Fair Market Value**” or “**FMV**” means an amount, unless the Committee determines otherwise, with respect to publicly traded Shares equal to the average of the high and low sales prices of the common stock as reported on the composite tape of the New York Stock Exchange for the date in which the determination of the fair market value is made or, if there are no sales of common stock on that date, then on the next preceding date on which there were sales of common stock. If Shares are not publicly traded, Fair Market Value shall be determined by the Committee in such manner as it deems appropriate. The Committee may determine Fair Market Value on other reasonable bases including a price based on the opening, closing, actual, high, low or average selling prices of a Share reported on the New York Stock Exchange or other established stock exchange (or exchanges) on the applicable date, the preceding trading day, the next succeeding trading day or an average of trading days, as determined by the Committee in its sole discretion. Such definition(s) of FMV shall be specified in each Award Agreement and may differ depending on whether FMV is in reference to the grant, exercise, vesting, settlement or payout of an Award. Notwithstanding anything in this Plan to the contrary, “Fair Market Value” shall be determined in a manner consistent with exemption from, and avoidance of adverse tax consequences under, Code Section 409A and, with respect to ISOs, also in a manner consistent with Code Section 422.

2.20 “**Full-Value Award**” means an Award other than in the form of an ISO, NSO or SAR, and which is settled with Shares.

2.21 “**Grant Date**” means the date an Award is granted to a Participant pursuant to the Plan.

2.22 “**Incentive Stock Option**” or “**ISO**” means an Option to purchase Shares granted under Article 6 to an Employee that is designated as an Incentive Stock Option and that is intended to meet the requirements of Code Section 422.

2.23 “**Nonemployee Director**” means a Director who is not an Employee.

2.24 “**Nonemployee Director Award**” means any NSO, SAR or Full-Value Award granted, whether singly, in combination, or in tandem, to a Participant who is a Nonemployee Director pursuant to such applicable terms, conditions and limitations as the Board or Committee may establish in accordance with this Plan.

2.25 “**Nonqualified Stock Option**” or “**NSO**” means an Option that is not intended to meet the requirements of Code Section 422, or that otherwise does not meet such requirements.

2.26 “**Option**” means an Incentive Stock Option or a Nonqualified Stock Option, as described in Article 6.

2.27 “**Other Stock-Based Award**” means an equity-based or equity-related Award not otherwise described in this Plan, granted pursuant to Article 10.

2.28 “**Participant**” means any eligible individual as set forth in Article 5 to whom an Award is granted.

2.29 “**Performance-Based Compensation**” means compensation under an Award that is intended to satisfy the requirements of Code Section 162(m) for certain performance-based compensation for Covered Employees.

2.30 “**Performance Measures**” means measures described in Article 12 upon which performance goals are based and which are approved by the Company’s shareholders pursuant to this Plan for Awards to qualify as Performance-Based Compensation.

2.31 “**Performance Period**” means the period of time during which the performance goals must be met in order to determine the degree of payout and/or vesting with respect to an Award.

2.32 “**Performance Share**” means an Award under Article 9 and subject to the terms of this Plan, denominated in Shares, the value of which at the time it is payable is a function of the extent to which, or whether, corresponding performance criteria have been achieved.

2.33 “**Period of Restriction**” means the period when Restricted Stock or Restricted Stock Units are subject to a substantial risk of forfeiture (based upon the passage of time, the achievement of performance goals, or upon the occurrence or non-occurrence of other events as determined by the Committee, in its sole discretion), as provided in Article 8.

2.34 “**Person**” shall have the meaning ascribed to such term in Section 3(a)(9) of the Exchange Act and as used in Sections 13(d) and 14(d) thereof, including a “group” as defined in Section 13(d) thereof.

2.35 “**Plan**” means this FirstEnergy Corp. 2007 Incentive Plan, as it may be amended from time to time.

2.36 “**Plan Year**” means the calendar year.

2.37 “**Restricted Stock**” means an Award granted to a Participant pursuant to Article 8, which is not a Restricted Stock Unit.

2.38 “**Restricted Stock Unit**” means an Award granted to a Participant pursuant to Article 8, pursuant to which no Shares are actually awarded to the Participant on the Grant Date.

2.39 “**Share**” means a share of common stock of the Company, \$.10 par value per share.

2.40 “**Stock Appreciation Right**” or “**SAR**” means an Award designated as a stock appreciation right, granted pursuant to Article 7.

2.41 “**Subsidiary**” means any corporation or other entity in which the Company has or obtains, directly or indirectly, a proprietary interest of more than fifty percent (50%) by reason of stock ownership or otherwise.

Article 3. Administration

3.1 General . The Committee shall be responsible for administering this Plan, subject to this Article and the other provisions of this Plan. The Committee shall consist of such number of Nonemployee Directors as is necessary for compliance with Code Section 162(m) and Rule 16b-4 of the Exchange Act, as and when applicable. The Committee may employ attorneys, consultants, accountants, agents, and other individuals, any of whom may be an Employee, and the Committee, the Company, and its officers, administrators and Directors shall be entitled to rely upon the advice, opinions or valuations of any such individuals. All actions taken and all interpretations and determinations made by the Committee shall be final and binding upon the Participants, the Company and all other individuals.

{EXHIBIT 10.4.DOC;1}

02590/PL001SD.DOC/05TOCcf 01/2007

3.2 Authority of the Committee . The Committee shall have full and exclusive discretionary power to interpret the terms of this Plan and any Award Agreement or other agreement or document ancillary or related to this Plan, to determine eligibility for Awards and to adopt such rules, regulations, forms, instruments and guidelines for administering this Plan as the Committee may deem necessary or proper. Such authority shall include selecting Award recipients, establishing all Award terms and conditions, including the terms and conditions set forth in Award Agreements, resolving or reconciling any ambiguity or inconsistency of or among provisions of the Plan, any Award Agreement or related documents, correcting any defect (including scrivener's errors), supplying any omission and, subject to Article 18, adopting modifications and amendments to this Plan or any Award Agreement, including any that are necessary to comply with, or obtain favorable treatment under, applicable laws.

Notwithstanding the foregoing, the Committee shall have no authority to adjust upwards the amount payable to a Covered Employee with respect to a particular Award, to take any of the foregoing actions, or to take any other action to the extent that such action or the Committee's ability to take such action would cause any Award under the Plan to any Covered Employee to fail to qualify as "performance-based compensation" within the meaning of Code Section 162(m)(4). Subject to Section 4.4, in no event shall the Committee have the right to: (i) cancel outstanding Options or SARs for the purpose of replacing or regranting such Options or SARs with an exercise price that is less than the original exercise price of the Option or SAR, or (ii) change the Option Price of an Option or SAR to an exercise price that is less than the original Option or SAR Exercise Price, without first obtaining the approval of shareholders. Also notwithstanding the foregoing, no action of the Committee (other than pursuant to Section 4.4) may be taken with respect to an outstanding Award except in accordance with Section 18.3.

3.3 Procedures of the Committee . All determinations of the Committee shall be made by not less than a majority of its members present at the meeting (in person or otherwise) at which a quorum is present. A majority of the entire Committee shall constitute a quorum for the transaction of business. Any action required or permitted to be taken at a meeting of the Committee may be taken without a meeting if a unanimous written consent, which sets forth the action, is signed (including electronic signatures) by each member of the Committee and filed with the minutes for proceedings of the Committee. Service on the Committee shall constitute service as a Director of the Company so that members of the Committee shall be entitled to indemnification, limitation of liability and reimbursement of expenses with respect to their services as members of the Committee to the same extent that they are entitled under the Company's Amended Code of Regulations and Ohio law for their services as Directors.

3.4 Delegation . The Committee may delegate to one or more of its members or to one or more officers or employees of the Company and its Subsidiaries or to one or more agents or advisors, such administrative duties or powers as it may deem advisable, and the Committee or any individuals to whom it has delegated duties or powers as aforesaid may employ one or more individuals to render advice with respect to any responsibility the Committee or such individuals may have under this Plan. The Committee may authorize one or more officers of the Company to do one or both of the following on the same basis as can the Committee: (a) designate Employees (other than Covered Employees) to be recipients of Awards; and (b) determine the size of any such Awards; provided, however, (i) the Committee shall not delegate such responsibilities to any such officer for Awards granted to an Employee who is considered an insider (as determined by the Board applying Section 16 of the Exchange Act and related guidance); (ii) the Committee action providing such authorization sets forth the total number of Awards such officer(s) may grant; and (iii) the officer(s) shall report periodically to the Committee regarding the nature and scope of the Awards granted pursuant to the authority delegated.

Article 4. Shares Subject to This Plan and Maximum Awards

4.1 Number of Shares Available for Awards.

- (a) Subject to adjustment as provided in Section 4.4, the maximum number of Shares available for grant to Participants under this Plan (the "Share Authorization") shall be:
 - (i) Six Million Five Hundred Fifty Thousand (6,550,000) Shares, plus
 - (ii) The number of Shares available for issuance under the Plan immediately prior to the Effective Date of this amended and restated Plan.
- (b) All Shares of the Share Authorization may be issued pursuant to ISOs under this Plan.
- (c) The maximum number of Shares of the Share Authorization that may be issued to Nonemployee Directors shall be Two Hundred Thousand (200,000) Shares.

4.2 Share Usage . Shares covered by an Award shall only be counted as used to the extent they are actually issued to a Participant or beneficiary. Any Shares related to Awards which terminate by expiration, forfeiture, cancellation or otherwise without the issuance of such Shares, are settled in cash in lieu of Shares, or are exchanged with the Committee's permission, prior to the issuance of Shares, for Awards not involving Shares, shall be available again for grant under this Plan. The Shares available for issuance under this Plan may be authorized and unissued Shares, treasury Shares or Shares obtained on the open market.

4.3 Annual Award Limits . Unless and until the Committee determines that an Award to a Covered Employee shall not be designed to qualify as Performance-Based Compensation, the following limits (each an "Annual Award Limit" and, collectively, "Annual Award Limits"), as adjusted pursuant to Sections 4.4 and 18.2, shall apply to grants of such Awards under this Plan for Plan Years beginning on or after January 1, 2007:

- (a) **Options** : The maximum aggregate number of Shares subject to Options granted in any one Plan Year to any one Participant shall be Five Hundred Thousand (500,000) Shares.
- (b) **SARs** : The maximum number of Shares subject to Stock Appreciation Rights granted in any one Plan Year to any one Participant shall be Five Hundred Thousand (500,000) Shares.
- (c) **Restricted Stock** : The maximum aggregate grant with respect to Awards of Restricted Stock in any one Plan Year to any one Participant shall be Two Hundred Fifty Thousand (250,000) Shares.
- (d) **Restricted Stock Units** : The maximum aggregate grant with respect to Awards of Restricted Stock Units in any one Plan Year to any one Participant shall be Two Hundred Fifty Thousand (250,000) Shares.
- (e) **Performance Shares** : The maximum aggregate Award of Performance Shares that any one Participant may receive in any one Plan Year shall be Two Hundred Fifty Thousand (250,000) Shares or an amount equal to the Fair Market Value of Two Hundred Fifty Thousand (250,000) Shares, determined as of the date of vesting.
- (f) **Cash-Based Awards** : The maximum aggregate amount awarded or credited with respect to Cash-Based Awards to any one Participant in any one Plan Year, including the 2007 Plan Year, may not exceed Five Million Dollars (\$5,000,000).

(g) **Other Stock-Based Awards** : The maximum aggregate grant with respect to Other Stock-Based Awards pursuant to Section 10.2 in any one Plan Year to any one Participant shall be Two Hundred Fifty Thousand (250,000) Shares.

4.4 Adjustments in Authorized Shares . In the event of any corporate event or transaction (including a change in the Shares of the Company or the capitalization of the Company) such as a merger, consolidation, reorganization, recapitalization, separation, partial or complete liquidation, stock dividend, stock split, reverse stock split, split up, spin-off, or other distribution of stock or property of the Company, combination of Shares, exchange of Shares, dividend in-kind, or other like change in capital structure, number of outstanding Shares or distribution (other than normal cash dividends) to shareholders of the Company, or any similar corporate event or transaction, the Committee, in order to prevent dilution or enlargement of Participants' rights under this Plan, shall substitute or adjust, as applicable, the number and kind of Shares that may be issued under this Plan or under particular forms of Awards, the number and kind of Shares subject to outstanding Awards, the Exercise Price applicable to outstanding Awards, the Annual Award Limits, and other value determinations applicable to outstanding Awards.

The Committee, in its sole discretion, may also make appropriate adjustments in the terms of any Awards under this Plan to reflect, or related to, such changes or distributions and to modify any other terms of outstanding Awards, including modifications of performance goals and changes in the length of Performance Periods. Subject to Article 18, but notwithstanding anything else herein to the contrary, without affecting the number of Shares reserved or available hereunder, the Committee may authorize the issuance or assumption of benefits under this Plan in connection with any merger, consolidation, acquisition of property or stock or reorganization upon such terms and conditions as it may deem appropriate.

The determination of the Committee as to the foregoing adjustments and substitutions, if any, shall be conclusive and binding on Participants and beneficiaries under this Plan. The adjustments and substitutions described in this Section shall be made in compliance with: (i) Code Sections 422 and 424 with respect to ISOs; (ii) Treasury Department Regulation Section 1.424-1 (and any successor) with respect to NSOs, applied as if the NSOs were ISOs; (iii) Code Section 409A, to the extent necessary for exemption therefrom, and to avoid adverse tax consequences thereunder; and (iv) Code Section 162(m) with respect to Awards granted to Covered Employees that the Committee intends be Performance-Based Compensation; unless specifically determined otherwise by the Committee.

{EXHIBIT 10.4.DOC;1}

02590/PL001SD.DOC/05TOCcf 01/2007

Article 5. Eligibility and Participation

5.1 Eligibility . Individuals eligible to participate in this Plan include all Employees and Directors.

5.2 Actual Participation . Subject to the provisions of this Plan, the Committee may, from time to time, select from all eligible individuals, those individuals (or classes or categories of individuals) to whom Awards shall be granted and shall determine, in its sole discretion, the nature and terms of each Award.

Article 6. Stock Options

6.1 Grant of Options . Subject to the terms of this Plan, Options may be granted to Participants in such number, and upon such terms, and at any time and from time to time, as shall be determined by the Committee, in its sole discretion; provided, however, that ISOs may be granted only to eligible Employees of the Company or of any parent or subsidiary corporation (as permitted under Code Sections 422 and 424) and only prior to the tenth anniversary of the Effective Date. An Employee who is employed by a Subsidiary may only be granted Options to the extent the Subsidiary is part of: (a) the Company's controlled group of corporations, or (b) a trade or business under common control; as of the Date of Grant, each as determined under the rules of Code Section 414, but substituting for this purpose ownership of at least fifty percent (50%) of the Subsidiary to determine the members of the controlled group of corporations and the entities under common control.

6.2 Award Agreement . Each Option grant shall be evidenced by an Award Agreement that shall specify the Exercise Price, the maximum duration of the Option, the number of Shares to which the Option pertains, the conditions upon which the Option shall become vested and exercisable, and such other provisions as the Committee shall determine which are not inconsistent with the terms of this Plan. The Award Agreement shall also specify whether the Option is intended to be an ISO or an NSO.

6.3 Exercise Price . The Exercise Price for each grant of an Option under this Plan shall be determined by the Committee in its sole discretion and shall be specified in the Award Agreement; provided, however, the Exercise Price must be at least equal to one hundred percent (100%) of the FMV of the underlying Shares on the Grant Date. With respect to a Participant who owns, directly or indirectly, more than ten percent (10%) of the total combined voting power of all classes of the stock of the Company, any Subsidiary or any Affiliate, the Exercise Price of Shares subject to an ISO shall be at least equal to one hundred ten percent (110%) of the FMV of such Shares on the Grant Date.

6.4 Term of Options . Each Option granted to a Participant shall expire at such time as the Committee shall determine at the time of grant; provided, however, no Option shall be exercisable later than the tenth (10th) anniversary of its Date of Grant.

6.5 Exercise of Options . Options shall be exercisable at such times and be subject to such restrictions and conditions as the Committee shall in each instance approve, which terms and restrictions need not be the same for each grant or for each Participant. The aggregate FMV of Shares with respect to which ISOs are exercisable for the first time by a grantee during any calendar year (under this Plan or any other plan adopted by the Company or its parent or subsidiary) shall not exceed one hundred thousand dollars (\$100,000). If such aggregate FMV (determined with respect to each ISO at the time of grant) exceeds such amount, such number of ISOs as have an aggregate FMV equal to the amount in excess of such amount shall be treated as NSOs.

6.6 Payment . Options shall be exercised by the delivery of a written notice of exercise to the Company or an agent designated by the Company in a form specified or accepted by the Committee, or by complying with any alternative procedures which may be authorized by the Committee, setting forth the number of Shares with respect to which the Option is to be exercised, accompanied by full payment for the Shares.

Payment of the Exercise Price is a condition precedent to the issuance of the Shares as to which an Option is exercised. The Exercise Price shall be payable to the Company in full by: (a) paying cash or its equivalent; (b) tendering (either by actual delivery or attestation) previously acquired Shares having an aggregate Fair Market Value at the time of exercise equal to the Exercise Price; (c) cashless (broker-assisted) exercise; (d) any combination of (a), (b), and (c); or (e) any other method or methods approved or accepted by the Committee in its sole discretion.

Subject to any governing rules or regulations, as soon as practicable after receipt of written notification of exercise and full payment (including satisfaction of any applicable tax withholding), the Company shall deliver to the Participant evidence of book entry Shares or, upon the Participant's request, Share certificates in an appropriate amount based upon the number of Shares purchased under the Option (s). Alternatively, if the relevant Award Agreement requires payment of cash or its equivalent at that time, the Company shall pay to the Participant the appropriate amount of cash or its equivalent.

6.7 Restrictions on Share Transferability . The Committee may impose such restrictions on any Shares acquired pursuant to the exercise of an Option granted under this Article as it may deem advisable including minimum holding period requirements and restrictions under applicable federal securities laws, the rules of any stock exchange or market upon which such Shares are then listed or traded or any blue sky or state securities laws applicable to such Shares.

6.8 Termination of Employment . If a Participant's employment terminates because of death, any outstanding Options the Participant may have become immediately exercisable until the earlier of the expiration date of the Options or the first anniversary of termination of employment. The person or persons acquiring the Participant's rights under the Options pursuant to Article 15 shall be entitled to exercise the Options.

If a Participant's employment terminates because of Disability or retirement, including early retirement (with retirement and early retirement defined for purposes of this Section under the then-existing rules of the Company or any of its Subsidiaries, as the case may be), any outstanding Options the Participant shall continue to vest per the vesting schedule in the relevant Award Agreement; provided, however, that if the Participant subsequently dies with unexercised Options, vesting and exercisability will be governed by the provisions of this section relating to termination of employment due to death.

If a Participant's employment terminates for reasons other than death, Disability, retirement (including early retirement) or Cause, the Participant may exercise any vested Options he or she may have until the earlier of the date ending 90 days after termination of employment and the date of expiration of the term of the Options. Otherwise, the Participant shall not have any rights with respect to the Options in addition to those he had at termination of employment. Notwithstanding the foregoing, the Committee in its sole discretion may extend the foregoing 90 day period to up to one year, but not beyond the expiration date of the Options.

If a Participant's employment terminates for Cause, any outstanding Options the Participant may have will be forfeited immediately.

6.9 Notification of Disqualifying Disposition . If any Participant disposes of Shares issued pursuant to an ISO under the circumstances described in Code Section 421(b) (relating to certain disqualifying dispositions), the Participant shall notify the Company of the disposition within ten (10) days thereof.

6.10 No Other Feature of Deferral . No Option granted pursuant to this Plan shall provide for any feature for the deferral of compensation other than the deferral of recognition of income until the later of the exercise or disposition of the Option, or the time the stock acquired pursuant to the exercise of the Option first becomes substantially vested.

Article 7. Stock Appreciation Rights

7.1 Grant of SARs . Subject to the terms of this Plan, SARs may be granted to Participants at any time, and from time to time, as shall be determined by the Committee in its sole discretion. However, an Employee of a Subsidiary may only be granted SARs to the extent the Subsidiary is: (a) part of the Company's controlled group of corporations, or (b) a trade or business under common control with the Company, as of the date of grant, each determined under the rules of Code Section 414, but substituting for this purpose ownership of at least fifty percent (50%) of the Subsidiary to determine the members of the controlled group of corporations and the entities under common control.

Subject to the terms of this Plan, the Committee shall have complete discretion in determining the number of SARs granted to each Participant and the terms and conditions pertaining to such SARs.

The Exercise Price for each SAR shall be determined by the Committee and shall be specified in the Award Agreement; provided, however, that the Exercise Price must be at least equal to one hundred percent (100%) of the FMV of the underlying Shares on the Grant Date.

7.2 SARs Agreement . Each SAR Award shall be evidenced by an Award Agreement that shall specify the Exercise Price, the term of the SAR and such other provisions as the Committee shall determine.

7.3 Term of SARs . The term of an SAR granted under this Plan shall be determined by the Committee, in its sole discretion, and except as determined otherwise by the Committee and specified in the SAR Award Agreement, no SAR shall be exercisable later than the tenth (10th) anniversary of its grant.

7.4 Exercise of SARs . SARs may be exercised upon the terms and conditions imposed by the Committee in its sole discretion.

7.5 Settlement of SARs . Upon the exercise of an SAR, a Participant shall be entitled to receive payment from the Company in an amount determined by multiplying:

- (a) The excess of the Fair Market Value of a Share on the date of exercise over the Exercise Price; by
- (b) The number of Shares with respect to which the SAR is exercised.

At the discretion of the Committee, payment upon the exercise of an SAR may be in cash, Shares or a combination thereof, or in any other manner approved by the Committee. The Committee's determination regarding the form of SAR payout shall be set forth in the Award Agreement pertaining to the grant of the SAR.

7.6 Termination of Employment . If a Participant's employment terminates, the exercisability of any outstanding SARs he or she may have will be subject to the provisions of Section 6.8, applied as if the SARs were Options.

7.7 Other Restrictions . The Committee shall impose such other conditions and restrictions on any Shares received upon exercise of an SAR granted pursuant to this Plan as it may deem necessary or advisable. These restrictions may include a requirement that the Participant hold the Shares received upon exercise of an SAR for a specified period of time.

7.8 No Other Feature of Deferral . No SAR granted pursuant to this Plan shall provide for any feature for the deferral of compensation other than the deferral of recognition of income until the exercise of the Stock Appreciation Right.

Article 8. Restricted Stock and Restricted Stock Units

8.1 Grant of Restricted Stock or Restricted Stock Units . Subject to the terms of this Plan, the Committee, at any time and from time to time, may grant Shares of Restricted Stock and/or Restricted Stock Units to Participants in such amounts as the Committee shall determine. For informational purposes, Restricted Stock Units are similar to Restricted Stock except that no Shares are actually awarded to the Participant on the Grant Date.

8.2 Restricted Stock or Restricted Stock Unit Agreement . Each Restricted Stock and Restricted Stock Unit grant shall be evidenced by an Award Agreement that shall specify the Period(s) of Restriction, the number of Shares of Restricted Stock or the number of Restricted Stock Units granted and such other provisions as the Committee shall determine.

8.3 Other Restrictions . The Committee shall impose such other conditions and/or restrictions on any Shares of Restricted Stock or Restricted Stock Units as it may deem advisable including requirements that Participants pay stipulated purchase prices for each Share of Restricted Stock or each Restricted Stock Unit, restrictions based upon the achievement of specific performance goals, time-based restrictions on vesting following the attainment of the performance goals, time-based restrictions and/or restrictions under applicable laws or under the requirements of any stock exchange or market upon which such Shares are listed or traded, or holding requirements or sale restrictions placed on the Shares by the Company upon vesting of such Restricted Stock or Restricted Stock Units.

To the extent deemed appropriate by the Committee, the Company may retain the certificates representing Shares of Restricted Stock in the Company's possession until such time as all conditions and/or restrictions applicable to such Shares have been satisfied or lapse.

Except as otherwise provided in this Article, Shares of Restricted Stock covered by each Restricted Stock Award shall become freely transferable by the Participant after all conditions and restrictions applicable to such Shares have been satisfied or lapse (including satisfaction of any applicable tax withholding obligations), and Restricted Stock Units shall be paid in cash, Shares or a combination of cash and Shares as the Committee, in its sole discretion, shall determine. The determination of the Committee with respect to the form of payment shall be set forth in the relevant Award Agreement.

8.4 Certificate Legend . In addition to any legends placed on certificates pursuant to Section 8.3, each certificate representing Shares of Restricted Stock granted pursuant to this Plan may bear a legend such as the following or as otherwise determined by the Committee in its sole discretion:

"The sale or other transfer of the shares of stock represented by this certificate, whether voluntary, involuntary, or by operation or law, is subject to certain restrictions on transfer set forth in the FirstEnergy Corp. 2007 Incentive Plan, in the rules and administrative procedures adopted pursuant to such Plan, and in a Restricted Stock Award Agreement dated _____. A copy of the Plan, such rules and procedures, and such Restricted Stock Award Agreement may be obtained from the Corporate Secretary of FirstEnergy Corp."

8.5 Voting Rights . Unless otherwise determined by the Committee and set forth in a Participant's Award Agreement, to the extent permitted or required by law, as determined by the Committee, Participants holding Shares of Restricted Stock granted hereunder may be granted the right to exercise full voting rights with respect to those Shares during the Period of Restriction. A Participant shall have no voting rights with respect to any Restricted Stock Units.

8.6 Termination of Employment . If a Participant's employment with the Company or its Subsidiaries terminates because of death or Disability during a Period of Restriction, the Period of Restriction shall automatically terminate. Except as otherwise provided in Section 8.3 and the relevant Award Agreement, the Restricted Stock shall become free of restrictions and fully transferable and Restricted Stock Units shall become Shares issuable free of restrictions, but in each case subject to the satisfaction of applicable tax withholding requirements.

If a Participant's employment terminates due to retirement, including early retirement (with retirement and early retirement defined for purposes of this Section under the then-existing rules of the Company or any of its Subsidiaries, as the case may be), the Committee in its sole discretion may waive or modify the restrictions remaining on any or all Shares of Restricted Stock or any or all Shares subject to Restricted Stock Units as it deems appropriate.

If a Participant's employment terminates due to death, Disability or retirement, then notwithstanding the foregoing, the Committee may provide that the Participant receives a prorated payment based on the Participant's number of full months of service during the Performance Period, further adjusted based on the achievement of the performance goals. The Committee may also require that a Participant have a minimum number of full months of service during the Performance Period to qualify for an Award payment.

If a Participant's employment terminates for any reason other than death, Disability or retirement, including early retirement, during a Period of Restriction, any Shares of Restricted Stock or Restricted Stock Units still subject to restrictions as of the date of such termination shall automatically be forfeited and returned to the Company; provided, however, that in the event termination is for a reason other than Cause, the Committee, in its sole discretion, may waive or modify the automatic forfeiture of any or all such Restricted Stock or Restricted Stock Units as it deems appropriate.

Article 9. Performance Shares

9.1 Grant of Performance Shares . Subject to the terms of this Plan, the Committee, at any time and from time to time, may grant Performance Shares to Participants in such amounts and upon such terms as the Committee shall determine.

9.2 Value of Performance Shares . Each Performance Share shall have an initial value equal to the Fair Market Value of a Share on the Grant Date. The Committee shall set performance goals in its sole discretion which, depending on the extent to which they are met, will determine the value and number of Performance Shares upon which payout will be based.

9.3 Earning of Performance Shares . Subject to the terms of this Plan, after the applicable Performance Period has ended, the holder of Performance Shares shall be entitled to receive payout based upon the value and number of Performance Shares earned by the Participant over the Performance Period determined as a function of the extent to which, or whether, the corresponding performance goals have been achieved.

9.4 Form and Timing of Payment of Performance Shares . Payment of earned Performance Shares shall be in such form and at such time as determined by the Committee and as evidenced in the Award Agreement. Subject to the terms of this Plan, the Committee, in its sole discretion, may pay earned Performance Shares in the form of cash or Shares (or in a combination thereof) equal to the value of the earned Performance Shares at the close of the applicable Performance Period, or as soon as practicable after the end of the Performance Period. Any Shares may be granted subject to any restrictions deemed appropriate by the Committee. The determination of the Committee with respect to the form of payout shall be set forth in the relevant Award Agreement.

9.5 Termination of Employment . If a Participant's employment terminates because of death, Disability or retirement, including early retirement (with retirement and early retirement defined for purposes of this Section under the then-existing rules of the Company or any of its Subsidiaries, as the case may be), the holder of a Performance Share shall receive a prorated payment based on the Participant's number of full months of service during the Performance Period, further adjusted based on the achievement of the performance goals, as determined by the Committee in its sole discretion. The Committee may require that a Participant have a minimum number of full months of service during the Performance Period to qualify for an Award payment. The Committee may make such adjustments to the terms of this paragraph as it may deem advisable to preserve deductibility under Code Section 162(m).

If a Participant's employment terminates for any reason other than death, Disability or retirement, including early retirement, all Performance Shares in which he or she then had any interest shall be forfeited; provided, however, that if termination is for a reason other than Cause, the Committee, in its sole discretion, may waive the automatic forfeiture provisions.

Article 10. Cash-Based Awards and Other Stock-Based Awards

10.1 Grant of Cash-Based Awards . Subject to the terms of the Plan, the Committee may, at any time and from time to time, grant Cash-Based Awards to Participants in such amounts and upon such terms as the Committee may determine. The Committee may designate Cash-Based Awards to Covered Employees as being Performance-Based Compensation.

10.2 Other Stock-Based Awards . The Committee may grant other types of equity-based or equity-related Awards not otherwise described in this Plan (including the grant or offer for sale of unrestricted Shares) in such amounts and subject to such terms and conditions as the Committee shall determine. Such Awards may involve the transfer of actual Shares to Participants, or payment in cash or otherwise of amounts based on the value of Shares. The Committee may designate Other Stock-Based Awards to Covered Employees as being Performance-Based Compensation.

10.3 Value of Cash-Based and Other Stock-Based Awards . Each Cash-Based Award shall specify a payment amount or payment range as determined by the Committee. Each Other Stock-Based Award shall be expressed in terms of Shares or units based on Shares, as determined by the Committee. The Committee may establish performance goals in its sole discretion. If the Committee exercises its discretion to establish performance goals, the number and/or value of Cash-Based Awards or Other Stock-Based Awards that will be paid out to the Participant will depend on the extent to which, or whether, the performance goals are met.

10.4 Payment of Cash-Based Awards and Other Stock-Based Awards . Any payment with respect to a Cash-Based Award or an Other Stock-Based Award shall be made in accordance with the terms of the Award, in cash or Shares, as the Committee determines.

10.5 Termination of Employment . The Committee shall determine the extent to which the Participant shall have the right to receive Cash-Based Awards or Other Stock-Based Awards following termination of the Participant's employment with, or provision of services to, the Company and Subsidiaries, as the case may be. Such provisions shall be determined in the sole discretion of the Committee, such provisions may be included in an agreement entered into with each Participant, but need not be uniform among all Awards of Cash-Based Awards or Other Stock-Based Awards issued pursuant to the Plan and may reflect distinctions based on the reasons for termination.

Article 11. Transferability of Awards

Except as otherwise provided in a Participant's Award Agreement or otherwise determined at any time by the Committee, no Award granted under this Plan may be sold, transferred, pledged, assigned or otherwise alienated or hypothecated, other than by will or by the laws of descent and distribution. In no event may an Award be transferred for value. Further, except as otherwise provided in a Participant's Award Agreement or otherwise determined at any time by the Committee, all Awards granted to a Participant under this Plan shall be exercisable during his or her lifetime only by the Participant.

Article 12. Performance Measures

12.1 Performance Measures . The performance goals upon which the payment or vesting of an Award to a Covered Employee that is intended to qualify as Performance-Based Compensation shall be limited to the following Performance Measures:

{EXHIBIT 10.4.DOC;1}

02590/PL001SD.DOC/05TOCcf 01/2007

- (a) Net earnings or net income (before or after taxes);
- (b) Income
- (c) Retained earnings;
- (d) Earnings per share;
- (e) Net sales or revenue growth;
- (f) Net operating profit or income;
- (g) Return measures (including return on assets, capital, invested capital, equity, sales or revenue);
- (h) Cash flow (including operating cash flow, free cash flow, cash flow return on equity and cash flow return on investment);
- (i) Earnings before or after taxes, interest, depreciation and/or amortization;
- (j) Gross or operating margins;
- (k) Productivity ratios;
- (l) Share price (including growth measures and total shareholder return);
- (m) Costs or cost control;
- (n) Margins;
- (o) Operating efficiency;
- (p) Operating and maintenance cost management
- (q) Demand-side management (including conservation and load management)
- (r) Market share;
- (s) Service reliability;
- (t) Energy production availability performance;
- (u) Results of customer satisfaction or employee satisfaction surveys;
- (v) Aggregate product price and other product price measures;
- (w) Working capital;
- (x) Economic value added or EVA[®] (net operating profit after tax minus the sum of capital multiplied by the cost of capital);
- (y) Management development;
- (z) Succession planning;
- (aa) Shaping legislative and regulatory initiatives and outcomes;
- (bb) Taxes;
- (cc) Safety record;
- (dd) Depreciation and amortization;
- (ee) Total shareholder return;
- (ff) Workforce hiring plan measures;
- (gg) Air quality control project management;
- (hh) Environmental;
- (ii) Risk management;
- (jj) Technology upgrade measures;
- (kk) Financial contribution to earnings from special projects or initiatives;
- (ll) Capital expenditures;
- (mm) Generation output;
- (nn) Power supply sourcing adequacy;

(oo)	Results of asset acquisitions;
(pp)	Results of asset divestitures;
(qq)	Capitalization;
(rr)	Credit metrics;
(ss)	Credit ratings;
(tt)	Compound growth rates (earnings, revenue, income from continuing operations, cash generation, etc.);
(uu)	Generation outage duration;
(vv)	Transmission outage duration;
(ww)	Distribution outage duration;
(xx)	Value creation;
(yy)	Effective tax rate;
(zz)	Financing flexibility;
(aaa)	Financing capability; and
(bbb)	Value returned to shareholders.

Any Performance Measure(s) may be used to measure the performance of the Company, Subsidiary or Subsidiaries as a whole or any business unit of the Company and/or a Subsidiary or Subsidiaries or any combination thereof, as the Committee may deem appropriate, or any of the above Performance Measures as compared to the performance of a group of comparator companies, or published or special index that the Committee, in its sole discretion, deems appropriate, or the Company may select a share price performance measure as compared to various stock market indices. The Committee also has the authority to provide for accelerated vesting of any Award based on the achievement of performance goals pursuant to the Performance Measures specified in this Article.

12.2 Evaluation of Performance . The Committee may provide in any such Award that any evaluation of performance may include or exclude any of the following events that occur during a Performance Period: (a) asset write-downs, (b) litigation or claim judgments or settlements, (c) the effect of changes in tax laws, accounting principles or other laws or provisions affecting reported results, (d) any reorganization and restructuring programs, (e) extraordinary nonrecurring items as described in Accounting Principles Board Opinion No. 30 and/or in management's discussion and analysis of financial condition and results of operations appearing in the Company's consolidated report to the investment community or investor letters, (f) acquisitions or divestitures and (g) foreign exchange gains and losses. To the extent such inclusions or exclusions affect Awards to Covered Employees, they shall be prescribed in a form that meets the requirements of Code Section 162(m) for deductibility except as otherwise determined by the Committee in its sole discretion.

12.3 Adjustment of Performance-Based Compensation . Awards that are intended to qualify as Performance-Based Compensation may not be adjusted upward. The Committee shall retain the discretion to adjust such Awards downward, either on a formula or discretionary basis or a combination of the two, as the Committee determines.

12.4 Committee Discretion . If applicable tax and/or securities laws change to permit Committee discretion to alter the governing Performance Measures without obtaining shareholder approval of such changes, the Committee shall have sole discretion to make such changes without obtaining shareholder approval. In addition, in the event the Committee determines that it is advisable to grant Awards that shall not qualify as Performance-Based Compensation, the Committee may make such grants without satisfying the requirements of Code Section 162(m) and base vesting on performance measures other than those set forth in Section 12.1.

Article 13. Nonemployee Director Awards

The Board or Committee shall establish the terms of any Awards to Nonemployee Directors.

Article 14. Dividend Equivalents

Any Participant selected by the Committee may be granted dividend equivalents based on the dividends declared on Shares that are subject to any Award, to be credited as of dividend payment dates, during the period between the date the Award is granted and the date the Award is exercised, vests or expires, as determined by the Committee. Dividend equivalents shall be converted to cash or additional Shares by a formula, at a time and subject to any limitations as may be determined by the Committee.

Article 15. Beneficiary Designation

Each Participant under this Plan may, from time to time, name any beneficiary or beneficiaries (who may be named contingently or successively) to whom any benefit payable for a particular type of Award under this Plan is to be paid in case of the Participant's death before the Participant receives any or all of such benefit. Each such designation shall revoke all prior designations by the same Participant with respect to the same type of Award, shall be in a form prescribed by the Committee and will be effective only when filed by the Participant in writing with the Company during the Participant's lifetime. In the absence of any such beneficiary designation, or a beneficiary designation for a particular type of Award, benefits remaining unpaid or rights remaining unexercised at the Participant's death shall be paid to or exercised by the Participant's executor, administrator or legal representative.

Article 16. Rights of Participants

16.1 Employment . Nothing in this Plan or an Award Agreement shall interfere with or limit in any way the right of the Company and its Subsidiaries to terminate any Participant's employment or service, at any time or for any reason, nor confer upon any Participant any right to continue employment or service as a Director for any specified period of time.

Neither an Award nor any benefits arising under this Plan shall constitute an employment contract with the Company or its Subsidiaries and, accordingly, subject to Articles 3 and 18, this Plan and the benefits hereunder may be terminated at any time in the sole and exclusive discretion of the Committee without giving rise to any liability on the part of the Company and its Subsidiaries.

16.2 Participation . No individual shall have the right to be selected to receive an Award under this Plan or, having been so selected, to be selected to receive a future Award.

16.3 Rights as a Shareholder . Except as otherwise provided herein, a Participant shall have none of the rights of a shareholder with respect to Shares covered by any Award until the Participant becomes the record holder of such Shares.

Article 17. Change in Control

17.1 Change in Control of the Company . Notwithstanding any other provision of this Plan to the contrary, the provisions of this Article shall apply in the event of a Change in Control unless otherwise determined by the Committee in connection with the grant of an Award as reflected in the applicable Award Agreement.

Upon a Change in Control, except to the extent that another Award meeting the requirements of Section 17.2 (a "Replacement Award") is provided to the Participant to replace such Award (the "Replaced Award"), all then-outstanding Stock Options and Stock Appreciation Rights shall immediately become fully vested and exercisable, and all other then-outstanding Awards whose exercisability depends merely on the satisfaction of a service obligation by a Participant to the Company or Subsidiary shall vest in full and be free of restrictions related to the vesting of such Awards. The treatment of any other Awards shall be as determined by the Committee in connection with the grant thereof, as reflected in the applicable Award Agreement.

Except to the extent that a Replacement Award is provided to the Participant, the Committee may, in its sole discretion: (a) determine that any or all outstanding Awards granted under the Plan, whether or not exercisable, will be canceled and terminated and that in connection with such cancellation and termination the holder of such Award may receive for each Share of Common Stock subject to such Awards a cash payment (or the delivery of shares of stock, other securities or a combination of cash, stock and securities equivalent to such cash payment) equal to the difference, if any, between the consideration received by shareholders of the Company in respect of a Share of Common Stock in connection with such transaction and the purchase price per share, if any, under the Award multiplied by the number of Shares of Common Stock subject to such Award; provided that if such product is zero or less, or to the extent that the Award is not then exercisable, the Awards will be canceled and terminated without payment therefor, or (b) provide that the period to exercise Options or Stock Appreciation Rights granted under the Plan shall be extended (but not beyond the expiration of such Options or Stock Appreciation Rights).

17.2 Replacement Awards . An Award shall meet the conditions of this Section (and hence qualify as a Replacement Award) if: (a) it has a value at least equal to the value of the Replaced Award as determined by the Committee in its sole discretion; (b) it relates to publicly traded equity securities of the Company or its successor in the Change in Control or another entity that is affiliated with the Company or its successor following the Change in Control; and (c) its other terms and conditions are not less favorable to the Participant than the terms and conditions of the Replaced Award (including the provisions that would apply in the event of a subsequent Change in Control). Without limiting the generality of the foregoing, the Replacement Award may take the form of a continuation of the Replaced Award if the requirements of the preceding sentence are satisfied. The determination of whether the conditions of this Section are satisfied shall be made by the Committee, as constituted immediately before the Change in Control, in its sole discretion.

17.3 Termination of Employment . Upon a termination of employment or termination of directorship of a Participant occurring in connection with or during the period of two (2) years after such Change in Control, other than for Cause: (a) all Replacement Awards held by the Participant shall become fully vested and (if applicable) exercisable and free of restrictions, and (b) all Stock Options and Stock Appreciation Rights held by the Participant immediately before the termination of employment or termination of directorship that the Participant held as of the date of the Change in Control or that constitute Replacement Awards shall remain exercisable until the earlier of one (1) year following such termination and expiration of the stated term of such Stock Option or SAR; provided that if the applicable Award Agreement provides for a longer period of exercisability, that provision shall control.

Article 18. Amendment, Modification, Suspension and Termination

18.1 Amendment, Modification, Suspension and Termination . Subject to Section 18.3, the Committee may, at any time and from time to time, alter, amend, modify, suspend or terminate this Plan and any Award Agreement in whole or in part; provided, however, that, without the prior approval of the Company's shareholders and except as provided in Section 4.4, Options or SARs issued under this Plan will not be repriced, replaced (with any other Awards), regranted through cancellation or regranted by lowering the Exercise Price of a previously granted Option or SAR, nor will any outstanding underwater Options or SARs under this Plan be purchased for cash.

18.2 Adjustment of Awards Upon the Occurrence of Certain Unusual or Nonrecurring Events . The Committee may make adjustments in the terms and conditions of, and the criteria included in, Awards in recognition of unusual or nonrecurring events (including the events described in Section 4.4) affecting the Company or the financial statements of the Company or of changes in applicable laws, regulations or accounting principles, whenever the Committee determines that such adjustments are appropriate in order to prevent unintended dilution or enlargement of the benefits or potential benefits intended to be made available under this Plan. The determination of the Committee as to the foregoing adjustments, if any, shall be conclusive and binding on Participants under this Plan.

18.3 Awards Previously Granted . Notwithstanding any other provision of this Plan to the contrary (other than Section 18.4), no termination, amendment, suspension or modification of this Plan or an Award Agreement shall materially and adversely affect any Award previously granted under this Plan without the written consent of the Participant who received such Award.

18.4 Amendment to Conform to Law .

- (a) Notwithstanding any other provision of this Plan to the contrary, the Board of Directors may amend the Plan or an Award Agreement prospectively or retroactively as it deems necessary or advisable to conform the Plan or an Award Agreement to any present or future law relating to plans of this or similar nature, and to the administrative regulations and rulings promulgated thereunder. By accepting an Award under this Plan, a Participant agrees to any amendment made pursuant to this Section to any Award granted under the Plan without further consideration or action.

- (b) Except as may otherwise be expressly provided in an Award Agreement, the Committee intends that Awards be exempt from, and avoid adverse tax consequences under, Code Section 409A and all Awards shall be interpreted, construed and administered accordingly. The Committee may amend, modify or reform the Plan or an Award Agreement, both prospectively and retroactively and without notice to or the consent of any Participant or beneficiary, to obtain or preserve such exemption or avoidance of adverse tax consequences. The Committee, in its sole discretion, shall determine to what extent, if any, this Plan or an Award Agreement must be amended, modified or reformed or a substitute Award or Award Agreement must be made.

Article 19. Withholding

19.1 Tax Withholding . The Company shall have the power and the right to deduct or withhold, or require a Participant to remit to the Company, the minimum statutory amount to satisfy federal, state and local taxes required by law or regulation to be withheld with respect to any taxable event arising as a result of this Plan.

19.2 Share Withholding or Open Market Sales . With respect to withholding required upon the exercise of Options or SARs, upon the lapse of restrictions on Restricted Stock and Restricted Stock Units, or upon the achievement of performance goals related to Performance Shares, or any other taxable event arising as a result of an Award granted hereunder, Participants may elect, subject to the approval of the Committee, to satisfy the withholding requirement by having the Company withhold Shares having a Fair Market Value on the date the withholding amount is to be determined in an amount equal to the minimum statutory tax or sell Shares on the open market having a Fair Market Value on the date the withholding amount is to be determined in an amount not to exceed the total tax that could be imposed on the transaction. All such elections shall be irrevocable, made in writing, and signed by the Participant, and shall be subject to any restrictions or limitations that the Committee, in its sole discretion, deems appropriate.

Article 20. Successors

All obligations of the Company under this Plan with respect to Awards shall be binding on any successor to the Company, whether the existence of such successor is the result of a direct or indirect purchase, merger, consolidation or otherwise, of all or substantially all of the business and/or assets of the Company.

Article 21. General Provisions

21.1 Legend . The certificates for Shares may include any legend which the Committee deems appropriate to reflect any restrictions on transfer of such Shares.

21.2 Interpretation . Except where otherwise indicated by the context, any masculine term used herein also shall include the feminine, the plural shall include the singular and the singular shall include the plural. The word "including" or any variation thereof, means "including, without limitation," and shall not be construed to limit any general statement that it follows to the specific or similar items or matters immediately following it.

21.3 Severability . In the event any provision of this Plan shall be found illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of this Plan, and this Plan shall be construed and enforced as if the illegal or invalid provision had not been included.

21.4 Requirements of Law . The granting of Awards and the issuance of Shares under this Plan shall be subject to all applicable laws, rules and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required.

21.5 Delivery of Title . The Company shall have no obligation to issue or deliver evidence of title for Shares issued under this Plan prior to:

- (a) Obtaining any approvals from governmental agencies that the Company determines are necessary or advisable; and
- (b) Completion of any registration or other qualification of the Shares under any applicable ruling of any governmental body that the Company determines are necessary or advisable.

21.6 Inability to Obtain Authority . The inability of the Company to obtain authority from any regulatory body having jurisdiction, which authority is deemed by the Company's counsel to be necessary to the lawful issuance and sale of any Shares hereunder, shall relieve the Company of any liability in respect of the failure to issue or sell such Shares as to which such authority is not obtained.

21.7 Investment Representations . The Committee may require any individual receiving Shares pursuant to an Award under this Plan to represent and warrant in writing that the individual is acquiring the Shares for investment purposes and without any intention to sell or distribute the Shares.

21.8 Uncertificated Shares . To the extent that this Plan provides for issuance of certificates to reflect the transfer of Shares, the transfer of those Shares may be effected on a noncertificated basis, to the extent not prohibited by applicable law or the rules of any stock exchange.

21.9 Unfunded Plan . Participants shall have no right, title or interest whatsoever in or to any investments that the Company and its Subsidiaries may make to aid it in meeting its obligations under this Plan. Nothing contained in this Plan, and no action taken pursuant to its provisions, shall create or be construed to create a trust of any kind or a fiduciary relationship between the Company and any Participant, beneficiary, legal representative or any other individual. To the extent that any individual acquires a right to receive payments from the Company or its Subsidiaries under this Plan, such right shall be no greater than the right of an unsecured general creditor of the Company or Subsidiary, as the case may be. All payments to be made hereunder shall be paid from the general funds of the Company or a Subsidiary, as the case may be, and no special or separate fund shall be established and no segregation of assets shall be made to assure payment of such amounts except as expressly set forth in this Plan.

21.10 No Fractional Shares . No fractional Shares shall be issued or delivered pursuant to this Plan or any Award. The Committee shall determine whether cash, Awards or other property shall be issued or paid in lieu of fractional Shares or whether such fractional Shares or any rights thereto shall be forfeited or otherwise eliminated.

21.11 Nonexclusivity of this Plan . The adoption of this Plan shall not be construed as creating any limitations on the power of the Board or Committee to adopt such other compensation arrangements as it may deem desirable for any Participant.

21.12 No Constraint on Corporate Action . Nothing in this Plan shall be construed to: (a) limit, impair, or otherwise affect the Company's or a Subsidiary's right or power to make adjustments, reclassifications, reorganizations or changes of its capital or business structure, or to merge or consolidate, or dissolve, liquidate, sell or transfer all or any part of its business or assets; or (b) limit the right or power of the Company or a Subsidiary to take any action which such entity deems to be necessary or appropriate.

21.13 Governing Law . The Plan and each Award Agreement shall be governed by the laws of the State of Ohio, excluding any conflicts or choice of law rule or principle that might otherwise refer construction or interpretation of this Plan to the substantive law of another jurisdiction. Unless otherwise provided in the Award Agreement, recipients of an Award and their beneficiaries, estates, successors and assignees are deemed to submit to the exclusive jurisdiction and venue of the federal or state courts of Ohio, to resolve any and all issues that may arise out of or relate to this Plan or any related Award Agreement.

21.14 Action Required. If a Participant or beneficiary is required to take any action under this Plan within a certain number of days, and the final day of such period ends on Saturday, Sunday or a federal holiday, the Participant or beneficiary must take such action no later than the last business day preceding such day.

{EXHIBIT 10.4.DOC;1}

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FIRSTENERGY CORP.

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2004	2005	2006	2007	2008
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	\$ 906,753	\$ 879,053	\$ 1,257,806	\$ 1,308,757	\$ 1,342,347
Interest and other charges, before reduction for amounts capitalized and deferred	692,068	675,424	727,956	785,539	761,291
Provision for income taxes	680,524	748,794	794,595	883,033	776,915
Interest element of rentals charged to income (a)	248,499	241,460	226,168	206,073	171,229
Earnings as defined	\$ 2,527,844	\$ 2,544,731	\$ 3,006,525	\$ 3,183,402	\$ 3,051,782
FIXED CHARGES AS DEFINED IN REGULATION S-K:					
Interest before reduction for amounts capitalized and deferred	\$ 670,655	\$ 659,886	\$ 721,068	\$ 785,539	\$ 761,291
Subsidiaries' preferred stock dividend requirements	21,413	15,538	6,888	-	-
Adjustments to subsidiaries' preferred stock dividends to state on a pre-income tax basis	16,071	13,236	4,351	-	-
Interest element of rentals charged to income (a)	248,499	241,460	226,168	206,073	171,229
Fixed charges as defined	\$ 956,638	\$ 930,120	\$ 958,475	\$ 991,612	\$ 932,520
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	2.64	2.74	3.14	3.21	3.27

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2004	2005	2006	2007	2008
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	\$ 322,239	\$ 208,560	\$ 418,653	\$ 528,864	\$ 506,410
Interest and other charges, before reduction for amounts capitalized and deferred	181,620	196,355	189,141	157,700	141,511
Provision for income taxes	229,575	124,499	236,348	304,608	293,181
Interest element of rentals charged to income (a)	1,056	1,434	1,797	24,669	99,360
Earnings as defined	\$ 734,490	\$ 530,848	\$ 845,939	\$ 1,015,841	\$ 1,040,462
FIXED CHARGES AS DEFINED IN REGULATION S-K:					
Interest before reduction for amounts capitalized and deferred	\$ 181,620	\$ 196,355	\$ 189,141	\$ 157,700	\$ 141,511
Interest element of rentals charged to income (a)	1,056	1,434	1,797	24,669	99,360
Fixed charges as defined	\$ 182,676	\$ 197,789	\$ 190,938	\$ 182,369	\$ 240,871
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	4.02	2.68	4.43	5.57	4.32

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

OHIO EDISON COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2004	2005	2006	2007	2008
(Dollars in thousands)					
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	\$ 342,766	\$ 330,398	\$ 211,639	\$ 197,166	\$ 211,746
Interest and other charges, before reduction for amounts capitalized and deferred	74,051	77,077	90,952	83,343	75,058
Provision for income taxes	278,303	309,995	123,343	101,273	98,584
Interest element of rentals charged to income (a)	104,239	101,862	89,354	79,954	74,962
Earnings as defined	\$ 799,359	\$ 819,332	\$ 515,288	\$ 461,736	\$ 460,350
FIXED CHARGES AS DEFINED IN REGULATION S-K:					
Interest before reduction for amounts capitalized and deferred	\$ 71,491	\$ 75,388	\$ 90,356	\$ 83,343	\$ 75,058
Subsidiaries' preferred stock dividend requirements	2,560	1,689	597	-	-
Adjustments to subsidiaries' preferred stock dividends to state on a pre-income tax basis	1,975	1,351	651	-	-
Interest element of rentals charged to income (a)	104,239	101,862	89,354	79,954	74,962
Fixed charges as defined	\$ 180,265	\$ 180,290	\$ 180,958	\$ 163,297	\$ 150,020
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	4.43	4.54	2.85	2.83	3.07

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

OHIO EDISON COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS
PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)

	Year Ended December 31,				
	2004	2005	2006	2007	2008
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	\$ 342,766	\$ 330,398	\$ 211,639	\$ 197,166	\$ 211,746
Interest and other charges, before reduction for amounts capitalized and deferred	74,051	77,077	90,952	83,343	75,058
Provision for income taxes	278,303	309,995	123,343	101,273	98,584
Interest element of rentals charged to income (a)	104,239	101,862	89,354	79,954	74,962
Earnings as defined	\$ 799,359	\$ 819,332	\$ 515,288	\$ 461,736	\$ 460,350
FIXED CHARGES AS DEFINED IN REGULATION S-K PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS):					
Interest before reduction for amounts capitalized and deferred	\$ 71,491	\$ 75,388	\$ 90,356	\$ 83,343	\$ 75,058
Preferred stock dividend requirements	5,062	4,324	5,149	-	-
Adjustments to preferred stock dividends to state on a pre-income tax basis	4,072	3,758	3,263	-	-
Interest element of rentals charged to income (a)	104,239	101,862	89,354	79,954	74,962
Fixed charges as defined plus preferred stock dividend requirements (pre-income tax basis)	\$ 184,864	\$ 185,332	\$ 188,122	\$ 163,297	\$ 150,020
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)					
	<u>4.32</u>	<u>4.42</u>	<u>2.74</u>	<u>2.83</u>	<u>3.07</u>

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2004	2005	2006	2007	2008
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	\$ 236,531	\$ 231,058	\$ 306,051	\$ 276,412	\$ 284,526
Interest and other charges, before reduction for amounts capitalized and deferred	138,678	132,226	141,710	138,977	125,976
Provision for income taxes	138,856	153,014	188,662	163,363	136,786
Interest element of rentals charged to income (a)	49,375	47,643	45,955	29,829	1,919
Earnings as defined	<u>\$ 563,440</u>	<u>\$ 563,941</u>	<u>\$ 682,378</u>	<u>\$ 608,581</u>	<u>\$ 549,207</u>
FIXED CHARGES AS DEFINED IN REGULATION S-K:					
Interest before reduction for amounts capitalized and deferred	\$ 138,678	\$ 132,226	\$ 141,710	\$ 138,977	\$ 125,976
Interest element of rentals charged to income (a)	49,375	47,643	45,955	29,829	1,919
Fixed charges as defined	<u>\$ 188,053</u>	<u>\$ 179,869</u>	<u>\$ 187,665</u>	<u>\$ 168,806</u>	<u>\$ 127,895</u>
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	<u>3.00</u>	<u>3.14</u>	<u>3.64</u>	<u>3.61</u>	<u>4.29</u>

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS
PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)

	Year Ended December 31,				
	2004	2005	2006	2007	2008
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	\$ 236,531	\$ 231,058	\$ 306,051	\$ 276,412	\$ 284,526
Interest and other charges, before reduction for amounts capitalized and deferred	138,678	132,226	141,710	138,977	125,976
Provision for income taxes	138,856	153,014	188,662	163,363	136,786
Interest element of rentals charged to income (a)	49,375	47,643	45,955	29,829	1,919
Earnings as defined	\$ 563,440	\$ 563,941	\$ 682,378	\$ 608,581	\$ 549,207
FIXED CHARGES AS DEFINED IN REGULATION S-K PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS):					
Interest before reduction for amounts capitalized and deferred	\$ 138,678	\$ 132,226	\$ 141,710	\$ 138,977	\$ 125,976
Preferred stock dividend requirements	7,008	2,918	-	-	-
Adjustments to preferred stock dividends to state on a pre-income tax basis	4,113	1,932	-	-	-
Interest element of rentals charged to income (a)	49,375	47,643	45,955	29,829	1,919
Fixed charges as defined plus preferred stock dividend requirements (pre-income tax basis)	\$ 199,174	\$ 184,719	\$ 187,665	\$ 168,806	\$ 127,895
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)					
	<u>2.83</u>	<u>3.05</u>	<u>3.64</u>	<u>3.61</u>	<u>4.29</u>

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

THE TOLEDO EDISON COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2004	2005	2006	2007	2008
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	\$ 86,283	\$ 76,164	\$ 99,404	\$ 91,239	\$ 74,915
Interest and other charges, before reduction for amounts capitalized and deferred	33,439	21,489	23,179	34,135	23,286
Provision for income taxes	52,350	73,931	59,869	53,736	29,824
Interest element of rentals charged to income (a)	82,879	80,042	77,158	57,393	37,172
Earnings as defined	<u>\$ 254,951</u>	<u>\$ 251,626</u>	<u>\$ 259,610</u>	<u>\$ 236,503</u>	<u>\$ 165,197</u>
FIXED CHARGES AS DEFINED IN REGULATION S-K:					
Interest before reduction for amounts capitalized and deferred	\$ 33,439	\$ 21,489	\$ 23,179	\$ 34,135	\$ 23,286
Interest element of rentals charged to income (a)	82,879	80,042	77,158	57,393	37,172
Fixed charges as defined	<u>\$ 116,318</u>	<u>\$ 101,531</u>	<u>\$ 100,337</u>	<u>\$ 91,528</u>	<u>\$ 60,458</u>
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	<u>2.19</u>	<u>2.48</u>	<u>2.59</u>	<u>2.58</u>	<u>2.73</u>

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

THE TOLEDO EDISON COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS
PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)

	Year Ended December 31,				
	2004	2005	2006	2007	2008
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	\$ 86,283	\$ 76,164	\$ 99,404	\$ 91,239	\$ 74,915
Interest and other charges, before reduction for amounts capitalized and deferred	33,439	21,489	23,179	34,135	23,286
Provision for income taxes	52,350	73,931	59,869	53,736	29,824
Interest element of rentals charged to income (a)	82,879	80,042	77,158	57,393	37,172
Earnings as defined	<u>\$ 254,951</u>	<u>\$ 251,626</u>	<u>\$ 259,610</u>	<u>\$ 236,503</u>	<u>\$ 165,197</u>
FIXED CHARGES AS DEFINED IN REGULATION S-K PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS):					
Interest before reduction for amounts capitalized and deferred	\$ 33,439	\$ 21,489	\$ 23,179	\$ 34,135	\$ 23,286
Preferred stock dividend requirements	8,844	7,795	9,409	-	-
Adjustments to preferred stock dividends to state on a pre-income tax basis	5,366	7,561	5,667	-	-
Interest element of rentals charged to income (a)	82,879	80,042	77,158	57,393	37,172
Fixed charges as defined plus preferred stock dividend requirements (pre-income tax basis)	<u>\$ 130,528</u>	<u>\$ 116,887</u>	<u>\$ 115,413</u>	<u>\$ 91,528</u>	<u>\$ 60,458</u>
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)					
	<u>1.95</u>	<u>2.15</u>	<u>2.25</u>	<u>2.58</u>	<u>2.73</u>

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2004	2005	2006	2007	2008
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	\$ 107,626	\$ 182,927	\$ 190,607	\$ 186,108	\$ 186,988
Interest and other charges, before reduction for amounts capitalized and deferred	86,111	85,519	94,035	107,232	106,316
Provision for income taxes	97,205	135,846	146,731	149,056	148,231
Interest element of rentals charged to income (a)	7,589	7,091	8,838	7,976	7,702
Earnings as defined	\$ 298,531	\$ 411,383	\$ 440,211	\$ 450,372	\$ 449,237
FIXED CHARGES AS DEFINED IN REGULATION S-K:					
Interest before reduction for amounts capitalized and deferred	\$ 86,111	\$ 85,519	\$ 94,035	\$ 107,232	\$ 106,316
Interest element of rentals charged to income (a)	7,589	7,091	8,838	7,976	7,702
Fixed charges as defined	\$ 93,700	\$ 92,610	\$ 102,873	\$ 115,208	\$ 114,018
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	3.19	4.44	4.28	3.91	3.94

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS
PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)

	Year Ended December 31,				
	2004	2005	2006	2007	2008
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	\$ 107,626	\$ 182,927	\$ 190,607	\$ 186,108	\$ 186,988
Interest and other charges, before reduction for amounts capitalized and deferred	86,111	85,519	94,035	107,232	106,316
Provision for income taxes	97,205	135,846	146,731	149,056	148,231
Interest element of rentals charged to income (a)	<u>7,589</u>	<u>7,091</u>	<u>8,838</u>	<u>7,976</u>	<u>7,702</u>
Earnings as defined	<u>\$ 298,531</u>	<u>\$ 411,383</u>	<u>\$ 440,211</u>	<u>\$ 450,372</u>	<u>\$ 449,237</u>
FIXED CHARGES AS DEFINED IN REGULATION S-K PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS):					
Interest before reduction for amounts capitalized and deferred	\$ 86,111	\$ 85,519	\$ 94,035	\$ 107,232	\$ 106,316
Preferred stock dividend requirements	500	500	1,018	-	-
Adjustments to preferred stock dividends to state on a pre-income tax basis	452	371	784	-	-
Interest element of rentals charged to income (a)	<u>7,589</u>	<u>7,091</u>	<u>8,838</u>	<u>7,976</u>	<u>7,702</u>
Fixed charges as defined plus preferred stock dividend requirements (pre-income tax basis)	<u>\$ 94,652</u>	<u>\$ 93,481</u>	<u>\$ 104,675</u>	<u>\$ 115,208</u>	<u>\$ 114,018</u>
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES PLUS PREFERRED STOCK DIVIDEND REQUIREMENTS (PRE-INCOME TAX BASIS)					
	<u>3.15</u>	<u>4.40</u>	<u>4.21</u>	<u>3.91</u>	<u>3.94</u>

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

METROPOLITAN EDISON COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2004	2005	2006 (b)	2007	2008
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	\$ 66,955	\$ 45,919	\$ (240,195)	\$ 95,463	\$ 88,033
Interest and other charges, before reduction for amounts capitalized and deferred	45,057	44,655	47,385	51,022	43,651
Provision for income taxes	38,217	30,084	77,326	68,270	60,898
Interest element of rentals charged to income (a)	1,401	1,597	1,616	2,160	2,132
Earnings as defined	\$ 151,630	\$ 122,255	\$ (113,868)	\$ 216,915	\$ 194,714
FIXED CHARGES AS DEFINED IN REGULATION S-K:					
Interest before reduction for amounts capitalized and deferred	\$ 45,057	\$ 44,655	\$ 47,385	\$ 51,022	\$ 43,651
Interest element of rentals charged to income (a)	1,401	1,597	1,616	2,160	2,132
Fixed charges as defined	\$ 46,458	\$ 46,252	\$ 49,001	\$ 53,182	\$ 45,783
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	3.26	2.64	(2.32)	4.08	4.25

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

(b) The earnings as defined in 2006 would need to increase \$162,869,000 for the fixed charge ratios to be 1.0.

PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2004	2005	2006	2007	2008
	(Dollars in thousands)				
EARNINGS AS DEFINED IN REGULATION S-K:					
Income before extraordinary items	\$ 36,030	\$ 27,553	\$ 84,182	\$ 92,938	\$ 88,170
Interest and other charges, before reduction for amounts capitalized and deferred	40,022	39,900	45,278	54,840	59,424
Provision for income taxes	30,001	16,613	56,539	64,015	57,647
Interest element of rentals charged to income (a)	3,016	3,225	3,247	3,214	3,319
Earnings as defined	\$ 109,069	\$ 87,291	\$ 189,246	\$ 215,007	\$ 208,560
FIXED CHARGES AS DEFINED IN REGULATION S-K:					
Interest before reduction for amounts capitalized and deferred	\$ 40,022	\$ 39,900	\$ 45,278	\$ 54,840	\$ 59,424
Interest element of rentals charged to income (a)	3,016	3,225	3,247	3,214	3,319
Fixed charges as defined	\$ 43,038	\$ 43,125	\$ 48,525	\$ 58,054	\$ 62,743
CONSOLIDATED RATIO OF EARNINGS TO FIXED CHARGES	2.53	2.02	3.90	3.70	3.32

(a) Includes the interest element of rentals where determinable plus 1/3 of rental expense where no readily defined interest element can be determined.

ANNUAL REPORT 2008



Contents	Page
Glossary of Terms	i-iii
Selected Financial Data	1-2
Management's Discussion and Analysis	3-58
Management Reports	59
Report of Independent Registered Public Accounting Firm	60
Consolidated Statements of Income	61
Consolidated Balance Sheets	62
Consolidated Statements of Common Stockholders' Equity	63
Consolidated Statements of Cash Flows	64
Notes to Consolidated Financial Statements	65-108

GLOSSARY OF TERMS

The following abbreviations and acronyms are used in this report to identify FirstEnergy Corp. and our 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
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
FEV	FirstEnergy Ventures Corp., invests in certain unregulated enterprises and business ventures
FGCO	FirstEnergy Generation Corp., owns and operates non-nuclear generating facilities
FirstEnergy	FirstEnergy Corp., a public utility holding company
FSG	FirstEnergy Facilities Services Group, LLC, former parent of several heating, ventilation, air conditioning and energy management companies
GPU	GPU, Inc., former parent of JCP&L, Met-Ed and Penelec, which merged with FirstEnergy on November 7, 2001
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
JCP&L Transition Funding	JCP&L Transition Funding LLC, a Delaware limited liability company and issuer of transition bonds
JCP&L Transition Funding II	JCP&L Transition Funding II LLC, a Delaware limited liability company and issuer of transition bonds
Met-Ed	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MYR	MYR Group, Inc., a utility infrastructure construction service company
NGC	FirstEnergy Nuclear Generation Corp., owns nuclear generating facilities
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
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
Pennsylvania Companies	Met-Ed, Penelec and Penn
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
Shelf Registrants	OE, CEI, TE, JCP&L, Met-Ed and Penelec
Shippingport	Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997
Signal Peak	A joint venture between FirstEnergy Ventures Corp. and Boich Companies, that owns mining and coal transportation operations near Roundup, Montana, formerly known as Bull Mountain
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
Utilities	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec
Waverly	The Waverly Power and Light Company, a wholly owned subsidiary of Penelec

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

ACO	Administrative Consent Order
AEP	American Electric Power Company, Inc.
ALJ	Administrative Law Judge
AMP-Ohio	American Municipal Power - Ohio
AOCL	Accumulated Other Comprehensive Loss
AQC	Air Quality Control
ARB	Accounting Research Bulletin
ARO	Asset Retirement Obligation
BGS	Basic Generation Service
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAT	Commercial Activity Tax
CBP	Competitive Bid Process
CO ₂	Carbon Dioxide
CTC	Competitive Transition Charge
DCPD	Deferred Compensation Plan for Outside Directors
DFI	Demand for information
DOE	United States Department of Energy

GLOSSARY OF TERMS Cont'd.

DOJ	United States Department of Justice
DRA	Division of Ratepayer Advocate
EDCP	Executive Deferred Compensation Plan
EEl	Edison Electric Institute
EIS	Energy Independence Strategy
EITF	Emerging Issues Task Force
EITF 08-6	Equity Method Investment Accounting Considerations
EMP	Energy Master Plan
EPA	United States Environmental Protection Agency
EPACT	Energy Policy Act of 2005
ESP	Electric Security Plan
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FIN 46R	FIN 46 (revised December 2003), "Consolidation of Variable Interest Entities"
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"
FirstCom	First Communications, Inc.
FMB	First Mortgage Bond
FSP	FASB Staff Position
FSP SFAS 115-1 and SFAS 124-1	FSP SFAS 115-1 and SFAS 124-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"
FTR	Financial Transmission Rights
GAAP	Accounting Principles Generally Accepted in the United States
GHG	Greenhouse Gases
HVAC	Heating, Ventilation and Air-conditioning
IRS	Internal Revenue Service
ISO	Independent System Operator
kV	Kilovolt
KWH	Kilowatt-hours
LED	Light-emitting Diode
LIBOR	London Interbank Offered Rate
LOC	Letter of Credit
LTIP	Long-term Incentive Program
MEW	Mission Energy Westside, Inc.
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service, Inc.
MRO	Market Rate Offer
MW	Megawatts
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NOV	Notice of Violation
NO _x	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NUGC	Non-Utility Generation Charge
OCA	Office of Consumer Advocate
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OSBA	Office of Small Business Advocate
OTC	Over the Counter
OVEC	Ohio Valley Electric Corporation
PCRB	Pollution Control Revenue Bond
PJM	PJM Interconnection L. L. C.
PLR	Provider of Last Resort; an electric utility's obligation to provide generation service to customers whose alternative supplier fails to deliver service

GLOSSARY OF TERMS Cont'd.

PPUC	Pennsylvania Public Utility Commission
PRP	Potentially Responsible Party
PSA	Power Supply Agreement
PUCO	Public Utilities Commission of Ohio
PUHCA	Public Utility Holding Company Act of 1935
RCP	Rate Certainty Plan
RECB	Regional Expansion Criteria and Benefits
RFP	Request for Proposal
RSP	Rate Stabilization Plan
RTC	Regulatory Transition Charge
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Service
S&P 500	Standard & Poor's Index of Widely Held Common Stocks
SBC	Societal Benefits Charge
SEC	U.S. Securities and Exchange Commission
SECA	Seams Elimination Cost Adjustment
SFAS	Statement of Financial Accounting Standards
SFAS 71	SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 87	SFAS No. 87, "Employers' Accounting for Pensions"
SFAS 101	SFAS No. 101, "Accounting for Discontinuation of Application of SFAS 71"
SFAS 106	SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 107	SFAS No. 107, "Disclosure about Fair Value of Financial Instruments"
SFAS 109	SFAS No. 109, "Accounting for Income Taxes"
SFAS 115	SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities"
SFAS 123(R)	SFAS No. 123(R), "Share-Based Payment"
SFAS 132(R)-1	SFAS No. 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets"
SFAS 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS 141(R)	SFAS No. 141(R), "Business Combinations"
SFAS 142	SFAS No. 142, "Goodwill and Other Intangible Assets"
SFAS 143	SFAS No. 143, "Accounting for Asset Retirement Obligations"
SFAS 144	SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets"
SFAS 157	SFAS No. 157, "Fair Value Measurements"
SFAS 158	SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)"
SFAS 159	SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115"
SFAS 160	SFAS No. 160, "Non-controlling Interests in Consolidated Financial Statements – an Amendment of ARB No. 51"
SFAS 161	SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an Amendment of FASB Statement No. 133"
SIP	State Implementation Plan(s) Under the Clean Air Act
SNCR	Selective Non-Catalytic Reduction
SO ₂	Sulfur Dioxide
TBC	Transition Bond Charge
TMI-1	Three Mile Island Unit 1
TMI-2	Three Mile Island Unit 2
TSC	Transmission Service Charge
VIE	Variable Interest Entity

The following selected financial data should be read in conjunction with, and is qualified in its entirety by reference to, the sections entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations" and with our consolidated financial statements and the "Notes to Consolidated Financial Statements." Our Consolidated Statements of Income are not necessarily indicative of future conditions or results of operations.

FIRSTENERGY CORP.

SELECTED FINANCIAL DATA

<u>For the Years Ended December 31,</u>	<u>2008</u>	<u>2007</u>	<u>2006</u>	<u>2005</u>	<u>2004</u>
	<i>(In millions, except per share amounts)</i>				
Revenues	\$ 13,627	\$ 12,802	\$ 11,501	\$ 11,358	\$ 11,600
Income From Continuing Operations	\$ 1,342	\$ 1,309	\$ 1,258	\$ 879	\$ 907
Net Income	\$ 1,342	\$ 1,309	\$ 1,254	\$ 861	\$ 878
Basic Earnings per Share of Common Stock:					
Income from continuing operations	\$ 4.41	\$ 4.27	\$ 3.85	\$ 2.68	\$ 2.77
Net earnings per basic share	\$ 4.41	\$ 4.27	\$ 3.84	\$ 2.62	\$ 2.68
Diluted Earnings per Share of Common Stock:					
Income from continuing operations	\$ 4.38	\$ 4.22	\$ 3.82	\$ 2.67	\$ 2.76
Net earnings per diluted share	\$ 4.38	\$ 4.22	\$ 3.81	\$ 2.61	\$ 2.67
Dividends Declared per Share of Common Stock (1)	\$ 2.20	\$ 2.05	\$ 1.85	\$ 1.705	\$ 1.9125
Total Assets	\$ 33,521	\$ 32,311	\$ 31,196	\$ 31,841	\$ 31,035
Capitalization as of December 31:					
Common Stockholders' Equity	\$ 8,283	\$ 8,977	\$ 9,035	\$ 9,188	\$ 8,590
Preferred Stock	-	-	-	184	335
Long-Term Debt and Other Long-Term Obligations	9,100	8,869	8,535	8,155	10,013
Total Capitalization	\$ 17,383	\$ 17,846	\$ 17,570	\$ 17,527	\$ 18,938
Weighted Average Number of Basic Shares Outstanding	304	306	324	328	327
Weighted Average Number of Diluted Shares Outstanding	307	310	327	330	329

- (1) Dividends declared in 2008 include four quarterly dividends of \$0.55 per share. Dividends declared in 2007 include three quarterly payments of \$0.50 per share in 2007 and one quarterly payment of \$0.55 per share in 2008. Dividends declared in 2006 include three quarterly payments of \$0.45 per share in 2006 and one quarterly payment of \$0.50 per share in 2007. Dividends declared in 2005 include two quarterly payments of \$0.4125 per share in 2005, one quarterly payment of \$0.43 per share in 2005 and one quarterly payment of \$0.45 per share in 2006. Dividends declared in 2004 include four quarterly dividends of \$0.375 per share paid in 2004 and a quarterly dividend of \$0.4125 per share paid in 2005.

PRICE RANGE OF COMMON STOCK

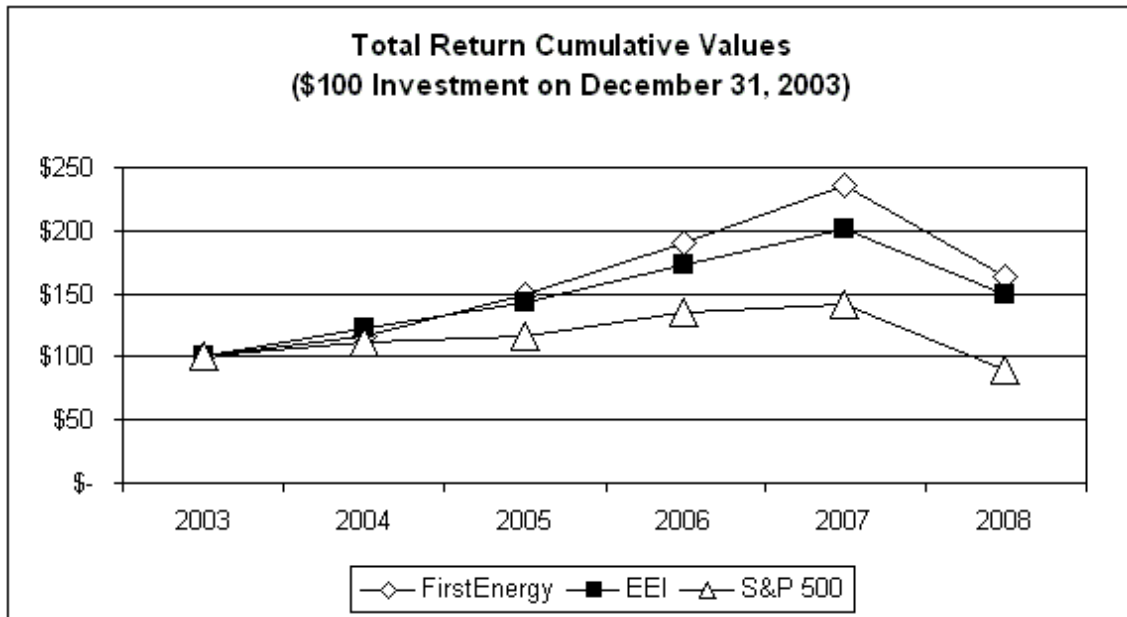
The common stock of FirstEnergy Corp. is listed on the New York Stock Exchange under the symbol "FE" and is traded on other registered exchanges.

	<u>2008</u>		<u>2007</u>	
First Quarter High-Low	\$ 78.51	\$ 64.44	\$ 67.11	\$ 57.77
Second Quarter High-Low	\$ 83.49	\$ 69.20	\$ 72.90	\$ 62.56
Third Quarter High-Low	\$ 84.00	\$ 63.03	\$ 68.31	\$ 58.75
Fourth Quarter High-Low	\$ 66.69	\$ 41.20	\$ 74.98	\$ 63.39
Yearly High-Low	\$ 84.00	\$ 41.20	\$ 74.98	\$ 57.77

Prices are from <http://finance.yahoo.com>.

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a \$100 investment on December 31, 2003 in FirstEnergy's common stock compared with the total cumulative returns of EEI's Index of Investor-Owned Electric Utility Companies and the S&P 500.



HOLDERS OF COMMON STOCK

There were 115,151 and 114,871 holders of 304,835,407 shares of FirstEnergy's common stock as of December 31, 2008 and January 31, 2009, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 11(A) to the consolidated financial statements.

FIRSTENERGY CORP.

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

Forward-Looking Statements: *This discussion includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding our management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Actual results may differ materially due to the speed and nature of increased competition in the electric utility industry and legislative and regulatory changes affecting how generation rates will be determined following the expiration of existing rate plans in Ohio and Pennsylvania, the impact of the PUCO's regulatory process on the Ohio Companies associated with the ESP and MRO filings, including any resultant mechanism under which the Ohio Companies may not fully recover costs (including, but not limited to, the costs of generation supply procured by the Ohio Companies, Regulatory Transition Charges and fuel charges), or the outcome of any competitive generation procurement process in Ohio, economic or weather conditions affecting future sales and margins, changes in markets for energy services, changing energy and commodity market prices and availability, replacement power costs being higher than anticipated or inadequately hedged, the continued ability of our regulated utilities to collect transition and other charges or to recover increased transmission costs, maintenance costs being higher than anticipated, other legislative and regulatory changes, revised environmental requirements, including possible greenhouse gas emission regulations, the potential impacts of the U.S. Court of Appeals' July 11, 2008 decision requiring revisions to the CAIR rules and the scope of any laws, rules or regulations that may ultimately take their place, the uncertainty of the timing and amounts of the capital expenditures needed to, among other things, implement the AQC Plan (including that such amounts could be higher than anticipated or that certain generating units may need to be shut down) or levels of emission reductions related to the Consent Decree resolving the NSR litigation or other potential regulatory initiatives, adverse regulatory or legal decisions and outcomes (including, but not limited to, the revocation of necessary licenses or operating permits and oversight) by the NRC (including, but not limited to, the Demand for Information issued to FENOC on May 14, 2007), the timing and outcome of various proceedings before the PUCO (including, but not limited to the distribution rate cases and the generation supply plan filing for the Ohio Companies and the successful resolution of the issues remanded to the PUCO by the Ohio Supreme Court regarding the RSP and the RCP, including the recovery of deferred fuel costs), Met-Ed's and Penelec's transmission service charge filings with the PPUC, the continuing availability of generating units and their ability to operate at or near full capacity, the ability to comply with applicable state and federal reliability standards, the ability to accomplish or realize anticipated benefits from strategic goals (including employee workforce initiatives), the ability to improve electric commodity margins and to experience growth in the distribution business, the changing market conditions that could affect the value of assets held in our nuclear decommissioning trusts, pension trusts and other trust funds, and cause us to make additional contributions sooner, or in an amount that is larger than currently anticipated, the ability to access the public securities and other capital and credit markets in accordance with our financing plan and the cost of such capital, changes in general economic conditions affecting us, the state of the capital and credit markets affecting us, interest rates and any actions taken by credit rating agencies that could negatively affect our access to financing or its costs and increase our requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees, the continuing decline of the national and regional economy and its impact on our major industrial and commercial customers, issues concerning the soundness of financial institutions and counterparties with which we do business, and the risks and other factors discussed from time to time in our SEC filings, and other similar factors. The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for our management to predict all such factors, nor assess the impact of any such factor on our business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. We expressly disclaim any current intention to update any forward-looking statements contained herein as a result of new information, future events, or otherwise.*

EXECUTIVE SUMMARY

Net income in 2008 was \$1.34 billion, or basic earnings of \$4.41 per share of common stock (\$4.38 diluted), compared with net income of \$1.31 billion, or basic earnings of \$4.27 per share (\$4.22 diluted), in 2007 and \$1.25 billion, or basic earnings of \$3.84 per share (\$3.81 diluted), in 2006.

Change in Basic Earnings Per Share From Prior Year	2008	2007
Basic Earnings Per Share – Prior Year	\$ 4.27	\$ 3.84
Gain on non-core asset sales – 2008/2007	0.02	0.04
Litigation settlement – 2008	0.03	-
Trust securities impairment	(0.20)	(0.03)
Saxton decommissioning regulatory asset – 2007	(0.05)	0.05
PPUC NUG accounting adjustment – 2006	-	0.02
Revenues	1.61	2.51
Fuel and purchased power	(1.24)	(1.51)
Amortization of regulatory assets	(0.07)	(0.31)
Deferral of new regulatory assets	(0.37)	-
Investment income	0.08	(0.03)
Interest expense	0.04	(0.11)
Reduced common shares outstanding	0.03	0.22
Other expenses	0.26	(0.42)
Basic Earnings Per Share	\$ 4.41	\$ 4.27

Financial Matters

Liquidity

We expect our existing sources of liquidity to remain sufficient to meet our anticipated obligations. We have access to more than \$4 billion of liquidity, of which approximately \$2.6 billion was undrawn as of January 31, 2009. During 2009 and in subsequent years, we expect to satisfy our obligations with a combination of cash from operations and funds from the capital markets. Since the middle of October 2008, our subsidiaries have issued \$1.2 billion of long-term debt securities in the capital markets (see Long-Term Financings below). We also expect that borrowing capacity under our existing credit facilities will continue to be available to manage our working capital requirements. In response to the current economic climate, we have taken several steps to strengthen our liquidity position and provide additional financial flexibility (see Strategy and Outlook).

Acquisition of Additional Equity Interests in the Perry Plant and Beaver Valley Unit 2

In May 2008, NGC purchased 56.8 MW of lessor equity interests in the OE 1987 sale and leaseback of the Perry Plant. In June 2008, NGC purchased approximately 43.5 MW of lessor equity interests in the OE 1987 sale and leaseback of Beaver Valley Unit 2 and 158.5 MW of lessor equity interests in the TE and CEI 1987 sale and leaseback of Beaver Valley Unit 2. The aggregate purchase price for NGC's acquisition of these lessor equity interests was approximately \$438 million. The Ohio Companies continue to lease these MW under the respective sale and leaseback arrangements and the related lease debt remains outstanding.

Non-Core Asset Sale

On March 7, 2008, we sold substantially all of the assets of FirstEnergy Telecom Services, Inc. to FirstCom for \$45 million in cash, with FirstCom assuming related liabilities. The sale resulted in an after-tax gain of approximately \$0.06 per share. We are a 15.6% shareholder in FirstCom.

New Credit Facilities

In May 2008, we, along with FES, entered into a new \$300 million, 364-day revolving credit facility with the Royal Bank of Scotland PLC. The pricing, terms and conditions are substantially similar to those contained in our current \$2.75 billion revolving credit agreement.

In response to recent turmoil in the credit markets, we, along with FES and FGCO, entered into a new \$300 million secured term loan facility with Credit Suisse in October 2008. Under the facility, FGCO is the borrower and we, along with FES, are guarantors. Generally, the facility is available to FGCO until October 7, 2009, with a minimum borrowing amount of \$100 million and a maturity of 30 days from the date of the borrowing. This facility is currently unused.

Long-Term Financings

In September 2008, we, along with the Shelf Registrants, filed an automatically effective shelf registration statement with the SEC. The shelf registration provides us the flexibility to issue and sell various types of securities, including common stock, preferred stock, debt securities, warrants, share purchase contracts, and share purchase units. The Shelf Registrants may utilize the shelf registration to offer and sell unsecured, and in some cases, secured debt securities. The following securities have been issued and sold under the shelf registration to date:

- OE – \$275 million of 8.25% Series of FMBs due 2038 issued on October 20, 2008;
- OE – \$25 million of 8.25% Series of FMBs due 2018 issued on October 20, 2008;
- CEI – \$300 million of 8.875% Series of FMBs due 2018 issued on November 18, 2008;
- Met-Ed – \$300 million of 7.70% Senior Notes due 2019 issued on January 20, 2009; and
- JCP&L – \$300 million of 7.35% Senior Notes due 2019 issued on January 27, 2009.

Rating Agency Action

On August 1, 2008, S&P changed its outlook for FirstEnergy and our subsidiaries from “negative” to “stable.” On November 5, 2008, S&P raised its senior unsecured rating on OE, Penn, CEI and TE to BBB from BBB-. Moody's outlook for FirstEnergy and our subsidiaries remains “stable.”

Regulatory Matters – Ohio

Ohio Legislative Process

On May 1, 2008, the Governor of Ohio signed SB221 into law, which became effective July 31, 2008. The bill requires all electric distribution utilities to file an ESP with the PUCO, which must contain a proposal for the supply and pricing of retail generation. A utility could also file an MRO in which it would have to demonstrate the following objective market criteria: the utility or its transmission service affiliate belongs to a FERC-approved RTO having a market-monitor function and the ability to take actions to identify and mitigate market power, and a published source of information is available publicly through a subscription that identifies pricing information for traded electricity and energy products that are contracted for delivery two years into the future.

Ohio Regulatory Proceedings

On July 31, 2008, our Ohio Companies filed both an ESP and an MRO with the PUCO. The comprehensive ESP included supply and pricing for retail generation service for up to a three-year period, in addition to seeking approval of outstanding issues pending before the PUCO in the Ohio Companies' distribution rate case and application to recover 2006-2007 deferred fuel costs. The MRO filing outlined a CBP for providing retail generation supply if the ESP was not implemented.

On November 25, 2008, the PUCO issued an order denying the MRO and on December 19, 2008, the PUCO approved the ESP, with substantial modifications. On December 22, 2008, the Ohio Companies filed an application for rehearing of the MRO and withdrew their application for the ESP, as allowed under Ohio law. The Ohio Companies cited that the ESP, as modified by the PUCO, no longer maintained a reasonable balance between rate stability for customers and a fair return on the Ohio Companies' investments to serve customers. The Ohio Companies also notified the PUCO of their intent to maintain current tariff rates as of January 1, 2009, as provided for under SB221.

On December 31, 2008, the Ohio Companies conducted a CBP, using an RFP format administered by an independent third party, for the procurement of electric generation for retail customers from January 5, 2009 through March 31, 2009. Four qualified wholesale bidders were selected, including FES, for 97% of the tranches offered in the RFP. The average winning bid price was equivalent to a retail rate of 6.98 cents per kilowatt-hour. Subsequent to the RFP, the remaining 3% of the Ohio Companies' wholesale energy and capacity needs were obtained through a bilateral contract with the lowest bidder in the RFP procurement. The power supply obtained through the foregoing processes provides generation service to the Ohio Companies' retail customers who choose not to shop with alternative suppliers.

On January 7, 2009, the PUCO ordered the Ohio Companies to file revised tariffs by January 12, 2009, reflecting the termination of OE's and TE's RTC as well as the termination of fuel recovery riders for each of the Ohio Companies, to be effective retroactive to January 1, 2009, on a service rendered basis. On January 9, 2009, the Ohio Companies filed a Motion to Stay to delay the effective date of the January 7, 2009 order in its entirety until the resolution of any appeal of the order. In addition, the Ohio Companies requested a fuel rider, proposing to recover the difference between costs incurred by the Ohio Companies to purchase power and the generation charges paid by their customers during the period January 1, 2009 through March 31, 2009. On January 14, 2009, the PUCO temporarily approved the fuel rider, subject to a future prudence review. The PUCO also issued an Entry requiring the Ohio Companies to concurrently implement the original January 7, 2009 order.

On January 21, 2009, the PUCO granted the Ohio Companies' application for an increase in distribution rates in the amount of \$137 million, as well as the application for rehearing to allow further consideration of the MRO filing. On January 29, 2009, the PUCO ordered its Staff to develop a proposal to establish an ESP for the Ohio Companies and further ordered that a conference be held on February 5, 2009 to discuss the Staff's proposal. The Ohio Companies, PUCO Staff, and other parties participated in that conference, and in a subsequent conference held on February 17, 2009. Following discussions with the Staff and other parties regarding the Staff's proposal, on February 19, 2009, the Ohio Companies filed an amended ESP application, including an attached Stipulation and Recommendation that was signed by the Ohio Companies, the Staff of the PUCO, and many of the intervening parties representing a diverse range of interests. On February 19, 2009, the PUCO attorney examiner issued an order setting this matter for hearing on part of the issues to begin on February 25, 2009, and a second hearing on the remainder of the provisions of the overall Stipulated ESP on March 11, 2009.

Regulatory Matters - Pennsylvania

Pennsylvania Legislative Process

On October 15, 2008, the Governor of Pennsylvania signed House Bill 2200 into law, which became effective on November 14, 2008, as Act 129 of 2008. The bill addresses issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; and smart meters and alternative energy. Act 129 requires utilities to file with the PPUC an energy efficiency and peak load reduction plan by July 1, 2009, and a smart meter procurement and installation plan by August 14, 2009. On January 15, 2009, in compliance with Act 129, the PPUC issued its guidelines for the filing of utilities' energy efficiency and peak load reduction plans.

Major provisions of the legislation include:

- power acquired by utilities to serve customers after rate caps expire will be procured through a competitive procurement process that must include a mix of long-term and short-term contracts and spot market purchases;
- the competitive procurement process must be approved by the PPUC and may include auctions, requests for proposal, and/or bilateral agreements;
- utilities must provide for the installation of smart meter technology within 15 years;
- a minimum reduction in peak demand of 4.5% by May 31, 2013;
- minimum reductions in energy consumption of 1% and 3% by May 31, 2011 and May 31, 2013, respectively; and
- an expanded definition of alternative energy to include additional types of hydroelectric and biomass facilities.

Pennsylvania Regulatory Proceedings

On May 22, 2008, the PPUC approved Met-Ed's and Penelec's annual updates to their TSC riders for the period June 1, 2008, through May 31, 2009. The TSCs include a component from under-recovery of actual transmission costs incurred during the prior period (Met-Ed - \$144 million and Penelec - \$4 million) and recovery of future transmission cost projections for June 2008 through May 2009 (Met-Ed - \$258 million and Penelec \$92 million). Met-Ed received PPUC approval for a transition approach that would recover past under-recovered costs plus carrying charges through the new TSC over thirty-one months and defer a portion of the projected costs (\$92 million) plus carrying charges for recovery through future TSCs by December 31, 2010. Various intervenors filed complaints against Met-Ed's and Penelec's TSC filings. In addition, the PPUC ordered an investigation to review the reasonableness of Met-Ed's TSC, while at the same time allowing the company to implement the rider on June 1, 2008, subject to refund. On July 15, 2008, the PPUC directed the ALJ to consolidate the complaints against Met-Ed with its investigation and a litigation schedule was adopted. Hearings and briefing for both companies are expected to conclude by the end of February 2009.

On September 25, 2008, Met-Ed and Penelec filed a Voluntary Prepayment Plan with the PPUC that would provide an opportunity for residential and small commercial customers to prepay an amount on their monthly electric bills during 2009 and 2010, which would earn interest at 7.5% and be used to reduce electric rates in 2011 and 2012. Met-Ed, Penelec, OCA and OSBA reached a settlement agreement on the Voluntary Prepayment Plan and have jointly requested that the PPUC approve the settlement. The ALJ issued a decision on January 29, 2009, recommending approval and adoption of the settlement without modification.

On February 20, 2009, Met-Ed and Penelec filed a generation procurement plan covering the period January 1, 2011 through May 31, 2013, with the PPUC. The companies' plan is designed to provide adequate and reliable service via a prudent mix of long-term, short-term and spot market generation supply, as required by Act 129. The plan proposes a staggered procurement schedule, which varies by customer class, through the use of a descending clock auction. Met-Ed and Penelec have requested PPUC approval of their plan in October 2009.

Regulatory Matters – New Jersey

New Jersey Energy Master Plan

On October 22, 2008, the Governor of New Jersey released the details of New Jersey's EMP, which includes goals to reduce energy consumption by a minimum of 20% by 2020, reduce peak demand by 5,700 MW by 2020, meet 30% of the state's electricity needs with renewable energy by 2020, and examine smart grid technology. The EMP outlines a series of goals and action items to meet set targets, while also continuing to develop the clean energy industry in New Jersey. The Governor will establish a State Energy Council to implement the recommendations outlined in the plan.

New Jersey Economic Assistance and Recovery Plan

In support of the New Jersey Governor's Economic Assistance and Recovery Plan, JCP&L announced its intent to spend approximately \$98 million on infrastructure and energy efficiency projects in 2009. An estimated \$40 million will be spent on infrastructure projects, including substation upgrades, new transformers, distribution line re-closers and automated breaker operations. Approximately \$34 million will be spent implementing new demand response programs as well as expanding on existing programs. Another \$11 million will be spent on energy efficiency, specifically replacing transformers and capacitor control systems and installing new LED street lights. The remaining \$13 million will be spent on energy efficiency programs that will complement those currently being offered. Completion of the projects is dependent upon regulatory approval for full recovery of the costs associated with plan implementation.

Solar Renewable Energy

On September 30, 2008, JCP&L filed a proposal in response to an NJBPU directive addressing solar project development in the State of New Jersey. Under the proposal, JCP&L would enter into long-term agreements to buy and sell Solar Renewable Energy Certificates (SREC) to provide a stable basis for financing solar generation projects. An SREC represents the solar energy attributes of one megawatt-hour of generation from a solar generation facility that has been certified by the NJBPU Office of Clean Energy. Under this proposal JCP&L would solicit SRECs to satisfy approximately 60%, 50%, and 40% of the incremental SREC purchases needed in its service territory through 2010, 2011 and 2012, respectively, to meet the Renewable Portfolio Standards adopted by the NJBPU in 2006. A schedule for further NJBPU proceedings has not yet been established.

Operational Matters

Record Generation Output

We set a new generation output record of 82.4 billion kilowatt-hours during 2008, an increase over the previous record of 82.0 billion kilowatt-hours established in 2006. This generation record reflects an annual all-time high for our nuclear fleet, which set a new generation output record of 32.2 billion kilowatt-hours during 2008, a 6% increase over the previous record established in 2007.

Wind Power Contract

On December 23, 2008, FES purchased a 17-year contract from Constellation Energy for the procurement of 99 MW of wind power from Twin Groves Wind Farm in Illinois. This purchase expands FES' renewable energy portfolio and brings its total wind power capacity under contract to 376 MW.

Fremont Plant

In January 2008, FGCO acquired a partially complete 707-MW natural gas fired generating plant in Fremont, Ohio from Calpine Corporation for \$253.6 million. FGCO completed an engineering study in June 2008, indicating an estimated additional \$208 million of capital expenditures will be required to complete the project. Approximately \$41 million of the incremental capital was invested in 2008. In December 2008, the construction schedule was extended to better reflect current and projected power supply needs; the plant is now expected to be brought on line in 2012. Original plans called for completion of the plant by 2010. The original estimate of \$208 million to complete the plant may be revised as a result of the new construction schedule.

Refueling Outages

On February 14, 2008, Davis-Besse returned to service following completion of its scheduled refueling outage, which began on December 30, 2007. In addition to replacing 76 of the 177 fuel assemblies, several improvement projects were completed, including rewinding the turbine generator and reinforcing welds on plant equipment.

On May 22, 2008, Beaver Valley Unit 2 returned to service following its regularly scheduled refueling outage. Major work activities completed during the outage included replacing approximately one-third of the fuel assemblies in the reactor, replacing the high pressure turbine rotor and inspecting the reactor vessel and other plant safety systems. During the refueling outage, the final phase of an extended power uprate project was also completed. Beaver Valley Unit 2 had operated for 520 consecutive days when it was taken off line for the outage.

New Long-Term Fuel Supply Arrangements

On July 16, 2008, FEV entered into a joint venture with the Boich Companies, a Columbus, Ohio-based coal company, to acquire a majority stake in the Bull Mountain Mine Operations, now called Signal Peak, near Roundup, Montana. This transaction is part of our strategy to secure high-quality fuel supplies at attractive prices to maximize the capacity of our existing fossil generating plants. The joint venture acquired 80 percent of the mining operations and 100 percent of the transportation operations, with FEV owning a 45 percent economic interest and an affiliate of the Boich Companies owning a 55 percent economic interest in the joint venture; both parties have a 50 percent voting interest in the joint venture. In a related transaction, we entered into a 15-year agreement to purchase up to 10 million tons of bituminous western coal annually from the mine. We also entered into agreements with the rail carriers associated with transporting coal from the mine to our generating stations, and expect to begin taking delivery of the coal in late 2009. The joint venture has the right to resell Signal Peak coal tonnage not used at our facilities and has call rights on such coal above certain levels.

September Windstorm

On September 14, 2008, the remnants of Hurricane Ike swept through Ohio and western Pennsylvania and produced unexpectedly high winds, reaching nearly 80 mph. More than one million customers of OE, CEI, Penn and Penelec were affected by the windstorm, which produced the largest storm-related outage in the history of any of those companies. Storm costs totaled approximately \$43 million, of which \$24 million was recognized as capital and \$19 million as O&M expense.

R.E. Burger Plant

On December 30, 2008, we filed a motion with the U.S. District Court for the Southern District of Ohio, requesting an additional 105 days to decide whether to install scrubbers and other environmental equipment for two 156 MW coal fired units at our R.E. Burger Plant, repower the units, or to shut them down in the next two years. Under the terms of a consent decree related to the 2005 NSR settlement, we were required to make a decision by December 31, 2008. On January 30, 2009, the Court granted us an extension until March 31, 2009, to make our decision.

FIRSTENERGY'S BUSINESS

We are a diversified energy company headquartered in Akron, Ohio, that operates primarily through three core business segments (see "Results of Operations").

- **Energy Delivery Services** transmits and distributes electricity through our eight utility operating companies, serving 4.5 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey and purchases power for its PLR and default service requirements in Pennsylvania and New Jersey. This business segment derives its revenues principally from the delivery of electricity within our service areas, cost recovery of regulatory assets and the sale of electric generation service to retail customers who have not selected an alternative supplier (default service) in its Pennsylvania and New Jersey franchise areas.

The service areas of our utilities are summarized below:

<u>Company</u>	<u>Area Served</u>	<u>Customers Served</u>
OE	Central and Northeastern Ohio	1,040,000
Penn	Western Pennsylvania	160,000
CEI	Northeastern Ohio	755,000
TE	Northwestern Ohio	312,000
JCP&L	Northern, Western and East Central New Jersey	1,093,000
Met-Ed	Eastern Pennsylvania	549,000
Penelec	Western Pennsylvania	590,000
ATSI	Service areas of OE, Penn, CEI and TE	

- **Competitive Energy Services** supplies the electric power needs of end-use customers through retail and wholesale arrangements, including associated company power sales to meet all or a portion of the PLR and default service requirements of our Ohio and Pennsylvania utility subsidiaries and competitive retail sales to customers primarily in Ohio, Pennsylvania, Maryland and Michigan. This business segment owns or leases and operates 19 generating facilities with a net demonstrated capacity of 13,710 MWs and also purchases electricity to meet sales obligations. The segment's net income is primarily derived from affiliated company power sales and non-affiliated electric generation sales revenues less the related costs of electricity generation, including purchased power and net transmission and ancillary costs charged by PJM and MISO to deliver energy to the segment's customers.
- **Ohio Transitional Generation Services** supplies the electric power needs of non-shopping customers under the default service requirements of our Ohio Companies. The segment's net income is primarily derived from electric generation sales revenues less the cost of power purchased from the competitive energy services segment through a full-requirements PSA arrangement with FES (through December 31, 2008), including net transmission and ancillary costs charged by MISO to deliver energy to retail customers.

Other operating segments include HVAC services (divestiture completed in 2006) and telecommunication services. We have substantially completed the divestiture of our non-core businesses (see Note 8 to the consolidated financial statements). The assets and revenues for the other business operations are below the quantifiable threshold for separate disclosure as "reportable operating segments."

STRATEGY AND OUTLOOK

We continue to focus on the primary objectives we have developed that support our business fundamentals – safety, generation, reliability, transitioning to competitive markets, managing our liquidity, and growing earnings. To achieve these objectives, we are pursuing the following strategies:

- strengthening our safety focus;
- maximizing the utilization of our generating fleet;
- meeting our transmission and distribution reliability goals;
- managing the transition to competitive market prices in Ohio and Pennsylvania;
- maintaining adequate and ready access to cash resources; and
- achieving our financial goals and commitments to shareholders.

Despite the recent global financial crisis and ongoing U.S. recession, our strategy remains intact. Our focus, however, has shifted in the near term as we respond to these events by identifying and implementing reasoned adjustments to our current plans. Following appropriate reviews, we have reduced our operational and capital spending plans and adjusted our financing plans for 2009-2011. Near-term, we expect to see a continued decline in sales due to the current recessionary environment, primarily in the industrial sector. Sales in 2009 are projected to be relatively flat compared with 2008.

Our gradual progression to competitive generation markets across our tri-state service territory and other strategies to improve performance and deliver consistent financial results is characterized by several important transition periods:

2005 to 2006

In 2005 and 2006, our efforts included preparing for competitive generation markets by improving the operational performance of our generating fleet and the reliability of our transmission and distribution system. The transfer of ownership of our generating assets in 2005 from the Ohio Companies and Penn to subsidiaries of FES, our competitive generation subsidiary, was key to preparing for market competition. With the previous divestiture of generation assets by JCP&L, Met-Ed and Penelec, and JCP&L's transition to competitive generation markets through the New Jersey BGS auction, we gained experience in producing and acquiring competitively priced electricity for customers while delivering a fair return to shareholders. We expect to utilize this experience as we continue to transition to competitive generation markets in Ohio and Pennsylvania.

To facilitate an equitable transition to competitive generation markets, we developed and received approval from the PUCO for an RSP that, along with the RCP, provided our customers in Ohio with reliable generation supply and price stability from 2006 through 2008.

2007 to 2008

Effective January 1, 2007, we successfully transitioned Penn to market-based retail rates for generation service through a competitive, wholesale power supply procurement process. During that year we also completed comprehensive rate cases for Met-Ed and Penelec, which better aligned their transmission and distribution rates with their rate base and costs to serve customers. Met-Ed and Penelec were unsuccessful in securing approval from the PPUC for generation rate increases. As a result, FES expects to continue to provide Met-Ed and Penelec with partial requirements for their PLR and default service load at below-market prices through the end of 2010 when their current rate caps expire.

Our transition to competitive generation markets was supported by continued strong operational results in 2008 led by generation output of 82.4 billion KWH. During the year, the net-demonstrated capacity at several of our units increased through cost-effective unit upgrades as part of our "asset mining" strategy. In addition, we made plant improvements that eliminated the impact of 149 MW of seasonal reductions in generating output caused by elevated summer temperature conditions on our peaking units. We also signed additional long-term contracts to purchase output from wind generators, making FES the largest wind provider in Pennsylvania and bringing our total renewable wind portfolio to 376 MW.

We made several strategic investments in 2008, including the purchase of the partially complete Fremont Plant, which is expected to begin commercial operation in 2012. The addition of this plant complements our existing fleet, giving us the option to dispatch in either MISO or PJM. Additionally, we entered into a joint venture to acquire a majority stake in the Signal Peak coal mining project. As part of that transaction, we also entered into a 15-year agreement to purchase up to 10 million tons of coal annually from the mine, securing a long-term western fuel supply at attractive prices. The higher Btu content of Signal Peak coal versus Powder River Basin coal is expected to help avoid fossil plant derates of approximately 170 to 200 MW, and helps support our incremental generation expansion plans. In the fourth quarter of 2008, FES assigned two existing Powder River Basin contracts to a third party in order to reduce its forecasted 2010 long coal position as a result of expected deliveries from Signal Peak.

In July 2008, we filed a comprehensive ESP with the PUCO that offered modest increases for customers in Ohio of approximately five percent annually through 2011. We concurrently filed an MRO, another option allowed under Ohio's energy law, which proposed a competitive bidding process for procuring electricity for Ohio customers. In November 2008, the PUCO issued an order denying our MRO. In December 2008, the PUCO approved, but substantially modified, our ESP. After determining that the plan no longer maintained a reasonable balance between providing customers with continued rate stability and a fair return on the Ohio Companies' investments to serve customers, we withdrew our application for the ESP as allowed by law (see Regulatory Matters – Ohio).

In late December 2008, our Ohio Companies conducted a competitive bidding process, using an RFP format managed by an independent third-party, for the procurement of electric generation for retail customers from January 5 through March 31, 2009. Four qualified wholesale bidders were selected for 97% of the available tranches up for bid, including FES, which was the successful bidder for 75 of the available tranches up for bid. Each tranche equals approximately 1% of the total load of the Ohio Companies. Approximately 50% of FES' estimated electric sales for the first quarter of 2009 are expected to be supplied under this agreement.

2009 to 2010

Earnings guidance for 2009 will be released following regulatory clarity in Ohio with respect to either an ESP or MRO. Higher pension and fuel costs, coupled with the elimination of deferral accounting for distribution-related operating expenses, are expected to negatively impact earnings. Expected drivers of 2009 earnings are discussed more fully below under "Financial Outlook."

Distribution rate increases went into effect for OE and TE in January 2009, and will go into effect for CEI in May 2009, as a result of rate cases filed in 2007. Transition cost amortization related to the Ohio Companies' rate plans ended for OE and TE on December 31, 2008.

As provided for under SB221, our Ohio Companies initially maintained 2008 tariffs for Ohio retail customers, pending approval of either an ESP or MRO, with plans to use continued OE and TE RTC recovery to reduce previously deferred costs. However, the PUCO issued an Order in January 2009, denying continued recovery of OE and TE RTC and fuel riders for all three Ohio Companies. In response, we filed an application for a fuel rider in order to recover the difference between costs incurred by the Ohio Companies to purchase power and the generation charges paid by their customers during the period January 1, 2009 through March 31, 2009. The PUCO temporarily approved the fuel rider, subject to a future prudence review. On February 19, 2009, the Ohio Companies filed an amended ESP application, including an attached Stipulation and Recommendation that was signed by the Ohio Companies, the Staff of the PUCO, and many of the intervening parties representing a diverse range of interests, which the PUCO attorney examiner set for a hearing to begin on February 25, 2009 (see Regulatory Matters – Ohio).

Financial results for 2009 and beyond will be affected by either an ESP or MRO ultimately being approved by the PUCO. Under the results of either an MRO or a CBP within an ESP, FES ultimately may serve only a portion of the Ohio Companies' retail generation needs, resulting in excess generation available for other wholesale or competitive market retail sales. These and other uncertainties will exist until a new Standard Service Offer is approved by the PUCO and a CBP for Ohio customers is completed. A subsequent CBP may be conducted to meet customer supply needs beyond March 31, 2009, or until either an ESP or MRO is approved by the PUCO for the Ohio Companies. Price uncertainty inherent in competitive markets exists in any CBP.

In Pennsylvania, the scheduled termination at the beginning of 2009 of a favorably-priced third-party supply contract serving Met-Ed and Penelec default service customers will also negatively affect earnings. Currently, FES is obligated to supply an estimated additional 4.5 billion KWH from its supply portfolio under the existing contract with Met-Ed and Penelec. However, because retail generation rates for Met-Ed and Penelec remain frozen at a level below current market prices through the end of 2010, FES may incur a related opportunity cost in 2009 and 2010, since it will be unable to sell this power at market prices.

As we look ahead to 2009 and beyond, we expect to continue our focus on operational excellence with an emphasis on continuous improvement in our core businesses to position for success in the next market transition phase. This includes ongoing incremental investment in projects to increase our generation capacity and energy production capability as well as programs to continue to improve transmission and distribution system reliability and customer service.

2011 and Beyond

Another major transition period for FirstEnergy will begin in 2011 as the current cap on Met-Ed's and Penelec's retail generation rates is scheduled to expire. Beginning in 2011, Met-Ed and Penelec expect to obtain their power supply from the competitive wholesale market and fully recover their costs through retail rates. In February 2009, Met-Ed and Penelec filed with the PPUC a generation procurement proposal for obtaining their power supply in 2011 and beyond. Assuming approval of this plan, we expect FES to redeploy the power currently sold to Met-Ed and Penelec to the wholesale market.

We will continue to be actively engaged in the regulatory process in Ohio and Pennsylvania as we manage the final transition to competitive generation markets. We also plan to continue our efforts to extract additional production capability from existing generating plants as discussed under "Capital Expenditures Outlook" below and maintain the financial and strategic flexibility necessary to move through this transition.

Financial Outlook

In response to the recent unprecedented volatility in the capital and credit markets, we continue to assess our exposure to counterparty credit risk, our access to funds in the capital and credit markets, and market-related changes in the value of our postretirement benefit trusts, nuclear decommissioning trusts and other investments. We have taken several steps to strengthen our liquidity position and provide additional flexibility to meet our anticipated obligations and those of our subsidiaries. These actions include:

- spending reductions of more than \$600 million compared to 2008 levels through appropriate changes in capital and operating and maintenance expenditures;
- delaying completion of the Fremont natural gas plant to better reflect current and projected power supply needs; and
- adjusting the construction schedule for the \$1.7 billion AQC project at our W.H. Sammis Plant in order to defer certain costs from our 2009 budget; we continue to expect to meet our completion deadline by the end of 2010.

Despite the recent financial crisis and ongoing U.S. recession, our financial strategy remains intact and is focused on delivering consistent financial results, improving financial strength and flexibility, optimizing cash flows to benefit investors, and maintaining our current investment-grade ratings.

The following summary of earnings drivers does not include the potential effects of the PUCO approving either the Amended Application containing the proposed Stipulated ESP or an MRO that may be implemented in Ohio.

Positive earnings drivers in 2009 are expected to include:

- increased FES generation margin from Ohio customers from generation supply during the first quarter as a result of the RFP competitive bidding process;
- decreased Ohio transition cost amortization (a non-cash item), reflecting the expiration of RTC for OE and TE in December 2008, partially offset by increased RTC amortization for CEI;
- improvements to operations and maintenance cost management, including staffing adjustments, changes in our compensation structure, fossil plant outage schedule changes and general cost-saving measures; and
- a distribution rate increase in Ohio.

Negative earnings drivers in 2009 are expected to include:

- decreased generation output, three nuclear refueling outages in 2009 compared to two in 2008 and a continued increase in fuel expense;
- lower wholesale market prices for electricity;
- the expiration of a favorable third-party power supply contract for Met-Ed and Penelec;
- increased pension costs related to 2008 market declines;

- elimination of the OE and TE RTC, and a reduction in CEI RTC revenues;
- increased depreciation and general taxes;
- the elimination of deferred distribution operating costs in Ohio; and
- reduced customer loads, particularly in the industrial sector.

Despite significant declines in the value of our pension plan investments, we currently estimate that contributions to the plan will not be required in 2009 or 2010. The overall actual investment return as of December 31, 2008 was a loss of 23.8% versus an assumed 9% return for the year. Based on a 7.0% discount rate, our 2009 pension and OPEB expense is expected to increase by \$230 million.

Our liquidity position remains strong, with access to more than \$4 billion of liquidity, of which approximately \$2.6 billion was available as of January 31, 2009. We intend to continue to fund our capital requirements through our projected cash flow from operations as well as from long-term debt issuances as capital market conditions warrant.

A driver for longer-term earnings growth is our continued effort to improve the utilization and output of our generation fleet. We are also expecting timely recovery of costs and capital investments in our regulated business. We plan to invest approximately \$4 billion in our regulated energy delivery services business during the 2009-2013 period and to pursue timely recovery of those costs in rates. We also expect rising prices for fuel, purchased power and other operating costs to continue during this period.

Capital Expenditures Outlook

We have reduced our capital expenditures forecast to reflect the current economic climate. Our capital expenditures forecast for 2009-2013 is approximately \$8.1 billion. Approximately \$506 million of this relates to AQC projects discussed under "Environmental Outlook" below. Annual expenditures for this program reached their peak in 2008, totaling \$638 million. AQC expenditures are expected to decline in 2009 to approximately \$414 million and by the end of 2010, we expect the program to be complete.

With respect to the remainder of our business, we anticipate average annual capital expenditures of approximately \$1.4 billion from 2009 through 2013. Distribution and transmission projects are expected to average approximately \$783 million per year over the next five years. Over that same period, annual expenditures for our competitive energy services business are expected to be lower in 2009 than 2008 as a result of lower AQC expenditures and reduced overall capital spending plans in response to the current economic climate.

Compared to the construction of new base-load generation assets, we believe our strategy of making incremental additions and operational improvements to our generating fleet to improve output and reliability provides several advantages including: lower capital costs; reduced technological risks; decreased risk of project cost overruns; and an accelerated time to market for the additional output.

Major capital investments planned at our nuclear plants during 2009 to 2013 include approximately \$375 million for replacement of the steam generator at Davis-Besse. While this project is not expected to be completed until 2014, fabrication of some equipment will begin in 2009. We also anticipate spending associated with the replacement of the steam generator at Beaver Valley Unit 2, replacement of the low pressure turbines at Beaver Valley and Perry, and other capital projects to total approximately \$351 million. Combined, these expenditures represent approximately \$1.1 billion of increased capital over a typical maintenance level for nuclear generation during the 2009 to 2013 period.

Projected non-AQC capital spending for 2009 and, on average, for each of the years in the 2010 to 2013 period are as follows:

Projected Non-AQC Capital Spending by Business Unit	2010 to 2013 Per Year Average	
	2009	Average
	<i>(In millions)</i>	
Energy Delivery	\$ 701	804
Nuclear	260	354
Fossil	219	255
Corporate & Other	58	116
Non-AQC Capital Spending	\$ 1,238	\$ 1,529

Projected capital expenditures for our AQC plan for 2009 and 2010, and the change in annual spending, are as follows:

Projected AQC Capital Spending	2009	2010
	<i>(In millions)</i>	
AQC*	\$ 414	\$ 92
Change from Prior Year	(224)	(322)

*Excludes the Burger Plant since a decision has been deferred regarding the future of the AQC project or closure of the plant.

Environmental Outlook

With respect to existing environmental laws and regulations, we believe our generation fleet is positioned for compliance due to substantial investment in pollution control equipment we have already made and will continue to make over the next few years pursuant to our AQC plan. The plan includes projects designed to ensure that all of the facilities in our generation fleet are operated in compliance with all applicable emissions standards and limits, including NO_x, SO₂ and mercury. It also fulfills the requirements imposed by the 2005 consent decree that resolved the Sammis NSR litigation. By 2010, we expect approximately 51% of our coal-fired generating fleet to have full NO_x and SO₂ equipment controls and to have significantly decreased our exposure to the volatile emission allowance market for NO_x and SO₂.

In December 2008 we filed a motion with the U.S. District Court for the Southern District of Ohio requesting an extension of the December 31, 2008 deadline in which to decide whether to install scrubbers and other environmental equipment for two 156 MW coal fired units at the R.E. Burger Plant, repower the units by switching from coal to natural gas, or to shut them down in the next two years. On January 30, 2009, the Court approved an extension until March 31, 2009.

The following table shows the percentage of our 2009 generating capacity made up of non-emitting and low-emitting generating units, including coal units retrofitted with best available control technology as well as projections for 2010.

Fleet Emission Control Status	2009		2010	
	Capacity (MW)	Fleet %	Capacity (MW)	Fleet %
Non-Emitting	4,642	34	4,642	34
Coal Controlled (SO ₂ / NO _x - full control)	2,626	19	3,826	28
Natural Gas Peaking	1,183	9	1,183	9
	<u>8,451</u>	<u>62</u>	<u>9,651</u>	<u>71</u>

Momentum continues to build in the United States for some form of regulation of GHG. We believe that our generation fleet is competitively positioned as we move toward a carbon-constrained world with about 34% of our generation output coming from non-emitting nuclear and hydro power.

While we have relatively low carbon intensity (i.e., CO₂ emitted per KWH) due primarily to our non-emitting nuclear fleet, our total CO₂ emissions will increase as fossil plant utilization increases. We are involved in the following research and other activities, as part of our GHG compliance strategy:

- Pilot testing of CO₂ capture and sequestration technology;
- Electric Power Research Institute's Coal Fleet for Tomorrow;
- Nuclear uprates and license renewals to increase and maintain FES' non-emitting nuclear units; and
- Participation in the DOE's Midwest Regional Carbon Sequestration Partnership, New Jersey's Clean Energy Program, and the EPA's Sulfur Hexafluoride Reduction Partnership.

In addition, we will remain actively engaged in the federal and state debate over future environmental requirements and legislation, especially those dealing with potential global climate change. Due to the significant uncertainty as to the final form of any such legislation at both the federal and state levels, it is possible that we could be required to make additional capital expenditures, which could adversely impact on our financial condition and results of operations.

Achieving Our Vision

Our success in these and other key areas, will help us continue to achieve our vision of being a leading regional energy provider, recognized for operational excellence, outstanding customer service and our commitment to safety; the choice for long-term growth, investment value and financial strength; and a company driven by the leadership, skills, diversity and character of our employees.

RISKS AND CHALLENGES

In executing our strategy, we face a number of industry and enterprise risks and challenges, including:

- risks arising from the reliability of our power plants and transmission and distribution equipment;
- changes in commodity prices could adversely affect our profit margins;
- we are exposed to operational, price and credit risks associated with selling and marketing products in the power markets that we do not always completely hedge against;
- the use of derivative contracts by us to mitigate risks could result in financial losses that may negatively impact our financial results;
- our risk management policies relating to energy and fuel prices, and counterparty credit are by their very nature risk related, and we could suffer economic losses despite such policies;
- nuclear generation involves risks that include uncertainties relating to health and safety, additional capital costs, the adequacy of insurance coverage and nuclear plant decommissioning;
- capital market performance and other changes may decrease the value of decommissioning trust fund, pension fund assets and other trust funds which then could require significant additional funding;
- we could be subject to higher costs and/or penalties related to mandatory NERC/FERC reliability standards;
- we rely on transmission and distribution assets that we do not own or control to deliver our wholesale electricity. If transmission is disrupted including our own transmission, or not operated efficiently, or if capacity is inadequate, our ability to sell and deliver power may be hindered;
- disruptions in our fuel supplies could occur, which could adversely affect our ability to operate our generation facilities and impact financial results;
- temperature variations as well as weather conditions or other natural disasters could have a negative impact on our results of operations and demand significantly below or above our forecasts could adversely affect our energy margins;
- we are subject to financial performance risks related to general economic cycles and also related to heavy manufacturing industries such as automotive and steel;
- increases in customer electric rates and the impact of the economic downturn may lead to a greater amount of uncollectible customer accounts;
- the goodwill of one or more of our operating subsidiaries may become impaired, which would result in write-offs of the impaired amounts;
- we face certain human resource risks associated with the availability of trained and qualified labor to meet our future staffing requirements;
- significant increases in our operation and maintenance expenses, including our health care and pension costs, could adversely affect our future earnings and liquidity;
- our business is subject to the risk that sensitive customer data may be compromised, which could result in an adverse impact to our reputation and/or results of operations;
- acts of war or terrorism could negatively impact our business;
- capital improvements and construction projects may not be completed within forecasted budget, schedule or scope parameters;
- changes in technology may significantly affect our generation business by making our generating facilities less competitive;

- we may acquire assets that could present unanticipated issues for our business in the future, which could adversely affect our ability to realize anticipated benefits of those acquisitions;
- complex and changing government regulations could have a negative impact on our results of operations;
- regulatory changes in the electric industry, including a reversal, discontinuance or delay of the present trend toward competitive markets, could affect our competitive position and result in unrecoverable costs adversely affecting our business and results of operations;
- the prospect of rising rates could prompt legislative or regulatory action to restrict or control such rate increases; this in turn could create uncertainty affecting planning, costs and results of operations and may adversely affect the utilities' ability to recover their costs, maintain adequate liquidity and address capital requirements;
- our profitability is impacted by our affiliated companies' continued authorization to sell power at market-based rates;
- there are uncertainties relating to our participation in RTOs;
- energy conservation and energy price increases could negatively impact our financial results;
- our business and activities are subject to extensive environmental requirements and could be adversely affected by such requirements;
- costs of compliance with environmental laws are significant, and the cost of compliance with future environmental laws, including limitations on GHG emissions could adversely affect cash flow and profitability;
- remediation of environmental contamination at current or formerly owned facilities;
- availability and cost of emission credits could materially impact our costs of operations;
- mandatory renewable portfolio requirements could negatively affect our costs;
- we are and may become subject to legal claims arising from the presence of asbestos or other regulated substances at some of our facilities;
- the continuing availability and operation of generating units is dependent on retaining the necessary licenses, permits, and operating authority from governmental entities, including the NRC;
- future changes in financial accounting standards may affect our reported financial results;
- interest rates and/or a credit rating downgrade could negatively affect our financing costs, our ability to access capital and our requirement to post collateral;
- we must rely on cash from our subsidiaries and any restrictions on our utility subsidiaries' ability to pay dividends or make cash payments to us may adversely affect our financial condition;
- we cannot assure common shareholders that future dividend payments will be made, or if made, in what amounts they may be paid;
- disruptions in the capital and credit markets may adversely affect our business, including the availability and cost of short-term funds for liquidity requirements, our ability to meet long-term commitments, our ability to hedge effectively our generation portfolio, and the competitiveness and liquidity of energy markets; each could adversely affect our results of operations, cash flows and financial condition;
- questions regarding the soundness of financial institutions or counterparties could adversely affect us;
- our electric utility operating affiliates in Ohio are currently in the midst of rate proceedings that have the potential to adversely affect our financial condition.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among our business segments. A reconciliation of segment financial results is provided in Note 15 to the consolidated financial statements. Net income by major business segment was as follows:

	<u>2008</u>	<u>2007</u>	<u>2006</u>	<u>Increase (Decrease)</u>	
				<u>2008 vs 2007</u>	<u>2007 vs 2006</u>
<i>(In millions, except per share amounts)</i>					
Net Income					
By Business Segment:					
Energy delivery services	\$ 833	\$ 862	\$ 893	\$ (29)	\$ (31)
Competitive energy services	472	495	393	(23)	102
Ohio transitional generation services	83	103	112	(20)	(9)
Other and reconciling adjustments*	(46)	(151)	(144)	105	(7)
Total	<u>\$ 1,342</u>	<u>\$ 1,309</u>	<u>\$ 1,254</u>	<u>\$ 33</u>	<u>\$ 55</u>
Basic Earnings Per Share:					
Income from continuing operations	\$ 4.41	\$ 4.27	\$ 3.85	\$ 0.14	\$ 0.42
Discontinued operations	-	-	(0.01)	-	0.01
Basic earnings per share	<u>\$ 4.41</u>	<u>\$ 4.27</u>	<u>\$ 3.84</u>	<u>\$ 0.14</u>	<u>\$ 0.43</u>
Diluted Earnings Per Share:					
Income from continuing operations	\$ 4.38	\$ 4.22	\$ 3.82	\$ 0.16	\$ 0.40
Discontinued operations	-	-	(0.01)	-	0.01
Diluted earnings per share	<u>\$ 4.38</u>	<u>\$ 4.22</u>	<u>\$ 3.81</u>	<u>\$ 0.16</u>	<u>\$ 0.41</u>

* Consists primarily of interest expense related to holding company debt, corporate support services revenues and expenses, and elimination of intersegment transactions.

Summary of Results of Operations – 2008 Compared with 2007

Financial results for our major business segments in 2008 and 2007 were as follows:

2008 Financial Results	Energy Delivery Services	Competitive Energy Services	Ohio Transitional Generation Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	\$ 8,540	\$ 1,333	\$ 2,820	\$ -	\$ 12,693
Other	626	238	82	(12)	934
Internal	-	2,968	-	(2,968)	-
Total Revenues	9,166	4,539	2,902	(2,980)	13,627
Expenses:					
Fuel	2	1,338	-	-	1,340
Purchased power	4,161	779	2,319	(2,968)	4,291
Other operating expenses	1,648	1,142	374	(122)	3,042
Provision for depreciation	417	243	-	17	677
Amortization of regulatory assets	1,002	-	51	-	1,053
Deferral of new regulatory assets	(329)	-	13	-	(316)
General taxes	640	109	6	23	778
Total Expenses	7,541	3,611	2,763	(3,050)	10,865
Operating Income	1,625	928	139	70	2,762
Other Income (Expense):					
Investment income (loss)	170	(34)	1	(78)	59
Interest expense	(410)	(152)	(1)	(191)	(754)
Capitalized interest	3	44	-	5	52
Total Other Expense	(237)	(142)	-	(264)	(643)
Income Before Income Taxes	1,388	786	139	(194)	2,119
Income taxes	555	314	56	(148)	777
Net Income	\$ 833	\$ 472	\$ 83	\$ (46)	\$ 1,342

2007 Financial Results	Energy	Competitive	Ohio	Other and	FirstEnergy
	Delivery	Energy	Transitional	Reconciling	Consolidated
	Services	Services	Generation	Adjustments	
	(In millions)		Services		
Revenues:					
External					
Electric	\$ 8,069	\$ 1,316	\$ 2,559	\$ -	\$ 11,944
Other	657	152	37	12	858
Internal	-	2,901	-	(2,901)	-
Total Revenues	8,726	4,369	2,596	(2,889)	12,802
Expenses:					
Fuel	5	1,173	-	-	1,178
Purchased power	3,733	764	2,240	(2,901)	3,836
Other operating expenses	1,700	1,160	305	(79)	3,086
Provision for depreciation	404	204	-	30	638
Amortization of regulatory assets	991	-	28	-	1,019
Deferral of new regulatory assets	(371)	-	(153)	-	(524)
General taxes	623	107	4	20	754
Total Expenses	7,085	3,408	2,424	(2,930)	9,987
Operating Income	1,641	961	172	41	2,815
Other Income (Expense):					
Investment income	240	16	1	(137)	120
Interest expense	(456)	(172)	(1)	(146)	(775)
Capitalized interest	11	20	-	1	32
Total Other Expense	(205)	(136)	-	(282)	(623)
Income Before Income Taxes	1,436	825	172	(241)	2,192
Income taxes	574	330	69	(90)	883
Net Income	\$ 862	\$ 495	\$ 103	\$ (151)	\$ 1,309

Changes Between 2008 and

2007 Financial Results - Increase (Decrease)

Revenues:					
External					
Electric	\$ 471	\$ 17	\$ 261	\$ -	\$ 749
Other	(31)	86	45	(24)	76
Internal	-	67	-	(67)	-
Total Revenues	440	170	306	(91)	825
Expenses:					
Fuel	(3)	165	-	-	162
Purchased power	428	15	79	(67)	455
Other operating expenses	(52)	(18)	69	(43)	(44)
Provision for depreciation	13	39	-	(13)	39
Amortization of regulatory assets	11	-	23	-	34
Deferral of new regulatory assets	42	-	166	-	208
General taxes	17	2	2	3	24
Total Expenses	456	203	339	(120)	878
Operating Income	(16)	(33)	(33)	29	(53)
Other Income (Expense):					
Investment income (loss)	(70)	(50)	-	59	(61)
Interest expense	46	20	-	(45)	21
Capitalized interest	(8)	24	-	4	20
Total Other Income (Expense)	(32)	(6)	-	18	(20)
Income Before Income Taxes	(48)	(39)	(33)	47	(73)
Income taxes	(19)	(16)	(13)	(58)	(106)
Net Income	\$ (29)	\$ (23)	\$ (20)	\$ 105	\$ 33

Energy Delivery Services – 2008 Compared to 2007

Net income decreased \$29 million to \$833 million in 2008 compared to \$862 million in 2007, primarily due to increased purchased power costs and lower investment income, partially offset by higher revenues.

Revenues –

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	2008	2007	Increase (Decrease)
		<i>(In millions)</i>	
Distribution services	\$ 3,882	\$ 3,909	\$ (27)
Generation sales:			
Retail	3,315	3,145	170
Wholesale	951	687	264
Total generation sales	4,266	3,832	434
Transmission	836	785	51
Other	182	200	(18)
Total Revenues	\$ 9,166	\$ 8,726	\$ 440

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

Electric Distribution KWH Deliveries	
Residential	(0.9) %
Commercial	(0.9) %
Industrial	(3.9) %
Total Distribution KWH Deliveries	(1.9) %

The decrease in electric distribution deliveries to residential and commercial customers was primarily due to reduced summer usage resulting from milder weather in 2008 compared to the same period of 2007, as cooling degree days decreased by 14.6%; heating degree days increased by 2.5%. In the industrial sector, a decrease in deliveries to automotive customers (18%) and steel customers (4%) was partially offset by an increase in usage by refining customers (3%).

The following table summarizes the price and volume factors contributing to the \$434 million increase in generation revenues in 2008 compared to 2007:

Sources of Change in Generation Revenues	Increase (Decrease)
	<i>(In millions)</i>
Retail:	
Effect of 2.2% decrease in sales volumes	\$ (69)
Change in prices	239
	170
Wholesale:	
Effect of 1.2% decrease in sales volumes	(8)
Change in prices	272
	264
Net Increase in Generation Revenues	\$ 434

The decrease in retail generation sales volumes reflected an increase in customer shopping in the service territories of Penn, Penelec, and JCP&L and the weather-related impacts described above. The increase in retail generation prices in 2008 was due to higher generation rates for JCP&L resulting from the New Jersey BGS auctions effective June 1, 2007 and June 1, 2008. Wholesale generation sales decreased principally as a result of JCP&L selling less power into the PJM market, reflecting decreased purchased power volumes from NUGs. The increase in wholesale prices reflected higher spot market prices for PJM market participants.

Transmission revenues increased \$51 million primarily due to higher transmission rates for Met-Ed and Penelec resulting from the annual update to their TSC riders in mid-2008. Met-Ed and Penelec defer the difference between revenues from their transmission rider and transmission costs incurred with no material effect on current period earnings (see Regulatory Matters – Pennsylvania).

Expenses –

The net revenue increase discussed above was more than offset by a \$456 million increase in expenses due to the following:

- Purchased power costs were \$428 million higher in 2008 due to higher unit costs and a decrease in the amount of NUG costs deferred. The increased unit costs primarily reflected the effect of higher JCP&L costs resulting from the BGS auction process. 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. The following table summarizes the sources of changes in purchased power costs:

<u>Source of Change in Purchased Power</u>	<u>Increase (Decrease)</u> <i>(In millions)</i>
Purchases from non-affiliates:	
Change due to increased unit costs	\$ 456
Change due to decreased volumes	(113)
	<u>343</u>
Purchases from FES:	
Change due to decreased unit costs	(18)
Change due to decreased volumes	(10)
	<u>(28)</u>
Decrease in NUG costs deferred	113
Net Increase in Purchased Power Costs	<u>\$ 428</u>

- Other operating expenses decreased \$52 million due primarily to:
 - a \$15 million decrease for contractor costs associated with vegetation management activities, as more of that work performed in 2008 related to capital projects;
 - a \$13 million decrease in uncollectible expense due primarily to the recognition of higher uncollectible reserves in 2007 and enhanced collection processes in 2008;
 - lower labor costs charged to operating expense of \$12 million, as a greater proportion of labor was devoted to capital-related projects in 2008; and
 - a \$6 million decline in regulatory program costs, including customer rebates.
- Amortization of regulatory assets increased \$11 million due to higher transition cost amortization for the Ohio Companies, partially offset by decreases at JCP&L for regulatory assets that were fully recovered at the end of 2007 and in the first half of 2008.
- The deferral of new regulatory assets during 2008 was \$42 million lower primarily due to the absence of the one-time deferral in 2007 of decommissioning costs related to the Saxton nuclear research facility (\$27 million) and lower PJM transmission cost deferrals (\$32 million) offset by increased societal benefit deferrals (\$15 million).
- Higher depreciation expense of \$13 million resulted from additional capital projects placed in service since 2007.
- General taxes increased \$17 million due to higher gross receipts taxes, property taxes and payroll taxes.

Other Expense –

Other expense increased \$32 million in 2008 compared to 2007 due to lower investment income of \$70 million, resulting primarily from the repayment of notes receivable from affiliates since 2007, partially offset by lower interest expense (net of capitalized interest) of \$38 million. The interest expense declined for the Ohio Companies due to their redemption of certain pollution control notes in the second half of 2007.

Competitive Energy Services – 2008 Compared to 2007

Net income for this segment was \$472 million in 2008 compared to \$495 million in 2007. The \$23 million reduction in net income reflects a decrease in gross generation margin (revenue less fuel and purchased power) and higher depreciation expense, which were partially offset by lower other operating expenses.

Revenues –

Total revenues increased \$170 million in 2008 compared to 2007. This increase primarily resulted from higher unit prices on affiliated generation sales to the Ohio Companies and increased non-affiliated wholesale sales, partially offset by lower retail sales.

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

Revenues by Type of Service	2008	2007	Increase (Decrease)
	<i>(In millions)</i>		
Non-Affiliated Generation Sales:			
Retail	\$ 615	\$ 712	\$ (97)
Wholesale	717	603	114
Total Non-Affiliated Generation Sales	1,332	1,315	17
Affiliated Generation Sales	2,968	2,901	67
Transmission	150	103	47
Other	89	50	39
Total Revenues	\$ 4,539	\$ 4,369	\$ 170

The lower retail revenues reflect reduced commercial and industrial contract renewals in the PJM market and the termination of certain government aggregation programs in MISO. Higher non-affiliated wholesale revenues resulted from higher capacity prices and increased sales volumes in PJM, partially offset by decreased sales volumes in MISO.

The increased affiliated company generation revenues were due to higher unit prices for the Ohio Companies partially offset by lower unit prices for the Pennsylvania Companies and decreased affiliated sales volumes. The higher unit prices reflected fuel-related increases in the Ohio Companies' retail generation rates. While unit prices for each of the Pennsylvania Companies did not change, the mix of sales among the companies caused the overall price to decline. The reduction in PSA sales volumes to the Ohio and Pennsylvania Companies was due to the milder weather and industrial sales changes discussed above and reduced default service requirements in Penn's service territory as a result of its RFP process.

The following tables summarize the price and volume factors contributing to changes in revenues from generation sales:

Source of Change in Non-Affiliated Generation Revenues	Increase (Decrease)
	<i>(In millions)</i>
Retail:	
Effect of 15.8% decrease in sales volumes	\$ (113)
Change in prices	16
	(97)
Wholesale:	
Effect of 3.8% increase in sales volumes	23
Change in prices	91
	114
Net Increase in Non-Affiliated Generation Revenues	\$ 17
Source of Change in Affiliated Generation Revenues	Increase (Decrease)
	<i>(In millions)</i>
Ohio Companies:	
Effect of 1.5% decrease in sales volumes	\$ (34)
Change in prices	129
	95
Pennsylvania Companies:	
Effect of 1.5% decrease in sales volumes	(10)
Change in prices	(18)
	(28)
Net Increase in Affiliated Generation Revenues	\$ 67

Transmission revenues increased \$47 million due primarily to higher transmission rates in MISO and PJM.

Expenses –

Total expenses increased \$203 million in 2008 due to the following factors:

- Fossil fuel costs increased \$155 million due to higher unit prices (\$163 million) partially offset by lower generation volume (\$8 million). The increased unit prices primarily reflect increased rates for existing eastern coal contracts, higher transportation surcharges, and emission allowance costs in 2008. Nuclear fuel expense was \$10 million higher as nuclear generation increased in 2008.
- Purchased power costs increased \$15 million due primarily to higher spot market and capacity prices, partially offset by reduced volume requirements.
- Fossil operating costs decreased \$22 million due to a gain on the sale of a coal contract in the fourth quarter of 2008 (\$20 million), reduced scheduled outage activity (\$17 million) and increased gains from emission allowance sales (\$7 million), partially offset by costs associated with a cancelled electro-catalytic oxidation project (\$13 million) and a \$7 million increase in labor costs.
- Transmission expense decreased \$35 million due to reduced congestion costs.
- Other operating costs increased \$39 million due primarily to the assignment of CEI's and TE's leasehold interests in the Bruce Mansfield Plant to FGCO in the fourth quarter of 2007 (\$31 million) and reduced life insurance investment values, partially offset by lower associated company billings and employee benefit costs.
- Higher depreciation expenses of \$39 million were due to the assignment of the Bruce Mansfield Plant leasehold interests to FGCO, and NGC's purchase of certain lessor equity interests in Perry and Beaver Valley Unit 2.

Other Expense –

Total other expense in 2008 was \$6 million higher than in 2007, principally due to a \$50 million decrease in net earnings from nuclear decommissioning trust investments due primarily to securities impairments resulting from market declines during 2008, partially offset by a decline in interest expense (net of capitalized interest) of \$44 million from the repayment of notes to affiliates since 2007.

Ohio Transitional Generation Services – 2008 Compared to 2007

Net income for this segment decreased to \$83 million in 2008 from \$103 million in 2007. Higher operating expenses and a decrease in the deferral of new regulatory assets were partially offset by higher generation revenues.

Revenues –

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

<u>Revenues by Type of Service</u>	<u>2008</u>	<u>2007</u>	<u>Increase (Decrease)</u>
	<i>(In millions)</i>		
Generation sales:			
Retail	\$ 2,453	\$ 2,248	\$ 205
Wholesale	11	7	4
Total generation sales	2,464	2,255	209
Transmission	431	333	98
Other	7	8	(1)
Total Revenues	<u>\$ 2,902</u>	<u>\$ 2,596</u>	<u>\$ 306</u>

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

<u>Source of Change in Generation Revenues</u>	<u>Increase (Decrease)</u> <i>(In millions)</i>
Retail:	
Effect of 1.6% decrease in sales volumes	\$ (37)
Change in prices	242
Net Increase in Retail Generation Revenues	\$ 205

The decrease in generation sales volume in 2008 was primarily due to milder weather and economic conditions. Cooling degree days in OE's, CEI's and TE's service territories for 2008 decreased by 27.7%, 13.6% and 20.3%, respectively, while heating degree days increased on average 5.5% from the previous year. In the industrial sector, a decrease in generation sales to automotive customers (18%) and steel customers (5%) was partially offset by an increase in usage by refining customers (3%). Average prices increased primarily due to an increase in the Ohio Companies' fuel cost recovery riders that became effective in January 2008.

Increased transmission revenue resulted from PUCO-approved transmission tariff increases that became effective July 1, 2007 and July 1, 2008. The difference between transmission revenues accrued and transmission expenses incurred is deferred, resulting in no material impact to current period earnings.

Expenses –

Purchased power costs were \$79 million higher due to higher unit costs for power purchased from FES. The factors contributing to the net increase are summarized in the following table:

<u>Source of Change in Purchased Power</u>	<u>Increase (Decrease)</u> <i>(In millions)</i>
Purchases from non-affiliates:	
Change due to unit costs	\$ -
Change due to decreased volumes	(15)
	<u>(15)</u>
Purchases from FES:	
Change due to increased unit costs	128
Change due to decreased volumes	(34)
	<u>94</u>
Net Increase in Purchased Power Costs	\$ 79

The higher unit costs reflect the increases in the Ohio Companies' retail generation rates, as provided for under the PSA with FES. The decrease in purchase volumes from FES was due to the lower retail generation sales requirements described above.

Other operating expenses increased \$69 million due primarily to reduced intersegment credits associated with the Ohio Companies' nuclear generation leasehold interests and increased MISO transmission-related expenses.

The deferral of new regulatory assets decreased by \$166 million and the amortization of regulatory assets increased \$23 million in 2008 as compared to 2007. MISO transmission deferrals and RCP fuel deferrals decreased as more transmission and generation costs were recovered from customers through PUCO-approved riders.

Other – 2008 Compared to 2007

Our financial results from other operating segments and reconciling items resulted in a \$105 million increase in net income in 2008 compared to 2007. The increase resulted primarily from a \$19 million after-tax gain from the sale of telecommunication assets, a \$10 million after-tax gain from the settlement of litigation relating to formerly-owned international assets, a \$41 million reduction in interest expense associated with the revolving credit facility, and income tax adjustments associated with the favorable settlement of tax positions taken on federal returns in prior years. These increases were partially offset by the absence of the gain from the sale of First Communications (\$13 million, net of taxes) in 2007.

Summary of Results of Operations – 2007 Compared with 2006

Financial results for our major business segments in 2006 were as follows:

2006 Financial Results	Energy Delivery Services	Competitive Energy Services	Ohio Transitional Generation Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
	(In millions)				
Revenues:					
External					
Electric	\$ 7,039	\$ 1,266	\$ 2,366	\$ -	\$ 10,671
Other	584	163	24	59	830
Internal	14	2,609	-	(2,623)	-
Total Revenues	7,637	4,038	2,390	(2,564)	11,501
Expenses:					
Fuel and purchased power	3,015	1,812	2,050	(2,624)	4,253
Other operating expenses	1,585	1,138	247	(5)	2,965
Provision for depreciation	379	190	-	27	596
Amortization of regulatory assets	841	-	20	-	861
Deferral of new regulatory assets	(375)	-	(125)	-	(500)
General taxes	599	90	10	21	720
Total Expenses	6,044	3,230	2,202	(2,581)	8,895
Operating Income	1,593	808	188	17	2,606
Other Income (Expense):					
Investment income	328	35	-	(214)	149
Interest expense	(431)	(200)	(1)	(89)	(721)
Capitalized interest	14	12	-	-	26
Subsidiaries' preferred stock dividends	(16)	-	-	9	(7)
Total Other Expense	(105)	(153)	(1)	(294)	(553)
Income From Continuing Operations Before					
Income Taxes	1,488	655	187	(277)	2,053
Income taxes	595	262	75	(137)	795
Income from continuing operations	893	393	112	(140)	1,258
Discontinued operations	-	-	-	(4)	(4)
Net Income	\$ 893	\$ 393	\$ 112	\$ (144)	\$ 1,254

Changes Between 2007 and

2006 Financial Results - Increase (Decrease)

Revenues:					
External					
Electric	\$ 1,030	\$ 50	\$ 193	\$ -	\$ 1,273
Other	73	(11)	13	(47)	28
Internal	(14)	292	-	(278)	-
Total Revenues	1,089	331	206	(325)	1,301
Expenses:					
Fuel and purchased power	723	125	190	(277)	761
Other operating expenses	115	22	58	(74)	121
Provision for depreciation	25	14	-	3	42
Amortization of regulatory assets	150	-	8	-	158
Deferral of new regulatory assets	4	-	(28)	-	(24)
General taxes	24	17	(6)	(1)	34
Total Expenses	1,041	178	222	(349)	1,092
Operating Income	48	153	(16)	24	209
Other Income (Expense):					
Investment income	(88)	(19)	1	77	(29)
Interest expense	(25)	28	-	(57)	(54)
Capitalized interest	(3)	8	-	1	6
Subsidiaries' preferred stock dividends	16	-	-	(9)	7
Total Other Income (Expense)	(100)	17	1	12	(70)
Income From Continuing Operations Before					
Income Taxes	(52)	170	(15)	36	139
Income taxes	(21)	68	(6)	47	88
Income from continuing operations	(31)	102	(9)	(11)	51
Discontinued operations	-	-	-	4	4
Net Income	\$ (31)	\$ 102	\$ (9)	\$ (7)	\$ 55

Energy Delivery Services – 2007 Compared to 2006

Net income decreased \$31 million to \$862 million in 2007 compared to \$893 million in 2006, primarily due to higher expenses, partially offset by increased revenues.

Revenues –

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	2007	2006	Increase (Decrease)
	<i>(In millions)</i>		
Distribution services	\$ 3,909	\$ 3,849	\$ 60
Generation sales:			
Retail	3,145	2,774	371
Wholesale	687	247	440
Total generation sales	3,832	3,021	811
Transmission	785	561	224
Other	200	206	(6)
Total Revenues	\$ 8,726	\$ 7,637	\$ 1,089

The change in distribution deliveries by customer class is summarized in the following table:

Electric Distribution KWH Deliveries	
Residential	4.3%
Commercial	3.7%
Industrial	(0.2)%
Net Increase in Distribution KWH Deliveries	2.6%

The increase in electric distribution deliveries to customers was primarily due to higher weather-related usage during 2007 compared to 2006 (heating degree days increased by 11.2% and cooling degree days increased by 16.7%). The higher revenues from increased distribution deliveries were partially offset by distribution rate decreases of \$86 million and \$21 million for Met-Ed and Penelec, respectively, as a result of a January 11, 2007 PPUC rate decision (see Regulatory Matters – Pennsylvania).

The following table summarizes the price and volume factors contributing to the \$811 million increase in generation sales revenues in 2007 compared to 2006:

Sources of Change in Generation Sales Revenues	Increase (Decrease)
	<i>(In millions)</i>
Retail:	
Effect of 1.7% decrease in sales volumes	\$ (48)
Change in prices	419
	371
Wholesale:	
Effect of 120% increase in sales volumes	297
Change in prices	143
	440
Net Increase in Generation Sales Revenues	\$ 811

The decrease in retail generation sales volume was primarily due to an increase in customer shopping in Penn's service territory in 2007. The increase in retail generation prices during 2007 compared to 2006 was primarily due to increased generation rates for JCP&L resulting from the New Jersey BGS auction process and an increase in NUGC rates authorized by the NJBPU. Wholesale generation sales increased principally as a result of Met-Ed and Penelec selling additional available power into the PJM market in 2007.

Transmission revenues increased \$224 million primarily due to higher transmission rates for Met-Ed and Penelec resulting from the January 2007 PPUC authorization for transmission cost recovery. Met-Ed and Penelec defer the difference between revenues received under their transmission rider and transmission costs incurred, with no material effect on current period earnings (see Regulatory Matters – Pennsylvania).

Expenses –

The increases in revenues discussed above were offset by an approximate \$1.0 billion increase in expenses due to the following:

- Purchased power costs were \$723 million higher in 2007 due to increases in both unit costs and volumes purchased. The increased unit costs reflected the effect of higher JCP&L costs resulting from the BGS auction process. The increased volumes purchased in 2007 resulted primarily from Met-Ed's and Penelec's higher sales to the PJM wholesale market. The following table summarizes the sources of changes in purchased power costs:

<u>Sources of Change in Purchased Power</u>	<u>Increase</u> <i>(In millions)</i>
Purchased Power:	
Change due to increased unit costs	\$ 349
Change due to increased volume	248
Decrease in NUG costs deferred	126
Net Increase in Purchased Power Costs	<u>\$ 723</u>

- Other operating expenses increased \$115 million primarily due to the net effects of:
 - an increase of \$101 million in MISO and PJM transmission expenses, resulting primarily from higher congestion costs; and
 - an increase in operation and maintenance expenses of \$19 million primarily due to increased labor, contractor costs and materials devoted to maintenance projects in 2007.
- Amortization of regulatory assets increased \$150 million compared to 2006 due primarily to recovery of deferred BGS costs through higher NUGC rates for JCP&L (as discussed above), recovery of deferred non-NUG stranded costs through application of CTC revenues for Met-Ed and higher transition cost amortization for the Ohio Companies.
- The deferral of new regulatory assets during 2007 was \$4 million less in 2007 than in 2006 primarily due to \$46 million of lower PJM transmission cost deferrals, partially offset by the deferral of previously expensed decommissioning costs of \$27 million related to the Saxton nuclear research facility (see "Regulatory Matters – Pennsylvania") and increased carrying charges earned on the Ohio Companies' RCP distribution deferrals of \$11 million.
- Depreciation expense increased \$25 million and general taxes increased \$24 million due primarily to property additions since 2006.
- Other expenses increased \$100 million in 2007 compared to 2006 primarily due to lower investment income of \$88 million resulting from the repayment of notes receivable from affiliates since 2006, and increased interest expense of \$25 million related to new debt issuances by CEI, JCP&L and Penelec. These increased costs were partially offset by the absence of \$16 million of preferred stock dividends paid in 2006.

Competitive Energy Services – 2007 Compared to 2006

Net income for this segment increased \$102 million to \$495 million in 2007 compared to \$393 million in 2006. This increase reflected an improvement in generation margin (revenues less fuel and purchased power), partially offset by higher operating expenses, depreciation and general taxes.

Revenues –

Total revenues increased \$331 million in 2007 compared to 2006 primarily as a result of higher unit prices for affiliated generation sales to the Ohio Companies and increased retail sales revenues, partially offset by lower non-affiliated wholesale sales revenues.

The higher retail revenues resulted from increased sales in both the MISO and PJM markets. The increase in MISO retail sales primarily reflects FES' increased sales to shopping customers in Penn's service territory. Lower non-affiliated wholesale revenues reflected the effect of decreased generation available for the non-affiliated wholesale market due to increased affiliated company power sales under the Ohio Companies' full-requirements PSA and the partial-requirements PSA with Met-Ed and Penelec.

The increased affiliated company generation revenues reflected both higher unit prices and increased sales volumes. The increase in PSA sales to the Ohio Companies was due to their higher retail generation sales requirements. Unit prices were higher because rates charged under FES' full-requirements PSAs reflect the increases in the Ohio Companies' composite retail generation rates. The higher sales to the Pennsylvania Companies were due to increased Met-Ed and Penelec generation sales requirements. These increases were partially offset by lower sales to Penn due to the implementation of its competitive solicitation process in 2007.

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

Revenues by Type of Service	2007	2006	Increase (Decrease)
	<i>(In millions)</i>		
Non-Affiliated Generation Sales:			
Retail	\$ 712	\$ 590	\$ 122
Wholesale	603	676	(73)
Total Non-Affiliated Generation Sales	1,315	1,266	49
Affiliated Generation Sales	2,901	2,609	292
Transmission	103	120	(17)
Other	50	43	7
Total Revenues	\$ 4,369	\$ 4,038	\$ 331

The following tables summarize the price and volume factors contributing to changes in revenues from generation sales:

Source of Change in Non-Affiliated Generation Sales	Increase (Decrease)
	<i>(In millions)</i>
Retail:	
Effect of 10.8% increase in sales volumes	\$ 63
Change in prices	59
	<u>122</u>
Wholesale:	
Effect of 22.7% decrease in sales volumes	(154)
Change in prices	81
	<u>(73)</u>
Net Increase in Non-Affiliated Generation Sales	\$ 49
Source of Change in Affiliated Generation Sales	Increase
	<i>(In millions)</i>
Ohio Companies:	
Effect of 3.4% increase in sales volumes	\$ 68
Change in prices	118
	<u>186</u>
Pennsylvania Companies:	
Effect of 14.9% increase in sales volumes	87
Change in prices	19
	<u>106</u>
Increase in Affiliated Generation Sales	\$ 292

Transmission revenues decreased \$17 million due in part to reduced FTR revenue resulting from fewer FTRs allocated by MISO (\$15 million) and PJM (\$9 million), partially offset by higher retail transmission revenues of \$8 million.

Expenses –

Total expenses increased \$178 million in 2007 compared to 2006 due to the following factors:

- Purchased power costs increased \$159 million due principally to higher volumes for replacement power related to the forced outages at the Bruce Mansfield and Perry Plants and costs associated with the new capacity market in PJM (\$25 million).
- Fossil generation operating costs were \$66 million higher due to the absence of gains from the sale of emissions allowances recognized in 2006 (\$27 million) and increased costs related to scheduled and forced maintenance outages during 2007.

- Lease expenses increased \$55 million primarily due to intercompany billings associated with the assignment of CEI's and TE's leasehold interests in the Bruce Mansfield Plant to FGCO and the Bruce Mansfield Unit 1 sale and leaseback transaction completed in 2007.
- Depreciation expenses were \$14 million higher due to property additions since 2006.
- General taxes were \$17 million higher as a result of increased gross receipts taxes and property taxes.

Partially offsetting the higher costs were:

- Fuel costs were \$34 million lower primarily due to reduced coal costs and emission allowance costs, offset by increases in nuclear fuel and natural gas costs. Coal costs were reduced due to \$38 million of reduced coal consumption reflecting lower generation. Reduced emission allowance costs (\$19 million) were partially offset by increased natural gas costs (\$7 million) due to increased consumption and nuclear fuel costs (\$15 million) due to increased consumption and higher prices.
- Nuclear generation operating costs were \$72 million lower due to fewer outages in 2007 compared to 2006 and reduced employee benefit costs.
- MISO transmission expense decreased by \$32 million from 2006 due primarily to a one-time resettlement of costs from generation providers to load serving entities.
- Total other expense in 2007 was \$17 million lower than in 2006 primarily due to lower interest expense, partially offset by decreased earnings on nuclear decommissioning trust investments.

Ohio Transitional Generation Services – 2007 Compared to 2006

Net income for this segment decreased to \$103 million in 2007 from \$112 million in 2006. Higher operating expenses, primarily for purchased power, were partially offset by higher generation revenues.

Revenues –

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

Revenues by Type of Service	2007	2006	Increase (Decrease)
		<i>(In millions)</i>	
Generation sales:			
Retail	\$ 2,248	\$ 2,095	\$ 153
Wholesale	7	13	(6)
Total generation sales	2,255	2,108	147
Transmission	333	280	53
Other	8	2	6
Total Revenues	\$ 2,596	\$ 2,390	\$ 206

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

Source of Change in Generation Sales Revenues	Increase
	<i>(In millions)</i>
Retail:	
Effect of 3.9% increase in sales volumes	\$ 82
Change in prices	71
Total Increase in Retail Generation Sales Revenues	\$ 153

The increase in generation sales was primarily due to higher weather-related usage in 2007 compared to 2006 and reduced customer shopping in Ohio. The percentage of generation services provided by alternative suppliers to total sales delivered by the Ohio Companies in their service areas decreased by 5.9 percentage points from 2006. Average prices increased primarily due to higher composite unit prices for returning customers.

Increased transmission revenues resulted from higher sales volumes and a PUCO-approved transmission tariff increase, which became effective July 1, 2007.

Expenses –

Purchased power costs were \$190 million higher due primarily to higher unit costs for power purchased from FES. The factors contributing to the higher costs are summarized in the following table:

<u>Source of Change in Purchased Power</u>	<u>Increase</u>
	<i>(In millions)</i>
Purchases from non-affiliates:	
Change due to unit costs	\$ -
Change due to volume purchased	4
	<u>4</u>
Purchases from FES:	
Change due to increased unit costs	114
Change due to volume purchased	72
	<u>186</u>
Total Increase in Purchased Power Costs	<u>\$ 190</u>

The increase in volumes purchased was due to the higher retail generation sales requirements. The higher unit costs reflect the increases in the Ohio Companies' composite retail generation rates, as provided for under the PSA with FES.

Other operating expenses increased \$58 million primarily due to MISO transmission-related expenses. The difference between transmission revenues accrued and transmission expenses incurred is deferred, resulting in no material impact to current period earnings.

Other – 2007 Compared to 2006

Our 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 \$7 million decrease in our net income in 2007 compared to 2006. The decrease includes the net effect of the sale of our interest in First Communications (\$13 million, net of taxes), the absence of subsidiaries' preferred stock dividends in 2007 (\$9 million) and the absence of a \$4 million loss included in 2006 results from discontinued operations.

DISCONTINUED OPERATIONS

Discontinued operations for 2006 included certain FSG subsidiaries and a portion of MYR. We sold 60% of MYR in March 2006 and began accounting for our remaining interest in MYR under the equity method of accounting for investments. Our remaining interest in MYR was sold in November 2006. MYR's results prior to the sale of the initial 60% in March 2006 and the gain on the March sale are included in discontinued operations. The 2006 MYR results subsequent to the March 2006 sale (recorded as equity investment income) and the gain on the November sale are included in income from continuing operations.

The following table summarizes the sources of income from discontinued operations:

<u>Discontinued Operations (Net of tax)</u>	<u>2006</u>
	<i>(In millions)</i>
Gain on sale – FSG subsidiaries	\$ 2
Reclassification of operating (loss) income	
to discontinued operations:	
FSG subsidiaries	(8)
MYR	2
Loss from discontinued operations	<u>\$ (4)</u>

POSTRETIREMENT BENEFITS

We provide a noncontributory qualified defined benefit pension plan that covers substantially all of our employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels. We also provide health care benefits, which include certain employee contributions, deductibles, and co-payments, upon retirement to employees hired prior to January 1, 2005, their dependents, and under certain circumstances, their survivors. Our benefit plan assets and obligations are remeasured annually using a December 31 measurement date. Strengthened equity markets during 2007 and a \$300 million voluntary cash pension contribution made in 2007 contributed to the reductions in postretirement benefits expenses in 2008. Pension and OPEB expenses are included in various cost categories and have contributed to cost decreases discussed above for 2008. Adverse market conditions during 2008 will increase 2009 costs, as discussed further below. The following table reflects the portion of qualified and non-qualified pension and OPEB costs that were charged to expense in the three years ended December 31, 2008:

Postretirement Benefits Costs (Credits)	2008	2007	2006
	<i>(In millions)</i>		
Pension	\$ (23)	\$ 7	\$ 45
OPEB	(37)	(41)	48
Total	<u>\$ (60)</u>	<u>\$ (34)</u>	<u>\$ 93</u>

Reductions in plan assets from investment losses during 2008 resulted in a decrease to the plans' funded status of \$1.7 billion and an after-tax decrease in common stockholders' equity of \$1.2 billion. As of December 31, 2008, our pension plan was underfunded and we currently anticipate that additional cash contributions will be required in 2011 for the 2010 plan year. The overall actual investment result during 2008 was a loss of 23.8% compared to an assumed 9% positive return. Based on a 7% discount rate, 2009 pre-tax net periodic pension and OPEB expense will be approximately \$170 million.

SUPPLY PLAN

Regulated Commodity Sourcing

Our Utilities have a default service obligation to provide the required power supply to non-shopping customers who have elected to continue to receive service under regulated retail tariffs. The volume of these sales can vary depending on the level of shopping that occurs. Supply plans vary by state and by service territory. JCP&L's default service supply is secured through a statewide competitive procurement process approved by the NJBPU. Penn's default service supply is provided through a competitive procurement process approved by the PPUC. For the first quarter of 2009, the default service supply for the Ohio Companies was sourced 4% from the spot market and 96% through a competitive procurement process. Absent resolution of the ESP or MRO, the Ohio Companies anticipate conducting a similar CBP for the period beginning April 1, 2009. The default service supply for Met-Ed and Penelec is secured through a series of existing, long-term bilateral purchase contracts with unaffiliated suppliers, and through a FERC-approved agreement with FES. If any unaffiliated suppliers fail to deliver power to any one of the Utilities' service areas, our Utility serving that area may need to procure the required power in the market in their role as a PLR.

Unregulated Commodity Sourcing

FES has retail and wholesale competitive load-serving obligations in Ohio, New Jersey, Maryland, Pennsylvania, Michigan and Illinois serving both affiliated and non-affiliated companies. FES provides energy products and services to customers under various PLR, shopping, competitive-bid and non-affiliated contractual obligations. In 2008, FES' generation service to affiliated companies was approximately 95% of its total generation obligation. Depending upon the resolution of regulatory proceedings relating to how the Ohio Companies will obtain their supply and thereafter the results of any CBP or other procurement process implemented in accordance with PUCO requirements, FES' service to affiliated companies may decrease, making more power available to the competitive wholesale markets and potentially subjecting FES to greater volatility in the prices it receives for its power. Geographically, approximately 68% of FES' obligation is located in the MISO market area and 32% is located in the PJM market area.

FES provides energy and energy related services, including the generation and sale of electricity and energy planning and procurement through retail and wholesale competitive supply arrangements. FES controls (either through ownership, lease, affiliated power contracts or participation in OVEC) 13,973 MW of installed generating capacity. FES supplies the power requirements of its competitive load-serving obligations through a combination of subsidiary-owned generation, non-affiliated contracts and spot market transactions.

CAPITAL RESOURCES AND LIQUIDITY

We expect our existing sources of liquidity to remain sufficient to meet our anticipated obligations and those of our subsidiaries. Our business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest and dividend payments. During 2009 and in subsequent years, we expect to satisfy these requirements with a combination of cash from operations and funds from the capital markets as market conditions warrant. We also expect that borrowing capacity under credit facilities will continue to be available to manage working capital requirements during those periods.

We, along with certain of our subsidiaries, have access to \$2.75 billion of short-term financing under a revolving credit facility that expires in August 2012. A total of 25 banks participate in the facility, with no one bank having more than 7.3% of the total commitments. As of January 31, 2009, we had \$720 million of bank credit facilities in addition to the \$2.75 billion revolving credit facility. On October 8, 2008, we obtained a \$300 million secured term loan facility with Credit Suisse to reinforce our liquidity in light of the unprecedented disruptions in the credit markets (this facility remains undrawn). In addition, an aggregate of \$550 million of accounts receivable financing facilities through the Ohio and Pennsylvania Companies may be accessed to meet working capital requirements and for other general corporate purposes. Our available liquidity as of January 31, 2009, is described in the following table.

Company	Type	Maturity	Commitment	Available Liquidity as of January 31, 2009
				<i>(In millions)</i>
FirstEnergy ⁽¹⁾	Revolving	Aug. 2012	\$ 2,750	\$ 405
FirstEnergy and FES	Revolving	May 2009	300	300
FirstEnergy	Bank lines	Various ⁽²⁾	120	20
FGCO	Term loan	Oct. 2009 ⁽³⁾	300	300
Ohio and Pennsylvania Companies	Receivables financing	Various ⁽⁴⁾	550	469
			Subtotal	\$ 1,494
			Cash	1,110
			Total	\$ 2,604

⁽¹⁾ FirstEnergy Corp. and subsidiary borrowers.

⁽²⁾ \$100 million matures November 30, 2009; \$20 million uncommitted line of credit with no maturity date.

⁽³⁾ Drawn amounts are payable within 30 days and may not be re-borrowed.

⁽⁴⁾ \$370 million expires February 22, 2010; \$180 million expires December 18, 2009.

In early October 2008, we negotiated with the banks that have issued irrevocable direct pay LOCs in support of our outstanding variable interest rate PCRBs (\$2.1 billion as of December 31, 2008) to extend the respective reimbursement obligations of our applicable subsidiary obligors in the event that such LOCs are drawn upon. As discussed below, the LOCs supporting these PCRBs may be drawn upon to pay the purchase price to bondholders that have exercised the right to tender their PCRBs for mandatory purchase. Approximately \$972 million of LOCs that previously required reimbursement within 30 days or less of a draw under the applicable LOC have now been modified to extend the reimbursement obligations to six months or June 2009, as applicable. Subject to market conditions, we expect to address our LOC expirations in 2009 by either renewing or replacing the majority of the LOCs. In addition, approximately \$250 million of our PCRBs that are currently supported by LOCs are expected to be remarketed or refinanced in fixed interest rate modes, thereby eliminating the need for credit support. The LOCs for our variable interest rate PCRBs were issued by seven banks, as summarized in the following table:

LOC Bank	Aggregate LOC Amount ⁽⁵⁾ <i>(In millions)</i>	LOC Termination Date	Reimbursements of LOC Draws Due
Barclays Bank ⁽¹⁾	\$ 149	June 2009	June 2009
Bank of America ^{(1) (2)}	101	June 2009	June 2009
The Bank of Nova Scotia ⁽¹⁾	255	Beginning June 2010	Shorter of 6 months or LOC termination date
The Royal Bank of Scotland ⁽¹⁾	131	June 2012	6 months
KeyBank ^{(1) (3)}	266	June 2010	6 months
Wachovia Bank ⁽⁶⁾	591	March 2009	March 2009
Barclays Bank ⁽⁴⁾	528	Beginning December 2010	30 days
PNC Bank	70	Beginning December 2010	180 days
Total	\$ 2,091		

⁽¹⁾ Due dates for reimbursements of LOC draws for these banks were extended in October 2008 from 30 days or less to the dates indicated.

⁽²⁾ Supported by 2 participating banks, with each having 50% of the total commitment.

⁽³⁾ Supported by 4 participating banks, with the LOC bank having 62% of the total commitment.

⁽⁴⁾ Supported by 18 participating banks, with no one bank having more than 14% of the total commitment.

⁽⁵⁾ Includes approximately \$21 million of applicable interest coverage.

⁽⁶⁾ On February 12, 2009, \$153 million was renewed, with termination in March 2014.

In February 2009, holders of approximately \$434 million in principal of LOC-supported PCRBs of NGC were notified that the applicable Wachovia Bank LOCs expire on March 18, 2009. As a result, these PCRBs are subject to mandatory purchase at a price equal to the principal amount, plus accrued and unpaid interest, which FES and NGC expect to fund through short-term borrowings. Subject to market conditions, FES and NGC expect to remarket or refinance these PCRBs during the remainder of 2009.

As of December 31, 2008, our net deficit in working capital (current assets less current liabilities) was principally due to short-term borrowings (\$2.4 billion) and the classification of certain variable interest rate PCRBs as currently payable long-term debt. Currently payable long-term debt as of December 31, 2008 included the following:

Currently Payable Long-term Debt

	<i>(In millions)</i>
PCRBs supported by bank LOCs ⁽¹⁾	\$ 2,070
FGCO & NGC unsecured PCRBS ⁽¹⁾	82
Penelec unsecured notes ⁽²⁾	100
CEI secured notes ⁽³⁾	150
NGC collateralized lease obligation bonds	36
Sinking fund requirements	38
	<u>\$ 2,476</u>

⁽¹⁾ Interest rate mode permits individual debt holders to put the respective debt back to the issuer prior to maturity.

⁽²⁾ Mature in April 2009.

⁽³⁾ Mature in November 2009.

Changes in Cash Position

During 2008, we received \$995 million of cash dividends from our subsidiaries and paid \$671 million in cash dividends to common shareholders. With the exception of Met-Ed, which is currently in an accumulated deficit position, there are no material restrictions on the payment of cash dividends by our subsidiaries. In addition to paying dividends from retained earnings, each of our electric utility subsidiaries has authorization from the FERC to pay cash dividends from paid-in capital accounts, as long as its debt to total capitalization ratio (without consideration of retained earnings) remains below 65%.

As of December 31, 2008, we had \$545 million in cash and cash equivalents compared to \$129 million as of December 31, 2007. Cash and cash equivalents consist of unrestricted, highly liquid instruments with an original or remaining maturity of three months or less. As of December 31, 2008, approximately \$472 million of cash and cash equivalents represented temporary overnight deposits. The major sources of changes in these balances are summarized below.

Cash Flows from Operating Activities

Our consolidated net cash from operating activities is provided primarily by our energy delivery services and competitive energy services businesses (see Results of Operations above). Net cash provided from operating activities was \$2.2 billion in 2008, \$1.7 billion in 2007 and \$1.9 billion in 2006, as summarized in the following table:

	2008	2007	2006
Net income	\$ 1,342	\$ 1,309	\$ 1,254
Non-cash charges	1,405	670	783
Pension trust contribution*	-	(300)	90
Working capital and other	(528)	15	(188)
	<u>\$ 2,219</u>	<u>\$ 1,694</u>	<u>\$ 1,939</u>

* The \$90 million cash inflow in 2006 represents reduced income taxes paid in 2006 relating to the \$300 million pension trust contribution made in January 2007.

Net cash provided from operating activities increased by \$525 million in 2008 primarily due to the absence of a \$300 million pension trust contribution in 2007, a \$735 million increase in non-cash charges, and a \$33 million increase in net income (see Results of Operations above), partially offset by a \$543 million decrease from working capital and other changes.

The increase in non-cash charges is primarily due to lower deferrals of new regulatory assets and purchased power costs and higher deferred income taxes. The deferral of new regulatory assets decreased primarily as a result of the Ohio Companies' transmission and fuel recovery riders that became effective in July 2007 and January 2008, respectively, and the absence of the deferral of decommissioning costs related to the Saxton nuclear research facility in the first quarter of 2007. Lower deferrals of purchased power costs reflected an increase in the market value of NUG power. The change in deferred income taxes is primarily due to additional tax depreciation under the Economic Stimulus Act of 2008, the settlement of tax positions taken on federal returns in prior years, and the absence of deferred income taxes related to the Bruce Mansfield Unit 1 sale and leaseback transaction in 2007. The changes in working capital and other primarily resulted from changes in accrued taxes of \$110 million and prepaid taxes of \$278 million, primarily due to increased tax payments. Changes in materials and supplies of \$131 million resulted from higher fossil fuel inventories and were partially offset by changes in receivables of \$107 million.

Net cash provided from operating activities decreased by \$245 million in 2007, compared to 2006, primarily due to the \$300 million pension trust contribution in 2007 and a \$113 million change in non-cash charges, partially offset by a \$203 million change in working capital and other and a \$55 million increase in net income (see Results of Operations above). The changes in working capital and other primarily resulted from changes in accrued taxes of \$246 million and materials and supplies of \$104 million, due to lower coal inventory levels, partially offset by changes in receivables of \$241 million due to higher sales and changes in accounts payable of \$48 million.

Cash Flows from Financing Activities

In 2008, net cash provided from financing activities was \$1.2 billion compared to net cash used of \$1.3 billion in 2007 and \$804 million in 2006. The change in 2008 was primarily due to higher short-term borrowings primarily for capital expenditures for environmental compliance and to fund strategic acquisitions, including the Fremont Plant (\$275 million), Signal Peak (\$125 million), and the purchase of lessor equity interests in Beaver Valley Unit 2 and Perry (\$438 million). The absence of the repurchases of common stock in 2007 and 2006 also contributed to the increase in the 2008 period. The following table summarizes security issuances and redemptions or repurchases during the three years ended December 31, 2008.

Securities Issued or Redeemed / Repurchased	2008	2007	2006
	<i>(In millions)</i>		
<i>New issues</i>			
First mortgage bonds	\$ 592	\$ -	\$ -
Pollution control notes	692	427	1,157
Senior secured notes	-	-	382
Unsecured notes	83	1,093	1,192
	<u>\$ 1,367</u>	<u>\$ 1,520</u>	<u>\$ 2,731</u>
<i>Redemptions / Repurchases</i>			
First mortgage bonds	\$ 126	\$ 293	\$ 41
Pollution control notes	698	436	1,189
Senior secured notes	35	188	182
Unsecured notes	175	153	1,100
Common stock	-	969	600
Preferred stock	-	-	193
	<u>\$ 1,034</u>	<u>\$ 2,039</u>	<u>\$ 3,305</u>
Short-term borrowings (repayments), net	<u>\$ 1,494</u>	<u>\$ (205)</u>	<u>\$ 386</u>

We had approximately \$2.4 billion of short-term indebtedness as of December 31, 2008 compared to approximately \$903 million as of December 31, 2007.

As of December 31, 2008, the Ohio Companies and Penn had the aggregate capability to issue approximately \$2.8 billion of additional FMBs on the basis of property additions and retired bonds under the terms of their respective mortgage indentures. The issuance of FMBs by the Ohio Companies is 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 FMBs) supporting pollution control notes or similar obligations, or as an extension, renewal or replacement of previously outstanding secured debt. In addition, these provisions would permit OE, CEI and TE to incur additional secured debt not otherwise permitted by a specified exception of up to \$168 million, \$179 million and \$117 million, respectively, as of December 31, 2008. On June 19, 2008, FGCO established an FMB indenture. Based upon its net earnings and available bondable property additions as of December 31, 2008, FGCO had the capability to issue \$3.0 billion of additional FMBs under the terms of that indenture. Met-Ed and Penelec had the capability to issue secured debt of approximately \$376 million and \$318 million, respectively, under provisions of their senior note indentures as of December 31, 2008.

On September 22, 2008, we, along with the Shelf Registrants, filed an automatically effective shelf registration statement with the SEC for an unspecified number and amount of securities to be offered thereon. The shelf registration provides us the flexibility to issue and sell various types of securities, including common stock, preferred stock, debt securities, warrants, share purchase contracts, and share purchase units. The Shelf Registrants may utilize the shelf registration statement to offer and sell unsecured, and in some cases, secured debt securities.

On October 20, 2008, OE issued and sold \$300 million of FMBs, comprised of \$275 million 8.25% Series due 2038 and \$25 million 8.25% Series due 2018. OE used the net proceeds from this offering to fund capital expenditures and for other general corporate purposes. On November 18, 2008, CEI issued and sold \$300 million of 8.875% Series of FMBs due 2018. CEI used the net proceeds from the sale to repay short-term borrowings and for other general corporate purposes. On January 20, 2009, Met-Ed issued and sold \$300 million of 7.70% Senior Notes due 2019. Met-Ed used the net proceeds from this offering to repay short-term borrowings. On January 27, 2009, JCP&L issued and sold \$300 million of 7.35% Senior Notes due 2019. JCP&L used the net proceeds from the sale to repay short-term borrowings, for capital expenditures, and for other general corporate purposes.

As of December 31, 2008, our currently payable long-term debt includes approximately \$2.1 billion (FES - \$1.9 billion, OE - \$100 million, Met-Ed - \$29 million and Penelec - \$45 million) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds, or if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

Prior to the third quarter of 2008, we had not experienced any unsuccessful remarketings of these variable-rate PCRBs. Coincident with recent disruptions in the variable-rate demand bond and capital markets generally, certain of the PCRBs had been tendered by bondholders to the trustee. All PCRBs that had been tendered were successfully remarketed.

We, along with certain of our subsidiaries, are party to a \$2.75 billion revolving credit facility (included in the borrowing capability table above). We have the capability to request an increase in the total commitments available under this facility up to a maximum of \$3.25 billion, subject to the discretion of each lender to provide additional commitments. Commitments under the facility are available until August 24, 2012, unless the lenders agree, at the request of the borrowers, to an unlimited number of additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each borrower are subject to a specified sub-limit, as well as applicable regulatory and other limitations.

The following table summarizes the borrowing sub-limits for each borrower under the facility, as well as the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations as of December 31, 2008:

Borrower	Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations
<i>(In millions)</i>		
FirstEnergy	\$ 2,750	\$ ⁽¹⁾
FES	1,000	⁽¹⁾
OE	500	500
Penn	50	39 ⁽²⁾
CEI	250 ⁽³⁾	500
TE	250 ⁽³⁾	500
JCP&L	425	428 ⁽²⁾
Met-Ed	250	300 ⁽²⁾
Penelec	250	300 ⁽²⁾
ATSI	⁽⁴⁾	50

⁽¹⁾ No regulatory approvals, statutory or charter limitations applicable.

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

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

⁽⁴⁾ The borrowing sub-limit for ATSI may be increased up to \$100 million by delivering notice to the administrative agent that either (i) ATSI has senior unsecured debt ratings of at least BBB- by S&P and Baa3 by Moody's or (ii) FirstEnergy has guaranteed ATSI's obligations of such borrower under the facility.

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

The revolving credit facility contains financial covenants requiring each borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%, measured at the end of each fiscal quarter. As of December 31, 2008, our debt to total capitalization ratios (as defined under the revolving credit facility) were as follows:

Borrower	
FirstEnergy ⁽¹⁾	63.0%
FES	56.7%
OE	48.6%
Penn	20.2%
CEI	55.1%
TE	46.1%
JCP&L	32.5%
Met-Ed	44.6%
Penelec	52.8%

⁽¹⁾ As of December 31, 2008, FirstEnergy could issue additional debt of approximately \$1.3 billion or recognize a reduction in equity of approximately \$700 million, and remain within the limitations of the financial covenants required by its revolving credit facility.

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.

Our regulated companies also have the ability to borrow from each other and FirstEnergy to meet their short-term working capital requirements. A similar but separate arrangement exists among our unregulated companies. FESC administers these two money pools and tracks our surplus funds and those of our 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 2008 was 2.93% for the regulated companies' money pool and 2.87% for the unregulated companies' money pool.

Our access to capital markets and costs of financing are influenced by the ratings of our securities. The following table displays our securities ratings as of December 31, 2008. On August 1, 2008, S&P changed its outlook for FirstEnergy and our subsidiaries from "negative" to "stable." On November 5, 2008, S&P raised its senior unsecured rating on OE, Penn, CEI and TE to BBB from BBB-. Moody's outlook for FirstEnergy and our subsidiaries remains "stable."

Issuer	Securities	S&P	Moody's
FirstEnergy	Senior unsecured	BBB-	Baa3
FES	Senior unsecured	BBB	Baa2
OE	Senior secured	BBB+	Baa1
	Senior unsecured	BBB	Baa2
Penn	Senior secured	A-	Baa1
CEI	Senior secured	BBB+	Baa2
	Senior unsecured	BBB	Baa3
TE	Senior unsecured	BBB	Baa3
JCP&L	Senior unsecured	BBB	Baa2
Met-Ed	Senior unsecured	BBB	Baa2
Penelec	Senior unsecured	BBB	Baa2

Cash Flows from Investing Activities

Net cash flows used in investing activities resulted principally from property additions. Additions for the energy delivery services segment primarily include expenditures related to transmission and distribution facilities. Capital spending by the competitive energy services segment is principally generation-related. The following table summarizes investing activities for the three years ended December 31, 2008 by business segment:

Summary of Cash Flows Provided from (Used for) Investing Activities	Property Additions	Investments	Other	Total
Sources (Uses)	<i>(In millions)</i>			
2008				
Energy delivery services	\$ (839)	\$ (41)	\$ (17)	\$ (897)
Competitive energy services	(1,835)	(14)	(56)	(1,905)
Other	(176)	106	(61)	(131)
Inter-Segment reconciling items	(38)	(12)	-	(50)
Total	\$ (2,888)	\$ 39	\$ (134)	\$ (2,983)
2007				
Energy delivery services	\$ (814)	\$ 53	\$ (6)	\$ (767)
Competitive energy services	(740)	1,300	-	560
Other	(21)	2	(14)	(33)
Inter-Segment reconciling items	(58)	(15)	-	(73)
Total	\$ (1,633)	\$ 1,340	\$ (20)	\$ (313)
2006				
Energy delivery services	\$ (629)	\$ 142	\$ (5)	\$ (492)
Competitive energy services	(644)	34	(40)	(650)
Other	(4)	102	(18)	80
Inter-Segment reconciling items	(38)	(9)	-	(47)
Total	\$ (1,315)	\$ 269	\$ (63)	\$ (1,109)

Net cash used for investing activities in 2008 increased by \$2.7 billion compared to 2007. The change was principally due to a \$1.3 billion increase in property additions and the absence of \$1.3 billion of cash proceeds from the Bruce Mansfield Unit 1 sale and leaseback transaction that occurred in the third quarter of 2007. The increased property additions reflected the acquisitions described above and higher planned AQC system expenditures in 2008. Cash used for other investing activities increased primarily as a result of the 2008 investments in the Signal Peak coal mining project and future-year emission allowances.

Net cash used for investing activities in 2007 decreased by \$796 million compared to 2006. The decrease was principally due to approximately \$1.3 billion in cash proceeds from the Bruce Mansfield Unit 1 sale and leaseback transaction. Partially offsetting the cash proceeds from the sale and leaseback transaction was a \$318 million increase in property additions which reflects AQC system and distribution system reliability program expenditures and a \$49 million decrease in cash provided from cash investments, primarily from the use of restricted cash investments to repay debt during 2006.

Our capital spending for the period 2009-2013 is expected to be approximately \$8.1 billion (excluding nuclear fuel), of which approximately \$1.6 billion applies to 2009. Investments for additional nuclear fuel during the 2009-2013 period are estimated to be approximately \$1.3 billion, of which about \$342 million applies to 2009. During the same periods, our nuclear fuel investments are expected to be reduced by approximately \$1.0 billion and \$137 million, respectively, as the nuclear fuel is consumed.

CONTRACTUAL OBLIGATIONS

As of December 31, 2008, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	Total	2009	20 10- 2011	20 12- 2013	Thereafter
	<i>(In millions)</i>				
Long-term debt	\$ 11,585	\$ 323	\$ 1,899	\$ 667	\$ 8,696
Short-term borrowings	2,397	2,397	-	-	-
Interest on long-term debt ⁽¹⁾	8,915	646	1,243	1,026	6,000
Operating leases ⁽²⁾	3,457	203	349	413	2,492
Fuel and purchased power ⁽³⁾	21,055	3,294	6,403	4,729	6,629
Capital expenditures	1,120	454	554	101	11
Pension funding	1,123	-	101	463	559
Other ⁽⁴⁾	272	8	4	120	140
Total	\$ 49,924	\$ 7,325	\$ 10,553	\$ 7,519	\$ 24,527

(1) Interest on variable-rate debt based on rates as of December 31, 2008.

(2) See Note 6 to the consolidated financial statements.

(3) Amounts under contract with fixed or minimum quantities based on estimated annual requirements.

(4) Includes amounts for capital leases (see Note 6) and contingent tax liabilities (see Note 9).

Guarantees and Other Assurances

As part of normal business activities, we enter into various agreements on behalf of our 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 either our or our subsidiaries' credit ratings.

As of December 31, 2008, our maximum exposure to potential future payments under outstanding guarantees and other assurances approximated \$4.4 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure
	<i>(In millions)</i>
FirstEnergy Guarantees of Subsidiaries	
Energy and Energy-Related Contracts ⁽¹⁾	\$ 408
LOC (long-term debt) – interest coverage ⁽²⁾	6
Other ⁽³⁾	<u>752</u>
	<u>1,166</u>
Subsidiaries' Guarantees	
Energy and Energy-Related Contracts	78
LOC (long-term debt) – interest coverage ⁽²⁾	10
FES' guarantee of FGCO's sale and leaseback obligations	<u>2,552</u>
	<u>2,640</u>
Surety Bonds	95
LOC (long-term debt) – interest coverage ⁽²⁾	5
LOC (non-debt) ⁽⁴⁾⁽⁵⁾	<u>462</u>
	562
Total Guarantees and Other Assurances	<u>\$ 4,368</u>

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

(2) Reflects the interest coverage portion of LOCs issued in support of floating-rate PCRBs with various maturities. The principal amount of floating-rate PCRBs of \$2.1 billion is reflected as debt on FirstEnergy's consolidated balance sheets.

(3) Includes guarantees of \$300 million for OVEC obligations and \$80 million for nuclear decommissioning funding assurances. Also includes \$300 million for a Credit Suisse credit facility for FGCO that is guaranteed by both FirstEnergy and FES.

(4) Includes \$37 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facility.

(5) Includes approximately \$291 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and \$134 million pledged in connection with the sale and leaseback of Perry Unit 1 by OE.

We guarantee energy and energy-related payments of our subsidiaries involved in energy commodity activities principally to facilitate or hedge normal physical transactions involving electricity, gas, emission allowances and coal. We also provide guarantees to various providers of credit support for the financing or refinancing by our subsidiaries of costs related to the acquisition of property, plant and equipment. These agreements legally obligate us to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financings where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, our guarantee enables the counterparty's legal claim to be satisfied by our other assets. We believe the likelihood is remote that such parental guarantees will increase amounts otherwise paid by us to meet our obligations incurred in connection with 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 to below investment grade or "material adverse event," the immediate posting of cash collateral, provision of an LOC or accelerated payments may be required of the subsidiary. As of December 31, 2008, our maximum exposure under these collateral provisions was \$585 million as shown below:

Collateral Provisions	FES	Utilities	Total
	<i>(In million)</i>		
Credit rating downgrade to below investment grade	\$ 266	\$ 259	\$ 525
Material adverse event	54	6	60
Total	\$ 320	\$ 265	\$ 585

Stress case conditions of a credit rating downgrade or “material adverse event” and hypothetical adverse price movements in the underlying commodity markets would increase the total potential amount to \$689 million, consisting of \$61 million due to “material adverse event” contractual clauses and \$628 million due to a below investment grade credit rating.

Most of our 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.

In addition to guarantees and surety bonds, FES’ contracts, including power contracts with affiliates awarded through competitive bidding processes, typically contain margining provisions which require the posting of cash or LOCs in amounts determined by future power price movements. Based on FES’ power portfolio as of December 31, 2008, and forward prices as of that date, FES had \$103 million outstanding in margining accounts. Under a hypothetical adverse change in forward prices (15% decrease in prices), FES would be required to post an additional \$98 million. Depending on the volume of forward contracts entered and future price movements, FES could be required to post significantly higher amounts for margining.

OFF-BALANCE SHEET ARRANGEMENTS

FES and the Ohio Companies have obligations that are not included on our Consolidated Balance Sheets related to sale and leaseback arrangements involving the Bruce Mansfield Plant, Perry Unit 1 and Beaver Valley Unit 2, which are satisfied through operating lease payments. The total present value of these sale and leaseback operating lease commitments, net of trust investments, decreased to \$1.7 billion as of December 31, 2008, from \$2.3 billion as of December 31, 2007, due primarily to NGC’s purchase of certain lessor equity interests in Perry Unit 1 and Beaver Valley Unit 2 (see Note 7).

We have equity ownership interests in certain businesses that are accounted for using the equity method of accounting for investments. There are no undisclosed material contingencies related to these investments. Certain guarantees that we do not expect to have a material current or future effect on our financial condition, liquidity or results of operations are disclosed under “Guarantees and Other Assurances” above.

MARKET RISK INFORMATION

We use various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price and interest rate fluctuations. Our Risk Policy Committee, comprised of members of senior management, provides general oversight for risk management activities throughout the company.

Commodity Price Risk

We are exposed to financial and market risks resulting from the fluctuation of interest rates and commodity prices -- electricity, energy transmission, natural gas, coal, nuclear fuel and emission allowances. To manage the volatility relating to these exposures, we use 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 our derivative hedging contracts qualify for the normal purchase and normal sale exception under SFAS 133 and are therefore excluded from the tables 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 or regulatory liability for below-market costs. The changes in the fair value of commodity derivative contracts related to energy production during 2008 are summarized in the following table:

Increase (Decrease) in the Fair Value of Derivative Contracts	Non-Hedge	Hedge	Total
	<i>(In millions)</i>		
Change in the Fair Value of Commodity Derivative Contracts:			
Outstanding net liability as of January 1, 2008	\$ (765)	\$ (26)	\$ (791)
Additions/change in value of existing contracts	194	(19)	175
Settled contracts	267	4	271
Outstanding net liability as of December 31, 2008 ⁽¹⁾	<u>\$ (304)</u>	<u>\$ (41)</u>	<u>\$ (345)</u>
Non-commodity Net Liabilities as of December 31, 2008:			
Interest rate swaps ⁽²⁾	-	(3)	(3)
Net Liabilities - Derivative Contracts as of December 31, 2008	<u>\$ (304)</u>	<u>\$ (44)</u>	<u>\$ (348)</u>
Impact of Changes in Commodity Derivative Contracts ⁽³⁾			
Income Statement effects (pre-tax)	\$ (1)	\$ -	\$ (1)
Balance Sheet effects:			
OCI (pre-tax)	\$ -	\$ (15)	\$ (15)
Regulatory asset (net)	\$ (462)	\$ -	\$ (462)

⁽¹⁾ Includes \$303 million of 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.

⁽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 December 31, 2008 as follows:

Balance Sheet Classification	Non-Hedge	Hedge	Total
	<i>(In millions)</i>		
Current-			
Other assets	\$ 1	11	\$ 12
Other liabilities	(2)	(43)	(45)
Non-Current-			
Other deferred charges	463	-	463
Other noncurrent liabilities	(766)	(12)	(778)
Net liabilities	<u>\$ (304)</u>	<u>\$ (44)</u>	<u>\$ (348)</u>

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, we rely on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. We use these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 5). Sources of information for the valuation of commodity derivative contracts as of December 31, 2008 are summarized by year in the following table:

Source of Information - Fair Value by Contract Year	2009	2010	2011	2012	2013	Thereafter	Total
	<i>(In millions)</i>						
Prices actively quoted ⁽¹⁾	\$ (16)	\$ (9)	\$ -	\$ -	\$ -	\$ -	\$ (25)
Other external sources ⁽²⁾	(248)	(200)	(172)	(100)	-	-	(720)
Prices based on models	-	-	-	-	45	355	400
Total ⁽³⁾	<u>\$ (264)</u>	<u>\$ (209)</u>	<u>\$ (172)</u>	<u>\$ (100)</u>	<u>\$ 45</u>	<u>\$ 355</u>	<u>\$ (345)</u>

⁽¹⁾ Exchange traded.

⁽²⁾ Broker quote sheets validated by observable market transactions.

⁽³⁾ Includes \$303 million in non-hedge commodity derivative contracts (primarily with NUGs), which are offset by a regulatory asset.

We perform sensitivity analyses to estimate our exposure to the market risk of our 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 our derivative instruments would not have had a material effect on our consolidated financial position (assets, liabilities and equity) or cash flows as of December 31, 2008. Based on derivative contracts held as of December 31, 2008, an adverse 10% change in commodity prices would decrease net income by approximately \$2 million during the next 12 months.

Interest Rate Risk

Our exposure to fluctuations in market interest rates is reduced since a significant portion of our debt has fixed interest rates, as noted in the table below.

Comparison of Carrying Value to Fair Value

Year of Maturity	2009	2010	2011	2012	2013	There- after	Total	Fair Value
<i>(Dollars in millions)</i>								
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	\$ 98	\$ 85	\$ 79	\$ 96	\$ 118	\$ 1,630	\$ 2,106	\$ 2,105
Average interest rate	5.6%	7.1%	7.8%	7.8%	7.6%	4.8%	5.3%	
Liabilities								
Long-term Debt:								
Fixed rate	\$ 323	\$ 245	\$ 1,592	\$ 104	\$ 563	\$ 6,448	\$ 9,275	\$ 8,836
Average interest rate	7.0%	6.1%	6.5%	7.9%	5.9%	6.7%	6.6%	
Variable rate		\$ 62				\$ 2,248	\$ 2,310	\$ 2,310
Average interest rate		3.4%				1.5%	1.5%	
Short-term Borrowings:	\$ 2,397						\$ 2,397	\$ 2,397
Average interest rate	1.2%						1.2%	

We are subject to the inherent interest rate risks related to refinancing maturing debt by issuing new debt securities. As discussed in Note 6 to the consolidated financial statements, our investments in capital trusts effectively reduce future lease obligations, also reducing interest rate risk.

Forward Starting Swap Agreements - Cash Flow Hedges

We utilize forward starting swap agreements (forward swaps) in order to hedge a portion of the consolidated interest rate risk associated with anticipated future issuances of fixed-rate, long-term debt securities for one or more of our consolidated subsidiaries in 2008 and 2009, and anticipated variable-rate, short-term debt. 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 and LIBOR rates between the date of hedge inception and the date of the debt issuance. We consider counterparty credit and nonperformance risk in our hedge assessments and continue to expect the forward-starting swaps to be effective in protecting against the risk of changes in future interest payments. During 2008, we entered into forward swaps with an aggregate notional value of \$1.3 billion and terminated forward swaps with an aggregate notional value of \$1.4 billion. We paid \$49 million in cash related to the terminations, \$7 million of which was deemed ineffective and recognized in current period earnings. The remaining effective portion will be recognized over the terms of the associated future debt. As of December 31, 2008, we had outstanding forward swaps with an aggregate notional amount of \$300 million and an aggregate fair value of \$(3) million.

Forward Starting Swaps	December 31, 2008			December 31, 2007		
	Notional Amount	Maturity Date	Fair Value	Notional Amount	Maturity Date	Fair Value
<i>(In millions)</i>						
Cash flow hedges	\$ 100	2009	\$ (2)	\$ -	2009	\$ -
	100	2010	(2)	-	2010	-
	-	2015	-	25	2015	(1)
	-	2018	-	325	2018	(1)
	100	2019	1	-	2019	-
	-	2020	-	50	2020	(1)
	<u>\$ 300</u>		<u>\$ (3)</u>	<u>\$ 400</u>		<u>\$ (3)</u>

Equity Price Risk

We provide a noncontributory qualified defined benefit pension plan that covers substantially all of our employees and non-qualified pension plans that cover certain employees. The plan provides defined benefits based on years of service and compensation levels. We also provide health care benefits, which include certain employee contributions, deductibles, and co-payments, upon retirement to employees hired prior to January 1, 2005, their dependents, and under certain circumstances, their survivors. Our benefit plan assets and obligations are remeasured annually using a December 31 measurement date. Reductions in plan assets from investment losses during 2008 resulted in a decrease to the plans' funded status of \$1.7 billion and an after-tax decrease to common stockholders' equity of \$1.2 billion. As of December 31, 2008, our pension plan was underfunded and we estimate that additional cash contributions will be required in 2011 for the 2010 plan year. The overall actual investment result during 2008 was a loss of 23.8% compared to an assumed 9% positive return. Based on a 7% discount rate, 2009 pre-tax net periodic pension and OPEB expense will be approximately \$170 million.

Nuclear decommissioning trust funds have been established to satisfy NGC's and our Utilities' nuclear decommissioning obligations. As of December 31, 2008, approximately 37% of the funds were invested in equity securities and 63% were invested in fixed income securities, with limitations related to concentration and investment grade ratings. The equity securities are carried at their market value of approximately \$627 million as of December 31, 2008. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a \$63 million reduction in fair value as of December 31, 2008. The decommissioning trusts of JCP&L and the Pennsylvania Companies are subject to regulatory accounting, with unrealized gains and losses recorded as regulatory assets or liabilities, since the difference between investments held in trust and the decommissioning liabilities will be recovered from or refunded to customers. NGC, OE and TE recognize in earnings the unrealized losses on available-for-sale securities held in their nuclear decommissioning trusts based on the guidance for other-than-temporary impairments provided in SFAS 115, FSP SFAS 115-1 and SFAS 124-1. Nuclear decommissioning trust securities impairments totaled \$123 million in 2008. We do not expect to make additional cash contributions to the nuclear decommissioning trusts in 2009, other than the required annual TMI-2 trust contribution that is collected through customer rates. However, should the trust funds continue to experience declines in market value, we may be required to take measures, such as providing financial guarantees through LOCs or parental guarantees or making additional contributions to the trusts to ensure that the trusts are adequately funded and meet minimum NRC funding requirements.

CREDIT RISK

Credit risk is the risk of an obligor's failure to meet the terms of any investment contract, loan agreement or otherwise perform as agreed. Credit risk arises from all activities in which success depends on issuer, borrower or counterparty performance, whether reflected on or off the balance sheet. We engage 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.

We maintain credit policies with respect to our 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 our credit program, we aggressively manage the quality of our portfolio of energy contracts, evidenced by a current weighted average risk rating for energy contract counterparties of BBB+ (S&P). As of December 31, 2008, the largest credit concentration was with JP Morgan, which is currently rated investment grade, representing 10.8% of our total approved credit risk.

REGULATORY MATTERS

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

- restructuring the electric generation business and allowing the Utilities' customers to select a competitive electric generation supplier other than the Utilities;
- establishing or defining the PLR obligations to customers in the Utilities' service areas;
- providing the Utilities with the opportunity to recover certain 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 Utilities' transmission and distribution systems; and
- requiring corporate separation of regulated and unregulated business activities.

The Utilities and ATSI recognize, as regulatory assets, costs which the FERC, the PUCO, the PPUC and the 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 \$133 million as of December 31, 2008 (JCP&L - \$61 million and Met-Ed - \$72 million). Regulatory assets not earning a current return (primarily for certain regulatory transition costs and employee postretirement benefits) are expected to be recovered by 2014 for JCP&L and by 2020 for Met-Ed. The following table discloses regulatory assets by company:

Regulatory Assets*	December 31, 2008	December 31, 2007	Decrease
		<i>(In millions)</i>	
OE	\$ 575	\$ 737	\$ (162)
CEI	784	871	(87)
TE	109	204	(95)
JCP&L	1,228	1,596	(368)
Met-Ed	413	523	(110)
ATSI	31	42	(11)
Total	\$ 3,140	\$ 3,973	\$ (833)

* Penelec had net regulatory liabilities of approximately \$137 million and \$49 million as of December 31, 2008 and December 31, 2007, respectively. These net regulatory liabilities are included in Other Non-current Liabilities on the Consolidated Balance Sheets.

Regulatory assets by source are as follows:

Regulatory Assets By Source	December 31, 2008	December 31, 2007	Increase (Decrease)
		<i>(In millions)</i>	
Regulatory transition costs	\$ 1,452	\$ 2,405	\$ (953)
Customer shopping incentives	420	516	(96)
Customer receivables for future income taxes	245	295	(50)
Loss on reacquired debt	51	57	(6)
Employee postretirement benefits	31	39	(8)
Nuclear decommissioning, decontamination and spent fuel disposal costs	(57)	(129)	72
Asset removal costs	(215)	(183)	(32)
MISO/PJM transmission costs	389	340	49
Fuel costs - RCP	214	220	(6)
Distribution costs - RCP	475	321	154
Other	135	92	43
Total	\$ 3,140	\$ 3,973	\$ (833)

Ohio

On January 4, 2006, the PUCO issued an order authorizing the Ohio Companies to recover certain increased fuel costs through a fuel rider and to defer certain other increased fuel costs to be incurred from January 1, 2006 through December 31, 2008, including interest on the deferred balances. The order also provided for recovery of the deferred costs over a twenty-five-year period through distribution rates. On August 29, 2007, the Supreme Court of Ohio concluded that the PUCO violated a provision of the Ohio Revised Code by permitting the Ohio Companies "to collect deferred increased fuel costs through future distribution rate cases, or to alternatively use excess fuel-cost recovery to reduce deferred distribution-related expenses" and remanded the matter to the PUCO for further consideration. On September 10, 2007, the Ohio Companies filed an application with the PUCO that requested the implementation of two generation-related fuel cost riders to collect the increased fuel costs that were previously authorized to be deferred. On January 9, 2008, the PUCO approved the Ohio Companies' proposed fuel cost rider to recover increased fuel costs incurred during 2008, which was approximately \$185 million. In addition, the PUCO ordered the Ohio Companies to file a separate application for an alternate recovery mechanism to collect the 2006 and 2007 deferred fuel costs. On February 8, 2008, the Ohio Companies filed an application proposing to recover \$226 million of deferred fuel costs and carrying charges for 2006 and 2007 pursuant to a separate fuel rider. Recovery of the deferred fuel costs was also addressed in the Ohio Companies' comprehensive ESP filing, which was subsequently withdrawn on December 22, 2008, and also as a part of the stipulation and recommendation which was attached to the amended application for an ESP, both as described below.

On June 7, 2007, the Ohio Companies filed an application for an increase in electric distribution rates with the PUCO and, on August 6, 2007, updated their filing to support a distribution rate increase of \$332 million. On December 4, 2007, the PUCO Staff issued its Staff Reports containing the results of its investigation into the distribution rate request. In its reports, the PUCO Staff recommended a distribution rate increase in the range of \$161 million to \$180 million, with \$108 million to \$127 million for distribution revenue increases and \$53 million for recovery of costs deferred under prior cases. During the evidentiary hearings and filing of briefs, the PUCO Staff decreased their recommended revenue increase to a range of \$117 million to \$135 million. On January 21, 2009, the PUCO granted the Ohio Companies' application to increase electric distribution rates by \$136.6 million (OE - \$68.9 million, CEI - \$29.2 million and TE - \$38.5 million). These increases went into effect for OE and TE on January 23, 2009, and will go into effect for CEI on May 1, 2009. Applications for rehearing of this order were filed by the Ohio Companies and one other party on February 20, 2009.

On May 1, 2008, Governor Strickland signed SB221, which became effective on July 31, 2008. The bill requires all utilities to file an ESP with the PUCO, which must contain a proposal for the supply and pricing of retail generation. A utility may also file an MRO with the PUCO, in which it would have to prove the following objective market criteria: 1) the utility or its transmission service affiliate belongs to a FERC approved RTO, or there is comparable and nondiscriminatory access to the electric transmission grid; 2) the RTO has a market-monitor function and the ability to mitigate market power or the utility's market conduct, or a similar market monitoring function exists with the ability to identify and monitor market conditions and conduct; and 3) a published source of information is available publicly or through subscription that identifies pricing information for traded electricity products, both on- and off-peak, scheduled for delivery two years into the future.

On July 31, 2008, the Ohio Companies filed with the PUCO a comprehensive ESP and MRO. The MRO filing outlined a CBP for providing retail generation supply if the ESP is not approved and implemented. The CBP would use a "slice-of-system" approach where suppliers bid on tranches (approximately 100 MW) of the Ohio Companies' total customer load. If the Ohio Companies proceed with the MRO option, successful bidders (including affiliates) would be required to post independent credit requirements and could be subject to significant collateral calls depending upon power price movement. The PUCO denied the MRO application on November 26, 2008. The Ohio Companies filed an application for rehearing on December 23, 2008, which the PUCO granted on January 21, 2009, for the purpose of further consideration of the matter.

The ESP proposed to phase in new generation rates for customers beginning in 2009 for up to a three-year period and resolve the Ohio Companies' collection of fuel costs deferred in 2006 and 2007, and the distribution rate request described above. On December 19, 2008, the PUCO significantly modified and approved the ESP as modified. On December 22, 2008, the Ohio Companies notified the PUCO that they were withdrawing and terminating the ESP application as allowed by the terms of SB221. The Ohio Companies further notified the PUCO that, pursuant to SB221, the Ohio Companies would continue their current rate plan in effect and filed tariffs to continue those rates.

On December 31, 2008, the Ohio Companies conducted a CBP, using an RFP format administered by an independent third party, for the procurement of electric generation for retail customers from January 5, 2009 through March 31, 2009. Four qualified wholesale bidders were selected, including FES, for 97% of the tranches offered in the RFP. The average winning bid price was equivalent to a retail rate of 6.98 cents per kilowatt-hour. Subsequent to the RFP, the remaining 3% of the Ohio Companies' wholesale energy and capacity needs were obtained through a bilateral contract with the lowest bidder in the RFP procurement. The power supply obtained through the foregoing processes provides generation service to the Ohio Companies' retail customers who choose not to shop with alternative suppliers.

Following comments by other parties on the Ohio Companies' December 22, 2008, filing which continued the current rate plan, the PUCO issued an Order on January 7, 2009, that prevented OE and TE from collecting RTC and discontinued the collection of two fuel riders for the Ohio Companies. The Ohio Companies filed an application for rehearing on January 9, 2009, and also filed an application for a new fuel rider to recover the increased costs for purchasing power during the period January 1, 2009 through March 31, 2009. On January 14, 2009, the PUCO approved the Ohio Companies' request for the new fuel rider, subject to further review, allowed current recovery of those costs for OE and TE, and allowed CEI to collect a portion of those costs currently and defer the remainder. The PUCO also ordered the Ohio Companies to file additional information in order for it to determine that the costs incurred are prudent and whether the recovery of such costs is necessary to avoid a confiscatory result. The Ohio Companies filed an application for rehearing on that order on January 26, 2009. The applications for rehearing remain pending and the Ohio Companies are unable to predict the ultimate resolution of these issues.

On January 29, 2009, the PUCO ordered its Staff to develop a proposal to establish an ESP for the Ohio Companies and further ordered that a conference be held on February 5, 2009 to discuss the Staff's proposal. The Ohio Companies, PUCO Staff, and other parties participated in that conference, and in a subsequent conference held on February 17, 2009. Following discussions with the Staff and other parties regarding the Staff's proposal, on February 19, 2009, the Ohio Companies filed an amended ESP application, including an attached Stipulation and Recommendation that was signed by the Ohio Companies, the Staff of the PUCO, and many of the intervening parties representing a diverse range of interests, which substantially reflected the terms as proposed by the Staff as modified through the negotiations of the parties. Specifically, the stipulated ESP provides that generation will be provided by FES at the average wholesale rate of the RFP process described above for April and May 2009 to the Ohio Companies for their non-shopping customers and that for the period of June 1, 2009 through May 31, 2011, retail generation prices will be based upon the outcome of a descending clock CBP on a slice-of-system basis. The PUCO may, at its discretion, phase-in a portion of any increase resulting from this CBP process by authorizing deferral of related purchased power costs, subject to specified limits. The proposed ESP further provides that the Ohio Companies will not seek a base distribution rate increase with an effective date before January 1, 2012, that CEI will agree to write-off approximately \$215 million of its Extended RTC balance, and that the Ohio Companies will collect a delivery service improvement rider at an overall average rate of \$.002 per kWh for the period of April 1, 2009 through December 31, 2011. If the Stipulated ESP is approved, one-time charges associated with implementing the ESP would be approximately \$250 million (including the CEI Extended RTC balance), or \$.53 per share of common stock. The proposed ESP also addresses a number of other issues, including but not limited to, rate design for various customer classes, resolution of the prudence review described above and the collection of deferred costs that were approved in prior proceedings. On February 19, 2009, the PUCO attorney examiner issued an order setting this matter for hearing to begin on February 25, 2009.

Pennsylvania

Met-Ed and Penelec purchase a portion of their PLR and default service requirements from FES through a fixed-price partial requirements wholesale power sales agreement. The agreement allows Met-Ed and Penelec to sell the output of NUG energy to the market and requires FES to provide energy at fixed prices to replace any NUG energy sold to the extent needed for Met-Ed and Penelec to satisfy their PLR and default service obligations. The fixed price under the agreement is expected to remain below wholesale market prices during the term of the agreement. 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 their fixed income securities. If FES ultimately determines to terminate, reduce, or significantly modify the agreement prior to the expiration of Met-Ed's and Penelec's generation rate caps in 2010, timely regulatory relief is not likely to be granted by the PPUC. See FERC Matters below for a description of the Third Restated Partial Requirements Agreement, executed by the parties on October 31, 2008, that limits the amount of energy and capacity FES must supply to Met-Ed and Penelec. In the event of a third party supplier default, the increased costs to Met-Ed and Penelec could be material.

On May 22, 2008, the PPUC approved the Met-Ed and Penelec annual updates to the TSC rider for the period June 1, 2008, through May 31, 2009. Various intervenors filed complaints against those filings. In addition, the PPUC ordered an investigation to review the reasonableness of Met-Ed's TSC, while at the same time allowing Met-Ed to implement the rider June 1, 2008, subject to refund. On July 15, 2008, the PPUC directed the ALJ to consolidate the complaints against Met-Ed with its investigation and a litigation schedule was adopted. Hearings and briefing for both companies are expected to conclude by the end of February 2009. The TSCs include a component from under-recovery of actual transmission costs incurred during the prior period (Met-Ed - \$144 million and Penelec - \$4 million) and future transmission cost projections for June 2008 through May 2009 (Met-Ed - \$258 million and Penelec - \$92 million). Met-Ed received PPUC approval for a transition approach that would recover past under-recovered costs plus carrying charges through the new TSC over thirty-one months and defer a portion of the projected costs (\$92 million) plus carrying charges for recovery through future TSCs by December 31, 2010.

On February 1, 2007, the Governor of Pennsylvania proposed an EIS. The EIS includes four pieces of proposed legislation that, according to the Governor, is designed to reduce energy costs, promote energy independence and stimulate the economy. Elements of the EIS include the installation of smart meters, funding for solar panels on residences and small businesses, conservation and demand reduction programs to meet energy growth, a requirement that electric distribution companies acquire power that results in the "lowest reasonable rate on a long-term basis," the utilization of micro-grids and a three year phase-in of rate increases. On July 17, 2007 the Governor signed into law two pieces of energy legislation. The first amended the Alternative Energy Portfolio Standards Act of 2004 to, among other things, increase the percentage of solar energy that must be supplied at the conclusion of an electric distribution company's transition period. The second law allows electric distribution companies, at their sole discretion, to enter into long term contracts with large customers and to build or acquire interests in electric generation facilities specifically to supply long-term contracts with such customers. A special legislative session on energy was convened in mid-September 2007 to consider other aspects of the EIS. As part of the 2008 state budget negotiations, the Alternative Energy Investment Act was enacted in July 2008 creating a \$650 million alternative energy fund to increase the development and use of alternative and renewable energy, improve energy efficiency and reduce energy consumption.

On October 15, 2008, the Governor of Pennsylvania signed House Bill 2200 into law which became effective on November 14, 2008 as Act 129 of 2008. The bill addresses issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters and alternative energy. Act 129 requires utilities to file with the PPUC an energy efficiency and peak load reduction plan by July 1, 2009 and a smart meter procurement and installation plan by August 14, 2009. On January 15, 2009, in compliance with Act 129, the PPUC issued its guidelines for the filing of utilities' energy efficiency and peak load reduction plans.

Major provisions of the legislation include:

- power acquired by utilities to serve customers after rate caps expire will be procured through a competitive procurement process that must include a mix of long-term and short-term contracts and spot market purchases;
- the competitive procurement process must be approved by the PPUC and may include auctions, RFPs, and/or bilateral agreements;
- utilities must provide for the installation of smart meter technology within 15 years;
- a minimum reduction in peak demand of 4.5% by May 31, 2013;

- minimum reductions in energy consumption of 1% and 3% by May 31, 2011 and May 31, 2013, respectively; and
- an expanded definition of alternative energy to include additional types of hydroelectric and biomass facilities.

Legislation addressing rate mitigation and the expiration of rate caps was not enacted in 2008 but may be considered in the legislative session which began in January 2009. While the form and impact of such legislation is uncertain, several legislators and the Governor have indicated their intent to address these issues in 2009.

On September 25, 2008, Met-Ed and Penelec filed a Voluntary Prepayment Plan with the PPUC that would provide an opportunity for residential and small commercial customers to prepay an amount on their monthly electric bills during 2009 and 2010 that would earn interest at 7.5% and be used to reduce electric rates in 2011 and 2012. Met-Ed, Penelec, OCA and OSBA reached a settlement agreement on the Voluntary Prepayment Plan and have jointly requested that the PPUC approve the settlement. The ALJ issued a decision on January 29, 2009, recommending approval and adoption of the settlement without modification.

On February 20, 2009, Met-Ed and Penelec filed a generation procurement plan covering the period January 1, 2011 through May 31, 2013, with the PPUC. The companies' plan is designed to provide adequate and reliable service via a prudent mix of long-term, short-term and spot market generation supply, as required by Act 129. The plan proposes a staggered procurement schedule, which varies by customer class, through the use of a descending clock auction. Met-Ed and Penelec have requested PPUC approval of their plan by October 2009.

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, costs incurred under NUG agreements, and certain other stranded costs, exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of December 31, 2008, the accumulated deferred cost balance totaled approximately \$220 million.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004, supporting 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. JCP&L responded to additional NJBPU staff discovery requests in May and November 2007 and also submitted comments in the proceeding in November 2007. A schedule for further NJBPU proceedings has not yet been set.

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of the PUHCA pursuant to the EPACT. The NJBPU approved regulations effective October 2, 2006 that 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. These regulations are not expected to materially impact us or JCP&L. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. The NJBPU Staff circulated revised drafts of the proposal to interested stakeholders in November 2006 and again in February 2007. On February 1, 2008, the NJBPU accepted proposed rules for publication in the New Jersey Register on March 17, 2008. A public hearing on these proposed rules was held on April 23, 2008 and comments from interested parties were submitted by May 19, 2008.

New Jersey statutes require that the state periodically undertake a planning process, known as the EMP, to address energy related issues including energy security, economic growth, and environmental impact. The EMP is to be developed with involvement of the Governor's Office and the Governor's Office of Economic Growth, and is to be prepared by a Master Plan Committee, which is chaired by the NJBPU President and includes representatives of several State departments.

The EMP was issued on October 22, 2008, establishing five major goals:

- maximize energy efficiency to achieve a 20% reduction in energy consumption by 2020;
- reduce peak demand for electricity by 5,700 MW by 2020;
- meet 30% of the state's electricity needs with renewable energy by 2020;

- examine smart grid technology and develop additional cogeneration and other generation resources consistent with the state's greenhouse gas targets; and
- invest in innovative clean energy technologies and businesses to stimulate the industry's growth in New Jersey.

The EMP will be followed by appropriate legislation and regulation as necessary. At this time, we cannot determine the impact, if any, the EMP may have on our operations or those of JCP&L.

In support of the New Jersey Governor's Economic Assistance and Recovery Plan, JCP&L announced its intent to spend approximately \$98 million on infrastructure and energy efficiency projects in 2009. An estimated \$40 million will be spent on infrastructure projects, including substation upgrades, new transformers, distribution line re-closers and automated breaker operations. Approximately \$34 million will be spent implementing new demand response programs as well as expanding on existing programs. Another \$11 million will be spent on energy efficiency, specifically replacing transformers and capacitor control systems and installing new LED street lights. The remaining \$13 million will be spent on energy efficiency programs that will complement those currently being offered. Completion of the projects is dependent upon regulatory approval for full recovery of the costs associated with plan implementation.

FERC Matters

Transmission Service between MISO and PJM

On November 18, 2004, the FERC issued an order eliminating the through and out rate for transmission service between the MISO and PJM regions. The FERC's intent was to eliminate multiple transmission charges for a single transaction between the MISO and PJM regions. The FERC also ordered MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a rate mechanism to recover lost transmission revenues created by elimination of this charge (referred to as the Seams Elimination Cost Adjustment or "SECA") during a 16-month transition period. The FERC issued orders in 2005 setting the SECA for hearing. The presiding judge issued an initial decision on August 10, 2006, rejecting the compliance filings made by MISO, PJM, and the transmission owners, and directing new compliance filings. This decision is subject to review and approval by the FERC. Briefs addressing the initial decision were filed on September 11, 2006 and October 20, 2006. A final order is pending before the FERC, and in the meantime, we have been negotiating and entering into settlement agreements with other parties in the docket to mitigate the risk of lower transmission revenue collection associated with an adverse order. On September 26, 2008, the MISO and PJM transmission owners filed a motion requesting that the FERC approve the pending settlements and act on the initial decision. On November 20, 2008, FERC issued an order approving uncontested settlements, but did not rule on the initial decision. On December 19, 2008, an additional order was issued approving two contested settlements.

PJM Transmission Rate Design

On January 31, 2005, certain PJM transmission owners made 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. Hearings were held and numerous parties appeared and litigated various issues concerning PJM rate design; notably AEP, which proposed to create a "postage stamp", or average rate for all high voltage transmission facilities across PJM and a zonal transmission rate for facilities below 345 kV. This proposal would have the effect of shifting recovery of the costs of high voltage transmission lines to other transmission zones, including those where JCP&L, Met-Ed, and Penelec serve load. On April 19, 2007, the FERC issued an order finding that the PJM transmission owners' existing "license plate" or zonal rate design was just and reasonable and ordered that the current license plate rates for existing transmission facilities be retained. On the issue of rates for new transmission facilities, the FERC directed that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp rate. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a "beneficiary pays" basis. The FERC found that PJM's current beneficiary-pays cost allocation methodology is not sufficiently detailed and, in a related order that also was issued on April 19, 2007, directed that hearings be held for the purpose of establishing a just and reasonable cost allocation methodology for inclusion in PJM's tariff.

On May 18, 2007, certain parties filed for rehearing of the FERC's April 19, 2007 order. On January 31, 2008, the requests for rehearing were denied. On February 11, 2008, AEP appealed the FERC's April 19, 2007, and January 31, 2008, orders to the federal Court of Appeals for the D.C. Circuit. The Illinois Commerce Commission, the PUCO and Dayton Power & Light have also appealed these orders to the Seventh Circuit Court of Appeals. The appeals of these parties and others have been consolidated for argument in the Seventh Circuit.

The FERC's orders on PJM rate design will prevent the allocation of a portion of the revenue requirement of existing transmission facilities of other utilities to JCP&L, Met-Ed and Penelec. In addition, the FERC's decision to allocate the cost of new 500 kV and above transmission facilities on a PJM-wide basis will reduce the costs of future transmission to be recovered from the JCP&L, Met-Ed and Penelec zones. A partial settlement agreement addressing the "beneficiary pays" methodology for below 500 kV facilities, but excluding the issue of allocating new facilities costs to merchant transmission entities, was filed on September 14, 2007. The agreement was supported by the FERC's Trial Staff, and was certified by the Presiding Judge to the FERC. On July 29, 2008, the FERC issued an order conditionally approving the settlement subject to the submission of a compliance filing. The compliance filing was submitted on August 29, 2008, and the FERC issued an order accepting the compliance filing on October 15, 2008. The remaining merchant transmission cost allocation issues were the subject of a hearing at the FERC in May 2008. An initial decision was issued by the Presiding Judge on September 18, 2008. PJM and FERC trial staff each filed a Brief on Exceptions to the initial decision on October 20, 2008. Briefs Opposing Exceptions were filed on November 10, 2008.

Post Transition Period Rate Design

The FERC had directed MISO, PJM, and the respective transmission owners to make filings on or before August 1, 2007 to reevaluate transmission rate design within MISO, and between MISO and PJM. On August 1, 2007, filings were made by MISO, PJM, and the vast majority of transmission owners, including our affiliates, which proposed to retain the existing transmission rate design. These filings were approved by the FERC on January 31, 2008. As a result of the FERC's approval, the rates charged to our load-serving affiliates for transmission service over existing transmission facilities in MISO and PJM are unchanged. In a related filing, MISO and MISO transmission owners requested that the current MISO pricing for new transmission facilities that spreads 20% of the cost of new 345 kV and higher transmission facilities across the entire MISO footprint (known as the RECB methodology) be retained.

On September 17, 2007, AEP filed a complaint under Sections 206 and 306 of the Federal Power Act seeking to have the entire transmission rate design and cost allocation methods used by MISO and PJM declared unjust, unreasonable, and unduly discriminatory, and to have the FERC fix a uniform regional transmission rate design and cost allocation method for the entire MISO and PJM "Super Region" that recovers the average cost of new and existing transmission facilities operated at voltages of 345 kV and above from all transmission customers. Lower voltage facilities would continue to be recovered in the local utility transmission rate zone through a license plate rate. AEP requested a refund effective October 1, 2007, or alternatively, February 1, 2008. On January 31, 2008, the FERC issued an order denying the complaint. The effect of this order is to prevent the shift of significant costs to our zones in MISO and PJM. A rehearing request by AEP was denied by the FERC on December 19, 2008. On February 17, 2009, AEP appealed the FERC's January 31, 2008, and December 19, 2008, orders to the U.S. Court of Appeals for the Seventh Circuit.

Interconnection Agreement with AMP-Ohio

On May 29, 2008, TE filed with the FERC a proposed Notice of Cancellation effective midnight December 31, 2008, of the Interconnection Agreement with AMP-Ohio. AMP-Ohio protested this filing. TE also filed a Petition for Declaratory Order seeking a FERC ruling, in the alternative if cancellation is not accepted, of TE's right to file for an increase in rates effective January 1, 2009, for power provided to AMP-Ohio under the Interconnection Agreement. AMP-Ohio filed a pleading agreeing that TE may seek an increase in rates, but arguing that any increase is limited to the cost of generation owned by TE affiliates. On August 18, 2008, the FERC issued an order that suspended the cancellation of the Agreement for five months, to become effective on June 1, 2009, and established expedited hearing procedures on issues raised in the filing and TE's Petition for Declaratory Order. On October 14, 2008, the parties filed a settlement agreement and mutual notice of cancellation of the Interconnection Agreement effective midnight December 31, 2008. On October 24, 2008 the presiding judge certified the settlement agreement as uncontested and on December 22, 2008, the FERC issued an order approving the uncontested settlement agreement. This latest action terminates the litigation and the Interconnection Agreement.

Duquesne's Request to Withdraw from PJM

On November 8, 2007, Duquesne Light Company (Duquesne) filed a request with the FERC to exit PJM and to join MISO. Duquesne's proposed move would affect numerous of our interests, including but not limited to the terms under which our Beaver Valley Plant would continue to participate in PJM's energy markets. We, therefore, intervened and participated fully in all of the FERC dockets that were related to Duquesne's proposed move.

In November, 2008, Duquesne and other parties, including us, negotiated a settlement that would, among other things, allow for Duquesne to remain in PJM and provide for a methodology for Duquesne to meet the PJM capacity obligations for the 2011-2012 auction that excluded the Duquesne load. The settlement agreement was filed on December 10, 2008 and approved by the FERC in an order issued on January 29, 2009. MISO opposed the settlement agreement pending resolution of exit fees alleged to be owed by Duquesne. The FERC did not resolve this issue in its order.

Complaint against PJM RPM Auction

On May 30, 2008, a group of PJM load-serving entities, state commissions, consumer advocates, and trade associations (referred to collectively as the RPM Buyers) filed a complaint at the FERC against PJM alleging that three of the four transitional RPM auctions yielded prices that are unjust and unreasonable under the Federal Power Act. On September 19, 2008, the FERC denied the RPM Buyers' complaint. However, the FERC did grant the RPM Buyers' request for a technical conference to review aspects of the RPM. The FERC also ordered PJM to file on or before December 15, 2008, a report on potential adjustments to the RPM program as suggested in a Brattle Group report. On December 12, 2008, PJM filed proposed tariff amendments that would adjust slightly the RPM program. PJM also requested that the FERC conduct a settlement hearing to address changes to the RPM and suggested that the FERC should rule on the tariff amendments only if settlement could not be reached in January, 2009. The request for settlement hearings was granted. Settlement had not been reached by January 9, 2009 and, accordingly, we along with other parties submitted comments on PJM's proposed tariff amendments. On January 15, 2009, the Chief Judge issued an order terminating settlement talks. On February 9, 2009, PJM and a group of stakeholders submitted an offer of settlement.

On October 20, 2008, the RPM Buyers filed a request for rehearing of the FERC's September 19, 2008 order. The FERC has not yet ruled on the rehearing request.

MISO Resource Adequacy Proposal

MISO made a filing on December 28, 2007 that would create an enforceable planning reserve requirement in the MISO tariff for load-serving entities such as the Ohio Companies, Penn Power, and FES. This requirement is proposed to become effective for the planning year beginning June 1, 2009. The filing would permit MISO to establish the reserve margin requirement for load-serving entities based upon a one day loss of load in ten years standard, unless the state utility regulatory agency establishes a different planning reserve for load-serving entities in its state. We believe the proposal promotes a mechanism that will result in commitments from both load-serving entities and resources, including both generation and demand side resources that are necessary for reliable resource adequacy and planning in the MISO footprint. Comments on the filing were filed on January 28, 2008. The FERC conditionally approved MISO's Resource Adequacy proposal on March 26, 2008, requiring MISO to submit to further compliance filings. Rehearing requests are pending on the FERC's March 26 Order. On May 27, 2008, MISO submitted a compliance filing to address issues associated with planning reserve margins. On June 17, 2008, various parties submitted comments and protests to MISO's compliance filing. We submitted comments identifying specific issues that must be clarified and addressed. On June 25, 2008, MISO submitted a second compliance filing establishing the enforcement mechanism for the reserve margin requirement which establishes deficiency payments for load-serving entities that do not meet the resource adequacy requirements. Numerous parties, including us, protested this filing.

On October 20, 2008, the FERC issued three orders essentially permitting the MISO Resource Adequacy program to proceed with some modifications. First, the FERC accepted MISO's financial settlement approach for enforcement of Resource Adequacy subject to a compliance filing modifying the cost of new entry penalty. Second, the FERC conditionally accepted MISO's compliance filing on the qualifications for purchased power agreements to be capacity resources, load forecasting, loss of load expectation, and planning reserve zones. Additional compliance filings were directed on accreditation of load modifying resources and price responsive demand. Finally, the FERC largely denied rehearing of its March 26 order with the exception of issues related to behind the meter resources and certain ministerial matters. On November 19, 2008, MISO made various compliance filings pursuant to these orders. Issuance of orders on these compliance filings is not expected to delay the June 1, 2009, start date for MISO Resource Adequacy.

FES Sales to Affiliates

On October 24, 2008, FES, on its own behalf and on behalf of its generation-controlling subsidiaries, filed an application with the FERC seeking a waiver of the affiliate sales restrictions between FES and the Ohio Companies. The purpose of the waiver is to ensure that FES will be able to continue supplying a material portion of the electric load requirements of the Ohio Companies in January 2009 pursuant to either an ESP or MRO as filed with the PUCO. FES previously obtained a similar waiver for electricity sales to its affiliates in New Jersey, New York, and Pennsylvania. On December 23, 2008, the FERC issued an order granting the waiver request and the Ohio Companies made the required compliance filing on December 30, 2008.

On October 31, 2008, FES executed a Third Restated Partial Requirements Agreement with Met-Ed, Penelec, and Waverly effective November 1, 2008. The Third Restated Partial Requirements Agreement limits the amount of capacity and energy required to be supplied by FES in 2009 and 2010 to roughly two-thirds of these affiliates' power supply requirements. Met-Ed, Penelec, and Waverly have committed resources in place for the balance of their expected power supply during 2009 and 2010. Under the Third Restated Partial Requirements Agreement, Met-Ed, Penelec, and Waverly are responsible for obtaining additional power supply requirements created by the default or failure of supply of their committed resources. Prices for the power provided by FES were not changed in the Third Restated Partial Requirements Agreement.

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 (the PUCO, the FERC, the NERC and the U.S. – Canada Power System Outage Task Force) regarding enhancements to regional reliability. The proposed enhancements were divided into two groups: enhancements that were to be completed in 2004; and enhancements that were to be completed after 2004. In 2004, we completed all of the enhancements that were recommended for completion in 2004. We are 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 that could require additional material expenditures.

In 2005, Congress amended the Federal Power Act to provide for federally-enforceable mandatory reliability standards. The mandatory reliability standards apply to the bulk power system and impose certain operating, record-keeping and reporting requirements on the Utilities and ATSI. The NERC is charged with establishing and enforcing these reliability standards, although it has delegated day-to-day implementation and enforcement of its responsibilities to eight regional entities, including Reliability *First* Corporation. All of our facilities are located within the Reliability *First* region. We actively participate in the NERC and Reliability *First* stakeholder processes, and otherwise monitor and manage our companies in response to the ongoing development, implementation and enforcement of the reliability standards.

We believe that we are in compliance with all currently-effective and enforceable reliability standards. Nevertheless, it is clear that the NERC, Reliability *First* and the FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. The financial impact of complying with new or amended standards cannot be determined at this time. However, the 2005 amendments to the Federal Power Act provide that all prudent costs incurred to comply with the new reliability standards be recovered in rates. Still, any future inability on our part to comply with the reliability standards for our bulk power system could result in the imposition of financial penalties and thus have a material adverse effect on our financial condition, results of operations and cash flows.

In April 2007, Reliability *First* performed a routine compliance audit of our bulk-power system within the MISO region and found it to be in full compliance with all audited reliability standards. Similarly, in October 2008, Reliability *First* performed a routine compliance audit of our bulk-power system within the PJM region and a final report is expected in early 2009. We currently do not expect any material adverse financial impact as a result of these audits.

ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate us with regard to air and water quality and other environmental matters. The effects of compliance on us with regard to environmental matters could have a material adverse effect on our earnings and competitive position to the extent that we compete with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations. We estimate capital expenditures for environmental compliance of approximately \$608 million for the period 2009-2013.

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

Clean Air Act Compliance

We are required to meet federally-approved SO₂ emissions regulations. Violations of such regulations can result in the shutdown of the generating unit involved and/or civil or criminal penalties of up to \$37,500 for each day the unit is in violation. The EPA has an interim enforcement policy for SO₂ regulations in Ohio that allows for compliance based on a 30-day averaging period. We believe we are currently in compliance with this policy, but cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The EPA Region 5 issued a Finding of Violation and NOV to the Bay Shore Power Plant dated June 15, 2006, alleging violations to various sections of the CAA. We have disputed those alleged violations based on our CAA permit, the Ohio SIP and other information provided to the EPA at an August 2006 meeting with the EPA. The EPA has several enforcement options (administrative compliance order, administrative penalty order, and/or judicial, civil or criminal action) and has indicated that such option may depend on the time needed to achieve and demonstrate compliance with the rules alleged to have been violated. On June 5, 2007, the EPA requested another meeting to discuss “an appropriate compliance program” and a disagreement regarding emission limits applicable to the common stack for Bay Shore Units 2, 3 and 4.

We comply with SO₂ reduction requirements under the Clean Air Act Amendments of 1990 by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NO_x reductions required by the 1990 Amendments are being achieved through combustion controls and the generation of more electricity at lower-emitting plants. In September 1998, the EPA finalized regulations requiring additional NO_x reductions at our 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. We believe our facilities are also complying with the NO_x budgets established under SIPs through combustion controls and post-combustion controls, including Selective Catalytic Reduction and SNCR systems, and/or using emission allowances.

In 1999 and 2000, the EPA issued an NOV and the DOJ filed a civil complaint against OE and Penn based on operation and maintenance of the W. H. Sammis Plant (Sammis NSR Litigation) and filed similar complaints involving 44 other U.S. power plants. This case and seven other similar cases are referred to as the NSR cases. OE's and Penn's settlement with the EPA, the DOJ and three states (Connecticut, New Jersey and New York) that resolved all issues related to the Sammis NSR litigation was approved by the Court on July 11, 2005. This settlement agreement, in the form of a consent decree, requires reductions of NO_x and SO₂ emissions at the Sammis, Burger, Eastlake and Mansfield 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. Capital expenditures necessary to complete requirements of the Sammis NSR Litigation consent decree are currently estimated to be \$506 million for 2009-2010 (with \$414 million expected to be spent in 2009). This amount is included in the estimated capital expenditures for environmental compliance referenced above, but excludes the potential AQC expenditures related to Burger Units 4 and 5 described below. On September 8, 2008, the Environmental Enforcement Section of the DOJ sent a letter to OE regarding its view that the company was not in compliance with the Sammis NSR Litigation consent decree because the installation of an SNCR at Eastlake Unit 5 was not completed by December 31, 2006. However, the DOJ acknowledged that stipulated penalties could not apply under the terms of the Sammis NSR Litigation consent decree because Eastlake Unit 5 was idled on December 31, 2006 pending installation of the SNCR and advised that it had exercised its discretion not to seek any other penalties for this alleged non-compliance. OE disputed the DOJ's interpretation of the consent decree in a letter dated September 22, 2008. Although the Eastlake Unit 5 issue is no longer active, OE filed a dispute resolution petition on October 23, 2008, with the United States District Court for the Southern District of Ohio, due to potential impacts on its compliance decisions with respect to Burger Units 4 and 5. On December 23, 2008, OE withdrew its dispute resolution petition and subsequently filed a motion to extend the date (from December 31, 2008 to April 15, 2009), under the Sammis NSR Litigation consent decree, to elect for Burger Units 4 and 5 to permanently shut down those units by December 31, 2010, or to repower them or to install flue gas desulfurization (FGD) by later dates. On January 30, 2009, the Court issued an order extending the election date from December 31, 2008 to March 31, 2009.

On April 2, 2007, the United States Supreme Court ruled that changes in annual emissions (in tons/year) rather than changes in hourly emissions rate (in kilograms/hour) must be used to determine whether an emissions increase triggers NSR. Subsequently, on May 8, 2007, the EPA proposed to revise the NSR regulations to utilize changes in the hourly emission rate (in kilograms/hour) to determine whether an emissions increase triggers NSR. On December 10, 2008, the EPA announced it would not finalize this proposed change to the NSR regulations.

On May 22, 2007, we and FGCO received a notice letter, required 60 days prior to the filing of a citizen suit under the federal CAA, alleging violations of air pollution laws at the Bruce Mansfield Plant, including opacity limitations. Prior to the receipt of this notice, the Plant was subject to a Consent Order and Agreement with the Pennsylvania Department of Environmental Protection concerning opacity emissions under which efforts to achieve compliance with the applicable laws will continue. On October 18, 2007, PennFuture filed a complaint, joined by three of its members, in the United States District Court for the Western District of Pennsylvania. On January 11, 2008, we filed a motion to dismiss claims alleging a public nuisance. On April 24, 2008, the Court denied the motion to dismiss, but also ruled that monetary damages could not be recovered under the public nuisance claim. In July 2008, three additional complaints were filed against FGCO in the United States District Court for the Western District of Pennsylvania seeking damages based on Bruce Mansfield Plant air emissions. In addition to seeking damages, two of the complaints seek to enjoin the Bruce Mansfield Plant from operating except in a "safe, responsible, prudent and proper manner", one being a complaint filed on behalf of twenty-one individuals and the other being a class action complaint, seeking certification as a class action with the eight named plaintiffs as the class representatives. On October 14, 2008, the Court granted FGCO's motion to consolidate discovery for all four complaints pending against the Bruce Mansfield Plant. FGCO believes the claims are without merit and intends to defend itself against the allegations made in these complaints.

On December 18, 2007, the state of New Jersey filed a CAA citizen suit alleging NSR violations at the Portland Generation Station against Reliant (the current owner and operator), Sithe Energy (the purchaser of the Portland Station from Met-Ed in 1999), GPU, Inc. and Met-Ed. Specifically, New Jersey alleges that "modifications" at Portland Units 1 and 2 occurred between 1980 and 1995 without preconstruction NSR or permitting under the CAA's prevention of significant deterioration program, and seeks injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. On March 14, 2008, Met-Ed filed a motion to dismiss the citizen suit claims against it and a stipulation in which the parties agreed that GPU, Inc. should be dismissed from this case. On March 26, 2008, GPU, Inc. was dismissed by the United States District Court. The scope of Met-Ed's indemnity obligation to and from Sithe Energy is disputed. On October 30, 2008, the state of Connecticut filed a Motion to Intervene, but the Court has yet to rule on Connecticut's Motion. On December 5, 2008, New Jersey filed an amended complaint, adding claims with respect to alleged modifications that occurred after GPU's sale of the plant. On January 14, 2009, the EPA issued a NOV to Reliant alleging new source review violations at the Portland Generation Station based on "modifications" dating back to 1986. Met-Ed is unable to predict the outcome of this matter. The EPA's January 14, 2009, NOV also alleged new source review violations at the Keystone and Shawville Stations based on "modifications" dating back to 1984. JCP&L, as the former owner of 16.67% of Keystone Station and Penelec, as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter.

On June 11, 2008, the EPA issued a Notice and Finding of Violation to MEW alleging that "modifications" at the Homer City Power Station occurred since 1988 to the present without preconstruction NSR or permitting under the CAA's prevention of significant deterioration program. MEW is seeking indemnification from Penelec, the co-owner (along with New York State Electric and Gas Company) and operator of the Homer City Power Station prior to its sale in 1999. The scope of Penelec's indemnity obligation to and from MEW is disputed. Penelec is unable to predict the outcome of this matter.

On May 16, 2008, FGCO received a request from the EPA for information pursuant to Section 114(a) of the CAA for certain operating and maintenance information regarding the Eastlake, Lakeshore, Bay Shore and Ashtabula generating plants to allow the EPA to determine whether these generating sources are complying with the NSR provisions of the CAA. On July 10, 2008, FGCO and the EPA entered into an ACO modifying that request and setting forth a schedule for FGCO's response. On October 27, 2008, FGCO received a second request from the EPA for information pursuant to Section 114(a) of the CAA for additional operating and maintenance information regarding the Eastlake, Lakeshore, Bay Shore and Ashtabula generating plants. FGCO intends to fully comply with the EPA's information requests, but, at this time, is unable to predict the outcome of this matter.

On August 18, 2008, we received a request from the EPA for information pursuant to Section 114(a) of the CAA for certain operating and maintenance information regarding the Avon Lake and Niles generating plants, as well as a copy of a nearly identical request directed to the current owner, Reliant Energy, to allow the EPA to determine whether these generating sources are complying with the NSR provisions of the CAA. We intend to fully comply with the EPA's information request, but, at this time, are unable to predict the outcome of this matter.

National Ambient Air Quality Standards

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 requires reductions of NO_x and SO₂ emissions in two phases (Phase I in 2009 for NO_x, 2010 for SO₂ and Phase II in 2015 for both NO_x and SO₂), ultimately capping SO₂ emissions in affected states to just 2.5 million tons annually and NO_x emissions to just 1.3 million tons annually. CAIR was challenged in the United States Court of Appeals for the District of Columbia and on July 11, 2008, the Court vacated CAIR "in its entirety" and directed the EPA to "redo its analysis from the ground up." On September 24, 2008, the EPA, utility, mining and certain environmental advocacy organizations petitioned the Court for a rehearing to reconsider its ruling vacating CAIR. On December 23, 2008, the Court reconsidered its prior ruling and allowed CAIR to remain in effect to "temporarily preserve its environmental values" until the EPA replaces CAIR with a new rule consistent with the Court's July 11, 2008 opinion. The future cost of compliance with these regulations may be substantial and will depend, in part, on the action taken by the EPA in response to the Court's ruling.

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, capping national mercury emissions at 38 tons by 2010 (as a "co-benefit" from implementation of SO₂ and NO_x emission caps under the EPA's CAIR program) and 15 tons per year by 2018. Several states and environmental groups appealed the CAMR to the United States Court of Appeals for the District of Columbia. On February 8, 2008, the Court vacated the CAMR, ruling that the EPA failed to take the necessary steps to "de-list" coal-fired power plants from its hazardous air pollutant program and, therefore, could not promulgate a cap-and-trade program. The EPA petitioned for rehearing by the entire Court, which denied the petition on May 20, 2008. On October 17, 2008, the EPA (and an industry group) petitioned the United States Supreme Court for review of the Court's ruling vacating CAMR. On February 6, 2009, the United States moved to dismiss its petition for certiorari. On February 23, 2009, the Supreme Court dismissed the United States' petition and denied the industry group's petition. Accordingly, the EPA could take regulatory action to promulgate new mercury emission standards for coal-fired power plants. FGCO's future cost of compliance with mercury regulations may be substantial and will depend on the action taken by the EPA and on how they are ultimately implemented.

Pennsylvania has submitted a new mercury rule for EPA approval that does not provide a cap-and-trade approach as in the CAMR, but rather follows a command-and-control approach imposing emission limits on individual sources. On January 30, 2009, the Commonwealth Court of Pennsylvania declared Pennsylvania's mercury rule "unlawful, invalid and unenforceable" and enjoined the Commonwealth from continued implementation or enforcement of that rule. It is anticipated that compliance with these regulations, if the Commonwealth Court's rulings were reversed on appeal and Pennsylvania's mercury rule was implemented, would not require the addition of mercury controls at the Bruce Mansfield Plant, our only Pennsylvania coal-fired power plant, until 2015, if at all.

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, including CO₂, emitted by developed countries by 2012. The United States signed the Kyoto Protocol in 1998 but it was never submitted for ratification by the United States Senate. However, the Bush administration had 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. Also, in an April 16, 2008 speech, former President Bush set a policy goal of stopping the growth of GHG emissions by 2025, as the next step beyond the 2012 strategy. In addition, 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. President Obama has announced his Administration's "New Energy for America Plan" that includes, among other provisions, ensuring that 10% of electricity in the United States comes from renewable sources by 2012, and 25% by 2025; and implementing an economy-wide cap-and-trade program to reduce GHG emissions 80% by 2050.

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. At the international level, efforts to reach a new global agreement to reduce GHG emissions post-2012 have begun with the Bali Roadmap, which outlines a two-year process designed to lead to an agreement in 2009. At the federal level, members of Congress have introduced several bills seeking to reduce emissions of GHG in the United States, and the Senate Environment and Public Works Committee has passed one such bill. State activities, primarily the northeastern states participating in the Regional Greenhouse Gas Initiative and western states led by California, have coordinated efforts to develop regional strategies to control emissions of certain GHGs.

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate CO₂ emissions from automobiles as "air pollutants" under the CAA. Although this decision did not address CO₂ emissions from electric generating plants, the EPA has similar authority under the CAA to regulate "air pollutants" from those and other facilities. On July 11, 2008, the EPA released an Advance Notice of Proposed Rulemaking, soliciting input from the public on the effects of climate change and the potential ramifications of regulation of CO₂ under the CAA.

We cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO₂ emissions could require significant capital and other expenditures. The CO₂ emissions per KWH of electricity generated by us is lower than many regional competitors due to our diversified generation sources, which include low or non-CO₂ 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 our plants. In addition, Ohio, New Jersey and Pennsylvania have water quality standards applicable to our 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 life is drawn into a facility's cooling water system). On January 26, 2007, the United States Court of Appeals for the Second Circuit remanded portions of the rulemaking dealing with impingement mortality and entrainment back to the EPA for further rulemaking and eliminated the restoration option from the EPA's regulations. On July 9, 2007, the EPA suspended this rule, noting that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. On April 14, 2008, the Supreme Court of the United States granted a petition for a writ of certiorari to review one significant aspect of the Second Circuit Court's opinion which is whether Section 316(b) of the Clean Water Act authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. Oral argument before the Supreme Court occurred on December 2, 2008 and a decision is anticipated during the first half of 2009. We are studying various control options and their costs and effectiveness. Depending on the results of such studies, the outcome of the Supreme Court's review of the Second Circuit's decision, the EPA's further rulemaking and any action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

The U.S. Attorney's Office in Cleveland, Ohio has advised FGCO that it is considering prosecution under the Clean Water Act and the Migratory Bird Treaty Act for three petroleum spills at the Edgewater, Lakeshore and Bay Shore plants which occurred on November 1, 2005, January 26, 2007 and February 27, 2007. FGCO is unable to predict the outcome of this matter.

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 non-hazardous waste.

Under NRC regulations, we must ensure that adequate funds will be available to decommission our nuclear facilities. As of December 31, 2008, we had approximately \$1.7 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. As part of the application to the NRC to transfer the ownership of Davis-Besse, Beaver Valley and Perry to NGC in 2005, we agreed to contribute another \$80 million to these trusts by 2010. Consistent with NRC guidance, utilizing a "real" rate of return on these funds of approximately 2% over inflation, these trusts are expected to exceed the minimum decommissioning funding requirements set by the NRC. Conservatively, these estimates do not include any rate of return that the trusts may earn over the 20-year plant useful life extensions that we (and Exelon for TMI-1 as it relates to the timing of the decommissioning of TMI-2) seek for these facilities.

The Utilities 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 may be liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2008, based on estimates of the total costs of cleanup, the Utilities' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately \$90 million have been accrued through December 31, 2008. Included in the total are accrued liabilities of approximately \$56 million for environmental remediation of former manufactured gas plants in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC.

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 in July 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, NJ, based on a common incident involving the failure of the bushings of two large transformers in the Red Bank substation resulting in planned and unplanned outages in the area during a 2-3 day period. In 2005, JCP&L renewed its motion to decertify the class based on a very limited number of class members who incurred damages and also filed a motion for summary judgment on the remaining plaintiffs' claims for negligence, breach of contract and punitive damages. In July 2006, the New Jersey Superior Court dismissed the punitive damage claim and again decertified the class based on the fact that a vast majority of the class members did not suffer damages and those that did would be more appropriately addressed in individual actions. Plaintiffs appealed this ruling to the New Jersey Appellate Division which, in March 2007, reversed the decertification of the Red Bank class and remanded this matter back to the Trial Court to allow plaintiffs sufficient time to establish a damage model or individual proof of damages. JCP&L filed a petition for allowance of an appeal of the Appellate Division ruling to the New Jersey Supreme Court which was denied in May 2007. Proceedings are continuing in the Superior Court and a case management conference with the presiding Judge was held on June 13, 2008. At that conference, the plaintiffs stated their intent to drop their efforts to create a class-wide damage model and, instead of dismissing the class action, expressed their desire for a bifurcated trial on liability and damages. The judge directed the plaintiffs to indicate, on or before August 22, 2008, how they intend to proceed under this scenario. Thereafter, the judge expects to hold another pretrial conference to address plaintiffs' proposed procedure. JCP&L has received the plaintiffs' proposed plan of action, and intends to file its objection to the proposed plan, and also file a renewed motion to decertify the class. JCP&L is defending this action but is unable to predict the outcome. No liability has been accrued as of December 31, 2008.

On December 9, 2008, a transformer at JCP&L's Oceanview substation failed, resulting in an outage on certain bulk electric system (transmission voltage) lines out of the Oceanview and Atlantic substations, with customers in the affected area losing power. Power was restored to most customers within a few hours, and to all customers within eleven hours. On December 16, 2008, JCP&L provided preliminary information about the event to certain regulatory agencies, including the NERC. In a letter dated January 30, 2009, the NERC submitted a written "Notice of Request for Information" (NOI) to JCP&L. The NOI asked for additional factual details about the December 9 event, which JCP&L provided in its response. JCP&L is not able to predict what actions, if any, the NERC may take in response to JCP&L's NOI submittal.

Nuclear Plant Matters

On May 14, 2007, the Office of Enforcement of the NRC issued a DFI to FENOC, following FENOC's reply to an April 2, 2007 NRC request for information about two reports prepared by expert witnesses for an insurance arbitration (the insurance claim was subsequently withdrawn by us in December 2007) related to Davis-Besse. The NRC indicated that this information was needed for the NRC "to determine whether an Order or other action should be taken pursuant to 10 CFR 2.202, to provide reasonable assurance that FENOC will continue to operate its licensed facilities in accordance with the terms of its licenses and the Commission's regulations." FENOC was directed to submit the information to the NRC within 30 days. On June 13, 2007, FENOC filed a response to the NRC's DFI reaffirming that it accepts full responsibility for the mistakes and omissions leading up to the damage to the reactor vessel head and that it remains committed to operating Davis-Besse and our other nuclear plants safely and responsibly. FENOC submitted a supplemental response clarifying certain aspects of the DFI response to the NRC on July 16, 2007. On August 15, 2007, the NRC issued a confirmatory order imposing these commitments. FENOC must inform the NRC's Office of Enforcement after it completes the key commitments embodied in the NRC's order. FENOC has conducted the employee training required by the confirmatory order and a consultant has performed follow-up reviews to ensure the effectiveness of that training. The NRC continues to monitor FENOC's compliance with all the commitments made in the confirmatory order.

In August 2007, FENOC submitted an application to the NRC to renew the operating licenses for the Beaver Valley Power Station (Units 1 and 2) for an additional 20 years. The NRC is required by statute to provide an opportunity for members of the public to request a hearing on the application. No members of the public, however, requested a hearing on the Beaver Valley license renewal application. On September 24, 2008, the NRC issued a draft supplemental Environmental Impact Statement for Beaver Valley. FENOC will continue to work with the NRC Staff as it completes its environmental and technical reviews of the license renewal application, and expects to obtain renewed licenses for the Beaver Valley Power Station in 2009. If renewed licenses are issued by the NRC, the Beaver Valley Power Station's licenses would be extended until 2036 and 2047 for Units 1 and 2, respectively.

Other Legal Matters

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

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 also sought injunctive relief to eliminate harmful emissions and repair property damage and the institution of a medical monitoring program for class members. On April 5, 2007, the Court rejected the plaintiffs' request to certify this case as a class action and, accordingly, did not appoint the plaintiffs as class representatives or their counsel as class counsel. On July 30, 2007, plaintiffs' counsel voluntarily withdrew their request for reconsideration of the April 5, 2007 Court order denying class certification and the Court heard oral argument on the plaintiffs' motion to amend their complaint, which OE opposed. On August 2, 2007, the Court denied the plaintiffs' motion to amend their complaint. Plaintiffs appealed the Court's denial of the motion for certification as a class action which the Ohio Court of Appeals (7th District) denied on December 11, 2008. The period to file a notice of appeal to the Ohio Supreme Court has expired.

JCP&L's bargaining unit employees filed a grievance challenging JCP&L's 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties' collective bargaining agreement. At the conclusion of the June 1, 2005 hearing, the arbitration panel decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the arbitration panel issued an opinion to award approximately \$16 million to the bargaining unit employees. On February 6, 2006, a federal district Court granted a union motion to dismiss, as premature, a JCP&L appeal of the award filed on October 18, 2005. A final order identifying the individual damage amounts was issued on October 31, 2007. The award appeal process was initiated. The union filed a motion with the federal Court to confirm the award and JCP&L filed its answer and counterclaim to vacate the award on December 31, 2007. JCP&L and the union filed briefs in June and July of 2008 and oral arguments were held in the fall. The Court has yet to render its decision. JCP&L recognized a liability for the potential \$16 million award in 2005.

The union employees at the Bruce Mansfield Plant have been working without a labor contract since February 15, 2008. The parties are continuing to bargain with the assistance of a federal mediator. We have a strike mitigation plan ready in the event of a strike.

We accrue legal liabilities only when we conclude that it is probable that we have an obligation for such costs and can reasonably estimate the amount of such costs. If it were ultimately determined that we or our subsidiaries have legal liability or are otherwise made subject to liability based on the above matters, it could have a material adverse effect on our or our subsidiaries' financial condition, results of operations and cash flows.

CRITICAL ACCOUNTING POLICIES

We prepare our consolidated financial statements in accordance with GAAP. Application of these principles often requires a high degree of judgment, estimates and assumptions that affect financial results. All of our assets are subject to their own specific risks and uncertainties and are regularly reviewed for impairment. Our more significant accounting policies are described below.

Revenue Recognition

We follow the accrual method of accounting for revenues, recognizing revenue for electricity that has been delivered to customers but not yet billed through the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis throughout the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for unbilled sales is recognized. The determination of unbilled sales requires management to make estimates regarding electricity available for retail load, transmission and distribution line losses, demand by customer class, weather-related impacts, prices in effect for each customer class and electricity provided by alternative suppliers.

Regulatory Accounting

Our energy delivery services segment is subject to regulation that sets the prices (rates) we are permitted to charge our customers based on costs that the regulatory agencies determine we are permitted to recover. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by an unregulated company. This ratemaking process results in the recording of regulatory assets based on anticipated future cash inflows. We regularly review these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future.

Ohio Transition Cost Amortization

In connection with the Ohio Companies' transition plan, the PUCO determined allowable transition costs based on amounts recorded on the regulatory books of the Ohio Companies. These costs exceeded those deferred or capitalized on our balance sheet prepared under GAAP since they included certain costs which had not yet been incurred or that were recognized on the regulatory financial statements (fair value purchase accounting adjustments). We use an effective interest method for amortizing the Ohio Companies' transition costs (OE's and TE's amortization was complete as of December 31, 2008), often referred to as a "mortgage-style" amortization. The interest rate under this method is equal to the rate of return authorized by the PUCO in the transition plan for each respective company. In computing the transition cost amortization, we include only the portion of the transition revenues associated with transition costs included on the balance sheet prepared under GAAP. Revenues collected for the off-balance sheet costs and the return associated with these costs are recognized as income when received. Amortization of deferred customer shopping incentives and interest costs are equal to the related revenue recovery that is recognized under the RCP (see Note 2 (A)).

Pension and Other Postretirement Benefits Accounting

Our reported costs of providing noncontributory qualified and non-qualified defined pension benefits and OPEB benefits other than pensions are dependent upon numerous factors resulting from actual plan experience and certain assumptions.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions we make to the plans and earnings on plan assets. Pension and OPEB costs may also be affected by changes to key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs.

In accordance with SFAS 87 and SFAS 106, changes in pension and OPEB obligations associated with these factors may not be immediately recognized as costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. SFAS 87 and SFAS 106 delay recognition of changes due to the long-term nature of pension and OPEB obligations and the varying market conditions likely to occur over long periods of time. As such, significant portions of pension and OPEB costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants and are significantly influenced by assumptions about future market conditions and plan participants' experience.

In December 2006, we adopted SFAS 158 which requires a net liability or asset to be recognized for the overfunded or underfunded status of our defined benefit pension and other postretirement benefit plans on the balance sheet and recognize changes in funded status in the year in which the changes occur through other comprehensive income. We will continue to apply the provisions of SFAS 87 and SFAS 106 in measuring plan assets and benefit obligations as of the balance sheet date and in determining the amount of net periodic benefit cost. The underfunded status of our qualified and non-qualified pension and OPEB plans at December 31, 2008 is \$1.7 billion.

In selecting an assumed discount rate, we consider currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. The assumed discount rate was 7.0%, 6.5%, and 6.0% as of December 31, 2008, 2007, and 2006, respectively.

Our assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by our pension trusts. In 2008 our qualified pension and OPEB plan assets actually lost \$1.4 billion or 23.8% and earned \$481 million or 8.9% in 2007. Our qualified pension and OPEB costs in 2008 and 2007 were computed using an assumed 9.0% rate of return on plan assets which generated \$514 million and \$499 million of expected returns on plan assets, respectively. The expected return of pension and OPEB assets is based on the trusts' asset allocation targets and the historical performance of risk-based and fixed income securities. The gains or losses generated as a result of the difference between expected and actual returns on plan assets are deferred and amortized and will increase or decrease future net periodic pension and OPEB cost, respectively.

Our qualified and non-qualified pension and OPEB net periodic benefit cost was a credit of \$116 million in 2008 and \$73 million in 2007 compared to costs of \$115 million in 2006. On January 2, 2007, we made a \$300 million voluntary contribution to our pension plan. In addition, during 2006, we amended our OPEB plan, effective in 2008, to cap our monthly contribution for many of the retirees and their spouses receiving subsidized health care coverage. We expect our 2009 qualified and non-qualified pension and OPEB costs (including amounts capitalized) to be \$238 million.

Health care cost trends continue to increase and will affect future OPEB costs. The 2008 and 2007 composite health care trend rate assumptions were approximately 9-11%, gradually decreasing to 5% in later years. In determining our trend rate assumptions, we included the specific provisions of our health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in our health care plans, and projections of future medical trend rates. The effect on our pension and OPEB costs from changes in key assumptions are as follows:

Increase in Costs from Adverse Changes in Key Assumptions

<u>Assumption</u>	<u>Adverse Change</u>	<u>Pension</u>	<u>OPEB</u>	<u>Total</u>
			<i>(In millions)</i>	
Discount rate	Decrease by 0.25%	\$ 14	\$ 3	\$ 17
Long-term return on assets	Decrease by 0.25%	\$ 9	\$ 1	\$ 10
Health care trend rate	Increase by 1%	n/a	\$ 7	\$ 7

Emission Allowances

We hold emission allowances for SO₂ and NO_x in order to comply with programs implemented by the EPA designed to regulate emissions of SO₂ and NO_x produced by power plants. Emission allowances are either granted to us by the EPA at zero cost or are purchased at fair value as needed to meet emission requirements. Emission allowances are not purchased with the intent of resale. Emission allowances eligible to be used in the current year are recorded in materials and supplies inventory at the lesser of weighted average cost or market value. Emission allowances eligible for use in future years are recorded as other investments. We recognize emission allowance costs as fuel expense during the periods that emissions are produced by our generating facilities. Excess emission allowances that are not needed to meet emission requirements may be sold and are reported as a reduction to other operating expenses.

Long-Lived Assets

In accordance with SFAS 144, we periodically evaluate our long-lived assets to determine whether conditions exist that would indicate that the carrying value of an asset might not be fully recoverable. The accounting standard requires that if the sum of future cash flows (undiscounted) expected to result from an asset is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. If impairment has occurred, we recognize a loss – calculated as the difference between the carrying value and the estimated fair value of the asset (discounted future net cash flows).

The calculation of future cash flows is based on assumptions, estimates and judgment about future events. The aggregate amount of cash flows determines whether an impairment is indicated. The timing of the cash flows is critical in determining the amount of the impairment.

Asset Retirement Obligations

In accordance with SFAS 143 and FIN 47, we recognize an ARO for the future decommissioning of our nuclear power plants and future remediation of other environmental liabilities associated with all of our long-lived assets. The ARO liability represents an estimate of the fair value of our current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. We use an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plants' current license, settlement based on an extended license term and expected remediation dates.

Income Taxes

We record income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by SFAS 142, we evaluate goodwill for impairment at least annually and make such evaluations more frequently if indicators of impairment arise. In accordance with the accounting standard, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. If impairment is indicated, we recognize a loss – calculated as the difference between the implied fair value of a reporting unit's goodwill and the carrying value of the goodwill. The forecasts used in our evaluations of goodwill reflect operations consistent with our general business assumptions. Unanticipated changes in those assumptions could have a significant effect on our future evaluations of goodwill.

NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

SFAS 141(R) – “Business Combinations”

In December 2007, the FASB issued SFAS 141(R), which: (i) requires the acquiring entity in a business combination to recognize all assets acquired and liabilities assumed in the transaction; (ii) establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and (iii) requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. The Standard includes both core principles and pertinent application guidance, eliminating the need for numerous EITF issues and other interpretative guidance. SFAS 141(R) will affect business combinations we enter into that close after January 1, 2009. In addition, the Standard also affects the accounting for changes in deferred tax valuation allowances and income tax uncertainties made after January 1, 2009, that were established as part of a business combination prior to the implementation of this Standard. Under SFAS 141(R), adjustments to the acquired entity’s deferred tax assets and uncertain tax position balances occurring outside the measurement period will be recorded as a component of income tax expense, rather than goodwill. The impact of our application of this Standard in periods after implementation will be dependent upon the nature of acquisitions at that time.

SFAS 160 - “Non-controlling Interests in Consolidated Financial Statements – an Amendment of ARB No. 51”

In December 2007, the FASB issued SFAS 160 that establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. This Statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is prohibited. The Statement is not expected to have a material impact on our financial statements.

SFAS 161 - “Disclosures about Derivative Instruments and Hedging Activities – an Amendment of FASB Statement No. 133”

In March 2008, the FASB issued SFAS 161 that enhances the current disclosure framework for derivative instruments and hedging activities. The Statement requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. The FASB believes that additional required disclosure of the fair values of derivative instruments and their gains and losses in a tabular format will provide a more complete picture of the location in an entity’s financial statements of both the derivative positions existing at period end and the effect of using derivatives during the reporting period. Disclosing information about credit-risk-related contingent features is designed to provide information on the potential effect on an entity’s liquidity from using derivatives. This Statement also requires cross-referencing within the footnotes to help users of financial statements locate important information about derivative instruments. The Statement is effective for reporting periods beginning after November 15, 2008. We expect this Standard to increase our disclosure requirements for derivative instruments and hedging activities.

EITF Issue No. 08-6 – “Equity Method Investment Accounting Considerations”

In November 2008, the FASB issued EITF 08-6, which clarifies how to account for certain transactions involving equity method investments. It provides guidance in determining the initial carrying value of an equity method investment, accounting for a change in an investment from equity method to cost method, assessing the impairment of underlying assets of an equity method investment, and accounting for an equity method investee’s issuance of shares. This statement is effective for transactions occurring in fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is not permitted. The impact of our application of this Standard in periods after implementation will be dependent upon the nature of future investments accounted for under the equity method.

FSP SFAS 132 (R)-1 – “Employers’ Disclosures about Postretirement Benefit Plan Assets”

In December 2008, the FASB issued Staff Position (FSP) SFAS 132(R)-1, which provides guidance on an employer’s disclosures about plan assets of a defined benefit pension or other postretirement plan. Requirements of this FSP include disclosures about investment policies and strategies, categories of plan assets, fair value measurements of plan assets, and significant categories of risk. This FSP is effective for fiscal years ending after December 15, 2009. We expect this Staff Position to increase our disclosure requirements for postretirement benefit plan assets.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2008 consolidated financial statements.

The Company's internal auditors, who are responsible to the Audit Committee of the Company's Board of Directors, review the results and performance of operating units within the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

The Company's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held ten meetings in 2008.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2008. The effectiveness of the Company's internal control over financial reporting, as of December 31, 2008, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page 60.

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, common stockholders' equity, and cash flows present fairly, in all material respects, the financial position of FirstEnergy Corp. and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in the notes to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions as of January 1, 2007 (Note 9) and defined benefit pension and other postretirement plans as of December 31, 2006 (Note 3).

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 24, 2009

FIRSTENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	2008	2007	2006
	<i>(In millions, except per share amounts)</i>		
REVENUES:			
Electric utilities	\$ 12,061	\$ 11,305	\$ 10,007
Unregulated businesses	1,566	1,497	1,494
Total revenues*	<u>13,627</u>	<u>12,802</u>	<u>11,501</u>
EXPENSES:			
Fuel	1,340	1,178	1,212
Purchased power	4,291	3,836	3,041
Other operating expenses	3,042	3,086	2,965
Provision for depreciation	677	638	596
Amortization of regulatory assets	1,053	1,019	861
Deferral of new regulatory assets	(316)	(524)	(500)
General taxes	778	754	720
Total expenses	<u>10,865</u>	<u>9,987</u>	<u>8,895</u>
OPERATING INCOME	<u>2,762</u>	<u>2,815</u>	<u>2,606</u>
OTHER INCOME (EXPENSE):			
Investment income, net (Note 5(B))	59	120	149
Interest expense	(754)	(775)	(721)
Capitalized interest	52	32	26
Subsidiaries' preferred stock dividends	-	-	(7)
Total other expense	<u>(643)</u>	<u>(623)</u>	<u>(553)</u>
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	2,119	2,192	2,053
INCOME TAXES	<u>777</u>	<u>883</u>	<u>795</u>
INCOME FROM CONTINUING OPERATIONS	1,342	1,309	1,258
Discontinued operations (net of income tax benefits of \$2 million) (Note 8)	-	-	(4)
NET INCOME	<u>\$ 1,342</u>	<u>\$ 1,309</u>	<u>\$ 1,254</u>
BASIC EARNINGS PER SHARE OF COMMON STOCK:			
Income from continuing operations	\$ 4.41	\$ 4.27	\$ 3.85
Discontinued operations (Note 8)	-	-	(0.01)
Net earnings per basic share	<u>\$ 4.41</u>	<u>\$ 4.27</u>	<u>\$ 3.84</u>
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING			
	<u>304</u>	<u>306</u>	<u>324</u>
DILUTED EARNINGS PER SHARE OF COMMON STOCK:			
Income from continuing operations	\$ 4.38	\$ 4.22	\$ 3.82
Discontinued operations (Note 8)	-	-	(0.01)
Net earnings per diluted share	<u>\$ 4.38</u>	<u>\$ 4.22</u>	<u>\$ 3.81</u>
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	<u>307</u>	<u>310</u>	<u>327</u>

* Includes \$432 million, \$425 million and \$400 million of excise tax collections in 2008, 2007 and 2006, respectively.

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

FIRSTENERGY CORP.

CONSOLIDATED BALANCE SHEETS

As of December 31,	2008	2007
	(In millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 545	\$ 129
Receivables-		
Customers (less accumulated provisions of \$28 million and \$36 million, respectively, for uncollectible accounts)	1,304	1,256
Other (less accumulated provisions of \$9 million and \$22 million, respectively, for uncollectible accounts)	167	165
Materials and supplies, at average cost	605	521
Prepaid taxes	283	32
Other	149	127
	<u>3,053</u>	<u>2,230</u>
PROPERTY, PLANT AND EQUIPMENT:		
In service	26,482	24,619
Less - Accumulated provision for depreciation	10,821	10,348
	<u>15,661</u>	<u>14,271</u>
Construction work in progress	2,062	1,112
	<u>17,723</u>	<u>15,383</u>
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,708	2,127
Investments in lease obligation bonds (Note 6)	598	717
Other	711	754
	<u>3,017</u>	<u>3,598</u>
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	5,575	5,607
Regulatory assets	3,140	3,973
Pension assets (Note 3)	-	700
Power purchase contract asset	434	215
Other	579	605
	<u>9,728</u>	<u>11,100</u>
	<u>\$ 33,521</u>	<u>\$ 32,311</u>
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	\$ 2,476	\$ 2,014
Short-term borrowings (Note 13)	2,397	903
Accounts payable	794	777
Accrued taxes	333	408
Other	1,098	1,046
	<u>7,098</u>	<u>5,148</u>
CAPITALIZATION:		
Common stockholders' equity-		
Common stock, \$0.10 par value, authorized 375,000,000 shares-304,835,407 outstanding	31	31
Other paid-in capital	5,473	5,509
Accumulated other comprehensive loss	(1,380)	(50)
Retained earnings	4,159	3,487
Total common stockholders' equity	<u>8,283</u>	<u>8,977</u>
Long-term debt and other long-term obligations (Note 11(C))	9,100	8,869
	<u>17,383</u>	<u>17,846</u>
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	2,163	2,671
Asset retirement obligations	1,335	1,267
Deferred gain on sale and leaseback transaction	1,027	1,060
Power purchase contract liability	766	1,018
Retirement benefits	1,884	894
Lease market valuation liability	308	663
Other	1,557	1,744
	<u>9,040</u>	<u>9,317</u>
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Notes 6 and 14)		
	<u>\$ 33,521</u>	<u>\$ 32,311</u>

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

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

	Comprehensive Income	Common Stock		Other Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Unallocated ESOP Common Stock
		Number of Shares	Par Value				
<i>(Dollars in millions)</i>							
Balance, January 1, 2006		329,836,276	\$ 33	\$ 7,043	\$ (20)	\$ 2,159	\$ (27)
Net income	\$ 1,254					1,254	
Unrealized gain on derivative hedges, net of \$10 million of income taxes	19				19		
Unrealized gain on investments, net of \$40 million of income taxes	69				69		
Comprehensive income	<u>\$ 1,342</u>						
Net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of \$292 million of income tax benefits (Note 3)					(327)		
Redemption premiums on preferred stock						(9)	
Stock options exercised				(28)			
Allocation of ESOP shares				33			17
Restricted stock units				11			
Stock-based compensation				6			
Repurchase of common stock		(10,630,759)	(1)	(599)			
Cash dividends declared on common stock						(598)	
Balance, December 31, 2006		319,205,517	32	6,466	(259)	2,806	(10)
Net income	\$ 1,309					1,309	
Unrealized loss on derivative hedges, net of \$8 million of income tax benefits	(17)				(17)		
Unrealized gain on investments, net of \$31 million of income taxes	47				47		
Pension and other postretirement benefits, net of \$169 million of income taxes (Note 3)	179				179		
Comprehensive income	<u>\$ 1,518</u>						
Stock options exercised				(40)			
Allocation of ESOP shares				26			10
Restricted stock units				23			
Stock-based compensation				2			
FIN 48 cumulative effect adjustment						(3)	
Repurchase of common stock		(14,370,110)	(1)	(968)			
Cash dividends declared on common stock						(625)	
Balance, December 31, 2007		304,835,407	31	5,509	(50)	3,487	-
Net income	\$ 1,342					1,342	
Unrealized loss on derivative hedges, net of \$16 million of income tax benefits	(28)				(28)		
Change in unrealized gain on investments, net of \$86 million of income tax benefits	(146)				(146)		
Pension and other postretirement benefits, net of \$697 million of income tax benefits (Note 3)	(1,156)				(1,156)		
Comprehensive income	<u>\$ 12</u>						
Stock options exercised				(36)			
Restricted stock units				(1)			
Stock-based compensation				1			
Cash dividends declared on common stock						(670)	
Balance, December 31, 2008		304,835,407	\$ 31	\$ 5,473	\$ (1,380)	\$ 4,159	\$ -

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

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2008	2007	2006
	<i>(In millions)</i>		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	\$ 1,342	\$ 1,309	\$ 1,254
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	677	638	596
Amortization of regulatory assets	1,053	1,019	861
Deferral of new regulatory assets	(316)	(524)	(500)
Nuclear fuel and lease amortization	112	101	90
Deferred purchased power and other costs	(226)	(346)	(445)
Deferred income taxes and investment tax credits, net	366	(9)	159
Investment impairment (Note 2(E))	123	26	27
Deferred rents and lease market valuation liability	(95)	(99)	(113)
Stock based compensation	(64)	(39)	(37)
Accrued compensation and retirement benefits	(140)	(37)	193
Gain on asset sales	(72)	(30)	(49)
Electric service prepayment programs	(77)	(75)	(64)
Cash collateral, net	(31)	(68)	(77)
Pension trust contributions	-	(300)	-
Decrease (increase) in operating assets-			
Receivables	(29)	(136)	105
Materials and supplies	(52)	79	(25)
Prepaid taxes	(251)	27	(20)
Increase (decrease) in operating liabilities-			
Accounts payable	10	51	99
Accrued taxes	(39)	71	(175)
Accrued interest	4	(8)	7
Other	(76)	44	53
Net cash provided from operating activities	<u>2,219</u>	<u>1,694</u>	<u>1,939</u>
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	1,367	1,520	2,731
Short-term borrowings, net	1,494	-	386
Redemptions and Repayments-			
Common stock	-	(969)	(600)
Preferred stock	-	-	(193)
Long-term debt	(1,034)	(1,070)	(2,512)
Short-term borrowings, net	-	(205)	-
Net controlled disbursement activity	10	(1)	(27)
Other	14	(1)	(3)
Common stock dividend payments	(671)	(616)	(586)
Net cash provided from (used for) financing activities	<u>1,180</u>	<u>(1,342)</u>	<u>(804)</u>
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(2,888)	(1,633)	(1,315)
Proceeds from asset sales	72	42	162
Proceeds from sale and leaseback transaction	-	1,329	-
Sales of investment securities held in trusts	1,656	1,294	1,651
Purchases of investment securities held in trusts	(1,749)	(1,397)	(1,666)
Cash investments and restricted funds (Note 5)	60	72	121
Other	(134)	(20)	(62)
Net cash used for investing activities	<u>(2,983)</u>	<u>(313)</u>	<u>(1,109)</u>
Net increase in cash and cash equivalents	416	39	26
Cash and cash equivalents at beginning of year	129	90	64
Cash and cash equivalents at end of year	<u>\$ 545</u>	<u>\$ 129</u>	<u>\$ 90</u>
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	<u>\$ 667</u>	<u>\$ 744</u>	<u>\$ 656</u>
Income taxes	<u>\$ 685</u>	<u>\$ 710</u>	<u>\$ 688</u>

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

FirstEnergy is a diversified energy company that holds, directly or indirectly, all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), ATSI, JCP&L, Met-Ed, Penelec, FENOC, FES and its subsidiaries FGCO and NGC, and FESC.

FirstEnergy and its subsidiaries follow GAAP and comply with the regulations, orders, policies and practices prescribed by the SEC, FERC and, as applicable, the 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.

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 7) when it is determined to be the VIE's primary beneficiary. Investments in non-consolidated affiliates over which FirstEnergy and its subsidiaries have the ability to exercise significant influence, but not control (20-50% 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 Sheets and the percentage share of the entity's earnings is reported in the Consolidated Statements of Income.

Certain prior year amounts have been reclassified to conform to the current year presentation. In the fourth quarter of 2008, FirstEnergy determined that certain NUG contracts should be reflected at fair value, with offsetting regulatory assets or liabilities. The December 31, 2007, balance sheet has been revised to record a derivative asset of \$215 million, offset by a regulatory liability. Unless otherwise indicated, defined terms used herein have the meanings set forth in the accompanying Glossary of Terms.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(A) ACCOUNTING FOR THE EFFECTS OF REGULATION

FirstEnergy accounts for the effects of regulation through the application of SFAS 71 to its operating utilities since their rates:

- are established by a third-party regulator with the authority to set rates that bind customers;
- are cost-based; and
- can be charged to and collected from customers.

An enterprise meeting all of these criteria capitalizes costs that would otherwise be charged to expense if the rate actions of its regulator make it probable that those costs will be recovered in future revenue. SFAS 71 is applied only to the parts of the business that meet the above criteria. If a portion of the business applying SFAS 71 no longer meets those requirements, previously recorded net regulatory assets are removed from the balance sheet in accordance with the guidance in SFAS 101.

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

- restructuring the electric generation business and allowing the Utilities' customers to select a competitive electric generation supplier other than the Utilities;
- establishing or defining the PLR obligations to customers in the Utilities' service areas;
- providing the Utilities 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 Utilities' transmission and distribution systems; and
- requiring corporate separation of regulated and unregulated business activities.

Regulatory Assets

The Utilities 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 expense as incurred. Regulatory assets that do not earn a current return (primarily for certain regulatory transition costs and employee postretirement benefits) totaled approximately \$133 million as of December 31, 2008 (JCP&L - \$61 million and Met-Ed - \$72 million). Regulatory assets not earning a current return will be recovered by 2014 for JCP&L and by 2020 for Met-Ed.

Regulatory assets on the Consolidated Balance Sheets are comprised of the following:

	<u>2008</u>	<u>2007</u>
	<i>(In millions)</i>	
Regulatory transition costs	\$ 1,452	\$ 2,405
Customer shopping incentives	420	516
Customer receivables for future income taxes	245	295
Loss on reacquired debt	51	57
Employee postretirement benefits	31	39
Nuclear decommissioning, decontamination and spent fuel disposal costs	(57)	(129)
Asset removal costs	(215)	(183)
MISO/PJM transmission costs	389	340
Fuel costs - RCP	214	220
Distribution costs - RCP	475	321
Other	135	92
Total*	<u>\$ 3,140</u>	<u>\$ 3,973</u>

* Penelec had net regulatory liabilities of approximately \$137 million and \$49 million as of December 31, 2008 and December 31, 2007, respectively. These net regulatory liabilities are included in Other Non-current Liabilities on the Consolidated Balance Sheets.

In accordance with the Ohio Companies' RCP, recovery of the aggregate of the regulatory transition costs and the Extended RTC (deferred customer shopping incentives and interest costs) amounts were completed for OE and TE as of December 31, 2008. CEI's recovery of regulatory transition costs is projected to be complete by April 2009, at which time recovery of its Extended RTC will begin, with recovery estimated to be complete as of December 31, 2010. At the end of its recovery period, any of CEI's remaining unamortized regulatory transition costs and Extended RTC balances will be reduced by applying any remaining cost of removal regulatory liability balances; any further remaining regulatory transition costs and Extended RTC balances will be written off. The RCP allowed the Ohio Companies to defer and capitalize certain distribution costs during the period January 1, 2006 through December 31, 2008, not to exceed \$150 million in each of the years 2006, 2007 and 2008. In addition, the Ohio Companies deferred certain fuel costs through December 31, 2007 that were incurred above the amount collected through a fuel recovery mechanism in accordance with the RCP (see Note 10(B)).

Transition Cost Amortization

CEI amortizes transition costs using the effective interest method. Extended RTC amortization, beginning in mid-2009, will be equal to the related revenue recovery that is recognized. CEI's estimated net amortization of regulatory transition costs and Extended RTC amounts (including associated carrying charges) under the RCP is expected to be \$216 million in 2009 and \$273 million in 2010 (see Note 10(B)).

Total regulatory assets for transition costs as of December 31, 2008 were \$1.5 billion, of which approximately \$1.2 billion and \$12 million apply to JCP&L and Met-Ed, respectively. JCP&L's and Met-Ed's regulatory transition costs include the deferral of above-market costs for power supplied from NUGs of \$555 million for JCP&L (recovered through BGS and NUGC revenues) and \$67 million for Met-Ed (recovered through CTC revenues). Projected above-market NUG costs are adjusted to fair value at the end of each quarter, with a corresponding offset to regulatory assets. Recovery of the remaining regulatory transition costs is expected to continue pursuant to various regulatory proceedings in New Jersey and Pennsylvania (See Note 10).

(B) REVENUES AND RECEIVABLES

The Utilities' principal business is providing electric service to customers in Ohio, Pennsylvania and New Jersey. The Utilities' retail customers are metered on a cycle basis. Electric revenues are recorded based on energy delivered through the end of the calendar month. An estimate of unbilled revenues is calculated to recognize electric service provided between the last meter reading and the end of the month. This estimate includes many factors, among which are historical customer usage, load profiles, estimated weather impacts, customer shopping activity and prices in effect for each class of customer. In each accounting period, the Utilities accrue the estimated unbilled amount receivable as revenue and reverse the related prior period estimate.

Receivables from customers include sales to residential, commercial and industrial customers and sales to wholesale customers. There was no material concentration of receivables as of December 31, 2008 with respect to any particular segment of FirstEnergy's customers. Total customer receivables were \$1.3 billion (billed – \$752 million and unbilled – \$552 million) and \$1.3 billion (billed – \$732 million and unbilled – \$524 million) as of December 31, 2008 and 2007, respectively.

(C) EARNINGS PER SHARE OF COMMON STOCK

Basic earnings per share of common stock is computed using the weighted average of actual common shares outstanding during the respective period as the denominator. The denominator for diluted earnings per share of common stock reflects the weighted average of common shares outstanding plus the potential additional common shares that could result if dilutive securities and other agreements to issue common stock were exercised. On August 10, 2006, FirstEnergy repurchased 10.6 million shares, approximately 3.2%, of its outstanding common stock through an accelerated share repurchase program. The initial purchase price was \$600 million, or \$56.44 per share. A final purchase price adjustment of \$27 million was settled in cash on April 2, 2007. On March 2, 2007, FirstEnergy repurchased approximately 14.4 million shares, or 4.5%, of its outstanding common stock through an additional accelerated share repurchase program at an initial price of approximately \$900 million. A final purchase price adjustment of \$51 million was settled in cash on December 13, 2007. The following table reconciles basic and diluted earnings per share of common stock:

Reconciliation of Basic and Diluted Earnings per Share of Common Stock	2008	2007	2006
	<i>(In millions, except per share amounts)</i>		
Income from continuing operations	\$ 1,342	\$ 1,309	\$ 1,258
Less: Redemption premium on subsidiary preferred stock	-	-	(9)
Income from continuing operations available to common shareholders	1,342	1,309	1,249
Discontinued operations	-	-	(4)
Net income available for common shareholders	<u>\$ 1,342</u>	<u>\$ 1,309</u>	<u>\$ 1,245</u>
Average shares of common stock outstanding – Basic	304	306	324
Assumed exercise of dilutive stock options and awards	3	4	3
Average shares of common stock outstanding – Diluted	<u>307</u>	<u>310</u>	<u>327</u>
Earnings per share:			
Basic earnings per share:			
Earnings from continuing operations	\$ 4.41	\$ 4.27	\$ 3.85
Discontinued operations	-	-	(0.01)
Net earnings per basic share	<u>\$ 4.41</u>	<u>\$ 4.27</u>	<u>\$ 3.84</u>
Diluted earnings per share:			
Earnings from continuing operations	\$ 4.38	\$ 4.22	\$ 3.82
Discontinued operations	-	-	(0.01)
Net earnings per diluted share	<u>\$ 4.38</u>	<u>\$ 4.22</u>	<u>\$ 3.81</u>

(D) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (except for nuclear generating assets which were adjusted to fair value in accordance with SFAS 144), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. FirstEnergy's accounting policy for planned major maintenance projects is to recognize liabilities as they are incurred. Property, plant and equipment balances as of December 31, 2008 and 2007 were as follows:

Property, Plant and Equipment	December 31, 2008			December 31, 2007		
	Unregulated	Regulated	Total	Unregulated	Regulated	Total
	(In millions)					
In service	\$ 10,236	\$ 16,246	\$ 26,482	\$ 8,795	\$ 15,824	\$ 24,619
Less accumulated depreciation	(4,403)	(6,418)	(10,821)	(4,037)	(6,311)	(10,348)
Net plant in service	\$ 5,833	\$ 9,828	\$ 15,661	\$ 4,758	\$ 9,513	\$ 14,271

FirstEnergy provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The respective annual composite rates for FirstEnergy's subsidiaries' electric plant in 2008, 2007 and 2006 are shown in the following table:

	Annual Composite Depreciation Rate		
	2008	2007	2006
OE	3.1%	2.9%	2.8%
CEI	3.5	3.6	3.2
TE	3.6	3.9	3.8
Penn	2.4	2.3	2.6
JCP&L	2.3	2.1	2.1
Met-Ed	2.3	2.3	2.3
Penelec	2.5	2.3	2.3
FGCO	4.7	4.0	4.1
NGC	2.8	2.8	2.7

Asset Retirement Obligations

FirstEnergy recognizes a liability for retirement obligations associated with tangible assets in accordance with SFAS 143 and FIN 47. These standards require recognition of the fair value of a liability for an ARO in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and depreciated over time, as described further in Note 12.

Nuclear Fuel

Property, plant and equipment includes nuclear fuel recorded at original cost, which includes material, enrichment, fabrication and interest costs incurred prior to reactor load. Nuclear fuel is amortized based on the units of production method.

(E) ASSET IMPAIRMENTS

Long-Lived Assets

FirstEnergy evaluates the carrying value of its long-lived assets when events or circumstances indicate that the carrying amount may not be recoverable. In accordance with SFAS 144, the carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If an impairment exists, a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. Fair value is estimated by using available market valuations or the long-lived asset's expected future net discounted cash flows. The calculation of expected cash flows is based on estimates and assumptions about future events.

Goodwill

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

The forecasts used in FirstEnergy's evaluations of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on FirstEnergy's future evaluations of goodwill. FirstEnergy's goodwill primarily relates to its energy delivery services segment. The impairment analysis includes a significant source of cash representing the Utilities' recovery of transition costs as described in Note 10.

FirstEnergy's 2008 annual review was completed in the third quarter of 2008 with no impairment indicated. Due to the significant downturn in the U.S. economy during the fourth quarter of 2008, goodwill was tested for impairment as of an interim date (December 31, 2008). No impairment was indicated for the former GPU companies. As discussed in Note 10(B) on February 19, 2009, the Ohio Companies filed an application for an amended ESP, which substantially reflects terms proposed by the PUCO Staff on February 2, 2009. Goodwill for the Ohio Companies was tested as of December 31, 2008, reflecting the projected results associated with the amended ESP. No impairment was indicated for the Ohio Companies. If the PUCO's final decision authorizes less revenue recovery than the amounts assumed, an additional impairment analysis will be performed at that time that could result in future goodwill impairment. During 2008, FirstEnergy adjusted goodwill of the former GPU companies by \$32 million due to the realization of tax benefits that had been reserved under purchase accounting.

FirstEnergy's 2007 annual review was completed in the third quarter of 2007, with no impairment indicated. In the third quarter of 2007, FirstEnergy adjusted goodwill for the former GPU companies by \$290 million due to the realization of tax benefits that had been reserved in purchase accounting.

FirstEnergy's 2006 annual review was completed in the third quarter of 2006 with no impairment indicated. The PPUC issued its order on January 11, 2007 related to the comprehensive rate filing made by Met-Ed and Penelec on April 10, 2006. Prior to issuing the order, the PPUC conducted an informal, nonbinding polling of Commissioners at its public meeting on December 21, 2006 that indicated that the rate increase ultimately granted could be substantially lower than the amounts requested. As a result of the polling, FirstEnergy determined that an interim review of goodwill for its energy delivery services segment would be required. No impairment was indicated as a result of that review.

A summary of the changes in FirstEnergy's goodwill for the three years ended December 31, 2008 is shown below by segment (see Note 15 - Segment Information):

	Energy Delivery Services	Competitive Energy Services	Ohio Transitional Generation Services	Other	Consolidated
	<i>(In millions)</i>				
Balance as of January 1, 2006	\$ 5,932	\$ 24	\$ -	\$ 54	\$ 6,010
Non-core asset sales				(53)	(53)
Adjustments related to GPU acquisition	(1)				(1)
Adjustments related to Centerior acquisition	(58)				(58)
Balance as of December 31, 2006	5,873	24	-	1	5,898
Adjustments related to GPU acquisition	(290)				(290)
Other				(1)	(1)
Balance as of December 31, 2007	5,583	24	-	-	5,607
Adjustments related to GPU acquisition	(32)				(32)
Balance as of December 31, 2008	<u>\$ 5,551</u>	<u>\$ 24</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 5,575</u>

Investments

At the end of each reporting period, FirstEnergy evaluates its investments for impairment. In accordance with SFAS 115, FSP SFAS 115-1 and SFAS 124-1, investments classified as available-for-sale securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. FirstEnergy first considers its intent and ability to hold the investment until recovery and then considers, among other factors, the duration and the extent to which the security's fair value has been less than its cost and the near-term financial prospects of the security issuer when evaluating investments for impairment. If the decline in fair value is determined to be other than temporary, the cost basis of the investment is written down to fair value. Upon adoption of FSP SFAS 115-1 and SFAS 124-1, FirstEnergy began recognizing in earnings the unrealized losses on available-for-sale securities held in its nuclear decommissioning trusts since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of other-than-temporary impairment. The fair value of FirstEnergy's investments are disclosed in Note 5(B).

(F) COMPREHENSIVE INCOME

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholders' equity, except those resulting from transactions with stockholders and from the adoption of SFAS 158 in December 2006. As of December 31, 2008, AOCL consisted of a net liability for unfunded retirement benefits net of income tax benefits (see Note 3) of \$1.3 billion, unrealized gains on investments in available-for-sale securities of \$45 million and unrealized losses on derivative instrument hedges of \$103 million. A summary of the changes in FirstEnergy's AOCL balance for the three years ended December 31, 2008 is shown below:

	<u>2008</u>	<u>2007</u>	<u>2006</u>
	<i>(In millions)</i>		
AOCL balance as of January 1	\$ (50)	\$ (259)	\$ (20)
Pension and other postretirement benefits:			
Prior service credit	(126)	(135)	-
Actuarial gain (loss)	(1,725)	483	-
Unrealized gain (loss) on available for sale securities	(232)	78	109
Unrealized gain (loss) on derivative hedges	(43)	(25)	29
Other comprehensive income (loss)	(2,126)	401	138
Income taxes (benefits) related to OCI	(796)	192	50
Other comprehensive income (loss), net of tax	(1,330)	209	88
Net liability for unfunded retirement benefits			
due to the implementation of SFAS 158, net of \$292 million of income tax benefits	-	-	(327)
AOCL balance as of December 31	<u>\$ (1,380)</u>	<u>\$ (50)</u>	<u>\$ (259)</u>

Other comprehensive income (loss) reclassified to net income in the three years ended December 31, 2008 is as follows:

	<u>2008</u>	<u>2007</u>	<u>2006</u>
	<i>(In millions)</i>		
Pension and other postretirement benefits, net of income taxes of \$32 million and \$20 million, respectively	\$ 48	\$ 25	\$ -
Gain on available for sale securities, net of income taxes of \$16 million, \$4 million and \$11 million, respectively	24	6	16
Loss on derivative hedges, net of income tax benefits of \$7 million, \$10 million and \$12 million, respectively	(12)	(16)	(20)
	<u>\$ 60</u>	<u>\$ 15</u>	<u>\$ (4)</u>

3. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

FirstEnergy provides a noncontributory qualified defined benefit pension plan that covers substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels. FirstEnergy's funding policy is based on actuarial computations using the projected unit credit method. On January 2, 2007, FirstEnergy made a \$300 million voluntary cash contribution to its qualified pension plan. In December 2008, The Worker, Retiree, and Employer Recovery Act of 2008 (WRERA) was enacted. Among other provisions, the WRERA provides temporary funding relief to defined benefit plans in light of the current economic crisis. It is expected that the WRERA will have a favorable impact on the level of minimum required contributions for years after 2009. FirstEnergy estimates that additional cash contributions will not be required before 2011.

FirstEnergy 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 also 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 and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. During 2006, FirstEnergy amended the OPEB plan effective in 2008 to cap the monthly contribution for many of the retirees and their spouses receiving subsidized health care coverage. During 2008, FirstEnergy further amended the OPEB plan effective in 2010 to limit the monthly contribution for pre-1990 retirees. In addition, FirstEnergy has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans and earnings on plan assets. Pension and OPEB costs may also be affected by changes in key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs. FirstEnergy uses a December 31 measurement date for its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of December 31, 2008.

Obligations and Funded Status As of December 31	Pension Benefits		Other Benefits	
	2008	2007	2008	2007
	(In millions)			
Change in benefit obligation				
Benefit obligation as of January 1	\$ 4,750	\$ 5,031	\$ 1,182	\$ 1,201
Service cost	87	88	19	21
Interest cost	299	294	74	69
Plan participants' contributions	-	-	25	23
Plan amendments	6	-	(20)	-
Medicare retiree drug subsidy	-	-	2	-
Actuarial (gain) loss	(152)	(381)	12	(30)
Benefits paid	(290)	(282)	(105)	(102)
Benefit obligation as of December 31	<u>\$ 4,700</u>	<u>\$ 4,750</u>	<u>\$ 1,189</u>	<u>\$ 1,182</u>
Change in fair value of plan assets				
Fair value of plan assets as of January 1	\$ 5,285	\$ 4,818	\$ 618	\$ 607
Actual return on plan assets	(1,251)	438	(152)	43
Company contribution	8	311	54	47
Plan participants' contribution	-	-	25	23
Benefits paid	(290)	(282)	(105)	(102)
Fair value of plan assets as of December 31	<u>\$ 3,752</u>	<u>\$ 5,285</u>	<u>\$ 440</u>	<u>\$ 618</u>
Qualified plan	\$ (774)	\$ 700		
Non-qualified plans	(174)	(165)		
Funded status	<u>\$ (948)</u>	<u>\$ 535</u>	\$ (749)	\$ (564)
Accumulated benefit obligation	\$ 4,367	\$ 4,397		
Amounts Recognized in the Statement of				
Financial Position				
Noncurrent assets	\$ -	\$ 700	\$ -	\$ -
Current liabilities	(8)	(7)	-	-
Noncurrent liabilities	(940)	(158)	(749)	(564)
Net asset (liability) as of December 31	<u>\$ (948)</u>	<u>\$ 535</u>	<u>\$ (749)</u>	<u>\$ (564)</u>
Amounts Recognized in				
Accumulated Other Comprehensive Income				
Prior service cost (credit)	\$ 80	\$ 83	\$ (912)	\$ (1,041)
Actuarial loss	2,182	623	801	635
Net amount recognized	<u>\$ 2,262</u>	<u>\$ 706</u>	<u>\$ (111)</u>	<u>\$ (406)</u>
Assumptions Used to Determine				
Benefit Obligations As of December 31				
Discount rate	7.00%	6.50%	7.00%	6.50%
Rate of compensation increase	5.20%	5.20%		
Allocation of Plan Assets				
As of December 31				
Asset Category				
Equity securities	47%	61%	56%	69%
Debt securities	38	30	38	27
Real estate	9	7	2	2
Private equities	3	1	1	-
Cash	3	1	3	2
Total	<u>100%</u>	<u>100%</u>	<u>100%</u>	<u>100%</u>

Estimated Items to be Amortized in 2009

Net Periodic Pension Cost from Accumulated Other Comprehensive Income	Pension Benefits	Other Benefits
	<i>(In millions)</i>	
Prior service cost (credit)	\$ 13	\$ (151)
Actuarial loss	\$ 170	\$ 63

Components of Net Periodic Benefit Costs	Pension Benefits			Other Benefits		
	2008	2007	2006	2008	2007	2006
	<i>(In millions)</i>					
Service cost	\$ 87	\$ 88	\$ 87	\$ 19	\$ 21	\$ 34
Interest cost	299	294	276	74	69	105
Expected return on plan assets	(463)	(449)	(396)	(51)	(50)	(46)
Amortization of prior service cost	13	13	13	(149)	(149)	(76)
Recognized net actuarial loss	8	45	62	47	45	56
Net periodic cost	<u>\$ (56)</u>	<u>\$ (9)</u>	<u>\$ 42</u>	<u>\$ (60)</u>	<u>\$ (64)</u>	<u>\$ 73</u>

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31

	Pension Benefits			Other Benefits		
	2008	2007	2006	2008	2007	2006
Discount rate	6.50%	6.00%	5.75%	6.50%	6.00%	5.75%
Expected long-term return on plan assets	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase	5.20%	3.50%	3.50%			

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. The assumed rates of return on pension plan assets consider historical market returns and economic forecasts for the types of investments held by FirstEnergy's pension trusts. The long-term rate of return is developed considering the portfolio's asset allocation strategy.

FirstEnergy generally employs a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return on plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, and small and large capitalization funds. Other assets such as real estate and private equity are used to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives are not used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on a continuing basis through periodic investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

Assumed Health Care Cost Trend Rates As of December 31

	2008	2007
Health care cost trend rate assumed for next year (pre/post-Medicare)	8.5-10%	9-11%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5%	5%
Year that the rate reaches the ultimate trend rate (pre/post-Medicare)	2015-2017	2015-2017

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	<i>(In millions)</i>	
Effect on total of service and interest cost	\$ 4	\$ (3)
Effect on accumulated postretirement benefit obligation	\$ 36	\$ (32)

Taking into account estimated employee future service, FirstEnergy expects to make the following pension benefit payments from plan assets and other benefit payments, net of the Medicare subsidy and participant contributions:

	Pension Benefits	Other Benefits
	<i>(In millions)</i>	
2009	\$ 302	\$ 85
2010	309	89
2011	314	94
2012	325	96
2013	338	99
Years 2014- 2018	1,906	524

4. STOCK-BASED COMPENSATION PLANS

FirstEnergy has four stock-based compensation programs: LTIP; EDCP; ESOP; and DCPD. In 2001, FirstEnergy also assumed responsibility for two stock-based plans as a result of its acquisition of GPU. No further stock-based compensation can be awarded under GPU's Stock Option and Restricted Stock Plan for MYR Group Inc. Employees (MYR Plan) or 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries (GPU Plan). All options and restricted stock under both plans have been converted into FirstEnergy options and restricted stock. Options under the GPU Plan became fully vested on November 7, 2001, and will expire on or before June 1, 2010.

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 year ended December 31, 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.

(A) LTIP

FirstEnergy's LTIP includes four stock-based compensation programs – restricted stock, restricted stock units, stock options, and performance shares. During 2005, FirstEnergy began issuing restricted stock units and reduced its use of stock options.

Under FirstEnergy's LTIP, total awards cannot exceed 29.1 million shares of common stock or their equivalent. Only stock options, restricted stock and restricted stock units have currently been designated to pay out in common stock, with vesting periods ranging from two months to ten years. Performance share awards are currently designated to be paid in cash rather than common stock and therefore do not count against the limit on stock-based awards. As of December 31, 2008, 8.7 million shares were available for future awards.

FirstEnergy records the actual tax benefit realized for tax deductions when awards are exercised or distributed. Realized tax benefits during the years ended December 31, 2008, 2007, and 2006 were \$43 million, \$34 million, and \$31 million, respectively. The excess of the deductible amount over the recognized compensation cost is recorded to stockholder's equity and reported as an other financing activity within the Consolidated Statements of Cash Flows.

Restricted Stock and Restricted Stock Units

Eligible employees receive awards of FirstEnergy common stock or stock units subject to restrictions. Those restrictions lapse over a defined period of time or based on performance. Dividends are received on the restricted stock and are reinvested in additional shares. Restricted common stock grants under the LTIP were as follows:

	2008	2007	2006
Restricted common shares granted	82,607	77,388	229,271
Weighted average market price	\$ 68.98	\$ 67.98	\$ 53.18
Weighted average vesting period (years)	5.03	4.61	4.47
Dividends restricted	Yes	Yes	Yes

Vesting activity for restricted common stock during the year was as follows:

Restricted Stock	Number Of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2008	639,657	\$ 48.69
Nonvested as of December 31, 2008	667,933	49.54
Vested in 2008	54,331	69.07

FirstEnergy grants two types of restricted stock unit awards -- discretionary-based and performance-based. With the discretionary-based, FirstEnergy grants the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of restricted stock units set forth in each agreement. With performance-based, FirstEnergy grants the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of restricted stock units set forth in the agreement subject to adjustment based on FirstEnergy's stock performance.

	<u>2008</u>	<u>2007</u>	<u>2006</u>
Restricted common share units granted	450,683	412,426	440,676
Weighted average vesting period (years)	3.14	3.22	3.32

Vesting activity for restricted stock units during the year was as follows:

Restricted Stock Units	Number Of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2008	1,208,780	\$ 51.09
Nonvested as of December 31, 2008	1,278,536	55.14
Granted during 2008	450,683	67.09
Vested in 2008	492,229	68.58

Compensation expense recognized in 2008, 2007 and 2006 for restricted stock and restricted stock units, net of amounts capitalized, was approximately \$29 million, \$24 million and \$15 million, respectively.

Stock Options

Stock options were granted to eligible employees allowing them to purchase a specified number of common shares at a fixed grant price over a defined period of time. Stock option activities under FirstEnergy stock option programs for the past three years were as follows:

Stock Option Activities	Number of Options	Weighted Average Exercise Price
Balance, January 1, 2006	8,866,256	\$ 33.57
(4,090,829 options exercisable)		31.97
Options granted	-	-
Options exercised	2,221,417	32.65
Options forfeited	26,550	33.36
Balance, December 31, 2006	6,618,289	33.88
(4,160,859 options exercisable)		32.85
Options granted	-	-
Options exercised	1,902,780	32.51
Options forfeited	9,575	38.39
Balance, December 31, 2007	4,705,934	34.42
(3,915,694 options exercisable)		33.55
Options granted	-	-
Options exercised	1,438,201	34.10
Options forfeited	1,325	38.76
Balance, December 31, 2008	3,266,408	34.56
(3,266,408 options exercisable)		34.56

Options outstanding by plan and range of exercise price as of December 31, 2008 were as follows:

Program	Options Outstanding and Exercisable			
	Range of Exercise Prices	Shares	Weighted Average Exercise Price	Remaining Contractual Life
FE Plan	\$ 19.31 - \$29.87	1,153,849	\$ 29.10	3.31
	\$ 30.17 - \$39.46	2,094,624	\$ 37.65	4.68
GPU Plan	\$ 23.75 - \$35.92	17,935	\$ 24.51	1.35
Total		<u>3,266,408</u>	\$ 34.56	4.18

As noted above, FirstEnergy reduced its use of stock options beginning in 2005 and increased its use of performance-based, restricted stock units. FirstEnergy did not accelerate out-of-the-money options in anticipation of adopting SFAS 123(R) on January 1, 2006. As a result, all unvested stock options vested in 2008. Compensation expense recognized for stock options during 2008 was not material. Cash received from the exercise of stock options in 2008, 2007 and 2006 was \$74 million, \$88 million and \$92 million, respectively.

Performance Shares

Performance shares are share equivalents and do not have voting rights. The shares track the performance of FirstEnergy's common stock over a three-year vesting period. During that time, dividend equivalents are converted into additional shares. The final account value may be adjusted based on the ranking of FirstEnergy stock performance to a composite of peer companies. Compensation expense recognized for performance shares during 2008, 2007 and 2006, net of amounts capitalized, totaled approximately \$8 million, \$20 million and \$25 million, respectively. Cash used to settle performance shares in 2008, 2007 and 2006 was \$14 million, \$10 million and \$7 million, respectively.

(B) ESOP

An ESOP Trust funded most of the matching contribution for FirstEnergy's 401(k) savings plan through December 31, 2007. All employees eligible for participation in the 401(k) savings plan are covered by the ESOP. Between 1990 and 1991, the ESOP borrowed \$200 million from OE and acquired 10,654,114 shares of OE's common stock (subsequently converted to FirstEnergy common stock) through market purchases. The ESOP loan was paid in full in 2008. Dividends on ESOP shares were used to service the debt. Dividends on common stock held by the ESOP and used to service debt were \$11 million as of December 31, 2007 and 2006. Shares were released from the ESOP on a pro-rata basis as debt service payments were made.

In 2007 and 2006, 521,818 shares and 922,978 shares, respectively, were allocated to employees with the corresponding expense recognized based on the shares allocated method. All shares had been allocated as of December 31, 2007. In 2008, shares of FirstEnergy common stock were purchased on the market and contributed to participants' accounts. Total ESOP-related compensation expense in 2008, 2007 and 2006, net of amounts capitalized and dividends on common stock, was \$40 million, \$28 million and \$27 million, respectively.

(C) EDCP

Under the EDCP, covered employees can direct a portion of their compensation, including annual incentive awards and/or long-term incentive awards, into an unfunded FirstEnergy stock account to receive vested stock units or into an unfunded retirement cash account. An additional 20% premium is received in the form of stock units based on the amount allocated to the FirstEnergy stock account. Dividends are calculated quarterly on stock units outstanding and are paid in the form of additional stock units. Upon withdrawal, stock units are converted to FirstEnergy shares. Payout typically occurs three years from the date of deferral; however, an election can be made in the year prior to payout to further defer shares into a retirement stock account that will pay out in cash upon retirement (see Note 3). Interest is calculated on the cash allocated to the cash account and the total balance will pay out in cash upon retirement. Of the 1.3 million EDCP stock units authorized, 504,909 stock units were available for future awards as of December 31, 2008. Compensation expense (income) recognized on EDCP stock units, net of amounts capitalized, was approximately (\$13) million in 2008, \$7 million in 2007 and \$5 million in 2006, respectively.

(D) DCPD

Under the DCPD, directors can elect to allocate all or a portion of their cash retainers, meeting fees and chair fees to deferred stock or deferred cash accounts. If the funds are deferred into the stock account, a 20% match is added to the funds allocated. The 20% match and any appreciation on it are forfeited if the director leaves the Board within three years from the date of deferral for any reason other than retirement, disability, death, upon a change in control, or when a director is ineligible to stand for re-election. Compensation expense is recognized for the 20% match over the three-year vesting period. Directors may also elect to defer their equity retainers into the deferred stock account; however, they do not receive a 20% match on that deferral. DCPD expenses recognized in each of 2008, 2007 and 2006 were approximately \$3 million. The net liability recognized for DCPD of approximately \$5 million as of December 31, 2008 and 2007 is included in the caption "Retirement benefits" on the Consolidated Balance Sheets.

5. FAIR VALUE OF FINANCIAL INSTRUMENTS

(A) LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

All borrowings with initial maturities of less than one year are defined as short-term financial instruments under GAAP and are reported on the Consolidated Balance Sheets at cost, which approximates their fair market value, in the caption "short-term borrowings." The following table provides the approximate fair value and related carrying amounts of long-term debt and other long-term obligations as shown in the table in Note 11(C) as of December 31:

	2008		2007	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	<i>(In millions)</i>			
Long-term debt	\$ 11,585	\$ 11,146	\$ 10,891	\$ 11,131

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective year. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to the FirstEnergy subsidiaries' ratings.

(B) INVESTMENTS

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. Investments other than cash and cash equivalents include held-to-maturity securities and available-for-sale securities. The Utilities and NGC periodically evaluate their investments for other-than-temporary impairment. They first consider their intent and ability to hold the investment until recovery and then consider, among other factors, the duration and the extent to which the security's fair value has been less than cost and the near-term financial prospects of the security issuer when evaluating investments for impairment.

Available-For-Sale Securities

The Utilities and NGC hold debt and equity securities within their nuclear decommissioning trusts, nuclear fuel disposal trusts and NUG trusts. These trust investments are classified as available-for-sale with the fair value representing quoted market prices. FirstEnergy has no securities held for trading purposes.

The following table provides the fair value of investments in available-for-sale securities as of December 31, 2008 and 2007. The fair value was determined using the specific identification method.

	2008	2007
	<i>(In millions)</i>	
Debt securities:		
– Government obligations ⁽¹⁾	\$ 953	\$ 851
– Corporate debt securities	175	191
– Mortgage-backed securities	6	17
	1,134	1,059
Equity securities	628	1,355
	\$ 1,762	\$ 2,414

(1) Excludes \$244 million and \$3 million of cash in 2008 and 2007, respectively.

The following table summarizes the amortized cost basis, unrealized gains and losses and fair values of investments in available-for-sale securities as of December 31:

	2008				2007			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	<i>(In millions)</i>							
Debt securities	\$ 1,082	\$ 56	\$ 4	\$ 1,134	\$ 1,036	\$ 27	\$ 4	\$ 1,059
Equity securities	589	39	-	628	995	360	-	1,355
	\$ 1,671	\$ 95	\$ 4	\$ 1,762	\$ 2,031	\$ 387	\$ 4	\$ 2,414

Proceeds from the sale of investments in available-for-sale securities, realized gains and losses on those sales, and interest and dividend income for the three years ended December 31, 2008 were as follows:

	2008	2007	2006
	<i>(In millions)</i>		
Proceeds from sales	\$ 1,656	\$ 1,294	\$ 1,651
Realized gains	115	103	121
Realized losses	237	53	105
Interest and dividend income	76	80	70

Unrealized gains applicable to OE's, TE's and the majority of NGC's decommissioning trusts are recognized in OCI in accordance with SFAS 115, as fluctuations in fair value will eventually impact earnings. The decommissioning trusts of JCP&L, Met-Ed and Penelec are subject to regulatory accounting in accordance with SFAS 71. Net unrealized gains and losses are recorded as regulatory assets or liabilities since the difference between investments held in trust and the decommissioning liabilities will be recovered from or refunded to customers.

The investment policy for the nuclear decommissioning trust funds restricts or limits the ability to hold certain types of assets including private or direct placements, warrants, securities of FirstEnergy, investments in companies owning nuclear power plants, financial derivatives, preferred stocks, securities convertible into common stock and securities of the trust fund's custodian or managers and their parents or subsidiaries.

Held-To-Maturity Securities

The following table provides the approximate fair value and related carrying amounts of investments in held-to-maturity securities (except for investments of \$265 million and \$314 million for 2008 and 2007, respectively, which are excluded by SFAS 107, "Disclosures about Fair Values of Financial Instruments") as of December 31:

	2008		2007	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	<i>(In millions)</i>			
Lease obligations bonds	\$ 598	\$ 599	\$ 717	\$ 814
Debt securities	75	75	73	73
Notes receivable	45	44	45	43
Restricted funds	1	1	3	3
Equity securities	27	27	29	29
	<u>\$ 746</u>	<u>\$ 746</u>	<u>\$ 867</u>	<u>\$ 962</u>

The fair value of investments in lease obligation bonds is based on the present value of the cash inflows based on the yield to maturity. The maturity dates range from 2009 to 2017. The carrying value of the restricted funds is assumed to approximate market value. The fair value of notes receivable represents the present value of the cash inflows based on the yield to maturity. The yields assumed were based on financial instruments with similar characteristics and terms. The maturity dates range from 2009 to 2016.

The following table provides the amortized cost basis, unrealized gains and losses, and fair values of investments in held-to-maturity securities excluding the restricted funds and notes receivable as of December 31:

	2008				2007			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	<i>(In millions)</i>							
Debt securities	\$ 673	\$ 14	\$ 13	\$ 674	\$ 790	\$ 97	\$ -	\$ 887
Equity securities	27	-	-	27	29	-	-	29
	<u>\$ 700</u>	<u>\$ 14</u>	<u>\$ 13</u>	<u>\$ 701</u>	<u>\$ 819</u>	<u>\$ 97</u>	<u>\$ -</u>	<u>\$ 916</u>

(C) SFAS 157 ADOPTION

Effective January 1, 2008, FirstEnergy adopted SFAS 157, which provides a framework for measuring fair value under GAAP and, among other things, requires enhanced disclosures about assets and liabilities recognized at fair value. FirstEnergy also adopted SFAS 159 on January 1, 2008, which provides the option to measure certain financial assets and financial liabilities at fair value. FirstEnergy has analyzed its financial assets and financial liabilities within the scope of SFAS 159 and, as of December 31, 2008, has elected not to record eligible assets and liabilities at fair value.

As defined in SFAS 157, fair value is the price that would be received for an asset or paid to transfer a liability (exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between willing market participants on the measurement date. SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy defined by SFAS 157 are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those where transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. FirstEnergy's Level 1 assets and liabilities primarily consist of exchange-traded derivatives and equity securities listed on active exchanges that are held in various trusts.

Level 2 – Pricing inputs are either directly or indirectly observable in the market as of the reporting date, other than quoted prices in active markets included in Level 1. FirstEnergy's Level 2 assets and liabilities consist primarily of investments in debt securities held in various trusts and commodity forwards. Additionally, Level 2 includes those financial instruments that are valued using models or other valuation methodologies based on assumptions that are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Instruments in this category include non-exchange-traded derivatives such as forwards and certain interest rate swaps.

Level 3 – Pricing inputs include inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. FirstEnergy develops its view of the future market price of key commodities through a combination of market observation and assessment (generally for the short term) and fundamental modeling (generally for the longer term). Key fundamental electricity model inputs are generally directly observable in the market or derived from publicly available historic and forecast data. Some key inputs reflect forecasts published by industry leading consultants who generally employ similar fundamental modeling approaches. Fundamental model inputs and results, as well as the selection of consultants, reflect the consensus of appropriate FirstEnergy management. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. FirstEnergy's Level 3 instruments consist of NUG contracts.

FirstEnergy utilizes market data and assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. FirstEnergy primarily applies the market approach for recurring fair value measurements using the best information available. Accordingly, FirstEnergy maximizes the use of observable inputs and minimizes the use of unobservable inputs.

The following table sets forth FirstEnergy's financial assets and financial liabilities that are accounted for at fair value by level within the fair value hierarchy as of December 31, 2008. As required by SFAS 157, assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. FirstEnergy's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Recurring Fair Value Measures	December 31, 2008			
	Level 1	Level 2	Level 3	Total
	<i>(In millions)</i>			
Assets:				
Derivatives	\$ -	\$ 40	\$ -	\$ 40
Nuclear decommissioning trusts ⁽¹⁾	537	1,166	-	1,703
NUG contracts ⁽²⁾	-	-	434	434
Other investments	19	381	-	400
Total	\$ 556	\$ 1,587	\$ 434	\$ 2,577
Liabilities:				
Derivatives	\$ 25	\$ 31	\$ -	\$ 56
NUG contracts ⁽²⁾	-	-	766	766
Total	\$ 25	\$ 31	\$ 766	\$ 822

(1) Balance excludes \$5 million of net receivables, payables and accrued income.

(2) NUG contracts are completely offset by regulatory assets.

The determination of the above fair value measures takes into consideration various factors required under SFAS 157. These factors include nonperformance risk, including counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of nonperformance risk was immaterial in the fair value measurements.

Exchange-traded derivative contracts, which include some futures and options, are generally based on unadjusted quoted market prices in active markets and are classified within Level 1. Forwards, options and swap contracts that are not exchange-traded are classified as Level 2 as the fair values of these items are based on Intercontinental Exchange quotes or market transactions in the OTC markets. In addition, complex or longer-term structured transactions can introduce the need for internally-developed model inputs that may not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is classified as Level 3.

Nuclear decommissioning trusts consist of equity securities listed on active exchanges classified as Level 1 and various debt securities and collective trusts classified as Level 2. Other investments represent the NUG trusts, spent nuclear fuel trusts and rabbi trust investments, which primarily consist of various debt securities and collective trusts classified as Level 2.

The following tables provide a reconciliation of changes in the fair value of NUG contracts classified as Level 3 in the fair value hierarchy during 2008 (in millions):

Balance as of January 1, 2008	\$	(803)
Settlements ⁽¹⁾		278
Unrealized gains (losses) ⁽¹⁾		193
Net transfers to (from) Level 3		-
Balance as of December 31, 2008	<u>\$</u>	<u>(332)</u>
Change in unrealized gains (losses) relating to		
instruments held as of December 31, 2008	<u>\$</u>	<u>193</u>

⁽¹⁾ Changes in the fair value of NUG contracts are completely offset by regulatory assets and do not impact earnings.

Under FSP FAS 157-2, "Effective Date of FASB Statement No. 157", FirstEnergy deferred until January 1, 2009, the election of SFAS 157 for financial assets and financial liabilities measured at fair value on a non-recurring basis and is currently evaluating the impact of SFAS 157 on those financial assets and financial liabilities.

(D) DERIVATIVES

FirstEnergy is exposed to financial risks resulting from the fluctuation of interest rates, foreign currencies 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 derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes. In addition to derivatives, FirstEnergy also enters into master netting agreements with certain third parties. FirstEnergy's Risk Policy Committee, comprised of members of senior management, provides general management oversight for risk management activities throughout FirstEnergy. 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.

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheet at their fair value unless they meet the normal purchase and normal sales criteria. Derivatives that meet that criteria are accounted for using traditional accrual accounting. The changes in the fair value of derivative instruments that do not meet the normal purchase and normal sales criteria are recorded as other expense, as 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, capital assets denominated in foreign currencies and anticipated interest payments associated with future debt issues. Other than interest-related hedges, FirstEnergy's maximum hedge term is typically two years. The effective portions of all cash flow 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 \$103 million included in AOCL as of December 31, 2008, for derivative hedging activity, as compared to \$75 million as of December 31, 2007, resulted from a net \$40 million increase related to current hedging activity and a \$12 million decrease due to net hedge losses reclassified to earnings during 2008. Based on current estimates, approximately \$28 million (after tax) of the net deferred losses on derivative instruments in AOCL as of December 31, 2008 are 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. In order to reduce counterparty exposure and lessen variable debt exposure under current market conditions, FirstEnergy unwound its remaining interest rate swaps. During 2008, FirstEnergy received \$3 million to terminate interest rate swaps with an aggregate notional value of \$250 million. As of December 31, 2008, FirstEnergy had no outstanding interest rate swaps hedging fixed-rate long term debt.

During 2008, 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 as outstanding debt matures during 2008 and 2009. 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 2008, FirstEnergy entered into swaps with a notional value of \$1.3 billion and terminated swaps with a notional value of \$1.4 billion for which it paid \$49 million, \$7 million of which was deemed ineffective and recognized in current period earnings. FirstEnergy will recognize the remaining \$42 million loss over the life of the associated future debt. As of December 31, 2008, FirstEnergy had forward swaps with an aggregate notional amount of \$300 million and a fair value of \$(3) million.

6. LEASES

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

In 1987, OE sold portions of its ownership interests in Perry Unit 1 and Beaver Valley Unit 2 and entered into operating leases on the portions sold for basic lease terms of approximately 29 years. In that same year, CEI and TE also sold portions of their ownership interests in Beaver Valley Unit 2 and Bruce Mansfield Units 1, 2 and 3 and entered into similar operating leases for lease terms of approximately 30 years. During the terms of their respective leases, OE, CEI and TE are responsible, to the extent of their leasehold interests, for costs associated with the units including construction expenditures, operation and maintenance expenses, insurance, nuclear fuel, property taxes and decommissioning. They have the right, at the expiration of the respective basic lease terms, to renew their respective leases. They also have the right to purchase the facilities at the expiration of the basic lease term or any renewal term at a price equal to the fair market value of the facilities. The basic rental payments are adjusted when applicable federal tax law changes.

On July 13, 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1, representing 779 MW of net demonstrated capacity. The purchase price of approximately \$1.329 billion (net after-tax proceeds of approximately \$1.2 billion) for the undivided interest was funded through a combination of equity investments by affiliates of AIG Financial Products Corp. and Union Bank of California, N.A. in six lessor trusts and proceeds from the sale of \$1.135 billion aggregate principal amount of 6.85% pass through certificates due 2034. A like principal amount of secured notes maturing June 1, 2034 were issued by the lessor trusts to the pass through trust that issued and sold the certificates. The lessor trusts leased the undivided interest back to FGCO for a term of approximately 33 years under substantially identical leases. FES has unconditionally and irrevocably guaranteed all of FGCO's obligations under each of the leases. This transaction, which is classified as an operating lease under GAAP for FES and FirstEnergy, generated tax capital gains of approximately \$815 million, all of which were offset by existing tax capital loss carryforwards. Accordingly, FirstEnergy reduced its tax loss carryforward valuation allowances in the third quarter of 2007, with a corresponding reduction to goodwill (see Note 2(E)).

Effective October 16, 2007 CEI and TE assigned their leasehold interests in the Bruce Mansfield Plant to FGCO and FGCO assumed all of CEI's and TE's obligations arising under those leases. FGCO subsequently transferred the Unit 1 portion of these leasehold interests, as well as FGCO's leasehold interests under its July 13, 2007 Bruce Mansfield Unit 1 sale and leaseback transaction, to a newly formed wholly-owned subsidiary on December 17, 2007. The subsidiary assumed all of the lessee obligations associated with the assigned interests. However, CEI and TE remain primarily liable on the 1987 leases and related agreements. FGCO remains primarily liable on the 2007 leases and related agreements, and FES remains primarily liable as a guarantor under the related 2007 guarantees, as to the lessors and other parties to the respective agreements. These assignments terminate automatically upon the termination of the underlying leases.

During the second quarter of 2008, NGC purchased 56.8 MW of lessor equity interests in the OE 1987 sale and leaseback of the Perry Plant and approximately 43.5 MW of lessor equity interests in the OE 1987 sale and leaseback of Beaver Valley Unit 2. In addition, NGC purchased 158.5 MW of lessor equity interests in the TE and CEI 1987 sale and leaseback of Beaver Valley Unit 2. The Ohio Companies continue to lease these MW under their respective sale and leaseback arrangements and the related lease debt remains outstanding.

Rentals for capital and operating leases for the three years ended December 31, 2008 are summarized as follows:

	<u>2008</u>	<u>2007</u>	<u>2006</u>
	<i>(In millions)</i>		
Operating leases			
Interest element	\$ 194	\$ 180	\$ 160
Other	187	196	190
Capital leases			
Interest element	1	-	1
Other ⁽¹⁾	6	1	2
Total rentals	<u>\$ 388</u>	<u>\$ 377</u>	<u>\$ 353</u>

⁽¹⁾ Includes \$5 million in 2008 of wind purchased power agreements classified as capital leases in accordance with EITF 01-8.

Established by OE in 1996, PNBV purchased a portion of the lease obligation bonds issued on behalf of lessors in OE's Perry Unit 1 and Beaver Valley Unit 2 sale and leaseback transactions. Similarly, CEI and TE established Shippingport in 1997 to purchase the lease obligation bonds issued on behalf of lessors in their Bruce Mansfield Units 1, 2 and 3 sale and leaseback transactions. The PNBV and Shippingport arrangements effectively reduce lease costs related to those transactions (see Note 7).

The future minimum lease payments as of December 31, 2008 are:

	Operating Leases		
	Lease Payments	Capital Trusts	Net
2009	\$ 310	\$ 107	\$ 203
2010	293	116	177
2011	288	116	172
2012	331	125	206
2013	337	130	207
Years thereafter	2,746	254	2,492
Total minimum lease payments	<u>\$ 4,305</u>	<u>\$ 848</u>	<u>\$ 3,457</u>

The present value of net minimum capital lease payments for FirstEnergy as of December 31, 2008, is \$8 million, of which \$1 million is classified as a current liability.

FirstEnergy has been notified by the lessor of certain vehicle and equipment leases of its election to terminate the lease arrangements effective November 2009. FirstEnergy is currently pursuing replacement lease arrangements with alternative lessors. In the event that replacement lease arrangements are not secured, FirstEnergy would be required to purchase the vehicles and equipment under lease at their unamortized value of approximately \$100 million upon termination of the lease.

FirstEnergy has recorded above-market lease liabilities for the Bruce Mansfield Plant associated with the 1997 merger between OE and Centerior. The total above-market lease obligation of \$755 million associated with the Bruce Mansfield Plant is being amortized on a straight-line basis through the end of 2016 (approximately \$46 million per year). As of December 31, 2008, the above-market lease liabilities for the Bruce Mansfield Plant totaled \$353 million, of which \$46 million is classified in the caption "other current liabilities."

7. 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.

Mining Operations

On July 16, 2008, FEV entered into a joint venture with the Boich Companies, a Columbus, Ohio-based coal company, to acquire a majority stake in the Signal Peak mining and coal transportation operations near Roundup, Montana. FirstEnergy made a \$125 million equity investment in the joint venture, which acquired 80% of the mining operations (Signal Peak Energy, LLC) and 100% of the transportation operations, with FEV owning a 45% economic interest and an affiliate of the Boich Companies owning a 55% economic interest in the joint venture. Both parties have a 50% voting interest in the joint venture. After January 2010, the joint venture will have 18 months to exercise an option to acquire the remaining 20% stake in the mining operations. In accordance with FIN 46R, FirstEnergy consolidated the mining and transportation operations of this joint venture in its financial statements.

Trusts

FirstEnergy's consolidated financial statements include those of PNBV and Shippingport. VIEs created in 1996 and 1997, respectively, to refinance debt originally issued in connection with sale and leaseback transactions described above. 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.

Loss Contingencies

FES and the Ohio Companies are exposed to losses under their applicable sale-leaseback agreements upon the occurrence of certain contingent events that each company considers unlikely to occur. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events that render the applicable plant worthless. Net discounted lease payments would not be payable if the casualty loss payments are made. The following table shows each company's net exposure to loss based upon the casualty value provisions mentioned above:

	<u>Maximum Exposure</u>	<u>Discounted Lease Payments, net</u> ⁽¹⁾	<u>Net Exposure</u>
		<i>(in millions)</i>	
FES	\$ 1,349	\$ 1,182	\$ 167
OE	778	574	204
CEI	713	81	632
TE	713	419	294

⁽¹⁾ The net present value of FirstEnergy's consolidated sale and leaseback operating lease commitments was \$1.7 billion as of December 31, 2008 (see NGC lessor equity interest purchases described in Note 6).

See Note 6 for a discussion of CEI's and TE's assignment of their leasehold interests in the Bruce Mansfield Plant to FGCO.

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 FirstEnergy's utility subsidiaries 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. Purchased power costs from these entities during 2008, 2007, and 2006 were \$178 million, \$177 million, and \$171 million, respectively.

8. DIVESTITURES AND DISCONTINUED OPERATIONS

On March 7, 2008, FirstEnergy sold certain telecommunication assets, resulting in a net after-tax gain of \$19.3 million. The sale of assets did not meet the criteria for classification as discontinued operations as of December 31, 2008.

In 2006, FirstEnergy sold certain of its remaining FSG subsidiaries for an aggregate net after-tax gain of \$2.2 million. In addition, FirstEnergy sold 60% of its interest in MYR for an after-tax gain of \$0.2 million in March 2006. As a result of the March sale, FirstEnergy deconsolidated MYR in the first quarter of 2006 and accounted for its remaining interest under the equity method of accounting for investments. In the fourth quarter of 2006, FirstEnergy sold its remaining MYR interest for an after-tax gain of \$8.6 million. The income for the period that MYR was accounted for as an equity method investment has not been included in discontinued operations; however, results for all reporting periods prior to the initial sale in March 2006, including the gain on the sale, were reported as discontinued operations.

Revenues associated with discontinued operations were \$225 million in 2006. The following table summarizes the net income operating results of discontinued operations for 2006:

	<u>2006</u>
	<i>(In millions)</i>
Loss before income taxes	\$ (8)
Income tax benefit	2
Gain on sale, net of tax	<u>2</u>
Loss from discontinued operations	<u>\$ (4)</u>

9. TAXES

Income Taxes

FirstEnergy records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and loss carryforwards and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to temporary tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled. Details of income taxes for the three years ended December 31, 2008 are shown below:

<u>For the Years Ended December 31,</u>	<u>2008</u>	<u>2007</u>	<u>2006</u>
	<i>(In millions)</i>		
PROVISION FOR INCOME TAXES:			
Currently payable-			
Federal	\$ 355	\$ 706	\$ 519
State	56	187	116
	<u>411</u>	<u>893</u>	<u>635</u>
Deferred, net-			
Federal	343	22	147
State	36	(18)	28
	<u>379</u>	<u>4</u>	<u>175</u>
Investment tax credit amortization	(13)	(14)	(15)
Total provision for income taxes	<u>\$ 777</u>	<u>\$ 883</u>	<u>\$ 795</u>

RECONCILIATION OF FEDERAL INCOME TAX EXPENSE AT STATUTORY RATE TO TOTAL PROVISION FOR INCOME TAXES:

Book income before provision for income taxes	\$ 2,119	\$ 2,192	\$ 2,053
Federal income tax expense at statutory rate	\$ 742	\$ 767	\$ 719
Increases (reductions) in taxes resulting from-			
Amortization of investment tax credits	(13)	(14)	(15)
State income taxes, net of federal income tax benefit	60	110	94
Other, net	(12)	20	(3)
Total provision for income taxes	<u>\$ 777</u>	<u>\$ 883</u>	<u>\$ 795</u>

Accumulated deferred income taxes as of December 31, 2008 and 2007 are as follows:

<u>As of December 31,</u>	<u>2008</u>	<u>2007</u>
	<i>(In millions)</i>	
Property basis differences	\$ 2,757	\$ 2,564
Regulatory transition charge	292	468
Pension and other postretirement obligations	(715)	(110)
Nuclear decommissioning activities	(130)	(13)
Customer receivables for future income taxes	145	149
Deferred customer shopping incentive	151	190
Deferred MISO/PJM transmission costs	167	151
Other regulatory assets - RCP	253	193
Unrealized losses on derivative hedges	(68)	(52)
Deferred sale and leaseback gain	(505)	(536)
Nonutility generation costs	(52)	(90)
Unamortized investment tax credits	(51)	(57)
Lease market valuation liability	(254)	(283)
Oyster Creek securitization (Note 11(C))	137	149
Loss carryforwards	(35)	(44)
Loss carryforward valuation reserve	27	31
All other	44	(39)
Net deferred income tax liability	<u>\$ 2,163</u>	<u>\$ 2,671</u>

On January 1, 2007, FirstEnergy adopted FIN 48, which provides guidance for accounting for uncertainty in income taxes in a company's financial statements in accordance with SFAS 109. This interpretation prescribes a financial statement recognition threshold and measurement attribute for tax positions taken or expected to be taken on a company's tax return. FIN 48 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 is a two-step process. The first step is to determine if it is more likely than not that a tax position will be sustained upon examination, based on the merits of the position, and should therefore be recognized. The second step is to measure a tax position that meets the more likely than not recognition threshold to determine the amount of income tax benefit to recognize in the financial statements.

As of January 1, 2007, the total amount of FirstEnergy's unrecognized tax benefits was \$268 million. FirstEnergy recorded a \$2.7 million cumulative effect adjustment to the January 1, 2007 balance of retained earnings to increase reserves for uncertain tax positions. Upon completion of the federal tax examinations for tax years 2004-2006, as well as other tax settlements reached in 2008, FirstEnergy recognized approximately \$42 million of net tax benefits, including \$7 million that favorably affected FirstEnergy's effective tax rate. The remaining balance of the tax benefits recognized in 2008 adjusted goodwill as a purchase price adjustment (\$20 million) and accumulated deferred income taxes for temporary tax items (\$15 million). During 2007, there were no material changes to FirstEnergy's unrecognized tax benefits. As of December 31, 2008, FirstEnergy expects that it is reasonably possible that approximately \$151 million of the unrecognized benefits may be resolved within the next twelve months, of which approximately \$147 million, if recognized, would affect FirstEnergy's effective tax rate. The potential decrease in the amount of unrecognized tax benefits is primarily associated with issues related to the capitalization of certain costs, capital gains and losses recognized on the disposition of assets and various other tax items.

A reconciliation of the change in the unrecognized tax benefits for the years 2008 and 2007 are as follows:

	<u>2008</u>	<u>2007</u>
	<i>(In millions)</i>	
Balance at beginning of year	\$ 272	\$ 268
Increase for tax positions related to the current year	14	1
Increase for tax positions related to prior years	-	3
Decrease for tax positions related to prior years	(56)	-
Decrease for settlements	(11)	-
Balance at end of year	<u>\$ 219</u>	<u>\$ 272</u>

FIN 48 also requires companies to recognize interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized in accordance with FIN 48 and the amount previously taken or expected to be taken on the tax return. FirstEnergy includes net interest and penalties in the provision for income taxes, consistent with its policy prior to implementing FIN 48. The reversal of accrued interest associated with the \$56 million in recognized tax benefits favorably affected FirstEnergy's effective tax rate in 2008 by \$12 million and an interest receivable of \$4 million was removed from the accrued interest for FIN 48 items. During the years ended December 31, 2008, 2007 and 2006, FirstEnergy recognized net interest expense of approximately \$2 million, \$19 million and \$9 million, respectively. The net amount of interest accrued as of December 31, 2008 and 2007 was \$59 million and \$53 million, respectively.

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS and state tax authorities. All state jurisdictions are open from 2001-2008. The IRS began reviewing returns for the years 2001-2003 in July 2004 and several items are under appeal. The federal audits for years 2004-2006 were completed in the third quarter of 2008 and several items are under appeal. The IRS began auditing the year 2007 in February 2007 and the year 2008 in February 2008 under its Compliance Assurance Process program. Both audits are expected to close before December 2009. Management believes that adequate reserves have been recognized and final settlement of these audits is not expected to have a material adverse effect on FirstEnergy's financial condition or results of operations.

On July 13, 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1, representing 779 MW of net demonstrated capacity (see Note 6). This transaction generated tax capital gains of approximately \$815 million, all of which were offset by existing tax capital loss carryforwards. Accordingly, FirstEnergy reduced its tax loss carryforward valuation allowance in the third quarter of 2007, with a corresponding reduction to goodwill (see Note 2(E)).

FirstEnergy has pre-tax net operating loss carryforwards for state and local income tax purposes of approximately \$987 million of which \$140 million is expected to be utilized. The associated deferred tax assets are \$8 million. These losses expire as follows:

<u>Expiration Period</u>	<u>Amount</u>
	<i>(In millions)</i>
2009-2013	\$ 195
2014-2018	3
2019-2023	492
2024-2028	297
	<u>\$ 987</u>

General Taxes

Details of general taxes for the three years ended December 31, 2008 are shown below:

<u>For the Years Ended December 31,</u>	<u>2008</u>	<u>2007</u>	<u>2006</u>
	<i>(In millions)</i>		
Real and personal property	\$ 240	\$ 237	\$ 222
Kilowatt-hour excise	249	250	241
State gross receipts	183	175	159
Social security and unemployment	95	87	83
Other	11	5	15
Total general taxes	<u>\$ 778</u>	<u>\$ 754</u>	<u>\$ 720</u>

Commercial Activity Tax

On June 30, 2005, tax legislation was enacted in the State of Ohio that created a new CAT tax, which is based on qualifying "taxable gross receipts" and does not consider any expenses or costs incurred to generate such receipts, except for items such as cash discounts, returns and allowances, and bad debts. The CAT tax was effective July 1, 2005, and replaced the Ohio income-based franchise tax and the Ohio personal property tax. The CAT tax is phased-in while the current income-based franchise tax is phased-out over a five-year period at a rate of 20% annually, beginning with the year ended 2005, and the personal property tax is phased-out over a four-year period at a rate of approximately 25% annually, beginning with the year ended 2005. During the phase-out period the Ohio income-based franchise tax was computed consistent with the prior tax law, except that the tax liability as computed was multiplied by 80% in 2005; 60% in 2006; 40% in 2007 and 20% in 2008, therefore eliminating the current income-based franchise tax over a five-year period. As a result of the new tax structure, all net deferred tax benefits that were not expected to reverse during the five-year phase-in period were written-off as of June 30, 2005.

10. REGULATORY MATTERS

(A) 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 (the PUCO, the FERC, the NERC and the U.S. – Canada Power System Outage Task Force) regarding enhancements to regional reliability. The proposed enhancements were divided into two groups: enhancements that were to be completed in 2004; and enhancements that were to be completed after 2004. In 2004, FirstEnergy completed all of the enhancements that were recommended for completion in 2004. 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 that could require additional material expenditures.

In 2005, Congress amended the Federal Power Act to provide for federally-enforceable mandatory reliability standards. The mandatory reliability standards apply to the bulk power system and impose certain operating, record-keeping and reporting requirements on the Utilities and ATSI. The NERC is charged with establishing and enforcing these reliability standards, although it has delegated day-to-day implementation and enforcement of its responsibilities to eight regional entities, including Reliability *First* Corporation. All of FirstEnergy's facilities are located within the Reliability *First* region. FirstEnergy actively participates in the NERC and Reliability *First* stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, it is clear that the NERC, Reliability *First* and the FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. The financial impact of complying with new or amended standards cannot be determined at this time. However, the 2005 amendments to the Federal Power Act provide that all prudent costs incurred to comply with the new reliability standards be recovered in rates. Still, any future inability on FirstEnergy's part to comply with the reliability standards for its bulk power system could result in the imposition of financial penalties and thus have a material adverse effect on its financial condition, results of operations and cash flows.

In April 2007, Reliability *yFirst* performed a routine compliance audit of FirstEnergy's bulk-power system within the Midwest ISO region and found it to be in full compliance with all audited reliability standards. Similarly, in October 2008, Reliability *First* performed a routine compliance audit of FirstEnergy's bulk-power system within the PJM region and a final report is expected in early 2009. FirstEnergy currently does not expect any material adverse financial impact as a result of these audits.

(B) OHIO

On January 4, 2006, the PUCO issued an order authorizing the Ohio Companies to recover certain increased fuel costs through a fuel rider and to defer certain other increased fuel costs to be incurred from January 1, 2006 through December 31, 2008, including interest on the deferred balances. The order also provided for recovery of the deferred costs over a twenty-five-year period through distribution rates. On August 29, 2007, the Supreme Court of Ohio concluded that the PUCO violated a provision of the Ohio Revised Code by permitting the Ohio Companies "to collect deferred increased fuel costs through future distribution rate cases, or to alternatively use excess fuel-cost recovery to reduce deferred distribution-related expenses" and remanded the matter to the PUCO for further consideration. On September 10, 2007, the Ohio Companies filed an application with the PUCO that requested the implementation of two generation-related fuel cost riders to collect the increased fuel costs that were previously authorized to be deferred. On January 9, 2008, the PUCO approved the Ohio Companies' proposed fuel cost rider to recover increased fuel costs incurred during 2008, which was approximately \$185 million. In addition, the PUCO ordered the Ohio Companies to file a separate application for an alternate recovery mechanism to collect the 2006 and 2007 deferred fuel costs. On February 8, 2008, the Ohio Companies filed an application proposing to recover \$226 million of deferred fuel costs and carrying charges for 2006 and 2007 pursuant to a separate fuel rider. Recovery of the deferred fuel costs was also addressed in the Ohio Companies' comprehensive ESP filing, which was subsequently withdrawn on December 22, 2008, and also as a part of the stipulation and recommendation which was attached to the amended application for an ESP, both as described below.

On June 7, 2007, the Ohio Companies filed an application for an increase in electric distribution rates with the PUCO and, on August 6, 2007, updated their filing to support a distribution rate increase of \$332 million. On December 4, 2007, the PUCO Staff issued its Staff Reports containing the results of its investigation into the distribution rate request. In its reports, the PUCO Staff recommended a distribution rate increase in the range of \$161 million to \$180 million, with \$108 million to \$127 million for distribution revenue increases and \$53 million for recovery of costs deferred under prior cases. During the evidentiary hearings and filing of briefs, the PUCO Staff decreased their recommended revenue increase to a range of \$117 million to \$135 million. On January 21, 2009, the PUCO granted the Ohio Companies' application to increase electric distribution rates by \$136.6 million (OE - \$68.9 million, CEI - \$29.2 million and TE - \$38.5 million). These increases went into effect for OE and TE on January 23, 2009, and will go into effect for CEI on May 1, 2009. Applications for rehearing of this order were filed by the Ohio Companies and one other party on February 20, 2009.

On May 1, 2008, Governor Strickland signed SB221, which became effective on July 31, 2008. The bill requires all utilities to file an ESP with the PUCO, which must contain a proposal for the supply and pricing of retail generation. A utility may also file an MRO with the PUCO, in which it would have to prove the following objective market criteria: 1) the utility or its transmission service affiliate belongs to a FERC approved RTO, or there is comparable and nondiscriminatory access to the electric transmission grid; 2) the RTO has a market-monitor function and the ability to mitigate market power or the utility's market conduct, or a similar market monitoring function exists with the ability to identify and monitor market conditions and conduct; and 3) a published source of information is available publicly or through subscription that identifies pricing information for traded electricity products, both on- and off-peak, scheduled for delivery two years into the future.

On July 31, 2008, the Ohio Companies filed with the PUCO a comprehensive ESP and MRO. The MRO filing outlined a CBP for providing retail generation supply if the ESP is not approved and implemented. The CBP would use a "slice-of-system" approach where suppliers bid on tranches (approximately 100 MW) of the Ohio Companies' total customer load. If the Ohio Companies proceed with the MRO option, successful bidders (including affiliates) would be required to post independent credit requirements and could be subject to significant collateral calls depending upon power price movement. The PUCO denied the MRO application on November 26, 2008. The Ohio Companies filed an application for rehearing on December 23, 2008, which the PUCO granted on January 21, 2009, for the purpose of further consideration of the matter.

The ESP proposed to phase in new generation rates for customers beginning in 2009 for up to a three-year period and resolve the Ohio Companies' collection of fuel costs deferred in 2006 and 2007, and the distribution rate request described above. On December 19, 2008, the PUCO significantly modified and approved the ESP as modified. On December 22, 2008, the Ohio Companies notified the PUCO that they were withdrawing and terminating the ESP application as allowed by the terms of SB221. The Ohio Companies further notified the PUCO that, pursuant to SB221, the Ohio Companies would continue their current rate plan in effect and filed tariffs to continue those rates.

On December 31, 2008, the Ohio Companies conducted a CBP, using an RFP format administered by an independent third party, for the procurement of electric generation for retail customers from January 5, 2009 through March 31, 2009. Four qualified wholesale bidders were selected, including FES, for 97% of the tranches offered in the RFP. The average winning bid price was equivalent to a retail rate of 6.98 cents per kilowatt-hour. Subsequent to the RFP, the remaining 3% of the Ohio Companies' wholesale energy and capacity needs were obtained through a bilateral contract with the lowest bidder in the RFP procurement. The power supply obtained through the foregoing processes provides generation service to the Ohio Companies' retail customers who choose not to shop with alternative suppliers.

Following comments by other parties on the Ohio Companies' December 22, 2008, filing which continued the current rate plan, the PUCO issued an Order on January 7, 2009, that prevented OE and TE from collecting RTC and discontinued the collection of two fuel riders for the Ohio Companies. The Ohio Companies filed an application for rehearing on January 9, 2009, and also filed an application for a new fuel rider to recover the increased costs for purchasing power during the period January 1, 2009 through March 31, 2009. On January 14, 2009, the PUCO approved the Ohio Companies' request for the new fuel rider, subject to further review, allowed current recovery of those costs for OE and TE, and allowed CEI to collect a portion of those costs currently and defer the remainder. The PUCO also ordered the Ohio Companies to file additional information in order for it to determine that the costs incurred are prudent and whether the recovery of such costs is necessary to avoid a confiscatory result. The Ohio Companies filed an application for rehearing on that order on January 26, 2009. The applications for rehearing remain pending and the Ohio Companies are unable to predict the ultimate resolution of these issues.

On January 29, 2009, the PUCO ordered its Staff to develop a proposal to establish an ESP for the Ohio Companies and further ordered that a conference be held on February 5, 2009 to discuss the Staff's proposal. The Ohio Companies, PUCO Staff, and other parties participated in that conference, and in a subsequent conference held on February 17, 2009. Following discussions with the Staff and other parties regarding the Staff's proposal, on February 19, 2009, the Ohio Companies filed an amended ESP application, including an attached Stipulation and Recommendation that was signed by the Ohio Companies, the Staff of the PUCO, and many of the intervening parties representing a diverse range of interests, which substantially reflected the terms as proposed by the Staff as modified through the negotiations of the parties. Specifically, the stipulated ESP provides that generation will be provided by FES at the average wholesale rate of the RFP process described above for April and May 2009 to the Ohio Companies for their non-shopping customers and that for the period of June 1, 2009 through May 31, 2011, retail generation prices will be based upon the outcome of a descending clock CBP on a slice-of-system basis. The PUCO may, at its discretion, phase-in a portion of any increase resulting from this CBP process by authorizing deferral of related purchased power costs, subject to specified limits. The proposed ESP further provides that the Ohio Companies will not seek a base distribution rate increase with an effective date before January 1, 2012, that CEI will agree to write-off approximately \$215 million of its Extended RTC balance, and that the Ohio Companies will collect a delivery service improvement rider at an overall average rate of \$.002 per kWh for the period of April 1, 2009 through December 31, 2011. If the Stipulated ESP is approved, one-time charges associated with implementing the ESP would be approximately \$250 million (including the CEI Extended RTC balance), or \$0.53 per share of common stock. The proposed ESP also addresses a number of other issues, including but not limited to, rate design for various customer classes, resolution of the prudence review described above and the collection of deferred costs that were approved in prior proceedings. On February 19, 2009, the PUCO attorney examiner issued an order setting this matter for hearing to begin on February 25, 2009.

(C) PENNSYLVANIA

Met-Ed and Penelec purchase a portion of their PLR and default service requirements from FES through a fixed-price partial requirements wholesale power sales agreement. The agreement allows Met-Ed and Penelec to sell the output of NUG energy to the market and requires FES to provide energy at fixed prices to replace any NUG energy sold to the extent needed for Met-Ed and Penelec to satisfy their PLR and default service obligations. The fixed price under the agreement is expected to remain below wholesale market prices during the term of the agreement. 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 their fixed income securities. If FES ultimately determines to terminate, reduce, or significantly modify the agreement prior to the expiration of Met-Ed's and Penelec's generation rate caps in 2010, timely regulatory relief is not likely to be granted by the PPUC. See FERC Matters below for a description of the Third Restated Partial Requirements Agreement, executed by the parties on October 31, 2008, that limits the amount of energy and capacity FES must supply to Met-Ed and Penelec. In the event of a third party supplier default, the increased costs to Met-Ed and Penelec could be material.

On May 22, 2008, the PPUC approved the Met-Ed and Penelec annual updates to the TSC rider for the period June 1, 2008, through May 31, 2009. Various intervenors filed complaints against those filings. In addition, the PPUC ordered an investigation to review the reasonableness of Met-Ed's TSC, while at the same time allowing Met-Ed to implement the rider June 1, 2008, subject to refund. On July 15, 2008, the PPUC directed the ALJ to consolidate the complaints against Met-Ed with its investigation and a litigation schedule was adopted. Hearings and briefing for both companies are expected to conclude by the end of February 2009. The TSCs include a component from under-recovery of actual transmission costs incurred during the prior period (Met-Ed - \$144 million and Penelec - \$4 million) and future transmission cost projections for June 2008 through May 2009 (Met-Ed - \$258 million and Penelec - \$92 million). Met-Ed received PPUC approval for a transition approach that would recover past under-recovered costs plus carrying charges through the new TSC over thirty-one months and defer a portion of the projected costs (\$92 million) plus carrying charges for recovery through future TSCs by December 31, 2010.

On February 1, 2007, the Governor of Pennsylvania proposed an EIS. The EIS includes four pieces of proposed legislation that, according to the Governor, is designed to reduce energy costs, promote energy independence and stimulate the economy. Elements of the EIS include the installation of smart meters, funding for solar panels on residences and small businesses, conservation and demand reduction programs to meet energy growth, a requirement that electric distribution companies acquire power that results in the "lowest reasonable rate on a long-term basis," the utilization of micro-grids and a three year phase-in of rate increases. On July 17, 2007 the Governor signed into law two pieces of energy legislation. The first amended the Alternative Energy Portfolio Standards Act of 2004 to, among other things, increase the percentage of solar energy that must be supplied at the conclusion of an electric distribution company's transition period. The second law allows electric distribution companies, at their sole discretion, to enter into long term contracts with large customers and to build or acquire interests in electric generation facilities specifically to supply long-term contracts with such customers. A special legislative session on energy was convened in mid-September 2007 to consider other aspects of the EIS. As part of the 2008 state budget negotiations, the Alternative Energy Investment Act was enacted in July 2008 creating a \$650 million alternative energy fund to increase the development and use of alternative and renewable energy, improve energy efficiency and reduce energy consumption.

On October 15, 2008, the Governor of Pennsylvania signed House Bill 2200 into law which became effective on November 14, 2008 as Act 129 of 2008. The bill addresses issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters and alternative energy. Act 129 requires utilities to file with the PPUC an energy efficiency and peak load reduction plan by July 1, 2009 and a smart meter procurement and installation plan by August 14, 2009. On January 15, 2009, in compliance with Act 129, the PPUC issued its guidelines for the filing of utilities' energy efficiency and peak load reduction plans.

Major provisions of the legislation include:

- power acquired by utilities to serve customers after rate caps expire will be procured through a competitive procurement process that must include a mix of long-term and short-term contracts and spot market purchases;
- the competitive procurement process must be approved by the PPUC and may include auctions, RFPs, and/or bilateral agreements;
- utilities must provide for the installation of smart meter technology within 15 years;
- a minimum reduction in peak demand of 4.5% by May 31, 2013;
- minimum reductions in energy consumption of 1% and 3% by May 31, 2011 and May 31, 2013, respectively; and
- an expanded definition of alternative energy to include additional types of hydroelectric and biomass facilities.

Legislation addressing rate mitigation and the expiration of rate caps was not enacted in 2008 but may be considered in the legislative session which began in January 2009. While the form and impact of such legislation is uncertain, several legislators and the Governor have indicated their intent to address these issues in 2009.

On September 25, 2008, Met-Ed and Penelec filed a Voluntary Prepayment Plan with the PPUC that would provide an opportunity for residential and small commercial customers to prepay an amount on their monthly electric bills during 2009 and 2010 that would earn interest at 7.5% and be used to reduce electric rates in 2011 and 2012. Met-Ed, Penelec, OCA and OSBA have reached a settlement agreement on the Voluntary Prepayment Plan and have jointly requested that the PPUC approve the settlement. The ALJ issued a decision on January 29, 2009, recommending approval and adoption of the settlement without modification.

On February 20, 2009, Met-Ed and Penelec filed a generation procurement plan covering the period January 1, 2011 through May 31, 2013, with the PPUC. The companies' plan is designed to provide adequate and reliable service via a prudent mix of long-term, short-term and spot market generation supply, as required by Act 129. The plan proposes a staggered procurement schedule, which varies by customer class, through the use of a descending clock auction. Met-Ed and Penelec have requested PPUC approval of their plan by October 2009.

(D) 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, costs incurred under NUG agreements, and certain other stranded costs, exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of December 31, 2008, the accumulated deferred cost balance totaled approximately \$220 million.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004, supporting 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. JCP&L responded to additional NJBPU staff discovery requests in May and November 2007 and also submitted comments in the proceeding in November 2007. A schedule for further NJBPU proceedings has not yet been set.

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of the PUHCA pursuant to the EPACT. The NJBPU approved regulations effective October 2, 2006 that 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. These regulations are not expected to materially impact FirstEnergy or JCP&L. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. The NJBPU Staff circulated revised drafts of the proposal to interested stakeholders in November 2006 and again in February 2007. On February 1, 2008, the NJBPU accepted proposed rules for publication in the New Jersey Register on March 17, 2008. A public hearing on these proposed rules was held on April 23, 2008 and comments from interested parties were submitted by May 19, 2008.

New Jersey statutes require that the state periodically undertake a planning process, known as the EMP, to address energy related issues including energy security, economic growth, and environmental impact. The EMP is to be developed with involvement of the Governor's Office and the Governor's Office of Economic Growth, and is to be prepared by a Master Plan Committee, which is chaired by the NJBPU President and includes representatives of several State departments.

The EMP was issued on October 22, 2008, establishing five major goals:

- maximize energy efficiency to achieve a 20% reduction in energy consumption by 2020;
- reduce peak demand for electricity by 5,700 MW by 2020;
- meet 30% of the state's electricity needs with renewable energy by 2020;
- examine smart grid technology and develop additional cogeneration and other generation resources consistent with the state's greenhouse gas targets; and
- invest in innovative clean energy technologies and businesses to stimulate the industry's growth in New Jersey.

The EMP will be followed by appropriate legislation and regulation as necessary. At this time, FirstEnergy cannot determine the impact, if any, the EMP may have on its operations or those of JCP&L.

In support of the New Jersey Governor's Economic Assistance and Recovery Plan, JCP&L announced its intent to spend approximately \$98 million on infrastructure and energy efficiency projects in 2009. An estimated \$40 million will be spent on infrastructure projects, including substation upgrades, new transformers, distribution line re-closers and automated breaker operations. Approximately \$34 million will be spent implementing new demand response programs as well as expanding on existing programs. Another \$11 million will be spent on energy efficiency, specifically replacing transformers and capacitor control systems and installing new LED street lights. The remaining \$13 million will be spent on energy efficiency programs that will complement those currently being offered. Completion of the projects is dependent upon regulatory approval for full recovery of the costs associated with plan implementation.

(E) FERC MATTERS

Transmission Service between MISO and PJM

On November 18, 2004, the FERC issued an order eliminating the through and out rate for transmission service between the MISO and PJM regions. The FERC's intent was to eliminate multiple transmission charges for a single transaction between the MISO and PJM regions. The FERC also ordered MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a rate mechanism to recover lost transmission revenues created by elimination of this charge (referred to as the Seams Elimination Cost Adjustment or "SECA") during a 16-month transition period. The FERC issued orders in 2005 setting the SECA for hearing. The presiding judge issued an initial decision on August 10, 2006, rejecting the compliance filings made by MISO, PJM, and the transmission owners, and directing new compliance filings. This decision is subject to review and approval by the FERC. Briefs addressing the initial decision were filed on September 11, 2006 and October 20, 2006. A final order is pending before the FERC, and in the meantime, FirstEnergy affiliates have been negotiating and entering into settlement agreements with other parties in the docket to mitigate the risk of lower transmission revenue collection associated with an adverse order. On September 26, 2008, the MISO and PJM transmission owners filed a motion requesting that the FERC approve the pending settlements and act on the initial decision. On November 20, 2008, FERC issued an order approving uncontested settlements, but did not rule on the initial decision. On December 19, 2008, an additional order was issued approving two contested settlements.

PJM Transmission Rate Design

On January 31, 2005, certain PJM transmission owners made 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. Hearings were held and numerous parties appeared and litigated various issues concerning PJM rate design; notably AEP, which proposed to create a "postage stamp", or average rate for all high voltage transmission facilities across PJM and a zonal transmission rate for facilities below 345 kV. This proposal would have the effect of shifting recovery of the costs of high voltage transmission lines to other transmission zones, including those where JCP&L, Met-Ed, and Penelec serve load. On April 19, 2007, the FERC issued an order finding that the PJM transmission owners' existing "license plate" or zonal rate design was just and reasonable and ordered that the current license plate rates for existing transmission facilities be retained. On the issue of rates for new transmission facilities, the FERC directed that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp rate. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a "beneficiary pays" basis. The FERC found that PJM's current beneficiary-pays cost allocation methodology is not sufficiently detailed and, in a related order that also was issued on April 19, 2007, directed that hearings be held for the purpose of establishing a just and reasonable cost allocation methodology for inclusion in PJM's tariff.

On May 18, 2007, certain parties filed for rehearing of the FERC's April 19, 2007 order. On January 31, 2008, the requests for rehearing were denied. On February 11, 2008, AEP appealed the FERC's April 19, 2007, and January 31, 2008, orders to the federal Court of Appeals for the D.C. Circuit. The Illinois Commerce Commission, the PUCO and Dayton Power & Light have also appealed these orders to the Seventh Circuit Court of Appeals. The appeals of these parties and others have been consolidated for argument in the Seventh Circuit.

The FERC's orders on PJM rate design will prevent the allocation of a portion of the revenue requirement of existing transmission facilities of other utilities to JCP&L, Met-Ed and Penelec. In addition, the FERC's decision to allocate the cost of new 500 kV and above transmission facilities on a PJM-wide basis will reduce the costs of future transmission to be recovered from the JCP&L, Met-Ed and Penelec zones. A partial settlement agreement addressing the "beneficiary pays" methodology for below 500 kV facilities, but excluding the issue of allocating new facilities costs to merchant transmission entities, was filed on September 14, 2007. The agreement was supported by the FERC's Trial Staff, and was certified by the Presiding Judge to the FERC. On July 29, 2008, the FERC issued an order conditionally approving the settlement subject to the submission of a compliance filing. The compliance filing was submitted on August 29, 2008, and the FERC issued an order accepting the compliance filing on October 15, 2008. The remaining merchant transmission cost allocation issues were the subject of a hearing at the FERC in May 2008. An initial decision was issued by the Presiding Judge on September 18, 2008. PJM and FERC trial staff each filed a Brief on Exceptions to the initial decision on October 20, 2008. Briefs Opposing Exceptions were filed on November 10, 2008.

Post Transition Period Rate Design

The FERC had directed MISO, PJM, and the respective transmission owners to make filings on or before August 1, 2007 to reevaluate transmission rate design within MISO, and between MISO and PJM. On August 1, 2007, filings were made by MISO, PJM, and the vast majority of transmission owners, including FirstEnergy affiliates, which proposed to retain the existing transmission rate design. These filings were approved by the FERC on January 31, 2008. As a result of the FERC's approval, the rates charged to FirstEnergy's load-serving affiliates for transmission service over existing transmission facilities in MISO and PJM are unchanged. In a related filing, MISO and MISO transmission owners requested that the current MISO pricing for new transmission facilities that spreads 20% of the cost of new 345 kV and higher transmission facilities across the entire MISO footprint (known as the RECB methodology) be retained.

On September 17, 2007, AEP filed a complaint under Sections 206 and 306 of the Federal Power Act seeking to have the entire transmission rate design and cost allocation methods used by MISO and PJM declared unjust, unreasonable, and unduly discriminatory, and to have the FERC fix a uniform regional transmission rate design and cost allocation method for the entire MISO and PJM "Super Region" that recovers the average cost of new and existing transmission facilities operated at voltages of 345 kV and above from all transmission customers. Lower voltage facilities would continue to be recovered in the local utility transmission rate zone through a license plate rate. AEP requested a refund effective October 1, 2007, or alternatively, February 1, 2008. On January 31, 2008, the FERC issued an order denying the complaint. The effect of this order is to prevent the shift of significant costs to the FirstEnergy zones in MISO and PJM. A rehearing request by AEP was denied by the FERC on December 19, 2008. On February 17, 2009, AEP appealed the FERC's January 31, 2008, and December 19, 2008, orders to the U.S. Court of Appeals for the Seventh Circuit.

Interconnection Agreement with AMP-Ohio

On May 29, 2008, TE filed with the FERC a proposed Notice of Cancellation effective midnight December 31, 2008, of the Interconnection Agreement with AMP-Ohio. AMP-Ohio protested this filing. TE also filed a Petition for Declaratory Order seeking a FERC ruling, in the alternative if cancellation is not accepted, of TE's right to file for an increase in rates effective January 1, 2009, for power provided to AMP-Ohio under the Interconnection Agreement. AMP-Ohio filed a pleading agreeing that TE may seek an increase in rates, but arguing that any increase is limited to the cost of generation owned by TE affiliates. On August 18, 2008, the FERC issued an order that suspended the cancellation of the Agreement for five months, to become effective on June 1, 2009, and established expedited hearing procedures on issues raised in the filing and TE's Petition for Declaratory Order. On October 14, 2008, the parties filed a settlement agreement and mutual notice of cancellation of the Interconnection Agreement effective midnight December 31, 2008. On October 24, 2008 the presiding judge certified the settlement agreement as uncontested and on December 22, 2008, the FERC issued an order approving the uncontested settlement agreement. This latest action terminates the litigation and the Interconnection Agreement.

Duquesne's Request to Withdraw from PJM

On November 8, 2007, Duquesne Light Company (Duquesne) filed a request with the FERC to exit PJM and to join MISO. Duquesne's proposed move would affect numerous FirstEnergy interests, including but not limited to the terms under which FirstEnergy's Beaver Valley Plant would continue to participate in PJM's energy markets. FirstEnergy, therefore, intervened and participated fully in all of the FERC dockets that were related to Duquesne's proposed move.

In November, 2008, Duquesne and other parties, including FirstEnergy, negotiated a settlement that would, among other things, allow for Duquesne to remain in PJM and provide for a methodology for Duquesne to meet the PJM capacity obligations for the 2011-2012 auction that excluded the Duquesne load. The settlement agreement was filed on December 10, 2008 and approved by the FERC in an order issued on January 29, 2009. MISO opposed the settlement agreement pending resolution of exit fees alleged to be owed by Duquesne. The FERC did not resolve this issue in its order.

Complaint against PJM RPM Auction

On May 30, 2008, a group of PJM load-serving entities, state commissions, consumer advocates, and trade associations (referred to collectively as the RPM Buyers) filed a complaint at the FERC against PJM alleging that three of the four transitional RPM auctions yielded prices that are unjust and unreasonable under the Federal Power Act. On September 19, 2008, the FERC denied the RPM Buyers' complaint. However, the FERC did grant the RPM Buyers' request for a technical conference to review aspects of the RPM. The FERC also ordered PJM to file on or before December 15, 2008, a report on potential adjustments to the RPM program as suggested in a Brattle Group report. On December 12, 2008, PJM filed proposed tariff amendments that would adjust slightly the RPM program. PJM also requested that the FERC conduct a settlement hearing to address changes to the RPM and suggested that the FERC should rule on the tariff amendments only if settlement could not be reached in January, 2009. The request for settlement hearings was granted. Settlement had not been reached by January 9, 2009 and, accordingly, FirstEnergy and other parties submitted comments on PJM's proposed tariff amendments. On January 15, 2009, the Chief Judge issued an order terminating settlement talks. On February 9, 2009, PJM and a group of stakeholders submitted an offer of settlement.

On October 20, 2008, the RPM Buyers filed a request for rehearing of the FERC's September 19, 2008 order. The FERC has not yet ruled on the rehearing request.

MISO Resource Adequacy Proposal

MISO made a filing on December 28, 2007 that would create an enforceable planning reserve requirement in the MISO tariff for load-serving entities such as the Ohio Companies, Penn Power, and FES. This requirement is proposed to become effective for the planning year beginning June 1, 2009. The filing would permit MISO to establish the reserve margin requirement for load-serving entities based upon a one day loss of load in ten years standard, unless the state utility regulatory agency establishes a different planning reserve for load-serving entities in its state. FirstEnergy believes the proposal promotes a mechanism that will result in commitments from both load-serving entities and resources, including both generation and demand side resources that are necessary for reliable resource adequacy and planning in the MISO footprint. Comments on the filing were filed on January 28, 2008. The FERC conditionally approved MISO's Resource Adequacy proposal on March 26, 2008, requiring MISO to submit to further compliance filings. Rehearing requests are pending on the FERC's March 26 Order. On May 27, 2008, MISO submitted a compliance filing to address issues associated with planning reserve margins. On June 17, 2008, various parties submitted comments and protests to MISO's compliance filing. FirstEnergy submitted comments identifying specific issues that must be clarified and addressed. On June 25, 2008, MISO submitted a second compliance filing establishing the enforcement mechanism for the reserve margin requirement which establishes deficiency payments for load-serving entities that do not meet the resource adequacy requirements. Numerous parties, including FirstEnergy, protested this filing.

On October 20, 2008, the FERC issued three orders essentially permitting the MISO Resource Adequacy program to proceed with some modifications. First, the FERC accepted MISO's financial settlement approach for enforcement of Resource Adequacy subject to a compliance filing modifying the cost of new entry penalty. Second, the FERC conditionally accepted MISO's compliance filing on the qualifications for purchased power agreements to be capacity resources, load forecasting, loss of load expectation, and planning reserve zones. Additional compliance filings were directed on accreditation of load modifying resources and price responsive demand. Finally, the FERC largely denied rehearing of its March 26 order with the exception of issues related to behind the meter resources and certain ministerial matters. On November 19, 2008, MISO made various compliance filings pursuant to these orders. Issuance of orders on these compliance filings is not expected to delay the June 1, 2009, start date for MISO Resource Adequacy.

FES Sales to Affiliates

On October 24, 2008, FES, on its own behalf and on behalf of its generation-controlling subsidiaries, filed an application with the FERC seeking a waiver of the affiliate sales restrictions between FES and the Ohio Companies. The purpose of the waiver is to ensure that FES will be able to continue supplying a material portion of the electric load requirements of the Ohio Companies in January 2009 pursuant to either an ESP or MRO as filed with the PUCO. FES previously obtained a similar waiver for electricity sales to its affiliates in New Jersey, New York, and Pennsylvania. On December 23, 2008, the FERC issued an order granting the waiver request and the Ohio Companies made the required compliance filing on December 30, 2008.

On October 31, 2008, FES executed a Third Restated Partial Requirements Agreement with Met-Ed, Penelec, and Waverly effective November 1, 2008. The Third Restated Partial Requirements Agreement limits the amount of capacity and energy required to be supplied by FES in 2009 and 2010 to roughly two-thirds of these affiliates' power supply requirements. Met-Ed, Penelec, and Waverly have committed resources in place for the balance of their expected power supply during 2009 and 2010. Under the Third Restated Partial Requirements Agreement, Met-Ed, Penelec, and Waverly are responsible for obtaining additional power supply requirements created by the default or failure of supply of their committed resources. Prices for the power provided by FES were not changed in the Third Restated Partial Requirements Agreement.

11. CAPITALIZATION

(A) COMMON STOCK

Retained Earnings and Dividends

As of December 31, 2008, FirstEnergy's unrestricted retained earnings were \$4.2 billion. Dividends declared in 2008 were \$2.20, which included four quarterly dividends of \$0.55 per share paid in the second, third and fourth quarters of 2008 and payable in the first quarter of 2009. Dividends declared in 2007 were \$2.05, which included three quarterly dividends of \$0.50 per share paid in the second, third and fourth quarters of 2007 and a quarterly dividend of \$0.55 per share paid in the first quarter of 2008. The amount and timing of all dividend declarations are subject to the discretion of the Board of Directors and its consideration of business conditions, results of operations, financial condition and other factors.

In addition to paying dividends from retained earnings, each of FirstEnergy's electric utility subsidiaries has authorization from the FERC to pay cash dividends to FirstEnergy from paid-in capital accounts, as long as its equity to total capitalization ratio (without consideration of retained earnings) remains above 35%. The articles of incorporation, indentures and various other agreements relating to the long-term debt and preferred stock of certain FirstEnergy subsidiaries contain provisions that could further restrict the payment of dividends on their common stock. With the exception of Met-Ed, which is currently in an accumulated deficit position, none of these provisions materially restricted FirstEnergy's subsidiaries' ability to pay cash dividends to FirstEnergy as of December 31, 2008.

(B) PREFERRED AND PREFERENCE STOCK

FirstEnergy's and the Utilities' preferred stock and preference stock authorizations are as follows:

	Preferred Stock		Preference Stock	
	Shares Authorized	Par Value	Shares Authorized	Par Value
FirstEnergy	5,000,000	\$ 100		
OE	6,000,000	\$ 100	8,000,000	no par
OE	8,000,000	\$ 25		
Penn	1,200,000	\$ 100		
CEI	4,000,000	no par	3,000,000	no par
TE	3,000,000	\$ 100	5,000,000	\$ 25
TE	12,000,000	\$ 25		
JCP&L	15,600,000	no par		
Met-Ed	10,000,000	no par		
Penelec	11,435,000	no par		

No preferred shares or preference shares are currently outstanding. The following table details the change in preferred shares outstanding during 2006. No shares were issued in 2007 or 2008.

	Not Subject to Mandatory Redemption	
	Number of Shares	Par or Stated Value
	<i>(Dollars in millions)</i>	
Balance, January 1, 2006	3,785,699	\$ 184
Redemptions-		
3.90% Series	(152,510)	(15)
4.40% Series	(176,280)	(18)
4.44% Series	(136,560)	(14)
4.56% Series	(144,300)	(14)
4.24% Series	(40,000)	(4)
4.25% Series	(41,049)	(4)
4.64% Series	(60,000)	(6)
\$4.25 Series	(160,000)	(16)
\$4.56 Series	(50,000)	(5)
\$4.25 Series	(100,000)	(10)
\$2.365 Series	(1,400,000)	(35)
Adjustable Series B	(1,200,000)	(30)
4.00% Series	(125,000)	(13)
Balance, December 31, 2006	-	\$ -

(C) LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

The following table presents the outstanding long-term debt and other long-term obligations of FirstEnergy as of December 31, 2008 and 2007:

	Weighted Average Interest Rate (%)	December 31, 2008	2007
		<i>(In millions)</i>	
FMBs:			
Due 2008-2013	6.08	\$ 29	\$ 155
Due 2014-2018	8.84	330	5
Due 2019-2023	7.91	7	7
Due 2024-2028	5.95	14	14
Due 2034-2038	8.25	275	-
Total FMBs		655	181
Secured Notes:			
Due 2008-2013	7.50	607	385
Due 2014-2018	7.25	613	522
Due 2019-2023	5.89	70	70
Due 2024-2028	-	-	25
Due 2029-2033	-	-	82
Total Secured Notes		1,290	1,084
Unsecured Notes:			
Due 2008-2013	6.12	2,253	2,360
Due 2014-2018	5.65	2,149	2,185
Due 2019-2023	2.90	689	689
Due 2024-2028	4.54	65	40
Due 2029-2033	5.83	2,247	2,162
Due 2034-2038	5.03	1,936	1,935
Due 2039-2043	1.29	255	255
Due 2044-2048	3.38	46	-
Total Unsecured Notes		9,640	9,626
Total		11,585	10,891
Capital lease obligations		8	4
Net unamortized discount on debt		(17)	(12)
Long-term debt due within one year		(2,476)	(2,014)
Total long-term debt and other long-term obligations		\$ 9,100	\$ 8,869

Securitized Transition Bonds

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

JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on FirstEnergy's and JCP&L's Consolidated Balance Sheets. As of December 31, 2008, \$369 million of the transition bonds were outstanding. The transition bonds are the sole obligations of JCP&L Transition Funding and JCP&L Transition Funding II and are collateralized by each company's equity and assets, which consist primarily of bondable transition property.

Bondable transition property represents the irrevocable right under New Jersey law of a utility company to charge, collect and receive from its customers, through a non-bypassable TBC, the principal amount and interest on transition bonds and other fees and expenses associated with their issuance. JCP&L sold its bondable transition property to JCP&L Transition Funding and JCP&L Transition Funding II and, as servicer, manages and administers the bondable transition property, including the billing, collection and remittance of the TBC, pursuant to separate servicing agreements with JCP&L Transition Funding and JCP&L Transition Funding II. For the two series of transition bonds, JCP&L is entitled to aggregate annual servicing fees of up to \$628,000 that are payable from TBC collections.

Other Long-term Debt

FGCO and each of the Utilities, except for JCP&L, have a first mortgage indenture under which they can issue FMBs secured by a direct first mortgage lien on substantially all of their property and franchises, other than specifically excepted property.

FirstEnergy and its subsidiaries have various debt covenants under their respective financing arrangements. The most restrictive of the debt covenants relate to the nonpayment of interest and/or principal on debt and the maintenance of certain financial ratios. There also exist cross-default provisions in a number of the respective financing arrangements of FirstEnergy, FES, FGCO, NGC and the Utilities. These provisions generally trigger a default in the applicable financing arrangement of an entity if it or any of its significant subsidiaries defaults under another financing arrangement of a certain principal amount, typically \$50 million. Although such defaults by any of the Utilities will generally cross-default FirstEnergy financing arrangements containing these provisions, defaults by FirstEnergy will not generally cross-default applicable financing arrangements of any of the Utilities. Defaults by any of FES, FGCO or NGC will generally cross-default to applicable financing arrangements of FirstEnergy and, due to the existence of guarantees by FirstEnergy of certain financing arrangements of FES, FGCO and NGC, defaults by FirstEnergy will generally cross-default FES, FGCO and NGC financing arrangements containing these provisions. Cross-default provisions are not typically found in any of the senior note or FMBs of FirstEnergy or the Utilities.

Based on the amount of FMBs authenticated by the respective mortgage bond trustees through December 31, 2008, the Utilities' annual sinking fund requirement for all FMBs issued under the various mortgage indentures amounted to \$34 million. Penn expects to deposit funds with its mortgage bond trustee in 2009 that will then be withdrawn upon the surrender for cancellation of a like principal amount of FMBs, specifically authenticated for such purposes against unfunded property additions or against previously retired FMBs. This method can result in minor increases in the amount of the annual sinking fund requirement. Met-Ed and Penelec could fulfill their sinking fund obligations by providing bondable property additions, previously retired FMBs or cash to the respective mortgage bond trustees.

As of December 31, 2008, FirstEnergy's currently payable long-term debt includes approximately \$2.2 billion (FES - \$2.0 billion, OE - \$100 million, Met-Ed - \$29 million and Penelec - \$45 million) of variable interest rate PCRBs, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds, or if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

Prior to the third quarter of 2008, FirstEnergy subsidiaries had not experienced any unsuccessful remarketings of these variable-rate PCRBs. Coincident with recent disruptions in the variable-rate demand bond and capital markets generally, certain of the PCRBs had been tendered by bondholders to the trustee. As of January 31, 2009, all PCRBs that had been tendered were successfully remarketed.

In February 2009, holders of approximately \$434 million in principal of LOC-supported PCRBs of NGC were notified that the applicable Wachovia Bank LOCs expire on March 18, 2009. As a result, these PCRBs are subject to mandatory purchase at a price equal to the principal amount, plus accrued and unpaid interest, which FES and NGC expect to fund through short-term borrowings. Subject to market conditions, FES and NGC expect to remarket or refinance these PCRBs during the remainder of 2009.

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

	<i>(In millions)</i>
2009	\$ 2,475
2010	322
2011	1,617
2012	160
2013	563

Included in the table above are amounts for the variable interest rate PCRBs described above. These amounts are \$2.2 billion, \$15 million, \$25 million and \$56 million in 2009, 2010, 2011 and 2012, respectively, representing the next time the debt holders may exercise their right to tender their PCRBs.

Obligations to repay certain PCRBs are secured by several series of FMBs. Certain PCRBs are entitled to the benefit of irrevocable bank LOCs of \$2.1 billion as of December 31, 2008, or noncancelable municipal bond insurance of \$39 million as of December 31, 2008, to pay principal of, or interest on, the applicable PCRBs. To the extent that drawings are made under the LOCs or the insurance, FGCO, NGC and the Utilities are entitled to a credit against their obligation to repay those bonds. FGCO, NGC and the Utilities pay annual fees of 0.35% to 1.70% of the amounts of the LOCs to the issuing banks and are obligated to reimburse the banks or insurers, as the case may be, for any drawings thereunder. The insurers hold FMBs as security for such reimbursement obligations.

OE has LOCs of \$291 million and \$134 million in connection with the sale and leaseback of Beaver Valley Unit 2 and Perry Unit 1, respectively. In 2004, OE entered into a Credit Agreement pursuant to which a standby LOC was issued in support of approximately \$236 million of the Beaver Valley Unit 2 LOCs and the issuer of the standby LOC obtained the right to pledge or assign participations in OE's reimbursement obligations under the credit agreement to a trust. The trust then issued and sold trust certificates to institutional investors that were designed to be the credit equivalent of an investment directly in OE.

12. 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.

The ARO liability of \$1.3 billion as of December 31, 2008 primarily relates to the nuclear decommissioning of the Beaver Valley, Davis-Besse, Perry and TMI-2 nuclear generating facilities. 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 December 31, 2008, the fair value of the decommissioning trust assets was approximately \$1.7 billion.

FIN 47 provides accounting standards for conditional retirement obligations associated with tangible long-lived assets, requiring recognition of the fair value of a liability for an ARO in the period in which it is incurred if a reasonable estimate can be identified. FIN 47 states that an obligation exists even though there may be uncertainty about timing or method of settlement and further clarifies SFAS 143, stating that the uncertainty surrounding the timing and method of settlement when settlement is conditional on a future event occurring should be reflected in the measurement of the liability, not in the recognition of the liability. Accounting for conditional ARO under FIN 47 is the same as described above for SFAS 143.

The following table describes the changes to the ARO balances during 2008 and 2007.

ARO Reconciliation	2008	2007
	<i>(In millions)</i>	
Balance at beginning of year	\$ 1,267	\$ 1,190
Liabilities incurred	5	-
Liabilities settled	(3)	(2)
Accretion	84	79
Revisions in estimated cash flows	(18)	-
Balance at end of year	<u>\$ 1,335</u>	<u>\$ 1,267</u>

13. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

FirstEnergy had approximately \$2.4 billion of short-term indebtedness as of December 31, 2008, comprised of \$2.3 billion of borrowings under a \$2.75 billion revolving line of credit and \$102 million of other bank borrowings. Total short-term bank lines of committed credit to FirstEnergy and the Utilities as of December 31, 2008 were approximately \$4.0 billion.

FirstEnergy, along with certain of its subsidiaries, are parties to a \$2.75 billion five-year revolving credit facility. FirstEnergy has the ability to request an increase in the total commitments available under this facility up to a maximum of \$3.25 billion, subject to the discretion of each lender to provide additional commitments. Commitments under the facility are available until August 24, 2012, unless the lenders agree, at the request of the borrowers, to an unlimited number of additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each borrower are subject to a specified sub-limit, as well as applicable regulatory and other limitations. The annual facility fee is 0.125%

The Utilities, 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. The receivables financing borrowing commitment by company are shown in the following table. There were no outstanding borrowings as of December 31, 2008.

<u>Subsidiary Company</u>	<u>Parent Company</u>	<u>Commitment</u>	<u>Annual Facility Fee</u>	<u>Maturity</u>
		<i>(In millions)</i>		
OES Capital, Incorporated	OE	\$ 170	0.20%	February 22, 2010
Centerior Funding Corporation	CEI	200	0.20	February 22, 2010
Penn Power Funding LLC	Penn	25	0.60	December 18, 2009
Met-Ed Funding LLC	Met-Ed	80	0.60	December 18, 2009
Penelec Funding LLC	Penelec	75	0.60	December 18, 2009
		<u>\$ 550</u>		

The weighted average interest rates on short-term borrowings outstanding as of December 31, 2008 and 2007 were 1.19% and 5.42%, respectively. The annual facility fees on all current committed short-term bank lines of credit range from 0.125% to 0.60%.

14. COMMITMENTS, GUARANTEES AND CONTINGENCIES

(A) NUCLEAR INSURANCE

The Price-Anderson Act limits the public liability relative to a single incident at a nuclear power plant to \$12.5 billion. The amount is covered by a combination of private insurance and an industry retrospective rating plan. FirstEnergy's maximum potential assessment under the industry retrospective rating plan would be \$470 million per incident but not more than \$70 million in any one year for each incident.

FirstEnergy is also insured under policies for each nuclear plant. Under these policies, up to \$2.8 billion is provided for property damage and decontamination costs. FirstEnergy has also obtained approximately \$2.0 billion of insurance coverage for replacement power costs. Under these policies, FirstEnergy can be assessed a maximum of approximately \$79 million for incidents at any covered nuclear facility occurring during a policy year which are in excess of accumulated funds available to the insurer for paying losses.

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

(B) 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 December 31, 2008, outstanding guarantees and other assurances aggregated approximately \$4.4 billion, consisting of parental guarantees - \$1.2 billion, subsidiaries' guarantees - \$2.6 billion, surety bonds - \$0.1 billion and LOCs - \$0.5 billion.

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy commodity activities principally to facilitate or hedge normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of credit support for the financing or refinancing by subsidiaries of costs related to 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 \$0.4 billion (included in the \$1.2 billion discussed above) as of December 31, 2008 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, provision of an LOC or accelerated payments may be required of the subsidiary. As of December 31, 2008, FirstEnergy's maximum exposure under these collateral provisions was \$585 million, consisting of \$60 million due to "material adverse event" contractual clauses and \$525 million due to a below investment grade credit rating. Additionally, stress case conditions of a credit rating downgrade or "material adverse event" and hypothetical adverse price movements in the underlying commodity markets would increase this amount to \$689 million, consisting of \$61 million due to "material adverse event" contractual clauses and \$628 million due to a below investment grade credit rating.

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees of \$95 million 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.

In addition to guarantees and surety bonds, FES' contracts, including power contracts with affiliates awarded through competitive bidding processes, typically contain margining provisions which require the posting of cash or LOCs in amounts determined by future power price movements. Based on FES' book of business as of December 31, 2008, and forward prices as of that date, FES had \$103 million outstanding in margining accounts. Under a hypothetical adverse change in forward prices (15% decrease in prices), FES would be required to post an additional \$98 million. Depending on the volume of forward contracts entered and future price movements, FES could be required to post significantly higher amounts for margining.

In July 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1. FES has unconditionally and irrevocably guaranteed all of FGCO's obligations under each of the leases (see Note 6). The related lessor notes and pass through certificates are not guaranteed by FES or FGCO, but the notes are secured by, among other things, each lessor trust's undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES' lease guaranty.

On October 8, 2008, to enhance their liquidity position in the face of the turbulent credit and bond markets, FirstEnergy, FES and FGCO entered into a \$300 million secured term loan facility with Credit Suisse. Under the facility, FGCO is the borrower and FES and FirstEnergy are guarantors. Generally, the facility is available to FGCO until October 7, 2009, with a minimum borrowing amount of \$100 million and maturity 30 days from the date of the borrowing. Once repaid, borrowings may not be re-borrowed.

Also in October 2008, FirstEnergy negotiated with the banks that have issued irrevocable direct pay LOCs in support of its outstanding variable interest rate PCRBs to extend the respective reimbursement obligations of the applicable FirstEnergy subsidiary obligors in the event that such LOCs are drawn upon. FirstEnergy's subsidiaries currently have approximately \$2.1 billion variable interest rate PCRBs outstanding (FES - \$1.9 billion, OE - \$100 million, Met-Ed - \$29 million and Penelec - \$45 million). The LOCs supporting these PCRBs may be drawn upon to pay the purchase price to bondholders that have exercised the right to tender their PCRBs for mandatory purchase. Approximately \$972 million of LOCs that previously required reimbursement within 30 days or less of a draw under the applicable LOC have now been modified to extend the reimbursement obligations to six months or June 2009, as applicable.

(C) 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 FirstEnergy 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. FirstEnergy estimates capital expenditures for environmental compliance of approximately \$608 million for the period 2009-2013.

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 become both probable and reasonably estimable.

Clean Air Act Compliance

FirstEnergy is required to meet federally-approved SO₂ emissions regulations. Violations of such regulations can result in the shutdown of the generating unit involved and/or civil or criminal penalties of up to \$37,500 for each day the unit is in violation. The EPA has an interim enforcement policy for SO₂ regulations in Ohio that allows for compliance based on a 30-day averaging period. FirstEnergy believes it is currently in compliance with this policy, but cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The EPA Region 5 issued a Finding of Violation and NOV to the Bay Shore Power Plant dated June 15, 2006, alleging violations to various sections of the CAA. FirstEnergy has disputed those alleged violations based on its CAA permit, the Ohio SIP and other information provided to the EPA at an August 2006 meeting with the EPA. The EPA has several enforcement options (administrative compliance order, administrative penalty order, and/or judicial, civil or criminal action) and has indicated that such option may depend on the time needed to achieve and demonstrate compliance with the rules alleged to have been violated. On June 5, 2007, the EPA requested another meeting to discuss "an appropriate compliance program" and a disagreement regarding emission limits applicable to the common stack for Bay Shore Units 2, 3 and 4.

FirstEnergy complies with SO₂ reduction requirements under the Clean Air Act Amendments of 1990 by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NO_x reductions required by the 1990 Amendments are being achieved through combustion controls and the generation of more electricity at lower-emitting plants. In September 1998, the EPA finalized regulations requiring additional NO_x reductions at FirstEnergy's facilities. The EPA's NO_x Transport Rule imposes uniform reductions of NO_x emissions (an approximate 85% reduction in utility plant NO_x emissions from projected 2007 emissions) across a region of nineteen states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on a conclusion that such NO_x emissions are contributing significantly to ozone levels in the eastern United States. FirstEnergy believes its facilities are also complying with the NO_x budgets established under SIPs through combustion controls and post-combustion controls, including Selective Catalytic Reduction and SNCR systems, and/or using emission allowances.

In 1999 and 2000, the EPA issued an NOV and the DOJ filed a civil complaint against OE and Penn based on operation and maintenance of the W. H. Sammis Plant (Sammis NSR Litigation) and filed similar complaints involving 44 other U.S. power plants. This case and seven other similar cases are referred to as the NSR cases. OE's and Penn's settlement with the EPA, the DOJ and three states (Connecticut, New Jersey and New York) that resolved all issues related to the Sammis NSR litigation was approved by the Court on July 11, 2005. This settlement agreement, in the form of a consent decree, requires reductions of NO_x and SO₂ emissions at the Sammis, Burger, Eastlake and Mansfield 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. Capital expenditures necessary to complete requirements of the Sammis NSR Litigation consent decree are currently estimated to be \$506 million for 2009-2010 (with \$414 million expected to be spent in 2009). This amount is included in the estimated capital expenditures for environmental compliance referenced above, but excludes the potential AQC expenditures related to Burger Units 4 and 5 described below. On September 8, 2008, the Environmental Enforcement Section of the DOJ sent a letter to OE regarding its view that the company was not in compliance with the Sammis NSR Litigation consent decree because the installation of an SNCR at Eastlake Unit 5 was not completed by December 31, 2006. However, the DOJ acknowledged that stipulated penalties could not apply under the terms of the Sammis NSR Litigation consent decree because Eastlake Unit 5 was idled on December 31, 2006 pending installation of the SNCR and advised that it had exercised its discretion not to seek any other penalties for this alleged non-compliance. OE disputed the DOJ's interpretation of the consent decree in a letter dated September 22, 2008. Although the Eastlake Unit 5 issue is no longer active, OE filed a dispute resolution petition on October 23, 2008, with the United States District Court for the Southern District of Ohio, due to potential impacts on its compliance decisions with respect to Burger Units 4 and 5. On December 23, 2008, OE withdrew its dispute resolution petition and subsequently filed a motion to extend the date (from December 31, 2008 to April 15, 2009), under the Sammis NSR Litigation consent decree, to elect for Burger Units 4 and 5 to permanently shut down those units by December 31, 2010, or to repower them or to install flue gas desulfurization (FGD) by later dates. On January 30, 2009, the Court issued an order extending the election date from December 31, 2008 to March 31, 2009.

On April 2, 2007, the United States Supreme Court ruled that changes in annual emissions (in tons/year) rather than changes in hourly emissions rate (in kilograms/hour) must be used to determine whether an emissions increase triggers NSR. Subsequently, on May 8, 2007, the EPA proposed to revise the NSR regulations to utilize changes in the hourly emission rate (in kilograms/hour) to determine whether an emissions increase triggers NSR. On December 10, 2008, the EPA announced it would not finalize this proposed change to the NSR regulations.

On May 22, 2007, FirstEnergy and FGCO received a notice letter, required 60 days prior to the filing of a citizen suit under the federal CAA, alleging violations of air pollution laws at the Bruce Mansfield Plant, including opacity limitations. Prior to the receipt of this notice, the Plant was subject to a Consent Order and Agreement with the Pennsylvania Department of Environmental Protection concerning opacity emissions under which efforts to achieve compliance with the applicable laws will continue. On October 18, 2007, PennFuture filed a complaint, joined by three of its members, in the United States District Court for the Western District of Pennsylvania. On January 11, 2008, FirstEnergy filed a motion to dismiss claims alleging a public nuisance. On April 24, 2008, the Court denied the motion to dismiss, but also ruled that monetary damages could not be recovered under the public nuisance claim. In July 2008, three additional complaints were filed against FGCO in the United States District Court for the Western District of Pennsylvania seeking damages based on Bruce Mansfield Plant air emissions. In addition to seeking damages, two of the complaints seek to enjoin the Bruce Mansfield Plant from operating except in a "safe, responsible, prudent and proper manner", one being a complaint filed on behalf of twenty-one individuals and the other being a class action complaint, seeking certification as a class action with the eight named plaintiffs as the class representatives. On October 14, 2008, the Court granted FGCO's motion to consolidate discovery for all four complaints pending against the Bruce Mansfield Plant. FGCO believes the claims are without merit and intends to defend itself against the allegations made in these complaints.

On December 18, 2007, the state of New Jersey filed a CAA citizen suit alleging NSR violations at the Portland Generation Station against Reliant (the current owner and operator), Sithe Energy (the purchaser of the Portland Station from Met-Ed in 1999), GPU, Inc. and Met-Ed. Specifically, New Jersey alleges that "modifications" at Portland Units 1 and 2 occurred between 1980 and 1995 without preconstruction NSR or permitting under the CAA's prevention of significant deterioration program, and seeks injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. On March 14, 2008, Met-Ed filed a motion to dismiss the citizen suit claims against it and a stipulation in which the parties agreed that GPU, Inc. should be dismissed from this case. On March 26, 2008, GPU, Inc. was dismissed by the United States District Court. The scope of Met-Ed's indemnity obligation to and from Sithe Energy is disputed. On October 30, 2008, the state of Connecticut filed a Motion to Intervene, but the Court has yet to rule on Connecticut's Motion. On December 5, 2008, New Jersey filed an amended complaint, adding claims with respect to alleged modifications that occurred after GPU's sale of the plant. On January 14, 2009, the EPA issued a NOV to Reliant alleging new source review violations at the Portland Generation Station based on "modifications" dating back to 1986. Met-Ed is unable to predict the outcome of this matter. The EPA's January 14, 2009, NOV also alleged new source review violations at the Keystone and Shawville Stations based on "modifications" dating back to 1984. JCP&L, as the former owner of 16.67% of Keystone Station and Penelec, as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter.

On June 11, 2008, the EPA issued a Notice and Finding of Violation to MEW alleging that "modifications" at the Homer City Power Station occurred since 1988 to the present without preconstruction NSR or permitting under the CAA's prevention of significant deterioration program. MEW is seeking indemnification from Penelec, the co-owner (along with New York State Electric and Gas Company) and operator of the Homer City Power Station prior to its sale in 1999. The scope of Penelec's indemnity obligation to and from MEW is disputed. Penelec is unable to predict the outcome of this matter.

On May 16, 2008, FGCO received a request from the EPA for information pursuant to Section 114(a) of the CAA for certain operating and maintenance information regarding the Eastlake, Lakeshore, Bay Shore and Ashtabula generating plants to allow the EPA to determine whether these generating sources are complying with the NSR provisions of the CAA. On July 10, 2008, FGCO and the EPA entered into an ACO modifying that request and setting forth a schedule for FGCO's response. On October 27, 2008, FGCO received a second request from the EPA for information pursuant to Section 114(a) of the CAA for additional operating and maintenance information regarding the Eastlake, Lakeshore, Bay Shore and Ashtabula generating plants. FGCO intends to fully comply with the EPA's information requests, but, at this time, is unable to predict the outcome of this matter.

On August 18, 2008, FirstEnergy received a request from the EPA for information pursuant to Section 114(a) of the CAA for certain operating and maintenance information regarding the Avon Lake and Niles generating plants, as well as a copy of a nearly identical request directed to the current owner, Reliant Energy, to allow the EPA to determine whether these generating sources are complying with the NSR provisions of the CAA. FirstEnergy intends to fully comply with the EPA's information request, but, at this time, is unable to predict the outcome of this matter.

National Ambient Air Quality Standards

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 requires reductions of NO_x and SO₂ emissions in two phases (Phase I in 2009 for NO_x, 2010 for SO₂ and Phase II in 2015 for both NO_x and SO₂), ultimately capping SO₂ emissions in affected states to just 2.5 million tons annually and NO_x emissions to just 1.3 million tons annually. CAIR was challenged in the United States Court of Appeals for the District of Columbia and on July 11, 2008, the Court vacated CAIR "in its entirety" and directed the EPA to "redo its analysis from the ground up." On September 24, 2008, the EPA, utility, mining and certain environmental advocacy organizations petitioned the Court for a rehearing to reconsider its ruling vacating CAIR. On December 23, 2008, the Court reconsidered its prior ruling and allowed CAIR to remain in effect to "temporarily preserve its environmental values" until the EPA replaces CAIR with a new rule consistent with the Court's July 11, 2008 opinion. The future cost of compliance with these regulations may be substantial and will depend, in part, on the action taken by the EPA in response to the Court's ruling.

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, capping national mercury emissions at 38 tons by 2010 (as a "co-benefit" from implementation of SO₂ and NO_x emission caps under the EPA's CAIR program) and 15 tons per year by 2018. Several states and environmental groups appealed the CAMR to the United States Court of Appeals for the District of Columbia. On February 8, 2008, the Court vacated the CAMR, ruling that the EPA failed to take the necessary steps to "de-list" coal-fired power plants from its hazardous air pollutant program and, therefore, could not promulgate a cap-and-trade program. The EPA petitioned for rehearing by the entire Court, which denied the petition on May 20, 2008. On October 17, 2008, the EPA (and an industry group) petitioned the United States Supreme Court for review of the Court's ruling vacating CAMR. On February 6, 2009, the United States moved to dismiss its petition for certiorari. On February 23, 2009, the Supreme Court dismissed the United States' petition and denied the industry group's petition. Accordingly, the EPA could take regulatory action to promulgate new mercury emission standards for coal-fired power plants. FGCO's future cost of compliance with mercury regulations may be substantial and will depend on the action taken by the EPA and on how they are ultimately implemented.

Pennsylvania has submitted a new mercury rule for EPA approval that does not provide a cap-and-trade approach as in the CAMR, but rather follows a command-and-control approach imposing emission limits on individual sources. On January 30, 2009, the Commonwealth Court of Pennsylvania declared Pennsylvania's mercury rule "unlawful, invalid and unenforceable" and enjoined the Commonwealth from continued implementation or enforcement of that rule. It is anticipated that compliance with these regulations, if the Commonwealth Court's rulings were reversed on appeal and Pennsylvania's mercury rule was implemented, would not require the addition of mercury controls at the Bruce Mansfield Plant, FirstEnergy's only Pennsylvania coal-fired power plant, until 2015, if at all.

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, including CO₂, emitted by developed countries by 2012. The United States signed the Kyoto Protocol in 1998 but it was never submitted for ratification by the United States Senate. However, the Bush administration had 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. Also, in an April 16, 2008 speech, former President Bush set a policy goal of stopping the growth of GHG emissions by 2025, as the next step beyond the 2012 strategy. In addition, 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. President Obama has announced his Administration's "New Energy for America Plan" that includes, among other provisions, ensuring that 10% of electricity in the United States comes from renewable sources by 2012, and 25% by 2025; and implementing an economy-wide cap-and-trade program to reduce GHG emissions 80% by 2050.

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. At the international level, efforts to reach a new global agreement to reduce GHG emissions post-2012 have begun with the Bali Roadmap, which outlines a two-year process designed to lead to an agreement in 2009. At the federal level, members of Congress have introduced several bills seeking to reduce emissions of GHG in the United States, and the Senate Environment and Public Works Committee has passed one such bill. State activities, primarily the northeastern states participating in the Regional Greenhouse Gas Initiative and western states led by California, have coordinated efforts to develop regional strategies to control emissions of certain GHGs.

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate CO₂ emissions from automobiles as “air pollutants” under the CAA. Although this decision did not address CO₂ emissions from electric generating plants, the EPA has similar authority under the CAA to regulate “air pollutants” from those and other facilities. On July 11, 2008, the EPA released an Advance Notice of Proposed Rulemaking, soliciting input from the public on the effects of climate change and the potential ramifications of regulation of CO₂ under the CAA.

FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO₂ emissions could require significant capital and other expenditures. The CO₂ 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-CO₂ 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 life is drawn into a facility's cooling water system). On January 26, 2007, the United States Court of Appeals for the Second Circuit remanded portions of the rulemaking dealing with impingement mortality and entrainment back to the EPA for further rulemaking and eliminated the restoration option from the EPA's regulations. On July 9, 2007, the EPA suspended this rule, noting that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. On April 14, 2008, the Supreme Court of the United States granted a petition for a writ of certiorari to review one significant aspect of the Second Circuit Court's opinion which is whether Section 316(b) of the Clean Water Act authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. Oral argument before the Supreme Court occurred on December 2, 2008 and a decision is anticipated during the first half of 2009. FirstEnergy is studying various control options and their costs and effectiveness. Depending on the results of such studies, the outcome of the Supreme Court's review of the Second Circuit's decision, the EPA's further rulemaking and any action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

The U.S. Attorney's Office in Cleveland, Ohio has advised FGCO that it is considering prosecution under the Clean Water Act and the Migratory Bird Treaty Act for three petroleum spills at the Edgewater, Lakeshore and Bay Shore plants which occurred on November 1, 2005, January 26, 2007 and February 27, 2007. FGCO is unable to predict the outcome of this matter.

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 non-hazardous waste.

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2008, FirstEnergy had approximately \$1.7 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. As part of the application to the NRC to transfer the ownership of Davis-Besse, Beaver Valley and Perry to NGC in 2005, FirstEnergy agreed to contribute another \$80 million to these trusts by 2010. Consistent with NRC guidance, utilizing a “real” rate of return on these funds of approximately 2% over inflation, these trusts are expected to exceed the minimum decommissioning funding requirements set by the NRC. Conservatively, these estimates do not include any rate of return that the trusts may earn over the 20-year plant useful life extensions that FirstEnergy (and Exelon for TMI-1 as it relates to the timing of the decommissioning of TMI-2) seeks for these facilities.

The Utilities 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 may be liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2008, based on estimates of the total costs of cleanup, the Utilities' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately \$90 million have been accrued through December 31, 2008. Included in the total are accrued liabilities of approximately \$56 million for environmental remediation of former manufactured gas plants in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC

(D) 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 in July 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, NJ, based on a common incident involving the failure of the bushings of two large transformers in the Red Bank substation resulting in planned and unplanned outages in the area during a 2-3 day period. In 2005, JCP&L renewed its motion to decertify the class based on a very limited number of class members who incurred damages and also filed a motion for summary judgment on the remaining plaintiffs' claims for negligence, breach of contract and punitive damages. In July 2006, the New Jersey Superior Court dismissed the punitive damage claim and again decertified the class based on the fact that a vast majority of the class members did not suffer damages and those that did would be more appropriately addressed in individual actions. Plaintiffs appealed this ruling to the New Jersey Appellate Division which, in March 2007, reversed the decertification of the Red Bank class and remanded this matter back to the Trial Court to allow plaintiffs sufficient time to establish a damage model or individual proof of damages. JCP&L filed a petition for allowance of an appeal of the Appellate Division ruling to the New Jersey Supreme Court which was denied in May 2007. Proceedings are continuing in the Superior Court and a case management conference with the presiding Judge was held on June 13, 2008. At that conference, the plaintiffs stated their intent to drop their efforts to create a class-wide damage model and, instead of dismissing the class action, expressed their desire for a bifurcated trial on liability and damages. The judge directed the plaintiffs to indicate, on or before August 22, 2008, how they intend to proceed under this scenario. Thereafter, the judge expects to hold another pretrial conference to address plaintiffs' proposed procedure. JCP&L has received the plaintiffs' proposed plan of action, and intends to file its objection to the proposed plan, and also file a renewed motion to decertify the class. JCP&L is defending this action but is unable to predict the outcome. No liability has been accrued as of December 31, 2008.

On December 9, 2008, a transformer at JCP&L's Oceanview substation failed, resulting in an outage on certain bulk electric system (transmission voltage) lines out of the Oceanview and Atlantic substations, with customers in the affected area losing power. Power was restored to most customers within a few hours, and to all customers within eleven hours. On December 16, 2008, JCP&L provided preliminary information about the event to certain regulatory agencies, including the NERC. In a letter dated January 30, 2009, the NERC submitted a written "Notice of Request for Information" (NOI) to JCP&L. The NOI asked for additional factual details about the December 9 event, which JCP&L provided in its response. JCP&L is not able to predict what actions, if any, the NERC may take in response to JCP&L's NOI submittal.

Nuclear Plant Matters

On May 14, 2007, the Office of Enforcement of the NRC issued a DFI to FENOC, following FENOC's reply to an April 2, 2007 NRC request for information about two reports prepared by expert witnesses for an insurance arbitration (the insurance claim was subsequently withdrawn by FirstEnergy in December 2007) related to Davis-Besse. The NRC indicated that this information was needed for the NRC "to determine whether an Order or other action should be taken pursuant to 10 CFR 2.202, to provide reasonable assurance that FENOC will continue to operate its licensed facilities in accordance with the terms of its licenses and the Commission's regulations." FENOC was directed to submit the information to the NRC within 30 days. On June 13, 2007, FENOC filed a response to the NRC's DFI reaffirming that it accepts full responsibility for the mistakes and omissions leading up to the damage to the reactor vessel head and that it remains committed to operating Davis-Besse and FirstEnergy's other nuclear plants safely and responsibly. FENOC submitted a supplemental response clarifying certain aspects of the DFI response to the NRC on July 16, 2007. On August 15, 2007, the NRC issued a confirmatory order imposing these commitments. FENOC must inform the NRC's Office of Enforcement after it completes the key commitments embodied in the NRC's order. FENOC has conducted the employee training required by the confirmatory order and a consultant has performed follow-up reviews to ensure the effectiveness of that training. The NRC continues to monitor FENOC's compliance with all the commitments made in the confirmatory order.

In August 2007, FENOC submitted an application to the NRC to renew the operating licenses for the Beaver Valley Power Station (Units 1 and 2) for an additional 20 years. The NRC is required by statute to provide an opportunity for members of the public to request a hearing on the application. No members of the public, however, requested a hearing on the Beaver Valley license renewal application. On September 24, 2008, the NRC issued a draft supplemental Environmental Impact Statement for Beaver Valley. FENOC will continue to work with the NRC Staff as it completes its environmental and technical reviews of the license renewal application, and expects to obtain renewed licenses for the Beaver Valley Power Station in 2009. If renewed licenses are issued by the NRC, the Beaver Valley Power Station's licenses would be extended until 2036 and 2047 for Units 1 and 2, respectively.

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 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 also sought injunctive relief to eliminate harmful emissions and repair property damage and the institution of a medical monitoring program for class members. On April 5, 2007, the Court rejected the plaintiffs' request to certify this case as a class action and, accordingly, did not appoint the plaintiffs as class representatives or their counsel as class counsel. On July 30, 2007, plaintiffs' counsel voluntarily withdrew their request for reconsideration of the April 5, 2007 Court order denying class certification and the Court heard oral argument on the plaintiffs' motion to amend their complaint, which OE opposed. On August 2, 2007, the Court denied the plaintiffs' motion to amend their complaint. Plaintiffs appealed the Court's denial of the motion for certification as a class action which the Ohio Court of Appeals (7th District) denied on December 11, 2008. The period to file a notice of appeal to the Ohio Supreme Court has expired.

JCP&L's bargaining unit employees filed a grievance challenging JCP&L's 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties' collective bargaining agreement. At the conclusion of the June 1, 2005 hearing, the arbitration panel decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the arbitration panel issued an opinion to award approximately \$16 million to the bargaining unit employees. On February 6, 2006, a federal district Court granted a union motion to dismiss, as premature, a JCP&L appeal of the award filed on October 18, 2005. A final order identifying the individual damage amounts was issued on October 31, 2007. The award appeal process was initiated. The union filed a motion with the federal Court to confirm the award and JCP&L filed its answer and counterclaim to vacate the award on December 31, 2007. JCP&L and the union filed briefs in June and July of 2008 and oral arguments were held in the fall. The Court has yet to render its decision. JCP&L recognized a liability for the potential \$16 million award in 2005.

The union employees at the Bruce Mansfield Plant have been working without a labor contract since February 15, 2008. The parties are continuing to bargain with the assistance of a federal mediator. FirstEnergy has a strike mitigation plan ready in the event of a strike.

FirstEnergy accrues legal 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. 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.

15. SEGMENT INFORMATION

FirstEnergy has three reportable operating segments: energy delivery services, competitive energy services and Ohio transitional generation services. The assets and revenues for all other business operations are below the quantifiable threshold for operating segments for separate disclosure as “reportable operating segments.”

The energy delivery services segment designs, constructs, operates and maintains FirstEnergy's regulated transmission and distribution systems and is responsible for the regulated generation commodity operations of FirstEnergy's Pennsylvania and New Jersey electric utility subsidiaries. Its revenues are primarily derived from the delivery of electricity, cost recovery of regulatory assets, and default service electric generation sales to non-shopping customers in its Pennsylvania and New Jersey franchise areas. Its results reflect the commodity costs of securing electric generation from FES under partial requirements purchased power agreements and from non-affiliated power suppliers as well as the net PJM transmission expenses related to the delivery of that generation load.

The competitive energy services segment supplies electric power to its electric utility affiliates, provides competitive electricity sales primarily in Ohio, Pennsylvania, Maryland and Michigan, owns or leases and operates FirstEnergy's generating facilities and purchases electricity to meet its sales obligations. The segment's net income is primarily derived from the affiliated company PSA sales and the non-affiliated electric generation sales revenues less the related costs of electricity generation, including purchased power and net transmission (including congestion) and ancillary costs charged by PJM and MISO to deliver electricity to the segment's customers. The segment's internal revenues represent the affiliated company PSA sales.

The Ohio transitional generation services segment represents the regulated generation commodity operations of FirstEnergy's Ohio electric utility subsidiaries. Its revenues are primarily derived from electric generation sales to non-shopping customers under the PLR obligations of the Ohio Companies. Its results reflect the purchase of electricity from the competitive energy services segment through full-requirements PSA arrangements, the deferral and amortization of certain fuel costs authorized for recovery by the energy delivery services segment and the net MISO transmission revenues and expenses related to the delivery of generation load. This segment's total assets consist of accounts receivable for generation revenues from retail customers.

Segment Financial Information	Energy Delivery Services	Competitive Energy Services	Ohio		Reconciling Adjustments	Consolidated
			Transitional Generation Services	Other		
(In millions)						
2008						
External revenues	\$ 9,166	\$ 1,571	\$ 2,902	\$ 72	\$ (84)	\$ 13,627
Internal revenues	-	2,968	-	-	(2,968)	-
Total revenues	9,166	4,539	2,902	72	(3,052)	13,627
Depreciation and amortization	1,090	243	64	4	13	1,414
Investment income	170	(34)	1	6	(84)	59
Net interest charges	407	108	1	2	184	702
Income taxes	555	314	56	(53)	(95)	777
Net income	833	472	83	116	(162)	1,342
Total assets	22,760	9,559	265	539	398	33,521
Total goodwill	5,551	24	-	-	-	5,575
Property additions	839	1,835	-	176	38	2,888
2007						
External revenues	\$ 8,726	\$ 1,468	\$ 2,596	\$ 39	\$ (27)	\$ 12,802
Internal revenues	-	2,901	-	-	(2,901)	-
Total revenues	8,726	4,369	2,596	39	(2,928)	12,802
Depreciation and amortization	1,024	204	(125)	4	26	1,133
Investment income	240	16	1	1	(138)	120
Net interest charges	445	152	1	4	141	743
Income taxes	574	330	69	4	(94)	883
Net income	862	495	103	12	(163)	1,309
Total assets	23,595	7,669	231	303	513	32,311
Total goodwill	5,583	24	-	-	-	5,607
Property additions	814	740	-	21	58	1,633
2006						
External revenues	\$ 7,623	\$ 1,429	\$ 2,390	\$ 95	\$ (36)	\$ 11,501
Internal revenues	14	2,609	-	-	(2,623)	-
Total revenues	7,637	4,038	2,390	95	(2,659)	11,501
Depreciation and amortization	845	190	(105)	4	23	957
Investment income	328	35	-	1	(215)	149
Net interest charges	433	188	1	6	74	702
Income taxes	595	262	75	(21)	(116)	795
Income from continuing operations	893	393	112	44	(184)	1,258
Discontinued operations	-	-	-	(4)	-	(4)
Net income	893	393	112	40	(184)	1,254
Total assets	22,863	6,978	215	297	843	31,196
Total goodwill	5,873	24	-	1	-	5,898
Property additions	629	644	-	4	38	1,315

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 and elimination of intersegment transactions.

Year	Electricity Sales	Energy Related Sales and Services
(In millions)		
2008	\$ 12,693	\$ -
2007	11,944	-
2006	10,671	48

* See Note 8 for discussion of discontinued operations.

16. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

SFAS 141(R) – “Business Combinations”

In December 2007, the FASB issued SFAS 141(R), which: (i) requires the acquiring entity in a business combination to recognize all assets acquired and liabilities assumed in the transaction; (ii) establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and (iii) requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. The Standard includes both core principles and pertinent application guidance, eliminating the need for numerous EITF issues and other interpretative guidance. SFAS 141(R) will affect business combinations entered into by FirstEnergy that close after January 1, 2009. In addition, the Standard also affects the accounting for changes in deferred tax valuation allowances and income tax uncertainties made after January 1, 2009, that were established as part of a business combination prior to the implementation of this Standard. Under SFAS 141(R), adjustments to the acquired entity’s deferred tax assets and uncertain tax position balances occurring outside the measurement period will be recorded as a component of income tax expense, rather than goodwill. The impact of FirstEnergy’s application of this Standard in periods after implementation will be dependent upon the nature of acquisitions at that time.

SFAS 160 - “Non-controlling Interests in Consolidated Financial Statements – an Amendment of ARB No. 51”

In December 2007, the FASB issued SFAS 160 that establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. This Statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is prohibited. The Statement is not expected to have a material impact on FirstEnergy’s financial statements.

SFAS 161 - “Disclosures about Derivative Instruments and Hedging Activities – an Amendment of FASB Statement No. 133”

In March 2008, the FASB issued SFAS 161 that enhances the current disclosure framework for derivative instruments and hedging activities. The Statement requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. The FASB believes that additional required disclosure of the fair values of derivative instruments and their gains and losses in a tabular format will provide a more complete picture of the location in an entity’s financial statements of both the derivative positions existing at period end and the effect of using derivatives during the reporting period. Disclosing information about credit-risk-related contingent features is designed to provide information on the potential effect on an entity’s liquidity from using derivatives. This Statement also requires cross-referencing within the footnotes to help users of financial statements locate important information about derivative instruments. The Statement is effective for reporting periods beginning after November 15, 2008. FirstEnergy expects this Standard to increase its disclosure requirements for derivative instruments and hedging activities.

EITF Issue No. 08-6 – “Equity Method Investment Accounting Considerations”

In November 2008, the FASB issued EITF 08-6, which clarifies how to account for certain transactions involving equity method investments. It provides guidance in determining the initial carrying value of an equity method investment, accounting for a change in an investment from equity method to cost method, assessing the impairment of underlying assets of an equity method investment, and accounting for an equity method investee’s issuance of shares. This statement is effective for transactions occurring in fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is not permitted. The impact of FirstEnergy’s application of this Standard in periods after implementation will be dependent upon the nature of future investments accounted for under the equity method.

FSP SFAS 132 (R)-1 – “Employers’ Disclosures about Postretirement Benefit Plan Assets”

In December 2008, the FASB issued Staff Position (FSP) SFAS 132(R)-1, which provides guidance on an employer’s disclosures about plan assets of a defined benefit pension or other postretirement plan. Requirements of this FSP include disclosures about investment policies and strategies, categories of plan assets, fair value measurements of plan assets, and significant categories of risk. This FSP is effective for fiscal years ending after December 15, 2009. FirstEnergy expects this Staff Position to increase its disclosure requirements for postretirement benefit plan assets.

17. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED)

The following summarizes certain consolidated operating results by quarter for 2008 and 2007.

Three Months Ended	March 31, 2008	June 30, 2008	September 30, 2008	December 31, 2008
<i>(In millions, except per share amounts)</i>				
Revenues	\$ 3,277	\$ 3,245	\$ 3,904	\$ 3,201
Expenses	2,660	2,663	3,058	2,484
Operating Income	617	582	846	717
Other Expense	154	159	137	193
Income Before Income Taxes	463	423	709	524
Income Taxes	187	160	238	192
Net Income	<u>\$ 276</u>	<u>\$ 263</u>	<u>\$ 471</u>	<u>\$ 332</u>
Earnings Per Share of Common Stock:				
Basic	<u>\$ 0.91</u>	<u>\$ 0.86</u>	<u>\$ 1.55</u>	<u>\$ 1.09</u>
Diluted	<u>\$ 0.90</u>	<u>\$ 0.85</u>	<u>\$ 1.54</u>	<u>\$ 1.09</u>

Three Months Ended	March 31, 2007	June 30, 2007	September 30, 2007	December 31, 2007
<i>(In millions, except per share amounts)</i>				
Revenues	\$ 2,973	\$ 3,109	\$ 3,641	\$ 3,079
Expenses	2,336	2,381	2,791	2,479
Operating Income	637	728	850	600
Other Expense	147	168	164	144
Income Before Income Taxes	490	560	686	456
Income Taxes	200	222	273	188
Net Income	<u>\$ 290</u>	<u>\$ 338</u>	<u>\$ 413</u>	<u>\$ 268</u>
Earnings Per Share of Common Stock:				
Basic	<u>\$ 0.92</u>	<u>\$ 1.11</u>	<u>\$ 1.36</u>	<u>\$ 0.88</u>
Diluted	<u>\$ 0.92</u>	<u>\$ 1.10</u>	<u>\$ 1.34</u>	<u>\$ 0.87</u>

ANNUAL REPORT 2008

FirstEnergy
Solutions

OhioEdison
A FirstEnergy Company

**the
Illuminating
Company**
A FirstEnergy Company

ToledoEdison
A FirstEnergy Company

**Jersey Central
Power & Light**
A FirstEnergy Company

Met-Ed
A FirstEnergy Company

Penelec
A FirstEnergy Company

<u>Contents</u>	<u>Page</u>
Glossary of Terms	iii-v
FirstEnergy Solutions Corp.	
Management's Narrative Analysis of Results of Operations	1-5
Management Reports	6
Report of Independent Registered Public Accounting Firm	7
Consolidated Statements of Income	8
Consolidated Balance Sheets	9
Consolidated Statements of Capitalization	10
Consolidated Statements of Common Stockholder's Equity	11
Consolidated Statements of Cash Flows	12
Ohio Edison Company	
Management's Narrative Analysis of Results of Operations	13-15
Management Reports	16
Report of Independent Registered Public Accounting Firm	17
Consolidated Statements of Income	18
Consolidated Balance Sheets	19
Consolidated Statements of Capitalization	20
Consolidated Statements of Common Stockholder's Equity	21
Consolidated Statements of Cash Flows	22
The Cleveland Electric Illuminating Company	
Management's Narrative Analysis of Results of Operations	23-25
Management Reports	26
Report of Independent Registered Public Accounting Firm	27
Consolidated Statements of Income	28
Consolidated Balance Sheets	29
Consolidated Statements of Capitalization	30
Consolidated Statements of Common Stockholder's Equity	31
Consolidated Statements of Cash Flows	32
The Toledo Edison Company	
Management's Narrative Analysis of Results of Operations	33-35
Management Reports	36
Report of Independent Registered Public Accounting Firm	37
Consolidated Statements of Income	38
Consolidated Balance Sheets	39
Consolidated Statements of Capitalization	40
Consolidated Statements of Common Stockholder's Equity	41
Consolidated Statements of Cash Flows	42
Jersey Central Power & Light Company	
Management's Narrative Analysis of Results of Operations	43-46
Management Reports	47
Report of Independent Registered Public Accounting Firm	48
Consolidated Statements of Income	49
Consolidated Balance Sheets	50
Consolidated Statements of Capitalization	51
Consolidated Statements of Common Stockholder's Equity	52
Consolidated Statements of Cash Flows	53

Contents (Cont'd)**Page****Metropolitan Edison Company**

Management's Narrative Analysis of Results of Operations	54-57
Management Reports	58
Report of Independent Registered Public Accounting Firm	59
Consolidated Statements of Income	60
Consolidated Balance Sheets	61
Consolidated Statements of Capitalization	62
Consolidated Statements of Common Stockholder's Equity	63
Consolidated Statements of Cash Flows	64

Pennsylvania Electric Company

Management's Narrative Analysis of Results of Operations	65-68
Management Reports	69
Report of Independent Registered Public Accounting Firm	70
Consolidated Statements of Income	71
Consolidated Balance Sheets	72
Consolidated Statements of Capitalization	73
Consolidated Statements of Common Stockholder's Equity	74
Consolidated Statements of Cash Flows	75

Combined Management's Discussion and Analysis of Registrant Subsidiaries

76-90

Combined Notes to Consolidated Financial Statements

91-145

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
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
FirstEnergy	FirstEnergy Corp., a public utility holding company
GPU	GPU, Inc., former parent of JCP&L, Met-Ed and Penelec, which merged with FirstEnergy on November 7, 2001
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
JCP&L Transition Funding	JCP&L Transition Funding LLC, a Delaware limited liability company and issuer of transition bonds
JCP&L Transition Funding II	JCP&L Transition Funding II LLC, a Delaware limited liability company and issuer of transition bonds
Met-Ed	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
NGC	FirstEnergy Nuclear Generation Corp., owns nuclear generating facilities
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
Ohio Companies	CEI, OE and TE
Pennsylvania Companies	Met-Ed, Penelec and Penn
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
Utilities	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec
Waverly	The Waverly Power and Light Company, a wholly owned subsidiary of Penelec

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

ACO	Administrative Consent Order
AEP	American Electric Power Company, Inc.
ALJ	Administrative Law Judge
AMP-Ohio	American Municipal Power - Ohio
AOCI	Accumulated Other Comprehensive Income
AOCL	Accumulated Other Comprehensive Loss
AQC	Air Quality Control
ARB	Accounting Research Bulletin
ARO	Asset Retirement Obligation
BGS	Basic Generation Service
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAT	Commercial Activity Tax
CBP	Competitive Bid Process
CO ₂	Carbon Dioxide
CTC	Competitive Transition Charge
DFI	Demand for Information
DOJ	United States Department of Justice
DRA	Division of Ratepayer Advocate
EIS	Energy Independence Strategy
EITF	Emerging Issues Task Force
EITF 01-8	Determining Whether an Arrangement Contains a Lease
EITF 08-6	Equity Method Investment Accounting Considerations
EMP	Energy Master Plan

GLOSSARY OF TERMS Cont'd.

EPA	Environmental Protection Agency
EPACT	Energy Policy Act of 2005
ESP	Electric Security Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FIN 46R	FIN 46 (revised December 2003), "Consolidation of Variable Interest Entities"
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 Bond
FSP	FASB Staff Position
FSP SFAS 115-1 and SFAS 124-1	FSP SFAS 115-1 and SFAS 124-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"
GAAP	Accounting Principles Generally Accepted in the United States
GHG	Greenhouse Gases
IRS	Internal Revenue Service
ISO	Independent System Operator
kV	Kilovolt
KWH	Kilowatt-hours
LED	Light-emitting Diode
LOC	Letter of Credit
MEW	Mission Energy Westside, Inc.
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service, Inc.
MRO	Market Rate Offer
MTC	Market Transition Charge
MW	Megawatts
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NOV	Notice of Violation
NO _x	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NUGC	Non-Utility Generation Charge
OCA	Office of Consumer Advocate
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OSBA	Office of Small Business Advocate
OTC	Over the Counter
PCRB	Pollution Control Revenue Bond
PJM	PJM Interconnection L. L. C.
PLR	Provider of Last Resort; an electric utility's obligation to provide generation service to customers whose alternative supplier fails to deliver service
PPUC	Pennsylvania Public Utility Commission
PRP	Potentially Responsible Party
PSA	Power Supply Agreement
PUCO	Public Utilities Commission of Ohio
PUHCA	Public Utility Holding Company Act of 1935
RCP	Rate Certainty Plan
RECB	Regional Expansion Criteria and Benefits
RFP	Request for Proposal
RSP	Rate Stabilization Plan
RTC	Regulatory Transition Charge
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Service
SBC	Societal Benefits Charge
SEC	U.S. Securities and Exchange Commission
SECA	Seams Elimination Cost Adjustment

GLOSSARY OF TERMS Cont'd.

SFAS	Statement of Financial Accounting Standards
SFAS 71	SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 101	SFAS No. 101, "Accounting for Discontinuation of Application of SFAS 71"
SFAS 107	SFAS No. 107, "Disclosure about Fair Value of Financial Instruments"
SFAS 109	SFAS No. 109, "Accounting for Income Taxes"
SFAS 115	SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities"
SFAS 132(R)-1	SFAS No. 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets"
SFAS 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS 141(R)	SFAS No. 141(R), "Business Combinations"
SFAS 142	SFAS No. 142, "Goodwill and Other Intangible Assets"
SFAS 143	SFAS No. 143, "Accounting for Asset Retirement Obligations"
SFAS 144	SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets"
SFAS 157	SFAS No. 157, "Fair Value Measurements"
SFAS 158	SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)"
SFAS 159	SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115"
SFAS 160	SFAS No. 160, "Non-controlling Interests in Consolidated Financial Statements – an Amendment of ARB No. 51"
SFAS 161	SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an Amendment of FASB Statement No. 133"
SIP	State Implementation Plan(s) Under the Clean Air Act
SNCR	Selective Non-Catalytic Reduction
SO ₂	Sulfur Dioxide
TBC	Transition Bond Charge
TMI-1	Three Mile Island Unit 1
TMI-2	Three Mile Island Unit 2
TSC	Transmission Service Charge
VIE	Variable Interest Entity

This combined Annual Report is separately filed by FirstEnergy Solutions Corp., Ohio Edison 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.

Forward-Looking Statements: This discussion includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Actual results may differ materially due to the speed and nature of increased competition in the electric utility industry and legislative and regulatory changes affecting how generation rates will be determined following the expiration of existing rate plans in Ohio and Pennsylvania, the impact of the PUCO's regulatory process on the Ohio Companies associated with the ESP and MRO filings, including any resultant mechanism under which the Ohio Companies may not fully recover costs (including, but not limited to, the costs of generation supply procured by the Ohio Companies, Regulatory Transition Charges and fuel charges), or the outcome of any competitive generation procurement process in Ohio, economic or weather conditions affecting future sales and margins, changes in markets for energy services, changing energy and commodity market prices and availability, replacement power costs being higher than anticipated or inadequately hedged, the continued ability of the Utilities to collect transition and other charges or to recover increased transmission costs, maintenance costs being higher than anticipated, other legislative and regulatory changes, revised environmental requirements, including possible greenhouse gas emission regulations, the potential impacts of the U.S. Court of Appeals' July 11, 2008 decision requiring revisions to the CAIR rules and the scope of any laws, rules or regulations that may ultimately take their place, the uncertainty of the timing and amounts of the capital expenditures needed to, among other things, implement the AQC Plan (including that such amounts could be higher than anticipated or that certain generating units may need to be shut down) or levels of emission reductions related to the Consent Decree resolving the NSR litigation or other potential regulatory initiatives, adverse regulatory or legal decisions and outcomes (including, but not limited to, the revocation of necessary licenses or operating permits and oversight) by the NRC (including, but not limited to, the Demand for Information issued to FENOC on May 14, 2007), the timing and outcome of various proceedings before the PUCO (including, but not limited to the distribution rate cases and the generation supply plan filing for the Ohio Companies and the successful resolution of the issues remanded to the PUCO by the Ohio Supreme Court regarding the RSP and the RCP, including the recovery of deferred fuel costs), Met-Ed's and Penelec's transmission service charge filings with the PPUC, the continuing availability of generating units and their ability to operate at or near full capacity, the ability to comply with applicable state and federal reliability standards, the ability to accomplish or realize anticipated benefits from strategic goals (including employee workforce initiatives), the ability to improve electric commodity margins and to experience growth in the distribution business, the changing market conditions that could affect the value of assets held in nuclear decommissioning trusts, pension trusts and other trust funds, and cause the registrants to make additional contributions sooner, or in an amount that is larger than currently anticipated, the ability to access the public securities and other capital and credit markets in accordance with FirstEnergy's financing plan and the cost of such capital, changes in general economic conditions affecting the registrants, the state of the capital and credit markets affecting the registrants, interest rates and any actions taken by credit rating agencies that could negatively affect the registrants' access to financing or its costs and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees, the continuing decline of the national and regional economy and its impact on the registrants' major industrial and commercial customers, issues concerning the soundness of financial institutions and counterparties with which the registrants do business, and the risks and other factors discussed from time to time in the registrant's SEC filings, and other similar factors. The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on the registrant's business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. 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.

FIRSTENERGY SOLUTIONS CORP.

**MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS**

FES is a wholly owned subsidiary of FirstEnergy. FES provides energy-related products and services primarily in Ohio, Pennsylvania, Michigan and Maryland, and through its subsidiaries, FGCO and NGC, owns or leases and operates and maintains FirstEnergy's fossil and hydroelectric generation facilities and owns FirstEnergy's nuclear generation facilities, respectively. FENOC, a wholly owned subsidiary of FirstEnergy, operates and maintains the nuclear generating facilities.

FES' revenues are primarily derived from the sale of electricity (provided from FES' generating facilities and through purchased power arrangements) to affiliated utility companies to meet all or a portion of their PLR and default service requirements. These affiliated power sales included a full-requirements PSA with OE, CEI and TE to supply each of their default service obligations through December 31, 2008, at prices that considered their respective PUCO-authorized billing rates. See Regulatory Matters – Ohio below for a discussion of power supply for 2009 and beyond. FES also has a partial requirements wholesale power sales agreement with its affiliates, Met-Ed and Penelec, to supply a portion of each of their respective default service obligations at fixed prices through 2009. This sales agreement is renewed annually unless cancelled by either party with at least a sixty day written notice prior to the end of the calendar year. The fixed prices under the partial requirements agreement are expected to remain below wholesale market prices during the term of the agreement. FES also supplies a portion of Penn's default service requirements at market-based rates as a result of Penn's 2008 competitive solicitations. FES' revenues also include competitive retail and wholesale sales to non-affiliated customers in Ohio, Pennsylvania, New Jersey, Maryland, Michigan and Illinois.

Results of Operations

Net income decreased to \$506 million in 2008 from \$529 million in 2007 primarily due to higher fuel, depreciation and other operating expenses and lower investment income, partially offset by higher revenues and lower purchased power and interest expenses.

Revenues

Revenues increased by \$193 million in 2008 compared to 2007 primarily due to increases in revenues from wholesale sales, partially offset by lower retail generation sales. The increase in revenues in 2008 from 2007 is summarized below:

<u>Revenues by Type of Service</u>	<u>2008</u>	<u>2007</u>	<u>Increase (Decrease)</u>
	<i>(In millions)</i>		
Non-Affiliated Generation Sales:			
Retail	\$ 615	\$ 712	\$ (97)
Wholesale	717	603	114
Total Non-Affiliated Generation Sales	1,332	1,315	17
Affiliated Wholesale Generation Sales	2,968	2,901	67
Transmission	150	103	47
Other	68	6	62
Total Revenues	<u>\$ 4,518</u>	<u>\$ 4,325</u>	<u>\$ 193</u>

Retail generation sales revenues decreased due to lower contract renewals for commercial and industrial customers in the PJM market and the termination of certain government aggregation programs in the MISO market. Non-affiliated wholesale revenues increased due to higher capacity prices and sales volumes in the PJM market, partially offset by decreased sales volumes in the MISO market.

Increased affiliated company wholesale sales resulted from higher unit prices for the Ohio Companies partially offset by lower unit prices for the Pennsylvania Companies and decreased sales volumes to all affiliates. Higher unit prices on sales to the Ohio Companies were due to the PSA provision that provides for prices to reflect the increase in the Ohio Companies' retail generation rates (see Regulatory Matters – Ohio). While unit prices for each of the Pennsylvania Companies did not change, the mix of sales among the companies caused the overall composite price to decline. The lower PSA affiliated sales volumes were due to milder weather and reduced default service requirements in Penn's service territory as a result of its RFP process.

The following tables summarize the price and volume factors contributing to changes in revenues from non-affiliated and affiliated generation sales in 2008 compared to 2007:

<u>Source of Change in Non-Affiliated Generation Revenues</u>	<u>Increase (Decrease)</u> <i>(In millions)</i>
Retail:	
Effect of 15.8% decrease in sales volumes	\$ (113)
Change in prices	16
	<u>(97)</u>
Wholesale:	
Effect of 3.8% increase in sales volumes	23
Change in prices	91
	<u>114</u>
Net Increase in Non-Affiliated Generation Revenues	<u>\$ 17</u>

<u>Source of Change in Affiliated Generation Revenues</u>	<u>Increase (Decrease)</u> <i>(In millions)</i>
Ohio Companies:	
Effect of 1.5% decrease in sales volumes	\$ (34)
Change in prices	129
	<u>95</u>
Pennsylvania Companies:	
Effect of 1.5% decrease in sales volumes	(10)
Change in prices	(18)
	<u>(28)</u>
Net Increase in Affiliated Generation Revenues	<u>\$ 67</u>

Transmission revenue increased \$47 million due primarily to higher rates for transmission service in MISO and PJM. Other revenue increased by \$62 million principally due to revenue from affiliated companies for the lessor equity interests in Beaver Valley Unit 2 and Perry that were acquired by NGC during the second quarter of 2008.

Expenses

Total expenses increased by \$194 million in 2008 compared to 2007. The following tables summarize the factors contributing to the changes in fuel and purchased power costs in 2008 from 2007:

<u>Source of Change in Fuel Costs</u>	<u>Increase (Decrease)</u> <i>(In millions)</i>
Fossil Fuel:	
Change due to volume consumed	\$ 90
Change due to increased unit costs	129
	<u>219</u>
Nuclear Fuel:	
Change due to volume consumed	8
Change due to increased unit costs	1
	<u>9</u>
Net Increase in Fuel Costs	<u>\$ 228</u>

<u>Source of Change in Purchased Power Costs</u>	<u>Increase (Decrease)</u> <i>(In millions)</i>
Purchased Power From Affiliates	
Change due to volume purchased	\$ (124)
Change due to decreased unit costs	(9)
	<u>(133)</u>
Purchased Power From Non-affiliates:	
Change due to volume purchased	(215)
Change due to increased unit costs	230
	<u>15</u>
Net Decrease in Purchased Power Costs	<u>\$ (118)</u>

Fossil fuel costs increased \$219 million in 2008, primarily as a result of the assignment of CEI's and TE's leasehold interest in the Bruce Mansfield Plant to FGCO in October 2007 (\$66 million) and higher unit prices due to increased coal transportation costs (\$112 million), increased prices for existing eastern coal contracts (\$32 million) and emission allowance costs (\$5 million). Nuclear fuel expense increased \$9 million, primarily reflecting higher generation in 2008.

Purchased power costs decreased as a result of reduced purchases from affiliates, partially offset by increased non-affiliated purchased power unit costs. Purchases from affiliated companies decreased as a result of the assignment of CEI's and TE's leasehold interests in the Mansfield Plant to FGCO; prior to the assignment, FGCO purchased the associated output from CEI and TE. Purchased power costs from non-affiliates increased primarily as a result of higher spot market prices in MISO and higher capacity prices in PJM, partially offset by reduced volumes reflecting lower retail sales requirements and more generation available from FES' facilities.

Other operating expenses increased by \$44 million in 2008 from 2007, primarily due to expenses associated with the assignment of CEI's and TE's leasehold interests in the Mansfield Plant to FGCO (\$38 million) and the sale and leaseback of Mansfield Unit 1 (\$74 million) completed in the second half of 2007. Transmission expenses decreased as a result of reduced congestion charges (\$35 million). Lower fossil operating costs were primarily due to a gain on the sale of a coal contract in the fourth quarter of 2008 (\$21 million), reduced scheduled outage activity (\$17 million) and increased gains from emission allowance sales (\$5 million), partially offset by costs associated with a cancelled electro-catalytic oxidation project (\$13 million).

Depreciation expense increased by \$39 million in 2008 primarily due to the assignment of the Mansfield Plant to FGCO described above and NGC's acquisition of certain lessor equity interests in the sale and leaseback of Perry and Beaver Valley Unit 2.

Other Expense

Other expense increased by \$33 million in 2008 primarily due to a \$49 million additional loss on nuclear decommissioning trust investments as a result of securities impairments during 2008 and reduced investment income from loans to the unregulated money pool (\$15 million). Interest expense to affiliates decreased \$36 million due to reduced loans from the unregulated money pool and the repayment of notes payable to affiliates since 2007, partially offset by higher other interest expense (net of capitalized interest) of \$5 million.

Working Capital

As of December 31, 2008, FES' net deficit in working capital (current assets less current liabilities) was principally due to short-term borrowings and the classification of certain variable interest rate PCRBs as currently payable long-term debt (see Note 10(C)). As of December 31, 2008, FES had access to \$1.3 billion of short-term financing under revolving credit facilities. In addition, FES has the ability to borrow from FirstEnergy under the unregulated money pool to meet its short-term working capital requirements.

Market Risk Information

FES 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.

Commodity Price Risk

FES 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, FES 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 FES' derivative contracts qualify for the normal purchase and normal sale exception under SFAS 133 and are therefore excluded from the table below. The change in the fair value of commodity derivative contracts related to energy production during 2008 is summarized in the following table:

Increase (Decrease) in the Fair Value of Derivative Contracts	Non-Hedge	Hedge	Total
		<i>(In millions)</i>	
Change in the fair value of commodity derivative contracts:			
Outstanding net liability as of January 1, 2008	\$ -	\$ (26)	\$ (26)
Additions/change in value of existing contracts	(1)	(19)	(20)
Settled contracts	-	4	4
Outstanding net liability as of December 31, 2008	\$ (1)	\$ (41)	\$ (42)
Non-commodity net liabilities as of December 31, 2008:			
Interest rate swaps	\$ -	\$ -	\$ -
Net liabilities – derivative contracts as of December 31, 2008	\$ (1)	\$ (41)	\$ (42)
Impact of changes in commodity derivative contracts ^(*)			
Income Statement effects (Pre-Tax)	\$ (1)	\$ -	\$ (1)
Balance Sheet effects:			
OCI (Pre-Tax)	\$ -	\$ (15)	\$ (15)

(*) 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 December 31, 2008 as follows:

Balance Sheet Classification	Non-Hedge	Hedge	Total
		<i>(In millions)</i>	
Current-			
Other assets	\$ 1	\$ 11	\$ 12
Other liabilities	(2)	(43)	(45)
Non-Current-			
Other deferred charges	-	-	-
Other noncurrent liabilities	-	(9)	(9)
Net liabilities	\$ (1)	\$ (41)	\$ (42)

The valuation of derivative contracts is based on observable market information to the extent that such information is available. FES uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making. Sources of information for the valuation of commodity derivative contracts by year are summarized in the following table:

Source of Information							
- Fair Value by Contract Year	2009	2010	2011	2012	2013	Thereafter	Total
				<i>(In millions)</i>			
Prices actively quoted ⁽¹⁾	\$ (16)	\$ (9)	\$ -	\$ -	\$ -	\$ -	\$ (25)
Broker quote sheets ⁽²⁾	(17)	-	-	-	-	-	(17)
Total	\$ (33)	\$ (9)	\$ -	\$ -	\$ -	\$ -	\$ (42)

(1) Exchange traded.

(2) Validated by observable market transactions.

FES 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 FES' derivative instruments would not have had a material effect on its consolidated financial position (assets, liabilities and equity) or cash flows as of December 31, 2008. Based on derivative contracts held as of December 31, 2008, an adverse 10% change in commodity prices would decrease net income by approximately \$2 million for the next 12 months.

FES' contracts, including power contracts with affiliates awarded through competitive bidding processes, typically contain margining provisions which require the posting of cash or LOCs in amounts determined by future power price movements. Based on FES' power portfolio as of December 31, 2008, and forward prices as of that date, FES had \$103 million outstanding in margining accounts. Under a hypothetical adverse change in forward prices (15% decrease in prices), FES would be required to post an additional \$98 million. Depending on the volume of forward contracts entered and future price movements, FES could be required to post significantly higher amounts for margining.

Interest Rate Risk

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

Comparison of Carrying Value to Fair Value

Year of Maturity	2009	2010	2011	2012	2013	There- after	Total	Fair Value
<i>(Dollars in millions)</i>								
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	\$ 11	\$ 74				\$ 653	\$ 738	\$ 737
Average interest rate	2.8%	5.0%				4.4%	4.4%	
Liabilities								
Long-term Debt:								
Fixed rate	\$ 41	\$ 53	\$ 58	\$ 68	\$ 75	\$ 182	\$ 477	\$ 453
Average interest rate	8.9%	8.9%	8.9%	9.0%	9.0%	7.4%	8.3%	
Variable rate						\$ 2,075	\$ 2,075	\$ 2,075
Average interest rate						1.5%	1.5%	
Short-term Borrowings:	\$ 1,265						\$ 1,265	\$ 1,265
Average interest rate	1.1%						1.1%	

Fluctuations in the fair value of NGC's decommissioning trust balances will eventually affect earnings (immediately for other-than-temporary impairments and affecting OCI initially for unrealized gains) based on the guidance in SFAS 115, FSP SFAS 115-1 and SFAS 124-1. As of December 31, 2008, NGC's decommissioning trust balance totaled \$1.0 billion, comprised of 37% equity securities and 63% debt instruments.

Equity Price Risk

Included in NGC's nuclear decommissioning trusts are marketable equity securities carried at their current fair value of approximately \$380 million as of December 31, 2008. A hypothetical 10% decrease in prices quoted by stock exchanges would result in an \$38 million reduction in fair value as of December 31, 2008 (see Note 5).

Credit Risk

Credit risk is the risk of an obligor's failure to meet the terms of any investment contract, loan agreement or otherwise perform as agreed. Credit risk arises from all activities in which success depends on issuer, borrower or counterparty performance, whether reflected on or off the balance sheet. FES 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.

FES maintains credit policies with respect to our 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, FES 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 December 31, 2008, the largest credit concentration was with JP Morgan, which is currently rated investment grade, representing 11.4% of FES' total approved credit risk.

Legal Proceedings

See the "Regulatory Matters," "Environmental Matters" and "Other Legal Proceedings" sections within the Combined Management's Discussion and Analysis of Registrant Subsidiaries for discussion of legal proceedings applicable to FES.

New Accounting Standards and Interpretations

See the "New Accounting Standards and Interpretations" section within the Combined Management's Discussion and Analysis of Registrant Subsidiaries for discussion of new accounting standards and interpretations applicable to FES.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Solutions Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2008 consolidated financial statements.

FirstEnergy Corp.'s internal auditors, who are responsible to the Audit Committee of FirstEnergy's Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held ten meetings in 2008.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2008.

This annual report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

To the Stockholder and Board of
Directors of FirstEnergy Solutions Corp.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of FirstEnergy Solutions Corp. and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in the notes to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions as of January 1, 2007 (Note 8) and defined benefit pension and other postretirement plans as of December 31, 2006 (Note 4).

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 24, 2009

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	2008	2007	2006
	<i>(In thousands)</i>		
REVENUES:			
Electric sales to affiliates (Note 3)	\$ 2,968,323	\$ 2,901,154	\$ 2,609,299
Electric sales to non-affiliates	1,332,364	1,315,141	1,265,604
Other	217,666	108,732	136,450
Total revenues	<u>4,518,353</u>	<u>4,325,027</u>	<u>4,011,353</u>
EXPENSES (Note 3):			
Fuel	1,315,293	1,087,010	1,105,657
Purchased power from affiliates	101,409	234,090	257,001
Purchased power from non-affiliates	778,882	764,090	590,491
Other operating expenses	1,084,548	1,041,039	1,027,564
Provision for depreciation	231,899	192,912	179,163
General taxes	88,004	87,098	73,332
Total expenses	<u>3,600,035</u>	<u>3,406,239</u>	<u>3,233,208</u>
OPERATING INCOME	<u>918,318</u>	<u>918,788</u>	<u>778,145</u>
OTHER INCOME (EXPENSE):			
Investment income (loss)	(22,678)	41,438	45,937
Miscellaneous income	1,698	11,438	8,565
Interest expense to affiliates (Note 3)	(29,829)	(65,501)	(162,673)
Interest expense - other	(111,682)	(92,199)	(26,468)
Capitalized interest	43,764	19,508	11,495
Total other expense	<u>(118,727)</u>	<u>(85,316)</u>	<u>(123,144)</u>
INCOME BEFORE INCOME TAXES	799,591	833,472	655,001
INCOME TAXES	<u>293,181</u>	<u>304,608</u>	<u>236,348</u>
NET INCOME	<u>\$ 506,410</u>	<u>\$ 528,864</u>	<u>\$ 418,653</u>

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

FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATED BALANCE SHEETS

As of December 31,	2008	2007
	<i>(In thousands)</i>	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 39	\$ 2
Receivables-		
Customers (less accumulated provisions of \$5,899,000 and \$8,072,000, respectively, for uncollectible accounts)	86,123	133,846
Associated companies	378,100	376,499
Other (less accumulated provisions of \$6,815,000 and \$9,000 respectively, for uncollectible accounts)	24,626	3,823
Notes receivable from associated companies	129,175	92,784
Materials and supplies, at average cost	521,761	427,015
Prepayments and other	112,535	92,340
	<u>1,252,359</u>	<u>1,126,309</u>
PROPERTY, PLANT AND EQUIPMENT:		
In service	9,871,904	8,294,768
Less - Accumulated provision for depreciation	4,254,721	3,892,013
	<u>5,617,183</u>	<u>4,402,755</u>
Construction work in progress	1,747,435	761,701
	<u>7,364,618</u>	<u>5,164,456</u>
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,033,717	1,332,913
Long-term notes receivable from associated companies	62,900	62,900
Other	61,591	40,004
	<u>1,158,208</u>	<u>1,435,817</u>
DEFERRED CHARGES AND OTHER ASSETS:		
Accumulated deferred income tax benefits	267,762	276,923
Lease assignment receivable from associated companies (Note 6)	71,356	215,258
Goodwill	24,248	24,248
Property taxes	50,104	47,774
Pension assets (Note 4)	-	16,723
Unamortized sale and leaseback costs	69,932	70,803
Other	96,434	43,953
	<u>579,836</u>	<u>695,682</u>
	<u>\$ 10,355,021</u>	<u>\$ 8,422,264</u>
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	\$ 2,024,898	\$ 1,441,196
Short-term borrowings-		
Associated companies	264,823	264,064
Other	1,000,000	300,000
Accounts payable-		
Associated companies	472,338	445,264
Other	154,593	177,121
Accrued taxes	79,766	171,451
Other	248,439	237,806
	<u>4,244,857</u>	<u>3,036,902</u>
CAPITALIZATION (See Consolidated Statements of Capitalization):		
Common stockholder's equity	2,944,423	2,414,231
Long-term debt and other long-term obligations	571,448	533,712
	<u>3,515,871</u>	<u>2,947,943</u>
NONCURRENT LIABILITIES:		
Deferred gain on sale and leaseback transaction	1,026,584	1,060,119
Accumulated deferred investment tax credits	62,728	61,116
Asset retirement obligations	863,085	810,114
Retirement benefits	194,177	63,136
Property taxes	50,104	48,095
Lease market valuation liability	307,705	353,210
Other	89,910	41,629
	<u>2,594,293</u>	<u>2,437,419</u>
COMMITMENTS AND CONTINGENCIES (Notes 6 & 13)		
	<u>\$ 10,355,021</u>	<u>\$ 8,422,264</u>

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

FIRSTENERGY SOLUTIONS CORP.

CONSOLIDATED STATEMENTS OF CAPITALIZATION

As of December 31,	2008	2007
	<i>(In thousands)</i>	
COMMON STOCKHOLDER'S EQUITY:		
Common stock, without par value, authorized 750 shares, 7 shares outstanding	\$ 1,464,229	\$ 1,164,922
Accumulated other comprehensive income (Note 2(F))	(91,871)	140,654
Retained earnings (Note 10(A))	1,572,065	1,108,655
Total	<u>2,944,423</u>	<u>2,414,231</u>
LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS (Note 10(C)):		
Secured notes:		
FirstEnergy Solutions Corp.		
5.150% due 2009-2015	22,868	-
FirstEnergy Nuclear Generation Corp.		
8.830% due 2009-2016	5,007	-
8.890% due 2009-2016	82,680	-
9.000% due 2009-2017	234,635	-
9.120% due 2009-2016	68,311	-
12.000% due 2009-2017	1,174	-
	<u>391,807</u>	<u>-</u>
Total secured notes	<u>414,675</u>	<u>-</u>
Unsecured notes:		
FirstEnergy Generation Corp.		
* 1.250% due 2017	28,525	28,525
* 3.375% due 2018	2,805	-
* 3.375% due 2018	2,985	-
* 1.050% due 2019	90,140	90,140
* 1.100% due 2020	141,260	141,260
* 1.250% due 2023	234,520	234,520
* 4.350% due 2028	15,000	15,000
* 7.125% due 2028	25,000	-
* 0.750% due 2029	6,450	6,450
* 1.000% due 2029	100,000	100,000
* 1.000% due 2040	43,000	43,000
* 0.850% due 2041	129,610	129,610
* 1.000% due 2041	26,000	26,000
* 1.100% due 2041	56,600	56,600
* 3.375% due 2047	46,300	-
	<u>948,195</u>	<u>871,105</u>
FirstEnergy Nuclear Generation Corp.		
5.390% due to associated companies 2025	62,900	62,900
* 7.250% due 2032	23,000	-
* 7.250% due 2032	33,000	-
* 0.950% due 2033	46,500	46,500
* 0.950% due 2033	54,600	54,600
* 1.000% due 2033	26,000	26,000
* 1.200% due 2033	99,100	99,100
* 1.300% due 2033	8,000	8,000
* 1.350% due 2033	135,550	135,550
* 1.380% due 2033	15,500	15,500
* 1.450% due 2033	62,500	62,500
* 1.450% due 2033	107,500	107,500
* 3.375% due 2033	9,100	-
* 3.375% due 2033	20,450	-
* 0.700% due 2034	7,200	7,200
* 0.750% due 2034	82,800	82,800
* 0.700% due 2035	72,650	72,650
* 0.750% due 2035	98,900	98,900
* 1.050% due 2035	60,000	60,000
* 1.350% due 2035	163,965	163,965
	<u>1,189,215</u>	<u>1,103,665</u>
Total unsecured notes	<u>2,137,410</u>	<u>1,974,770</u>
Capital lease obligations (Note 6)	44,319	199
Net unamortized discount on debt	(58)	(61)
Long-term debt due within one year	(2,024,898)	(1,441,196)
Total long-term debt and other long-term obligations	<u>571,448</u>	<u>533,712</u>
TOTAL CAPITALIZATION	<u>\$ 3,515,871</u>	<u>\$ 2,947,943</u>

* Denotes variable rate issue with applicable year-end interest rate shown.

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Comprehensive Income	Common Stock		Accumulated Other Comprehensive Income (Loss)	Retained Earnings
		Number of Shares	Carrying Value		
<i>(Dollars in thousands)</i>					
Balance, January 1, 2006		8	\$ 1,048,734	\$ 65,461	\$ 287,139
Net income	\$ 418,653				418,653
Net unrealized loss on derivative instruments, net					
of \$5,082,000 of income tax benefits	(8,248)			(8,248)	
Unrealized gain on investments, net of \$33,698,000 of income taxes	58,654			58,654	
Comprehensive income	<u>\$ 469,059</u>				
Net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of \$10,825,000 of income tax benefits (Note 4)				(4,144)	
Stock options exercised, restricted stock units and other adjustments			1,568		
Cash dividends declared on common stock					(8,454)
Balance, December 31, 2006		8	1,050,302	111,723	697,338
Net income	\$ 528,864				528,864
Net unrealized loss on derivative instruments, net					
of \$3,337,000 of income tax benefits	(5,640)			(5,640)	
Unrealized gain on investments, net of \$26,645,000 of income taxes	41,707			41,707	
Pension and other postretirement benefits, net of \$604,000 of income taxes (Note 4)	(7,136)			(7,136)	
Comprehensive income	<u>\$ 557,795</u>				
Repurchase of common stock		(1)	(600,000)		
Equity contribution from parent			700,000		
Stock options exercised, restricted stock units and other adjustments			4,141		
Consolidated tax benefit allocation			10,479		
FIN 48 cumulative effect adjustment					(547)
Cash dividends declared on common stock					(117,000)
Balance, December 31, 2007		7	1,164,922	140,654	1,108,655
Net income	\$ 506,410				506,410
Net unrealized loss on derivative instruments, net					
of \$5,512,000 of income tax benefits	(9,200)			(9,200)	
Change in unrealized gain on investments, net of \$82,014,000 of income tax benefits	(137,689)			(137,689)	
Pension and other postretirement benefits, net of \$47,853,000 of income tax benefits (Note 4)	(85,636)			(85,636)	
Comprehensive income	<u>\$ 273,885</u>				
Equity contribution from parent			280,000		
Stock options exercised, restricted stock units and other adjustments			13,262		
Consolidated tax benefit allocation			6,045		
Cash dividends declared on common stock					(43,000)
Balance, December 31, 2008		7	\$ 1,464,229	\$ (91,871)	\$ 1,572,065

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

FIRSTENERGY SOLUTIONS CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2008	2007	2006
	<i>(In thousands)</i>		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	\$ 506,410	\$ 528,864	\$ 418,653
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	231,899	192,912	179,163
Nuclear fuel and lease amortization	111,978	100,720	89,178
Deferred rents and lease market valuation liability	(43,263)	69	-
Deferred income taxes and investment tax credits, net	116,626	(334,545)	115,878
Investment impairment (Note 2(E))	115,207	22,817	10,255
Accrued compensation and retirement benefits	16,011	6,419	25,052
Commodity derivative transactions, net	5,100	5,930	24,144
Gain on asset sales	(38,858)	(12,105)	(37,663)
Cash collateral, net	(60,621)	(31,059)	40,680
Pension trust contributions	-	(64,020)	-
Decrease (increase) in operating assets-			
Receivables	59,782	(99,048)	(15,462)
Materials and supplies	(59,983)	56,407	(1,637)
Prepayments and other current assets	(12,302)	(13,812)	(5,237)
Increase (decrease) in operating liabilities-			
Accounts payable	34,467	(104,599)	19,970
Accrued taxes	(90,568)	61,119	12,235
Accrued interest	1,398	1,143	4,101
Other	(40,355)	(22,895)	(20,469)
Net cash provided from operating activities	<u>852,928</u>	<u>294,317</u>	<u>858,841</u>
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	618,375	427,210	1,156,910
Equity contributions from parent	280,000	700,000	-
Short-term borrowings, net	700,759	-	46,402
Redemptions and Repayments-			
Common stock	-	(600,000)	-
Long-term debt	(462,540)	(1,536,411)	(1,130,910)
Short-term borrowings, net	-	(458,321)	-
Common stock dividend payments	(43,000)	(117,000)	(8,454)
Other	(5,147)	(5,199)	(6,899)
Net cash provided from (used for) financing activities	<u>1,088,447</u>	<u>(1,589,721)</u>	<u>57,049</u>
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(1,835,629)	(738,709)	(577,287)
Proceeds from asset sales	23,077	12,990	34,215
Proceeds from sale and leaseback transaction	-	1,328,919	-
Sales of investment securities held in trusts	950,688	655,541	1,066,271
Purchases of investment securities held in trusts	(987,304)	(697,763)	(1,066,271)
Loan repayments from (loans to) associated companies	(36,391)	734,862	(333,030)
Other	(55,779)	(436)	(39,788)
Net cash provided from (used for) investing activities	<u>(1,941,338)</u>	<u>1,295,404</u>	<u>(915,890)</u>
Net change in cash and cash equivalents	37	-	-
Cash and cash equivalents at beginning of year	<u>2</u>	<u>2</u>	<u>2</u>
Cash and cash equivalents at end of year	<u>\$ 39</u>	<u>\$ 2</u>	<u>\$ 2</u>
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	<u>\$ 92,103</u>	<u>\$ 136,121</u>	<u>\$ 173,337</u>
Income taxes	<u>\$ 196,963</u>	<u>\$ 613,814</u>	<u>\$ 155,771</u>

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



OHIO EDISON COMPANY
MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

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. They provide generation services to those franchise customers electing to retain OE and Penn as their power supplier. Until December 31, 2008, OE purchased power for delivery and resale from a full requirements power sale agreement with its affiliate FES at a fixed price that was reflected in rates approved by the PUCO. See Regulatory Matters – Ohio below for a discussion of power supply for 2009 and beyond.

Results of Operations

Net income increased to \$212 million in 2008 from \$197 million in 2007. The increase primarily resulted from higher electric sales revenues and lower purchased power costs, partially offset by a decrease in the deferral of new regulatory assets and lower investment income.

Revenues

Revenues increased by \$110 million, or 4.4%, in 2008 compared with 2007, primarily due to increases in retail generation revenues (\$78 million) and distribution throughput revenues (\$21 million).

Retail generation revenues increased primarily due to higher average prices across all customer classes, partially offset by decreased KWH sales. The higher average prices included the 2008 fuel cost recovery rider that became effective January 16, 2008 (see Regulatory Matters – Ohio). Reduced summer usage in 2008 compared to 2007 contributed to the decreased KWH sales to residential and commercial customers (cooling degree days decreased by 27.7% and 26.1% in OE's and Penn's service territories, respectively). Commercial and industrial retail KWH sales were also impacted by increased customer shopping in Penn's service territory in 2008 and weakening economic conditions.

Changes in retail generation sales and revenues in 2008 from 2007 are summarized in the following tables:

<u>Retail Generation KWH Sales</u>	<u>Decrease</u>
Residential	(0.9) %
Commercial	(1.6) %
Industrial	(5.7) %
Decrease in Generation Sales	(2.7) %

<u>Retail Generation Revenues</u>	<u>Increase</u>
	<i>(In millions)</i>
Residential	\$ 41
Commercial	19
Industrial	18
Increase in Generation Revenues	\$ 78

Revenues from distribution throughput increased by \$21 million in 2008 compared to 2007 due to higher average unit prices for all customer classes, partially offset by lower KWH deliveries. The higher average prices resulted from Ohio transmission rider increases that became effective July 1, 2007 and July 1, 2008. The lower KWH deliveries to residential and commercial customers reflected the milder weather conditions described above. Reduced deliveries to industrial customers reflected the downturn in the economy.

Changes in distribution KWH deliveries and revenues in 2008 from 2007 are summarized in the following tables.

<u>Distribution KWH Deliveries</u>	<u>Decrease</u>
Residential	(1.4)%
Commercial	(1.7)%
Industrial	(4.8)%
Other	(0.1)%
Decrease in Distribution Deliveries	(2.7)%

<u>Distribution Revenues</u>	<u>Increase</u>
	<u>(In millions)</u>
Residential	\$ 8
Commercial	6
Industrial	5
Other	2
Increase in Distribution Revenues	\$ 21

Expenses

Total expenses increased by \$67 million in 2008 from 2007. The following table presents changes from the prior year by expense category.

<u>Expenses – Changes</u>	<u>Increase</u>
	<u>(Decrease)</u>
	<u>(In millions)</u>
Purchased power costs	\$ (41)
Other operating costs	(2)
Provision for depreciation	2
Amortization of regulatory assets	24
Deferral of new regulatory assets	79
General taxes	5
Net Increase in Expenses	\$ 67

Lower purchased power costs in 2008 reflected the lower retail generation KWH sales, reducing the purchase volumes required. The decrease in other operating costs for 2008 was primarily due to lower employee benefit expenses. Higher depreciation expense in 2008 reflected capital additions since the end of 2007. Higher amortization of regulatory assets in 2008 was principally due to increased amortization of MISO transmission cost deferrals. The decrease in the deferral of new regulatory assets for 2008 was primarily due to lower MISO cost deferrals (\$25 million) and lower RCP fuel deferrals (\$59 million), as more transmission and generation costs were recovered from customers through PUCO-approved riders. The increase in general taxes for 2008 was primarily due to higher Pennsylvania capital stock taxes.

Other Income

Other income decreased \$31 million in 2008 compared with 2007 primarily due to reductions in interest income on associated company notes receivable resulting from principal payments made in 2007 and a lower net receivable position from the regulated money pool in 2008 compared to 2007.

Income taxes decreased in 2008, primarily due to the favorable resolution of tax positions taken on federal returns in prior years.

Interest Rate Risk

OE's exposure to fluctuations in market interest rates is reduced since a significant portion of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for OE's investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

<u>Year of Maturity</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>There-</u>	<u>after</u>	<u>Total</u>	<u>Fair</u>
	<u>(Dollars in millions)</u>								
<u>Assets</u>									
Investments Other Than Cash and Cash Equivalents:									
Fixed Income	\$ 25	\$ 29	\$ 31	\$ 34	\$ 39	\$ 438	\$ 596	\$ 618	
Average interest rate	8.5%	8.6%	8.6%	8.7%	8.7%	7.0%	7.4%		
<u>Liabilities</u>									
Long-term Debt:									
Fixed rate	\$ 1	\$ 65	\$ 1	\$ 1	\$ 2	\$ 1,062	\$ 1,132	\$ 1,123	
Average interest rate	9.2%	5.5%	9.7%	9.7%	7.5%	7.0%	6.9%		
Variable rate						\$ 100	\$ 100	\$ 100	
Average interest rate						2.3%	2.3%		
Short-term Borrowings:	\$ 2						\$ 2	\$ 2	
Average interest rate	0.0%						0.0%		

Equity Price Risk

Included in OE's nuclear decommissioning trusts are marketable equity securities carried at their market value of approximately \$18 million as of December 31, 2008. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a \$2 million reduction in fair value as of December 31, 2008 (see Note 5). As part of the intra-system generation asset transfers in 2005, OE's nuclear decommissioning trust investments were transferred to NGC with the exception of its retained leasehold interests in nuclear generation assets

Legal Proceedings

See the "Regulatory Matters," "Environmental Matters" and "Other Legal Proceedings" sections within the Combined Management's Discussion and Analysis of Registrant Subsidiaries for discussion of other legal proceedings applicable to OE.

New Accounting Standards and Interpretations

See the "New Accounting Standards and Interpretations" section within the Combined Management's Discussion and Analysis of Registrant Subsidiaries for discussion of new accounting standards and interpretations applicable to OE.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of Ohio Edison Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2008 consolidated financial statements.

FirstEnergy Corp.'s internal auditors, who are responsible to the Audit Committee of FirstEnergy's Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held ten meetings in 2008.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2008.

This annual report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of Ohio Edison Company and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in the notes to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions as of January 1, 2007 (Note 8) and defined benefit pension and other postretirement plans as of December 31, 2006 (Note 4).

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 24, 2009

OHIO EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	2008	2007	2006
	<i>(In thousands)</i>		
REVENUES (Note 3):			
Electric sales	\$ 2,487,956	\$ 2,375,306	\$ 2,312,956
Excise and gross receipts tax collections	113,805	116,223	114,500
Total revenues	2,601,761	2,491,529	2,427,456
EXPENSES (Note 3):			
Purchased power from affiliates	1,203,314	1,261,439	1,263,805
Purchased power from non-affiliates	114,972	98,344	12,170
Other operating costs	565,893	567,726	576,141
Provision for depreciation	79,444	77,405	72,982
Amortization of regulatory assets	216,274	191,885	190,245
Deferral of new regulatory assets	(98,541)	(177,633)	(159,465)
General taxes	186,396	181,104	180,446
Total expenses	2,267,752	2,200,270	2,136,324
OPERATING INCOME	334,009	291,259	291,132
OTHER INCOME (EXPENSE) (Note 3):			
Investment income	56,103	85,848	130,853
Miscellaneous income (expense)	(5,138)	4,409	1,751
Interest expense	(75,058)	(83,343)	(90,355)
Capitalized interest	414	266	2,198
Subsidiary's preferred stock dividend requirements	-	-	(597)
Total other income (expense)	(23,679)	7,180	43,850
INCOME BEFORE INCOME TAXES	310,330	298,439	334,982
INCOME TAXES	98,584	101,273	123,343
NET INCOME	211,746	197,166	211,639
PREFERRED STOCK DIVIDEND REQUIREMENTS AND REDEMPTION PREMIUM			
	-	-	4,552
EARNINGS ON COMMON STOCK	\$ 211,746	\$ 197,166	\$ 207,087

The accompanying Combined 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

As of December 31,	2008	2007
	<i>(In thousands)</i>	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 146,343	\$ 732
Receivables-		
Customers (less accumulated provisions of \$6,065,000 and \$8,032,000, respectively, for uncollectible accounts)	277,377	248,990
Associated companies	234,960	185,437
Other (less accumulated provisions of \$7,000 and \$5,639,000, respectively, for uncollectible accounts)	14,492	12,395
Notes receivable from associated companies	222,861	595,859
Prepayments and other	5,452	10,341
	<u>901,485</u>	<u>1,053,754</u>
UTILITY PLANT:		
In service	2,903,290	2,769,880
Less - Accumulated provision for depreciation	1,113,357	1,090,862
	<u>1,789,933</u>	<u>1,679,018</u>
Construction work in progress	37,766	50,061
	<u>1,827,699</u>	<u>1,729,079</u>
OTHER PROPERTY AND INVESTMENTS:		
Long-term notes receivable from associated companies	256,974	258,870
Investment in lease obligation bonds (Note 6)	239,625	253,894
Nuclear plant decommissioning trusts	116,682	127,252
Other	100,792	36,037
	<u>714,073</u>	<u>676,053</u>
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	575,076	737,326
Pension assets (Note 4)	-	228,518
Property taxes	60,542	65,520
Unamortized sale and leaseback costs	40,130	45,133
Other	33,710	48,075
	<u>709,458</u>	<u>1,124,572</u>
	<u>\$ 4,152,715</u>	<u>\$ 4,583,458</u>
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	\$ 101,354	\$ 333,224
Short-term borrowings-		
Associated companies	-	50,692
Other	1,540	2,609
Accounts payable-		
Associated companies	131,725	174,088
Other	26,410	19,881
Accrued taxes	77,592	89,571
Accrued interest	25,673	22,378
Other	85,209	65,163
	<u>449,503</u>	<u>757,606</u>
CAP IT ALIZATION (See Consolidated Statements of Capitalization):		
Common stockholder's equity	1,294,054	1,576,175
Long-term debt and other long-term obligations	1,122,247	840,591
	<u>2,416,301</u>	<u>2,416,766</u>
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	653,475	781,012
Accumulated deferred investment tax credits	13,065	16,964
Asset retirement obligations	80,647	93,571
Retirement benefits	308,450	178,343
Deferred revenues - electric service programs	4,634	46,849
Other	226,640	292,347
	<u>1,286,911</u>	<u>1,409,086</u>
COMMITMENTS AND CONTINGENCIES (Notes 6 and 13)		
	<u>\$ 4,152,715</u>	<u>\$ 4,583,458</u>

The accompanying Combined 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 CAPITALIZATION

As of December 31,	2008	2007
	<i>(In thousands)</i>	
COMMON STOCKHOLDER'S EQUITY:		
Common stock, without par value, 175,000,000 shares authorized, 60 shares outstanding	\$ 1,224,416	\$ 1,220,512
Accumulated other comprehensive income (loss) (Note 2(F))	(184,385)	48,386
Retained earnings (Note 10(A))	254,023	307,277
Total	<u>1,294,054</u>	<u>1,576,175</u>
LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS (Note 10(C)):		
Ohio Edison Company-		
First mortgage bonds:		
8.250% due 2018	25,000	-
8.250% due 2038	275,000	-
Total	<u>300,000</u>	<u>-</u>
Secured notes:		
5.375% due 2028	-	13,522
6.895% weighted average interest rate due 2008-2010	1,324	3,900
Total	<u>1,324</u>	<u>17,422</u>
Unsecured notes:		
4.000% due 2008	-	175,000
* 3.000% due 2014	50,000	50,000
5.450% due 2015	150,000	150,000
6.400% due 2016	250,000	250,000
* 3.850% due 2018	-	33,000
* 3.800% due 2018	-	23,000
* 1.500% due 2023	50,000	50,000
6.875% due 2036	350,000	350,000
Total	<u>850,000</u>	<u>1,081,000</u>
Pennsylvania Power Company-		
First mortgage bonds:		
9.740% due 2008-2019	10,747	11,721
7.625% due 2023	6,500	6,500
Total	<u>17,247</u>	<u>18,221</u>
Secured notes:		
5.400% due 2013	1,000	1,000
5.375% due 2028	-	1,734
Total	<u>1,000</u>	<u>2,734</u>
Unsecured notes:		
5.390% due 2010 to associated company	62,900	62,900
Total	<u>62,900</u>	<u>62,900</u>
Capital lease obligations (Note 6)	4,219	329
Net unamortized discount on debt	(13,089)	(8,791)
Long-term debt due within one year	(101,354)	(333,224)
Total long-term debt and other long-term obligations	<u>1,122,247</u>	<u>840,591</u>
TOTAL CAPITALIZATION	<u>\$ 2,416,301</u>	<u>\$ 2,416,766</u>

* Denotes variable rate issue with applicable year-end interest rate shown.

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

OHIO EDISON COMPANY

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	<u>Comprehensive Income</u>	<u>Common Stock</u>		<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Retained Earnings</u>
		<u>Number of Shares</u>	<u>Carrying Value</u>		
		<i>(Dollars in thousands)</i>			
Balance, January 1, 2006		100	\$ 2,297,253	\$ 4,094	\$ 200,844
Net income	\$ 211,639				211,639
Unrealized gain on investments, net of \$4,455,000 of income taxes	7,954			7,954	
Comprehensive income	<u>\$ 219,593</u>				
Net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of \$22,287,000 of income tax benefits (Note 4)				(8,840)	
Affiliated company asset transfers			(87,893)		
Restricted stock units			58		
Stock-based compensation			82		
Repurchase of common stock		(20)	(500,000)		
Preferred stock redemption adjustments			(1,059)		604
Preferred stock redemption premiums					(2,928)
Cash dividends on preferred stock					(1,423)
Cash dividends declared on common stock					(148,000)
Balance, December 31, 2006		80	1,708,441	3,208	260,736
Net income	\$ 197,166				197,166
Unrealized gain on investments, net of \$2,784,000 of income taxes	3,874			3,874	
Pension and other postretirement benefits, net of \$37,820,000 of income taxes (Note 4)	41,304			41,304	
Comprehensive income	<u>\$ 242,344</u>				
Restricted stock units			129		
Stock-based compensation			17		
Repurchase of common stock		(20)	(500,000)		
Consolidated tax benefit allocation			11,925		
FIN 48 cumulative effect adjustment					(625)
Cash dividends declared on common stock					(150,000)
Balance, December 31, 2007		60	1,220,512	48,386	307,277
Net income	\$ 211,746				211,746
Change in unrealized gain on investments, net of \$5,702,000 of income tax benefits	(10,370)			(10,370)	
Pension and other postretirement benefits, net of \$121,425,000 of income tax benefits (Note 4)	(222,401)			(222,401)	
Comprehensive loss	<u>\$ (21,025)</u>				
Restricted stock units			(16)		
Stock-based compensation			1		
Consolidated tax benefit allocation			3,919		
Cash dividends declared on common stock					(265,000)
Balance, December 31, 2008		60	\$ 1,224,416	\$ (184,385)	\$ 254,023

The accompanying Combined Notes to Consolidated Financial Statements as the relate to Ohio Edison Company are an integral part of these statements.

OHIO EDISON COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2008	2007	2006
	<i>(In thousands)</i>		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	\$ 211,746	\$ 197,166	\$ 211,639
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	79,444	77,405	72,982
Amortization of regulatory assets	216,274	191,885	190,245
Deferral of new regulatory assets	(98,541)	(177,633)	(159,465)
Amortization of lease costs	(7,702)	(7,425)	(7,928)
Deferred income taxes and investment tax credits, net	16,125	423	(68,259)
Accrued compensation and retirement benefits	17,139	(46,313)	5,004
Electric service prepayment programs	(42,215)	(39,861)	(34,983)
Pension trust contributions	-	(20,261)	-
Decrease (increase) in operating assets-			
Receivables	(61,926)	(57,461)	103,925
Prepayments and other current assets	5,937	3,265	1,275
Increase (decrease) in operating liabilities-			
Accounts payable	14,166	15,649	(53,798)
Accrued taxes	(8,983)	(81,079)	23,436
Accrued interest	3,295	(2,334)	16,379
Other	(247)	6,129	6,617
Net cash provided from operating activities	<u>344,512</u>	<u>59,555</u>	<u>307,069</u>
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	292,169	-	593,978
Redemptions and Repayments-			
Common stock	-	(500,000)	(500,000)
Preferred stock	-	-	(78,480)
Long-term debt	(249,897)	(112,497)	(613,002)
Short-term borrowings, net	(51,761)	(114,475)	(186,511)
Dividend Payments-			
Common stock	(315,000)	(100,000)	(148,000)
Preferred stock	-	-	(1,423)
Other	(3,432)	-	(1,798)
Net cash used for financing activities	<u>(327,921)</u>	<u>(826,972)</u>	<u>(935,236)</u>
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(182,512)	(145,311)	(123,210)
Sales of investment securities held in trusts	120,744	37,736	39,226
Purchases of investment securities held in trusts	(127,680)	(43,758)	(41,300)
Loan repayments from (loans to) associated companies, net	373,138	(79,115)	78,101
Collection of principal on long-term notes receivable	1,756	960,327	553,734
Cash investments	(57,792)	37,499	112,584
Other	1,366	59	8,815
Net cash provided from investing activities	<u>129,020</u>	<u>767,437</u>	<u>627,950</u>
Net increase (decrease) in cash and cash equivalents	145,611	20	(217)
Cash and cash equivalents at beginning of year	732	712	929
Cash and cash equivalents at end of year	<u>\$ 146,343</u>	<u>\$ 732</u>	<u>\$ 712</u>
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	<u>\$ 67,508</u>	<u>\$ 80,958</u>	<u>\$ 57,243</u>
Income taxes	<u>\$ 118,834</u>	<u>\$ 133,170</u>	<u>\$ 156,610</u>

The accompanying Combined Notes to Consolidated Financial Statements as the relate to Ohio Edison Company are an integral part of these statements.

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

MANAGEMENT'S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS

CEI is a wholly owned, electric utility subsidiary of FirstEnergy. CEI conducts business in northeastern Ohio, providing regulated electric distribution services. CEI also provides generation services to those customers electing to retain CEI as their power supplier. Until December 31, 2008, CEI purchased power for delivery and resale from a full requirements power sale agreement with its affiliate FES at a fixed price that was reflected in rates approved by the PUCO. See Regulatory Matters – Ohio below for a discussion of power supply for 2009 and beyond.

Results of Operations

Net income in 2008 increased to \$285 million from \$276 million in 2007. The increase resulted primarily from the elimination of fuel costs and lower other operating costs, due to the assignment of leasehold interests in generating assets to FGCO, partially offset by lower revenues and regulatory asset deferrals and higher purchased power costs and regulatory asset amortization.

Revenues

Revenues decreased by \$7 million, or 0.4%, in 2008 compared to 2007, primarily due to a decrease in wholesale generation revenues (\$92 million), partially offset by increases in retail generation revenues (\$64 million), distribution revenues (\$6 million), and transmission revenues (\$16 million).

Wholesale generation revenues decreased due to the assignment of CEI's leasehold interests in the Bruce Mansfield Plant to FGCO in October 2007. Prior to the assignment, CEI sold power from its interests in the plant to FGCO.

Retail generation revenues increased in 2008 due to higher average unit prices across all customer classes, partially offset by a decrease in sales volume compared to 2007. The higher average unit prices were driven by the 2008 fuel cost recovery rider that became effective January 16, 2008 (see Regulatory Matters – Ohio). Milder weather in 2008, compared to 2007, contributed to the decrease in sales volume; a 13.6% decrease in cooling degrees days was partially offset by a 4.5% increase in heating degree days. Weakening economic conditions in CEI's service territory contributed to reduced generation KWH sales in the industrial sector, primarily to automotive customers.

Changes in retail generation sales and revenues in 2008 compared to 2007 are summarized in the following tables:

<u>Retail KWH Sales</u>	<u>Decrease</u>
Residential	(0.3)%
Commercial	(0.7)%
Industrial	(2.6)%
Decrease in Retail Sales	(1.4)%

<u>Retail Generation Revenues</u>	<u>Increase</u>
	<i>(In millions)</i>
Residential	\$ 23
Commercial	17
Industrial	24
Increase in Generation Revenues	\$ 64

Revenues from distribution throughput increased by \$6 million in 2008 compared to 2007 primarily due to higher average unit prices for all customer classes, partially offset by decreases in KWH deliveries. The higher average unit prices resulted from transmission rider increases that became effective July 1, 2007 and July 1, 2008. The lower KWH deliveries in 2008 reflected the weather and economic impacts described above.

Changes in distribution KWH deliveries and revenues in 2008 compared to 2007 are summarized in the following tables.

<u>Distribution KWH Deliveries</u>	<u>Decrease</u>
Residential	(1.1)%
Commercial	(1.9)%
Industrial	(2.9)%
Decrease in Distribution Deliveries	(2.1)%

<u>Distribution Revenues</u>	<u>Increase</u>
	<i>(In millions)</i>
Residential	\$ -
Commercial	3
Industrial	3
Increase in Distribution Revenues	\$ 6

Transmission revenues were higher in 2008, compared to 2007, due to increased MISO auction revenue rights. CEI defers the difference between revenue from its transmission rider and net transmission costs incurred, resulting in no material effect to current period earnings.

Expenses

Total expenses decreased by \$9 million in 2008 compared to 2007. The following table presents the change from the prior year by expense category:

<u>Expenses - Changes</u>	<u>Increase (Decrease)</u>
	<i>(In millions)</i>
Fuel costs	\$ (40)
Purchased power costs	22
Other operating costs	(51)
Provision for depreciation	(3)
Amortization of regulatory assets	19
Deferral of new regulatory assets	42
General taxes	2
Net Decrease in Expenses	\$ (9)

The absence of fuel costs in 2008 was due to the assignment of CEI's leasehold interests in the Mansfield Plant to FGCO in October 2007. Prior to the assignment, CEI incurred fuel expenses and other operating costs related to its leasehold interest in the plant. Higher purchased power costs reflected higher unit prices, as provided for under the PSA with FES, partially offset by a decrease in volume due to lower KWH sales. Other operating costs were lower primarily due to the assignment of CEI's leasehold interests in the Mansfield plant as described above. Higher amortization of regulatory assets resulted from increased transition cost amortization (\$13 million) under the effective interest method and increased amortization of transmission cost deferrals (\$6 million). The decrease in the deferral of new regulatory assets was primarily due to lower transmission cost deferrals (\$16 million) and RCP fuel cost deferrals (\$40 million), as more transmission and generation costs were recovered from customers through PUCO-approved riders, partially offset by higher RCP distribution deferrals (\$12 million).

Other Expense

Other expense increased by \$21 million in 2008 compared to 2007 primarily due to lower investment income and miscellaneous income, partially offset by a reduction in interest expense. Lower investment income resulted primarily from repayments during 2007 of notes receivable from associated companies. The lower interest expense was primarily due to long-term debt redemptions during 2007. Miscellaneous income decreased primarily due to reduced life insurance investment values and the absence of a make-whole payment in 2007 related to the redemption of lessor notes associated with CEI's leasehold interest in Mansfield Unit 1, which was subsequently assigned to FGCO.

Income taxes decreased in 2008, primarily due to the favorable resolution of tax positions taken on federal returns in prior years.

Interest Rate Risk

CEI has little exposure to fluctuations in market interest rates because most of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for CEI's investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	2009	2010	2011	2012	2013	There- after	Total	Fair Value
<i>(Dollars in millions)</i>								
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	\$ 37	\$ 49	\$ 53	\$ 66	\$ 75	\$ 146	\$ 426	\$ 435
Average interest rate	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	
Liabilities								
Long-term Debt:								
Fixed rate	\$ 150	\$ 18	\$ 20	\$ 22	\$ 324	\$ 1,207	\$ 1,741	\$ 1,618
Average interest rate	7.4%	7.7%	7.7%	7.7%	5.8%	7.2%	7.0%	
Short-term Borrowings:	\$ 228						\$ 228	\$ 228
Average interest rate	1.8%						1.8%	

Legal Proceedings

See the "Regulatory Matters," "Environmental Matters" and "Other Legal Proceedings" sections within the Combined Management's Discussion and Analysis of Registrant Subsidiaries for discussion of legal proceedings applicable to CEI.

New Accounting Standards and Interpretations

See the "New Accounting Standards and Interpretations" section within the Combined Management's Discussion and Analysis of Registrant Subsidiaries for discussion of new accounting standards and interpretations applicable to CEI.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of The Cleveland Electric Illuminating Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2008 consolidated financial statements.

FirstEnergy Corp.'s internal auditors, who are responsible to the Audit Committee of FirstEnergy's Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held ten meetings in 2008.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2008.

This annual report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

To the Stockholder and Board of Directors of
The Cleveland Electric Illuminating Company:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of The Cleveland Electric Illuminating Company and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in the notes to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions as of January 1, 2007 (Note 8) and defined benefit pension and other postretirement plans as of December 31, 2006 (Note 4).

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 24, 2009

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	2008	2007	2006
	<i>(In thousands)</i>		
REVENUES (Note 3):			
Electric sales	\$ 1,746,309	\$ 1,753,385	\$ 1,702,089
Excise tax collections	69,578	69,465	67,619
Total revenues	<u>1,815,887</u>	<u>1,822,850</u>	<u>1,769,708</u>
EXPENSES (Note 3):			
Fuel	-	40,551	50,291
Purchased power (primarily from affiliates)	770,480	748,214	704,517
Other operating costs	259,438	310,274	290,904
Provision for depreciation	72,383	75,238	63,589
Amortization of regulatory assets	163,534	144,370	127,403
Deferral of new regulatory assets	(107,571)	(149,556)	(128,220)
General taxes	143,058	141,551	134,663
Total expenses	<u>1,301,322</u>	<u>1,310,642</u>	<u>1,243,147</u>
OPERATING INCOME	<u>514,565</u>	<u>512,208</u>	<u>526,561</u>
OTHER INCOME (EXPENSE) (Note 3):			
Investment income	34,392	57,724	100,816
Miscellaneous income (expense)	(2,455)	7,902	6,428
Interest expense	(125,976)	(138,977)	(141,710)
Capitalized interest	786	918	2,618
Total other expense	<u>(93,253)</u>	<u>(72,433)</u>	<u>(31,848)</u>
INCOME BEFORE INCOME TAXES	421,312	439,775	494,713
INCOME TAXES	<u>136,786</u>	<u>163,363</u>	<u>188,662</u>
NET INCOME	<u>\$ 284,526</u>	<u>\$ 276,412</u>	<u>\$ 306,051</u>

The accompanying Combined 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

As of December 31,	2008	2007
	<i>(In thousands)</i>	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 226	\$ 232
Receivables-		
Customers (less accumulated provisions of \$5,916,000 and \$7,540,000, respectively, for uncollectible accounts)	276,400	251,000
Associated companies	113,182	166,587
Other	13,834	12,184
Notes receivable from associated companies	19,060	52,306
Prepayments and other	2,787	2,327
	<u>425,489</u>	<u>484,636</u>
UTILITY PLANT:		
In service	2,221,660	2,256,956
Less - Accumulated provision for depreciation	846,233	872,801
	<u>1,375,427</u>	<u>1,384,155</u>
Construction work in progress	40,651	41,163
	<u>1,416,078</u>	<u>1,425,318</u>
OTHER PROPERTY AND INVESTMENTS:		
Investment in lessor notes (Note 7)	425,715	463,431
Other	10,249	10,285
	<u>435,964</u>	<u>473,716</u>
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	1,688,521	1,688,521
Regulatory assets	783,964	870,695
Pension assets (Note 4)	-	62,471
Property taxes	71,500	76,000
Other	10,818	32,987
	<u>2,554,803</u>	<u>2,730,674</u>
	<u>\$ 4,832,334</u>	<u>\$ 5,114,344</u>
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	\$ 150,688	\$ 207,266
Short-term borrowings-		
Associated companies	227,949	531,943
Accounts payable-		
Associated companies	106,074	169,187
Other	7,195	5,295
Accrued taxes	87,810	94,991
Accrued interest	13,932	13,895
Other	40,095	34,350
	<u>633,743</u>	<u>1,056,927</u>
CAP IT ALIZATION (See Consolidated Statements of Capitalization):		
Common stockholder's equity	1,603,882	1,489,835
Long-term debt and other long-term obligations	1,591,586	1,459,939
	<u>3,195,468</u>	<u>2,949,774</u>
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	704,270	725,523
Accumulated deferred investment tax credits	13,030	18,567
Retirement benefits	128,738	93,456
Deferred revenues - electric service programs	3,510	27,145
Lease assignment payable to associated companies (Note 6)	40,827	131,773
Other	112,748	111,179
	<u>1,003,123</u>	<u>1,107,643</u>
COMMITMENTS AND CONTINGENCIES (Notes 6 and 13)		
	<u>\$ 4,832,334</u>	<u>\$ 5,114,344</u>

The accompanying Combined 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 CAPITALIZATION

As of December 31,	2008	2007
	<i>(In thousands)</i>	
COMMON STOCKHOLDER'S EQUITY:		
Common stock, without par value, 105,000,000 shares authorized, 67,930,743 shares outstanding	\$ 878,785	\$ 873,536
Accumulated other comprehensive loss (Note 2(F))	(134,857)	(69,129)
Retained earnings (Note 10(A))	859,954	685,428
Total	1,603,882	1,489,835
LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS (Note 10(C)):		
First mortgage bonds-		
6.860% due 2008	-	125,000
8.875% due 2018	300,000	-
Total	300,000	125,000
Secured notes-		
7.430% due 2009	150,000	150,000
7.880% due 2017	300,000	300,000
5.375% due 2028	-	5,993
* 3.750% due 2030	-	81,640
Total	450,000	537,633
Unsecured notes-		
5.650% due 2013	300,000	300,000
5.700% due 2017	250,000	250,000
5.950% due 2036	300,000	300,000
7.664% due to associated companies 2009-2016 (Note 7)	141,210	153,044
Total	991,210	1,003,044
Capital lease obligations (Note 6)	3,062	3,748
Net unamortized discount on debt	(1,998)	(2,220)
Long-term debt due within one year	(150,688)	(207,266)
Total long-term debt and other long-term obligations	1,591,586	1,459,939
TOTAL CAPITALIZATION	\$ 3,195,468	\$ 2,949,774

* Denotes variable rate issue with applicable year-end interest rate shown.

The accompanying Combined 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 STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	<u>Comprehensive Income</u>	<u>Common Stock</u>		<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Retained Earnings</u>
		<u>Number of Shares</u>	<u>Carrying Value</u>		
<i>(Dollars in thousands)</i>					
Balance, January 1, 2006		79,590,689	\$ 1,354,924	\$ -	\$ 587,150
Net income and comprehensive income	\$ 306,051				306,051
Net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of \$69,609,000 of income tax benefits (Note 4)				(104,431)	
Repurchase of common stock		(11,659,946)	(300,000)		
Affiliated company asset transfers			(194,910)		
Restricted stock units			86		
Stock-based compensation			33		
Cash dividends declared on common stock					(180,000)
Balance, December 31, 2006		67,930,743	860,133	(104,431)	713,201
Net income	\$ 276,412				276,412
Pension and other postretirement benefits, net of \$30,705,000 of income taxes (Note 4)				35,302	
Comprehensive income	\$ 311,714				
Restricted stock units			184		
Stock-based compensation			10		
Consolidated tax benefit allocation			13,209		
FIN 48 cumulative effect adjustment					(185)
Cash dividends declared on common stock					(304,000)
Balance, December 31, 2007		67,930,743	873,536	(69,129)	685,428
Net income	\$ 284,526				284,526
Pension and other postretirement benefits, net of \$33,136,000 of income tax benefits (Note 4)				(65,728)	
Comprehensive income	\$ 218,798				
Restricted stock units			(1)		
Stock-based compensation			1		
Consolidated tax benefit allocation			5,249		
Cash dividends declared on common stock					(110,000)
Balance, December 31, 2008		67,930,743	\$ 878,785	\$ (134,857)	\$ 859,954

The accompanying Combined 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 STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2008	2007	2006
	<i>(In thousands)</i>		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	\$ 284,526	\$ 276,412	\$ 306,051
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	72,383	75,238	63,589
Amortization of regulatory assets	163,534	144,370	127,403
Deferral of new regulatory assets	(107,571)	(149,556)	(128,220)
Deferred rents and lease market valuation liability		(357,679)	(71,943)
Deferred income taxes and investment tax credits, net	11,918	(22,767)	(17,093)
Accrued compensation and retirement benefits	1,563	3,196	2,367
Electric service prepayment programs	(23,634)	(24,443)	(19,673)
Pension trust contributions	-	(24,800)	-
Decrease (increase) in operating assets-			
Receivables	66,963	209,426	(137,711)
Prepayments and other current assets	(450)	(152)	160
Increase (decrease) in operating liabilities-			
Accounts payable	13,787	(316,638)	293,214
Accrued taxes	(3,149)	(33,659)	7,342
Accrued interest	37	(5,138)	147
Other	6,290	706	(6,387)
Net cash provided from (used for) operating activities	<u>486,197</u>	<u>(225,484)</u>	<u>419,246</u>
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	300,000	249,602	298,416
Short-term borrowings, net	-	277,581	-
Redemptions and Repayments-			
Common stock	-	-	(300,000)
Long-term debt	(213,319)	(492,825)	(376,702)
Short-term borrowings, net	(315,827)	-	(143,272)
Dividend Payments-			
Common stock	(185,000)	(204,000)	(180,000)
Other	(2,568)	(2,709)	(2,754)
Net cash used for financing activities	<u>(416,714)</u>	<u>(172,351)</u>	<u>(704,312)</u>
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(137,265)	(149,131)	(119,795)
Loan repayments from (loans to) associated companies, net	33,246	6,714	(7,813)
Collection of principal on long-term notes receivable	-	486,634	376,135
Investments in lessor notes	37,707	56,179	44,556
Other	(3,177)	(2,550)	(8,003)
Net cash provided from (used for) investing activities	<u>(69,489)</u>	<u>397,846</u>	<u>285,080</u>
Net increase (decrease) in cash and cash equivalents	(6)	11	14
Cash and cash equivalents at beginning of year	232	221	207
Cash and cash equivalents at end of year	<u>\$ 226</u>	<u>\$ 232</u>	<u>\$ 221</u>
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	\$ 122,834	\$ 141,390	\$ 135,276
Income taxes	\$ 153,042	\$ 186,874	\$ 180,941

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

THE TOLEDO EDISON COMPANY
MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

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. Until December 31, 2008, TE purchased power for delivery and resale from a full requirements power sale agreement with its affiliate FES at a fixed price that was reflected in rates approved by the PUCO. See Regulatory Matters – Ohio below for a discussion of power supply for 2009 and beyond.

Results of Operations

Net income in 2008 decreased to \$75 million from \$91 million in 2007. The decrease resulted primarily from lower electric sales revenues, higher purchased power costs and a decrease in the deferral of new regulatory assets, partially offset by lower other operating costs.

Revenues

Revenues decreased \$68 million, or 7.1%, in 2008 compared to 2007 due to lower wholesale generation revenues (\$133 million), partially offset by increased retail generation revenues (\$49 million), distribution revenues (\$7 million) and transmission revenues (\$9 million).

The decrease in wholesale revenues was primarily due to lower associated company sales of KWH from TE's leasehold interests in generating plants. Revenues from TE's leasehold interests in Beaver Valley Unit 2 decreased by \$68 million due to the unit's 39-day refueling outage in the second quarter of 2008 and the incremental pricing impacts related to the termination of TE's sale agreement with CEI. At the end of 2007, TE terminated its Beaver Valley Unit 2 output sale agreement with CEI. During 2008, TE sold the 158 MW entitlement from its 18.26% leasehold interest in the unit to NGC. Revenues from PSA sales decreased by \$69 million in 2008 due to the assignment of TE's leasehold interests in the Bruce Mansfield Plant to FGCO in October 2007. Prior to the assignment, TE sold power from its interests in the plant to FGCO.

Retail generation revenues increased in 2008 due to higher average prices across all customer classes and increased KWH sales to residential and commercial customers compared to 2007. The higher average prices were driven by the 2008 fuel cost recovery rider that became effective January 16, 2008 (see Regulatory Matters – Ohio). The increase in sales to residential and commercial customers was due primarily to less customer shopping; generation services provided by alternative suppliers as a percentage of total sales delivered in TE's franchise area to residential and commercial customers decreased by one and five percentage points, respectively. Reduced industrial KWH sales, principally to the automotive and steel sectors, reflected weakening economic conditions.

Changes in retail electric generation KWH sales and revenues in 2008 from 2007 are summarized in the following tables.

<u>Retail KWH Sales</u>	<u>Increase (Decrease)</u>
Residential	0.5%
Commercial	6.4%
Industrial	(6.8)%
Net Decrease in Retail KWH Sales	(2.4)%

<u>Retail Generation Revenues</u>	<u>Increase (In millions)</u>
Residential	\$ 11
Commercial	16
Industrial	22
Increase in Retail Generation Revenues	\$ 49

Revenues from distribution throughput increased by \$7 million in 2008 compared to 2007 due to higher average unit prices for all customer classes, partially offset by lower KWH deliveries. The higher average prices resulted from PUCO-approved transmission rider increases that became effective July 1, 2007 and July 1, 2008. The reduction in commercial and industrial KWH deliveries reflected the economic downturn.

Changes in distribution KWH deliveries and revenues in 2008 from 2007 are summarized in the following tables.

<u>Distribution KWH Deliveries</u>	<u>Decrease</u>
Residential	(0.6)%
Commercial	(1.3)%
Industrial	(6.8)%
Decrease in Distribution Deliveries	(3.8)%

<u>Distribution Revenues</u>	<u>Increase</u>
	<i>(In millions)</i>
Residential	\$ 4
Commercial	2
Industrial	1
Increase in Distribution Revenues	\$ 7

Expenses

Total expenses decreased \$24 million in 2008 from 2007. The following table presents changes from the prior year by expense category.

<u>Expenses – Changes</u>	<u>Increase (Decrease)</u>
	<i>(In millions)</i>
Purchased power costs	\$ 15
Other operating costs	(89)
Provision for depreciation	(4)
Amortization of regulatory assets	5
Deferral of new regulatory assets	48
General taxes	1
Net Decrease in Expenses	\$ (24)

Higher purchased power costs primarily reflected higher unit prices as provided for under the PSA with FES, partially offset by a decrease in volume due to lower retail generation KWH sales. Other operating costs decreased primarily due to the reversal of the above-market lease liability (\$31 million) associated with TE's leasehold interest in Beaver Valley Unit 2, as a result of the termination of the CEI sale agreement described above, and lower fuel costs (\$26 million) and other operating costs (\$30 million) due to the assignment of TE's leasehold interests in the Mansfield Plant in October 2007. These decreases were partially offset by increased costs (\$8 million) associated with TE's leasehold interests in Beaver Valley Unit 2, due to a refueling outage in the second quarter of 2008. Depreciation expense decreased primarily due to the transfer of leasehold improvements for the Mansfield Plant and Beaver Valley Unit 2 to FGCO and NGC, respectively, during 2008.

The increase in the amortization of regulatory assets was primarily due to increased amortization of transmission cost deferrals (\$7 million), partially offset by lower amortization of transition cost deferrals (\$3 million). The change in the deferral of new regulatory assets was primarily due to lower RCP distribution cost deferrals (\$24 million) due to the application of overrecovered RTC revenues to the deferred balance, and lower deferred fuel costs (\$19 million) and MISO transmission expenses (\$5 million), as more generation and transmission costs were recovered from customers through PUCO-approved riders. Higher general taxes primarily reflected increased KWH taxes, property taxes and Ohio commercial activity taxes.

Other Expense

Other expense decreased \$4 million in 2008 compared to 2007, primarily due to lower interest expense, partially offset by lower investment income. The lower interest expense resulted from lower money pool borrowings from associated companies in 2008 and the redemption of long-term debt (\$89 million aggregate principal amount in 2008 and the second half of 2007). The decrease in investment income resulted primarily from repayments in 2007 of notes receivable from associated companies, customer accounts receivable financing activity and redemptions of lessor notes.

Interest Rate Risk

TE has little exposure to fluctuations in market interest rates because most of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for TE's investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

<u>Year of Maturity</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>There- after</u>	<u>Total</u>	<u>Fair Value</u>
<i>(Dollars in millions)</i>								
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	\$ 12	\$ 18	\$ 21	\$ 22	\$ 25	\$ 165	\$ 263	\$ 274
Average interest rate	7.7%	7.7%	7.7%	7.7%	7.7%	6.2%	6.8%	
Liabilities								
Long-term Debt:								
Fixed rate						\$ 300	\$ 300	\$ 244
Average interest rate						6.2%	6.2%	
Short-term Borrowings:	\$ 111						\$ 111	\$ 111
Average interest rate	1.5%						1.5%	

Legal Proceedings

See the "Regulatory Matters," "Environmental Matters" and "Other Legal Proceedings" sections within the Combined Management's Discussion and Analysis of Registrant Subsidiaries for discussion of legal proceedings applicable to TE.

New Accounting Standards and Interpretations

See the "New Accounting Standards and Interpretations" section within the Combined Management's Discussion and Analysis of Registrant Subsidiaries for discussion of new accounting standards and interpretations applicable to TE.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of The Toledo Edison Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2008 consolidated financial statements.

FirstEnergy Corp.'s internal auditors, who are responsible to the Audit Committee of FirstEnergy's Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held ten meetings in 2008.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2008.

This annual report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of The Toledo Edison Company and its subsidiary at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in the notes to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions as of January 1, 2007 (Note 8) and defined benefit pension and other postretirement plans as of December 31, 2006 (Note 4).

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 24, 2009

THE TOLEDO EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	2008	2007	2006
	<i>(In thousands)</i>		
REVENUES (Note 3):			
Electric sales	\$ 865,016	\$ 934,772	\$ 899,930
Excise tax collections	30,489	29,173	28,071
Total revenues	<u>895,505</u>	<u>963,945</u>	<u>928,001</u>
EXPENSES (Note 3):			
Purchased power (primarily from affiliates)	413,344	398,423	368,654
Other operating costs	190,441	279,047	284,561
Provision for depreciation	32,422	36,743	33,310
Amortization of regulatory assets	109,201	104,348	95,032
Deferral of new regulatory assets	(15,097)	(62,664)	(54,946)
General taxes	52,324	50,640	50,869
Total expenses	<u>782,635</u>	<u>806,537</u>	<u>777,480</u>
OPERATING INCOME	<u>112,870</u>	<u>157,408</u>	<u>150,521</u>
OTHER INCOME (EXPENSE) (Note 3):			
Investment income	22,823	27,713	38,187
Miscellaneous expense	(7,832)	(6,651)	(7,379)
Interest expense	(23,286)	(34,135)	(23,179)
Capitalized interest	164	640	1,123
Total other income (expense)	<u>(8,131)</u>	<u>(12,433)</u>	<u>8,752</u>
INCOME BEFORE INCOME TAXES	104,739	144,975	159,273
INCOME TAXES	<u>29,824</u>	<u>53,736</u>	<u>59,869</u>
NET INCOME	74,915	91,239	99,404
PREFERRED STOCK DIVIDEND REQUIREMENTS	<u>-</u>	<u>-</u>	<u>9,409</u>
EARNINGS ON COMMON STOCK	<u>\$ 74,915</u>	<u>\$ 91,239</u>	<u>\$ 89,995</u>

The accompanying Combined 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

As of December 31,	2008	2007
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 14	\$ 22
Receivables-		
Customers	751	449
Associated companies	61,854	88,796
Other (less accumulated provisions of \$203,000 and \$615,000, respectively, for uncollectible accounts)	23,336	3,116
Notes receivable from associated companies	111,579	154,380
Prepayments and other	1,213	865
	<u>198,747</u>	<u>247,628</u>
UTILITY PLANT:		
In service	870,911	931,263
Less - Accumulated provision for depreciation	407,859	420,445
	<u>463,052</u>	<u>510,818</u>
Construction work in progress	9,007	19,740
	<u>472,059</u>	<u>530,558</u>
OTHER PROPERTY AND INVESTMENTS:		
Investment in lessor notes (Note 6)	142,687	154,646
Long-term notes receivable from associated companies	37,233	37,530
Nuclear plant decommissioning trusts	73,500	66,759
Other	1,668	1,756
	<u>255,088</u>	<u>260,691</u>
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	500,576	500,576
Regulatory assets	109,364	203,719
Pension assets (Note 4)	-	28,601
Property taxes	22,970	21,010
Other	48,706	20,496
	<u>681,616</u>	<u>774,402</u>
	<u>\$ 1,607,510</u>	<u>\$ 1,813,279</u>
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	\$ 34	\$ 34
Accounts payable-		
Associated companies	70,455	245,215
Other	4,812	4,449
Notes payable to associated companies	111,242	13,396
Accrued taxes	24,433	30,245
Lease market valuation liability	36,900	36,900
Other	23,183	22,747
	<u>271,059</u>	<u>352,986</u>
CAPITALIZATION (See Statements of Capitalization) :		
Common stockholder's equity	480,050	485,191
Long-term debt and other long-term obligations	299,626	303,397
	<u>779,676</u>	<u>788,588</u>
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	78,905	103,463
Accumulated deferred investment tax credits	6,804	10,180
Lease market valuation liability (Note 6)	273,100	310,000
Retirement benefits	73,106	63,215
Asset retirement obligations	30,213	28,366
Deferred revenues - electric service programs	1,458	12,639
Lease assignment payable to associated companies	30,529	83,485
Other	62,660	60,357
	<u>556,775</u>	<u>671,705</u>
COMMITMENTS AND CONTINGENCIES (Notes 6 and 13)		
	<u>\$ 1,607,510</u>	<u>\$ 1,813,279</u>

The accompanying Combined 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 CAPITALIZATION

As of December 31,	2008	2007
	<i>(In thousands)</i>	
COMMON STOCKHOLDER'S EQUITY:		
Common stock, \$5 par value, 60,000,000 shares authorized, 29,402,054 shares outstanding	\$ 147,010	\$ 147,010
Other paid-in capital	175,879	173,169
Accumulated other comprehensive loss (Note 2(F))	(33,372)	(10,606)
Retained earnings (Note 10(A))	190,533	175,618
Total	<u>480,050</u>	<u>485,191</u>
LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS (Note 10(C)):		
Secured notes-		
5.375% due 2028	-	3,751
Unsecured notes-		
6.150% due 2037	300,000	300,000
Capital lease obligations (Note 6)	80	114
Net unamortized discount on debt	(420)	(434)
Long-term debt due within one year	(34)	(34)
Total long-term debt and other long-term obligations	<u>299,626</u>	<u>303,397</u>
TOTAL CAPITALIZATION	<u>\$ 779,676</u>	<u>\$ 788,588</u>

The accompanying Combined 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 STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	<u>Comprehensive Income</u>	<u>Common Stock</u>		<u>Other Paid-In Capital</u>	<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Retained Earnings</u>
		<u>Number of Shares</u>	<u>Par Value</u>			
<i>(Dollars in thousands)</i>						
Balance, January 1, 2006		39,133,887	\$ 195,670	\$ 473,638	\$ 4,690	\$ 189,428
Net income	\$ 99,404					99,404
Unrealized gain on investments, net						
of \$211,000 of income taxes	462				462	
Comprehensive income	<u>\$ 99,866</u>					
Net liability for unfunded retirement benefits						
due to the implementation of SFAS 158, net						
of \$26,929,000 of income tax benefits (Note 4)					(41,956)	
Affiliated company asset transfers				(130,571)		
Repurchase of common stock		(9,731,833)	(48,660)	(176,341)		
Preferred stock redemption premiums						(4,840)
Restricted stock units				38		
Stock-based compensation				22		
Cash dividends on preferred stock						(4,569)
Cash dividends declared on common stock						(75,000)
Balance, December 31, 2006		29,402,054	147,010	166,786	(36,804)	204,423
Net income	\$ 91,239					91,239
Unrealized gain on investments, net						
of \$1,089,000 of income taxes	1,901				1,901	
Pension and other postretirement benefits, net						
of \$15,077,000 of income taxes (Note 4)	24,297				24,297	
Comprehensive income	<u>\$ 117,437</u>					
Restricted stock units				53		
Stock-based compensation				2		
Consolidated tax benefit allocation				6,328		
FIN 48 cumulative effect adjustment						(44)
Cash dividends declared on common stock						(120,000)
Balance, December 31, 2007		29,402,054	147,010	173,169	(10,606)	175,618
Net income	\$ 74,915					74,915
Unrealized gain on investments, net						
of \$1,421,000 of income taxes	2,372				2,372	
Pension and other postretirement benefits, net						
of \$11,630,000 of income tax benefits (Note 4)	(25,138)				(25,138)	
Comprehensive income	<u>\$ 52,149</u>					
Restricted stock units				47		
Stock-based compensation				1		
Consolidated tax benefit allocation				2,662		
Cash dividends declared on common stock						(60,000)
Balance, December 31, 2008		29,402,054	\$ 147,010	\$ 175,879	\$ (33,372)	\$ 190,533

The accompanying Combined 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 STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2008	2007	2006
	<i>(In thousands)</i>		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	\$ 74,915	\$ 91,239	\$ 99,404
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	32,422	36,743	33,310
Amortization of regulatory assets	109,201	104,348	95,032
Deferral of new regulatory assets	(15,097)	(62,664)	(54,946)
Deferred rents and lease market valuation liability	(37,938)	265,981	(32,925)
Deferred income taxes and investment tax credits, net	(16,869)	(26,318)	(37,133)
Accrued compensation and retirement benefits	1,483	5,276	4,415
Electric service prepayment programs	(11,181)	(10,907)	(9,060)
Pension trust contribution	-	(7,659)	-
Decrease (increase) in operating assets-			
Receivables	20,186	(64,489)	6,387
Prepayments and other current assets	(348)	(13)	208
Increase (decrease) in operating liabilities-			
Accounts payable	(164,397)	8,722	39,847
Accrued taxes	(5,812)	(14,954)	(2,026)
Accrued interest	(17)	(1,350)	1,899
Other	(3,289)	5,188	4,640
Net cash provided from (used for) operating activities	<u>(16,741)</u>	<u>329,143</u>	<u>149,052</u>
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	-	-	299,550
Short-term borrowings, net	97,846	-	62,909
Redemptions and Repayments-			
Common stock	-	-	(225,000)
Preferred stock	-	-	(100,840)
Long-term debt	(3,860)	(85,797)	(202,550)
Short-term borrowings, net	-	(153,567)	-
Dividend Payments-			
Common stock	(70,000)	(85,000)	(75,000)
Preferred stock	-	-	(4,569)
Other	(131)	-	(2,887)
Net cash provided from (used for) financing activities	<u>23,855</u>	<u>(324,364)</u>	<u>(248,387)</u>
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(57,385)	(58,871)	(61,232)
Loan repayments from (loans to) associated companies, net	42,822	(51,002)	(52,178)
Collection of principal on long-term notes receivable	276	91,308	202,787
Redemption of lessor notes (Note 6)	11,959	14,847	9,305
Sales of investment securities held in trusts	37,931	44,682	53,458
Purchases of investment securities held in trusts	(40,960)	(47,853)	(53,724)
Other	(1,765)	2,110	926
Net cash provided from (used for) investing activities	<u>(7,122)</u>	<u>(4,779)</u>	<u>99,342</u>
Net change in cash and cash equivalents	(8)	-	7
Cash and cash equivalents at beginning of year	22	22	15
Cash and cash equivalents at end of year	<u>\$ 14</u>	<u>\$ 22</u>	<u>\$ 22</u>
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	\$ 22,203	\$ 33,841	\$ 17,785
Income taxes	<u>\$ 62,879</u>	<u>\$ 73,845</u>	<u>\$ 95,753</u>

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

JERSEY CENTRAL POWER & LIGHT COMPANY

MANAGEMENT'S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS

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 franchise customers electing to retain JCP&L as their power supplier. JCP&L procures electric supply to serve its BGS customers through a statewide auction process approved by the NJBPU.

Results of Operations

Net income increased to \$187 million in 2008 from \$186 million in 2007. The increase was primarily due to higher operating revenues, lower other operating costs and lower amortization of regulatory assets, partially offset by higher purchased power costs and other expenses.

Revenues

Revenues increased \$228 million, or 7%, in 2008 compared with 2007 due to higher retail generation revenues (\$182 million) and higher wholesale revenues (\$62 million), partially offset by a decrease in distribution throughput (\$7 million).

Retail generation revenues from all customer classes increased due to higher unit prices resulting from the BGS auctions effective June 1, 2007, and June 1, 2008, partially offset by decreased retail generation KWH sales. Residential and commercial sales volumes decreased primarily as a result of milder weather (heating degree days and cooling degree days decreased by 2.3% and 6.4%, respectively, in 2008 compared to 2007). Customer shopping also contributed to the decreased sales volumes in the commercial sector (shopping increased by 3.5 percentage points in 2008 compared to 2007). Industrial sales volumes decreased primarily due to weakening economic conditions and increased customer shopping.

Changes in retail generation KWH sales and revenues by customer class in 2008 compared to 2007 are summarized in the following tables:

Retail Generation KWH Sales	Decrease
Residential	(1.7)%
Commercial	(6.1)%
Industrial	(6.3)%
Decrease in Generation Sales	(3.7)%
Retail Generation Revenues	Increase
	<i>(In millions)</i>
Residential	\$ 124
Commercial	52
Industrial	6
Increase in Generation Revenues	\$ 182

Wholesale generation revenues increased \$62 million in 2008 primarily due to higher market prices for NUG sales in PJM, partially offset by a decrease in sales volume compared to 2007.

JCP&L defers amounts by which the costs of supplying BGS and costs incurred under NUG agreements exceed amounts collected through BGS and NUGC rates from retail customers and revenues from the sale of NUG power.

Distribution revenues decreased \$7 million in 2008 compared to 2007 due to lower KWH deliveries, reflecting the weather and economic impacts described above, partially offset by a slight increase in composite unit prices.

Changes in distribution KWH deliveries and revenues by customer class in 2008 compared to 2007 are summarized in the following tables:

Distribution KWH Deliveries	Decrease
Residential	(1.7)%
Commercial	(1.6)%
Industrial	(3.9)%
Decrease in Distribution Deliveries	(2.0)%

<u>Distribution Revenues</u>	<u>Decrease</u>
	<i>(In millions)</i>
Residential	\$ (1)
Commercial	(5)
Industrial	(1)
Decrease in Distribution Revenues	\$ (7)

Expenses

Total expenses increased by \$214 million in 2008 compared to 2007. The following table presents changes from the prior year period by expense category:

<u>Expenses - Changes</u>	<u>Increase (Decrease)</u>
	<i>(In millions)</i>
Purchased power costs	\$ 248
Other operating costs	(23)
Provision for depreciation	11
Amortization of regulatory assets	(23)
General taxes	1
Net increase in expenses	\$ 214

Purchased power costs increased in 2008 primarily due to higher unit prices resulting from the BGS auctions effective June 1, 2007, and June 1, 2008, partially offset by a decrease in purchases due to the lower generation KWH sales discussed above. Other operating costs decreased primarily as a result of lower professional and contractor costs charged to expense (more costs were dedicated to capital projects in 2008) and lower employee benefit expenses. Depreciation expense increased primarily due to an increase in depreciable property during 2007. Amortization of regulatory assets decreased in 2008 primarily due to the completion in December 2007 of regulatory asset recovery associated with TMI-2 and lower transition cost amortization due to the lower KWH deliveries discussed above.

Other Expenses

Other expenses increased by \$15 million in 2008 compared to 2007 primarily due to interest expense associated with JCP&L's \$550 million issuance of senior notes in May 2007, reduced life insurance investment values and lower interest income on regulatory asset balances.

Sale of Investment

On April 17, 2008, JCP&L closed the sale of its 86-MW Forked River Power Plant to Maxim Power Corp. for \$20 million. In conjunction with this sale, FES entered into a 10-year tolling agreement with Maxim for the entire capacity of the plant. The sale is subject to regulatory accounting and did not have a material impact on JCP&L's earnings in 2008. The New Jersey Rate Counsel has appealed the NJBPU's approval of the sale to the Appellate Division of the Superior Court of New Jersey, where it is currently pending.

Market Risk Information

JCP&L 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.

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. Certain 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 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 or regulatory liability for below-market costs. The change in the fair value of commodity derivative contracts related to energy production during 2008 is summarized in the following table:

Decrease in the Fair Value of Derivative Contracts	Non-Hedge	Hedge	Total
		<i>(In millions)</i>	
Change in the fair value of commodity derivative contracts:			
Outstanding net liabilities as of January 1, 2008	\$ (740)	\$ -	\$ (740)
Additions/Changes in value of existing contracts	1	-	1
Settled contracts	229	-	229
Net Liabilities - Derivatives Contracts as of December 31, 2008 ⁽¹⁾	\$ (510)	\$ -	\$ (510)
Impact of Changes in Commodity Derivative Contracts ⁽²⁾			
Income Statement Effects (Pre-Tax)	\$ -	\$ -	\$ -
Balance Sheet Effects:			
Regulatory Asset (Net)	\$ (230)	\$ -	\$ (230)

(1) Includes \$510 million in non-hedge commodity derivative contracts (primarily with NUGs) that are offset by a regulatory asset, with no impact to earnings.

(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 December 31, 2008 as follows:

Balance Sheet Classification	Non-Hedge	Hedge	Total
		<i>(In millions)</i>	
Non-Current-			
Other deferred charges	\$ 22	\$ -	\$ 22
Other noncurrent liabilities	(532)	-	(532)
Net liabilities	\$ (510)	\$ -	\$ (510)

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 December 31, 2008 are summarized by year in the following table:

Source of Information - Fair Value by Contract Year	2009	2010	2011	2012	2013	Thereafter	Total
				<i>(In millions)</i>			
Broker quote sheets ⁽¹⁾	\$ (161)	\$ (149)	\$ (109)	\$ (41)	\$ -	\$ -	\$ (460)
Prices based on models	-	-	-	-	(25)	(25)	(50)
Total ⁽²⁾	\$ (161)	\$ (149)	\$ (109)	\$ (41)	\$ (25)	\$ (25)	\$ (510)

(1) Validated by observable market transactions.

(2) Includes \$510 million in non-hedge commodity derivative contracts (primarily with NUGs) that are offset by a regulatory asset, with no impact to earnings.

JCP&L performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% adverse shift in quoted market prices in the near term on derivative instruments would not have had a material effect on JCP&L's consolidated financial position or cash flows as of December 31, 2008. Based on derivative contracts held as of December 31, 2008, an adverse 10% change in commodity prices would not have a material effect on JCP&L's net income for the next 12 months.

Interest Rate Risk

JCP&L's exposure to fluctuations in market interest rates is reduced since a significant portion of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for JCP&L's investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	2009	2010	2011	2012	2013	There- after	Total	Fair Value
<i>(Dollars in millions)</i>								
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income		\$ 1				\$ 258	\$ 259	\$ 259
Average interest rate		4.0%				4.6%	4.6%	
Liabilities								
Long-term Debt:								
Fixed rate	\$ 29	\$ 31	\$ 32	\$ 34	\$ 36	\$ 1,407	\$ 1,569	\$ 1,520
Average interest rate	5.3%	5.4%	5.6%	5.7%	5.7%	5.8%	5.8%	
Short-term Borrowings:	\$ 121						\$ 121	\$ 121
Average interest rate	1.5%						1.5%	

Equity Price Risk

Included in JCP&L's nuclear decommissioning trusts are marketable equity securities carried at their market value of approximately \$66 million as of December 31, 2008. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a \$7 million reduction in fair value as of December 31, 2008 (see Note 5).

Legal Proceedings

See the "Regulatory Matters," "Environmental Matters" and "Other Legal Proceedings" sections within the Combined Management's Discussion and Analysis of Registrant Subsidiaries for discussion of other legal proceedings applicable to JCP&L.

New Accounting Standards and Interpretations

See the "New Accounting Standards and Interpretations" section within the Combined Management's Discussion and Analysis of Registrant Subsidiaries for discussion of new accounting standards and interpretations applicable to JCP&L.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of Jersey Central Power & Light Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2008 consolidated financial statements.

FirstEnergy Corp.'s internal auditors, who are responsible to the Audit Committee of FirstEnergy's Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held ten meetings in 2008.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2008.

This annual report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of Jersey Central Power & Light Company and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in the notes to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions as of January 1, 2007 (Note 8) and defined benefit pension and other postretirement plans as of December 31, 2006 (Note 4).

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 24, 2009

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	2008	2007	2006
	<i>(In thousands)</i>		
REVENUES (Note 3):			
Electric sales	\$ 3,420,772	\$ 3,191,999	\$ 2,617,390
Excise tax collections	51,481	51,848	50,255
Total revenues	3,472,253	3,243,847	2,667,645
EXPENSES (Note 3):			
Purchased power from affiliates	-	-	25,102
Purchased power from non-affiliates	2,206,251	1,957,975	1,496,227
Other operating costs	302,894	325,814	320,847
Provision for depreciation	96,482	85,459	83,172
Amortization of regulatory assets	364,816	388,581	274,704
General taxes	67,340	66,225	63,925
Total expenses	3,037,783	2,824,054	2,263,977
OPERATING INCOME	434,470	419,793	403,668
OTHER INCOME (EXPENSE):			
Miscellaneous income (expense)	(1,037)	8,570	13,323
Interest expense (Note 3)	(99,459)	(96,988)	(83,411)
Capitalized interest	1,245	3,789	3,758
Total other expense	(99,251)	(84,629)	(66,330)
INCOME BEFORE INCOME TAXES	335,219	335,164	337,338
INCOME TAXES	148,231	149,056	146,731
NET INCOME	186,988	186,108	190,607
PREFERRED STOCK DIVIDEND REQUIREMENTS	-	-	1,018
EARNINGS ON COMMON STOCK	\$ 186,988	\$ 186,108	\$ 189,589

The accompanying Combined 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

As of December 31,	2008	2007
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 66	\$ 94
Receivables-		
Customers (less accumulated provisions of \$3,230,000 and \$3,691,000, respectively, for uncollectible accounts)	340,485	321,026
Associated companies	265	21,297
Other	37,534	59,244
Notes receivable - associated companies	16,254	18,428
Prepaid taxes	10,492	1,012
Other	18,066	17,603
	<u>423,162</u>	<u>438,704</u>
UTILITY PLANT:		
In service	4,307,556	4,175,125
Less - Accumulated provision for depreciation	1,551,290	1,516,997
	<u>2,756,266</u>	<u>2,658,128</u>
Construction work in progress	77,317	90,508
	<u>2,833,583</u>	<u>2,748,636</u>
OTHER PROPERTY AND INVESTMENTS:		
Nuclear fuel disposal trust	181,468	176,512
Nuclear plant decommissioning trusts	143,027	175,869
Other	2,145	2,083
	<u>326,640</u>	<u>354,464</u>
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	1,228,061	1,595,662
Goodwill	1,810,936	1,826,190
Pension assets (Note 4)	-	100,615
Other	29,946	29,809
	<u>3,068,943</u>	<u>3,552,276</u>
	<u>\$ 6,652,328</u>	<u>\$ 7,094,080</u>
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	\$ 29,094	\$ 27,206
Short-term borrowings-		
Associated companies	121,380	130,381
Accounts payable-		
Associated companies	12,821	7,541
Other	198,742	193,848
Accrued taxes	20,561	3,124
Accrued interest	9,197	9,318
Other	133,091	103,286
	<u>524,886</u>	<u>474,704</u>
CAPITALIZATION (See Consolidated Statements of Capitalization):		
Common stockholder's equity	2,729,010	3,017,864
Long-term debt and other long-term obligations	1,531,840	1,560,310
	<u>4,260,850</u>	<u>4,578,174</u>
NONCURRENT LIABILITIES:		
Power purchase contract liability	531,686	763,173
Accumulated deferred income taxes	689,065	800,214
Nuclear fuel disposal costs	196,235	192,402
Asset retirement obligations	95,216	89,669
Retirement benefits	190,182	2,468
Other	164,208	193,276
	<u>1,866,592</u>	<u>2,041,202</u>
COMMITMENTS AND CONTINGENCIES (Notes 6 and 13)		
	<u>\$ 6,652,328</u>	<u>\$ 7,094,080</u>

The accompanying Combined 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 CAPITALIZATION

As of December 31,	2008	2007
	<i>(In thousands)</i>	
COMMON STOCKHOLDER'S EQUITY:		
Common stock, \$10 par value, 16,000,000 shares authorized, 14,421,637 shares outstanding	\$ 144,216	\$ 144,216
Other paid-in capital	2,644,756	2,655,941
Accumulated other comprehensive loss (Note 2(F))	(216,538)	(19,881)
Retained earnings (Note 10(A))	156,576	237,588
Total	<u>2,729,010</u>	<u>3,017,864</u>
LONG-TERM DEBT (Note 10(C)):		
Secured notes-		
5.390% due 2008-2010	33,469	52,273
5.250% due 2008-2012	33,229	41,631
5.810% due 2010-2013	77,075	77,075
5.410% due 2012-2014	25,693	25,693
6.160% due 2013-2017	99,517	99,517
5.520% due 2014-2018	49,220	49,220
5.610% due 2018-2021	51,139	51,139
Total	<u>369,342</u>	<u>396,548</u>
Unsecured notes-		
5.625% due 2016	300,000	300,000
5.650% due 2017	250,000	250,000
4.800% due 2018	150,000	150,000
6.400% due 2036	200,000	200,000
6.150% due 2037	300,000	300,000
Total	<u>1,200,000</u>	<u>1,200,000</u>
Net unamortized discount on debt	(8,408)	(9,032)
Long-term debt due within one year	(29,094)	(27,206)
Total long-term debt	<u>1,531,840</u>	<u>1,560,310</u>
TOTAL CAPITALIZATION	<u>\$ 4,260,850</u>	<u>\$ 4,578,174</u>

The accompanying Combined 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 STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Comprehensive Income	Common Stock		Other Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
		Number of Shares	Par Value			
<i>(Dollars in thousands)</i>						
Balance, January 1, 2006		15,371,270	\$ 153,713	\$ 3,003,190	\$ (2,030)	\$ 55,890
Net income	\$ 190,607					190,607
Net unrealized gain on derivative instruments, net of \$101,000 of income taxes	147				147	
Comprehensive income	<u>\$ 190,754</u>					
Net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of \$42,233,000 of income tax benefits (Note 4)					(42,371)	
Repurchase of common stock		(361,935)	(3,620)	(73,381)		
Preferred stock redemption premium						(663)
Restricted stock units				101		
Stock-based compensation				48		
Cash dividends on preferred stock						(354)
Cash dividends declared on common stock						(100,000)
Purchase accounting fair value adjustment				(21,679)		
Balance, December 31, 2006		15,009,335	150,093	2,908,279	(44,254)	145,480
Net income	\$ 186,108					186,108
Net unrealized gain on derivative instruments, net of \$11,000 of income taxes	293				293	
Pension and other postretirement benefits, net of \$23,644,000 of income taxes (Note 4)	24,080				24,080	
Comprehensive income	<u>\$ 210,481</u>					
Restricted stock units				198		
Stock-based compensation				3		
Consolidated tax benefit allocation				4,637		
Repurchase of common stock		(587,698)	(5,877)	(119,123)		
Cash dividends declared on common stock						(94,000)
Purchase accounting fair value adjustment				(138,053)		
Balance, December 31, 2007		14,421,637	144,216	2,655,941	(19,881)	237,588
Net income	\$ 186,988					186,988
Net unrealized gain on derivative instruments	276				276	
Pension and other postretirement benefits, net of \$131,317,000 of income tax benefits (Note 4)	(196,933)				(196,933)	
Comprehensive loss	<u>\$ (9,669)</u>					
Restricted stock units				3		
Stock-based compensation				1		
Consolidated tax benefit allocation				4,065		
Cash dividends declared on common stock						(268,000)
Purchase accounting fair value adjustment				(15,254)		
Balance, December 31, 2008		14,421,637	\$ 144,216	\$ 2,644,756	\$ (216,538)	\$ 156,576

The accompanying Combined 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 STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2008	2007	2006
	<i>(In thousands)</i>		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	\$ 186,988	\$ 186,108	\$ 190,607
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	96,482	85,459	83,172
Amortization of regulatory assets	364,816	388,581	274,704
Deferred purchased power and other costs	(165,071)	(203,157)	(281,498)
Deferred income taxes and investment tax credits, net	12,834	(30,791)	43,896
Accrued compensation and retirement benefits	(35,791)	(23,441)	(12,670)
Cash collateral from (returned to) suppliers	23,106	(31,938)	(109,108)
Pension trust contributions	-	(17,800)	-
Decrease (increase) in operating assets-			
Receivables	8,042	(73,259)	1,103
Materials and supplies	348	(364)	61
Prepaid taxes	(9,562)	12,321	5,385
Other current assets	(38)	2,096	(2,134)
Increase (decrease) in operating liabilities-			
Accounts payable	10,174	(39,396)	53,330
Accrued taxes	2,582	11,658	(52,905)
Accrued interest	(121)	(5,140)	(5,458)
Other	(13,002)	5,369	1,272
Net cash provided from operating activities	<u>481,787</u>	<u>266,306</u>	<u>189,757</u>
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	-	543,807	382,400
Short-term borrowings, net	-	-	5,194
Redemptions and Repayments-			
Long-term debt	(27,206)	(325,337)	(207,231)
Short-term borrowings, net	(9,001)	(56,159)	-
Common stock	-	(125,000)	(77,000)
Preferred stock	-	-	(13,312)
Dividend Payments-			
Common stock	(268,000)	(94,000)	(100,000)
Preferred stock	-	-	(354)
Other	(80)	(609)	-
Net cash used for financing activities	<u>(304,287)</u>	<u>(57,298)</u>	<u>(10,303)</u>
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(178,358)	(199,856)	(160,264)
Proceeds from asset sales	20,000	-	-
Loan repayments from (loans to) associated companies, net	2,173	6,029	(6,037)
Sales of investment securities held in trusts	248,185	195,973	216,521
Purchases of investment securities held in trusts	(265,441)	(212,263)	(219,416)
Other	(4,087)	1,162	(10,319)
Net cash used for investing activities	<u>(177,528)</u>	<u>(208,955)</u>	<u>(179,515)</u>
Net increase (decrease) in cash and cash equivalents	(28)	53	(61)
Cash and cash equivalents at beginning of year	94	41	102
Cash and cash equivalents at end of year	<u>\$ 66</u>	<u>\$ 94</u>	<u>\$ 41</u>
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	<u>\$ 99,731</u>	<u>\$ 102,492</u>	<u>\$ 80,101</u>
Income taxes	<u>\$ 145,943</u>	<u>\$ 156,073</u>	<u>\$ 134,279</u>

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

METROPOLITAN EDISON COMPANY
MANAGEMENT'S NARRATIVE
ANALYSIS OF RESULTS OF OPERATIONS

Met-Ed is a wholly owned electric utility subsidiary of FirstEnergy. Met-Ed conducts business in eastern Pennsylvania, providing regulated electric transmission and distribution services. Met-Ed also provides generation service to those customers electing to retain Met-Ed as their power supplier. Met-Ed has a partial requirements wholesale power sales agreement with FES, to supply a portion of each of its default service obligations at fixed prices through 2009. This sales agreement is renewed annually unless cancelled by either party with at least a sixty day written notice prior to the end of the calendar year.

Results of Operations

In 2008, Met-Ed reported net income of \$88 million compared to \$95 million 2007. The decrease was primarily due to higher purchased power costs, net amortization of regulatory assets and other operating costs, partially offset by higher revenues.

Revenues

Revenues increased by \$142 million, or 9.4%, in 2008 compared to 2007 principally due to higher wholesale generation revenues and distribution throughput revenues. Wholesale revenues increased by \$111 million in 2008 compared to 2007, primarily reflecting higher PJM spot market prices. Increased distribution throughput revenues were partially offset by decreases in retail generation revenues and PJM transmission revenues.

In 2008, retail generation revenues decreased \$3 million primarily due to lower KWH sales to industrial customers due to the weakening economy, partially offset by higher KWH sales to commercial customers and higher composite unit prices in all customer classes.

Changes in retail generation sales and revenues in 2008 compared to 2007 are summarized in the following tables:

<u>Retail Generation KWH Sales</u>	<u>Increase (Decrease)</u>
Residential	-
Commercial	1.3 %
Industrial	(4.0)%
Net Decrease in Retail Generation Sales	(0.7)%

<u>Retail Generation Revenues</u>	<u>Increase (Decrease)</u>
	<i>(In millions)</i>
Residential	\$ 1
Commercial	3
Industrial	(7)
Net Decrease in Retail Generation Revenues	\$ (3)

Revenues from distribution throughput increased \$47 million in 2008 compared to 2007. Higher rates received for transmission services, resulting from the annual update of Met-Ed's TSC rider effective June 1, 2008 (see Regulatory Matters). Decreased KWH deliveries in the industrial customer class were partially offset by increased KWH deliveries to commercial customers.

Changes in distribution KWH deliveries and revenues in 2008 compared to 2007 are summarized in the following tables:

<u>Distribution KWH Deliveries</u>	<u>Increase (Decrease)</u>
Residential	-
Commercial	1.3 %
Industrial	(4.0)%
Net Decrease in Distribution Deliveries	(0.7)%

<u>Distribution Revenues</u>	<u>Increase</u>
	<i>(In millions)</i>
Residential	\$ 21
Commercial	17
Industrial	9
Increase in Distribution Revenues	\$ 47

Transmission revenues decreased by \$15 million in 2008 compared to 2007, primarily due to decreased auction revenue rights in PJM. Met-Ed defers the difference between transmission revenues and net transmission costs incurred, resulting in no material effect to current period earnings.

Expenses

Total operating expenses increased by \$153 million in 2008 compared to 2007. The following table presents changes from the prior year by expense category:

<u>Expenses – Changes</u>	<u>Increase</u>
	<i>(In millions)</i>
Purchased power costs	\$ 112
Other operating costs	10
Provision for depreciation	2
Amortization of regulatory assets	8
Deferral of new regulatory assets	15
General taxes	6
Increase in expenses	\$ 153

Purchased power costs increased by \$112 million in 2008 due to higher composite unit prices paid to non-affiliates in the PJM market. Other operating costs increased by \$10 million in 2008 primarily due to higher transmission expenses resulting from higher transmission losses and congestion costs, partially offset by the absence of costs associated with an ice storm in Met-Ed's service territory in the fourth quarter of 2007 that caused widespread damage to its electrical system.

Amortization of regulatory assets increased in 2008 due to higher CTC revenues applied to non-NUG costs. The deferral of new regulatory assets decreased in 2008 primarily due to the absence of the 2007 deferral of previously expensed decommissioning costs (\$15 million) for the Saxton nuclear research facility and decreased transmission cost deferrals (\$6 million) partially offset by higher universal service charge deferrals (\$6 million).

In 2008, general taxes increased primarily due to higher gross receipts taxes resulting from increased sales revenues.

Other Expense

Other expense increased \$4 million in 2008 primarily due to a \$10 million decrease in interest earned on stranded regulatory assets, reflecting lower regulatory asset balances, partially offset by lower interest expense of \$7 million due to decreased borrowings from the regulated money pool.

Market Risk Information

Met-Ed uses various market risk sensitive instruments, including derivative contracts, 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.

Commodity Price Risk

Met-Ed 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, Met-Ed 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. Certain of Met-Ed'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 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 or regulatory liability for below-market costs. The change in the fair value of commodity derivative contracts related to energy production during 2008 is summarized in the following table:

Increase (Decrease) in the Fair Value of Derivative Contracts	Non-Hedge	Hedge	Total
	<i>(In millions)</i>		
Change in the Fair Value of Commodity Derivative Contracts			
Outstanding net liabilities as of January 1, 2008	\$ (9)	\$ -	\$ (9)
Additions/Changes in value of existing contracts	144	-	144
Settled contracts	29	-	29
Net Assets - Derivatives Contracts as of December 31, 2008 ⁽¹⁾	\$ 164	\$ -	\$ 164
Impact of Changes in Commodity Derivative Contracts ⁽²⁾			
Income Statement Effects (Pre-Tax)	\$ -	\$ -	\$ -
Balance Sheet Effects:			
Regulatory Liability (net)	\$ (173)	\$ -	\$ (173)

(1) Includes \$164 million in non-hedge commodity derivative contracts (primarily with NUGs) that are offset by a regulatory liability with no impact to earnings.

(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 December 31, 2008 as follows:

	Non-Hedge	Hedge	Total
	<i>(In millions)</i>		
Non-Current-			
Other deferred charges	\$ 314	\$ -	\$ 314
Other noncurrent liabilities	(150)	-	(150)
Net assets	\$ 164	\$ -	\$ 164

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 December 31, 2008 are summarized by year in the following table:

Source of Information - Fair Value by Contract Year	2009	2010	2011	2012	2013	Thereafter	Total
	<i>(In millions)</i>						
Broker quote sheets ⁽¹⁾	\$ (39)	\$ (29)	\$ (28)	\$ (23)	\$ -	\$ -	\$ (119)
Prices based on models	-	-	-	-	42	241	283
Total ⁽²⁾	\$ (39)	\$ (29)	\$ (28)	\$ (23)	\$ 42	\$ 241	\$ 164

(1) Validated by observable market transactions.

(2) Includes \$164 million in non-hedge commodity derivative contracts (primarily with NUGs) that are offset by a regulatory liability with no impact to earnings.

Met-Ed performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% adverse shift in quoted market prices in the near term on derivative instruments would not have had a material effect on Met-Ed's consolidated financial position or cash flows as of December 31, 2008. Based on derivative contracts held as of December 31, 2008, an adverse 10% change in commodity prices would not have a material effect on Met-Ed's net income for the next 12 months.

Interest Rate Risk

Met-Ed's exposure to fluctuations in market interest rates is reduced since a significant portion of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for Met-Ed's investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	2009	2010	2011	2012	2013	There- after	Total	Fair Value
<i>(Dollars in millions)</i>								
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income						\$ 116	\$ 116	\$ 116
Average interest rate						4.4%	4.4%	
Liabilities								
Long-term Debt:								
Fixed rate		\$ 100			\$ 150	\$ 263	\$ 513	\$ 490
Average interest rate		4.5%			5.0%	4.9%	4.8%	
Variable rate						\$ 29	\$ 29	\$ 29
Average interest rate						1.1%	1.1%	
Short-term Borrowings:	\$ 265						\$ 265	\$ 265
Average interest rate	0.9%						0.9%	

Equity Price Risk

Included in Met-Ed's nuclear decommissioning trusts are marketable equity securities carried at their market value of approximately \$110 million as of December 31, 2008. A hypothetical 10% decrease in prices quoted by stock exchanges would result in an \$11 million reduction in fair value as of December 31, 2008 (see Note 5).

Legal Proceedings

See the "Regulatory Matters," "Environmental Matters" and "Other Legal Proceedings" sections within the Combined Management's Discussion and Analysis of Registrant Subsidiaries for discussion of legal proceedings applicable to Met-Ed.

New Accounting Standards and Interpretations

See the "New Accounting Standards and Interpretations" section within the Combined Management's Discussion and Analysis of Registrant Subsidiaries for discussion of new accounting standards and interpretations applicable to Met-Ed.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of Metropolitan Edison Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2008 consolidated financial statements.

FirstEnergy Corp.'s internal auditors, who are responsible to the Audit Committee of FirstEnergy's Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held ten meetings in 2008.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2008.

This annual report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of Metropolitan Edison Company and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in the notes to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions as of January 1, 2007 (Note 8) and defined benefit pension and other postretirement plans as of December 31, 2006 (Note 4).

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 24, 2009

METROPOLITAN EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	2008	2007	2006
	<i>(In thousands)</i>		
REVENUES:			
Electric sales	\$ 1,573,781	\$ 1,437,498	\$ 1,175,655
Gross receipts tax collections	79,221	73,012	67,403
Total revenues	1,653,002	1,510,510	1,243,058
EXPENSES:			
Purchased power from affiliates (Note 3)	303,779	290,205	177,836
Purchased power from non-affiliates	593,203	494,284	456,597
Other operating costs (Note 3)	429,745	419,512	304,243
Provision for depreciation	44,556	42,798	41,715
Amortization of regulatory assets	131,542	123,410	115,672
Deferral of new regulatory assets	(110,038)	(124,821)	(126,571)
Goodwill impairment (Note 2(E))	-	-	355,100
General taxes	85,643	80,135	77,411
Total expenses	1,478,430	1,325,523	1,402,003
OPERATING INCOME (LOSS)	174,572	184,987	(158,945)
OTHER INCOME (EXPENSE):			
Interest income	17,647	28,953	34,402
Miscellaneous income (expense)	105	(339)	8,042
Interest expense (Note 3)	(43,651)	(51,022)	(47,385)
Capitalized interest	258	1,154	1,017
Total other expense	(25,641)	(21,254)	(3,924)
INCOME (LOSS) BEFORE INCOME TAXES	148,931	163,733	(162,869)
INCOME TAXES	60,898	68,270	77,326
NET INCOME (LOSS)	\$ 88,033	\$ 95,463	\$ (240,195)

The accompanying Combined 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

As of December 31,	2008	2007
	<i>(In thousands)</i>	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 144	\$ 135
Receivables-		
Customers (less accumulated provisions of \$3,616,000 and \$4,327,000, respectively, for uncollectible accounts)	159,975	142,872
Associated companies	17,034	27,693
Other	19,828	18,909
Notes receivable from associated companies	11,446	12,574
Prepaid taxes	6,121	14,615
Other	1,621	1,348
	216,169	218,146
UTILITY PLANT:		
In service	2,065,847	1,972,388
Less - Accumulated provision for depreciation	779,692	751,795
	1,286,155	1,220,593
Construction work in progress	32,305	30,594
	1,318,460	1,251,187
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	226,139	286,831
Other	976	1,360
	227,115	288,191
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	416,499	424,313
Regulatory assets	412,994	522,767
Pension assets (Note 4)	-	51,427
Power purchase contract asset	300,141	141,356
Other	31,031	36,411
	1,160,665	1,176,274
	\$ 2,922,409	\$ 2,933,798
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	\$ 28,500	\$ -
Short-term borrowings-		
Associated companies	15,003	185,327
Other	250,000	100,000
Accounts payable-		
Associated companies	28,707	29,855
Other	55,330	66,694
Accrued taxes	16,238	16,020
Accrued interest	6,755	6,778
Other	30,647	27,393
	431,180	432,067
CAPITALIZATION (See Consolidated Statements of Capitalization) :		
Common stockholder's equity	1,004,064	1,048,632
Long-term debt and other long-term obligations	513,752	542,130
	1,517,816	1,590,762
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	387,757	438,890
Accumulated deferred investment tax credits	7,767	8,390
Nuclear fuel disposal costs	44,328	43,462
Asset retirement obligations	170,999	160,726
Retirement benefits	145,218	8,681
Power purchase contract liability	150,324	169,176
Other	67,020	81,644
	973,413	910,969
COMMITMENTS AND CONTINGENCIES (Notes 6 and 13)		
	\$ 2,922,409	\$ 2,933,798

The accompanying Combined 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 CAPITALIZATION

As of December 31,	2008	2007
	<i>(In thousands)</i>	
COMMON STOCKHOLDER'S EQUITY:		
Common stock, without par value, 900,000 shares authorized, 859,500 shares outstanding	\$ 1,196,172	\$ 1,203,186
Accumulated other comprehensive loss (Note 2(F))	(140,984)	(15,397)
Accumulated deficit (Note 10(A))	(51,124)	(139,157)
Total	<u>1,004,064</u>	<u>1,048,632</u>
LONG-TERM DEBT (Note 10(C)):		
First mortgage bonds-		
5.950% due 2027	13,690	13,690
Total	<u>13,690</u>	<u>13,690</u>
Unsecured notes-		
4.450% due 2010	100,000	100,000
4.950% due 2013	150,000	150,000
4.875% due 2014	250,000	250,000
* 1.100% due 2021	28,500	28,500
Total	<u>528,500</u>	<u>528,500</u>
Net unamortized premium (discount) on debt	62	(60)
Long-term debt due within one year	(28,500)	-
Total long-term debt	<u>513,752</u>	<u>542,130</u>
TOTAL CAPITALIZATION	<u>\$ 1,517,816</u>	<u>\$ 1,590,762</u>

* Denotes variable rate issue with applicable year-end interest rate shown.

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

METROPOLITAN EDISON COMPANY

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Comprehensive Income (Loss)	Common Stock		Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Accumulated Deficit)
		Number of Shares	Carrying Value		
<i>(Dollars in thousands)</i>					
Balance, January 1, 2006		859,500	\$ 1,287,093	\$ (1,569)	\$ 30,575
Net loss	\$ (240,195)				(240,195)
Net unrealized gain on derivative instruments, net of \$139,000 of income taxes	196			196	
Comprehensive loss	<u>\$ (239,999)</u>				
Net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of \$26,715,000 of income tax benefits (Note 4)				(25,143)	
Restricted stock units			50		
Stock-based compensation			38		
Cash dividends declared on common stock					(25,000)
Purchase accounting fair value adjustment			(11,106)		
Balance, December 31, 2006		859,500	1,276,075	(26,516)	(234,620)
Net Income	\$ 95,463				95,463
Net unrealized gain on derivative instruments	335			335	
Pension and other postretirement benefits, net of \$11,666,000 of income taxes (Note 4)	10,784			10,784	
Comprehensive income	<u>\$ 106,582</u>				
Restricted stock units			104		
Stock-based compensation			7		
Consolidated tax benefit allocation			1,237		
Purchase accounting fair value adjustment			(74,237)		
Balance, December 31, 2007		859,500	1,203,186	(15,397)	(139,157)
Net Income	\$ 88,033				88,033
Net unrealized gain on derivative instruments	335			335	
Pension and other postretirement benefits, net of \$86,030,000 of income tax benefits (Note 4)	(125,922)			(125,922)	
Comprehensive loss	<u>\$ (37,554)</u>				
Restricted stock units			9		
Stock-based compensation			1		
Consolidated tax benefit allocation			791		
Purchase accounting fair value adjustment			(7,815)		
Balance, December 31, 2008		859,500	\$ 1,196,172	\$ (140,984)	\$ (51,124)

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

METROPOLITAN EDISON COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2008	2007	2006
	<i>(In thousands)</i>		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	\$ 88,033	\$ 95,463	\$ (240,195)
Adjustments to reconcile net income (loss) to net cash from operating activities-			
Provision for depreciation	44,556	42,798	41,715
Amortization of regulatory assets	131,542	123,410	115,672
Deferred costs recoverable as regulatory assets	(25,132)	(70,778)	(82,674)
Deferral of new regulatory assets	(110,038)	(124,821)	(126,571)
Deferred income taxes and investment tax credits, net	49,939	35,502	50,278
Accrued compensation and retirement benefits	(23,244)	(18,852)	(6,876)
Goodwill impairment	-	-	355,100
Loss on sale of investment	-	5,432	-
Cash collateral from (to) suppliers	-	1,600	(1,580)
Pension trust contributions	-	(11,012)	-
Decrease (increase) in operating assets-			
Receivables	(24,282)	(38,220)	37,107
Prepayments and other current assets	8,223	(926)	(4,385)
Increase (decrease) in operating liabilities-			
Accounts payable	(12,512)	(62,760)	94,582
Accrued taxes	470	10,128	(5,647)
Accrued interest	(23)	(718)	(1,804)
Other	15,629	12,870	(2,633)
Net cash provided from (used for) operating activities	<u>143,161</u>	<u>(884)</u>	<u>222,089</u>
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	28,500	-	-
Short-term borrowings, net	-	143,826	1,260
Redemptions and Repayments-			
Long-term debt	(28,568)	(50,000)	(100,000)
Short-term borrowings, net	(20,324)	-	-
Dividend Payments-			
Common stock	-	-	(25,000)
Other	(266)	(35)	(7)
Net cash provided from (used for) financing activities	<u>(20,658)</u>	<u>93,791</u>	<u>(123,747)</u>
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(110,301)	(103,711)	(84,817)
Proceeds from sale of investment	-	4,953	-
Sales of investment securities held in trusts	181,007	184,619	176,460
Purchases of investment securities held in trusts	(193,061)	(196,140)	(185,943)
Loan repayments from (loans to) associated companies, net	1,128	18,535	(3,242)
Other	(1,267)	(1,158)	(790)
Net cash used for investing activities	<u>(122,494)</u>	<u>(92,902)</u>	<u>(98,332)</u>
Net increase in cash and cash equivalents	9	5	10
Cash and cash equivalents at beginning of year	135	130	120
Cash and cash equivalents at end of year	<u>\$ 144</u>	<u>\$ 135</u>	<u>\$ 130</u>
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	\$ 38,627	\$ 44,501	\$ 44,597
Income taxes	<u>\$ 16,872</u>	<u>\$ 30,741</u>	<u>\$ 42,173</u>

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

PENNSYLVANIA ELECTRIC COMPANY

MANAGEMENT'S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS

Penelec is a wholly owned electric utility subsidiary of FirstEnergy. Penelec conducts business in northern and south central Pennsylvania, providing regulated transmission and distribution services. Penelec also provides generation services to those customers electing to retain Penelec as their power supplier. Penelec has a partial requirements wholesale power sales agreement with FES, to supply a portion of each of its default service obligations at fixed prices through 2009. This sales agreement is renewed annually unless cancelled by either party with at least a sixty day written notice prior to the end of the calendar year.

Results of Operations

Net income decreased to \$88 million in 2008, compared to \$93 million in 2007. The decrease was primarily due to increased purchased power costs and net amortization of regulatory assets, partially offset by higher revenues and decreased other operating costs.

Revenues

Revenues increased by \$112 million, or 8.0%, in 2008 compared to 2007 primarily due to higher retail and wholesale generation revenues, distribution throughput revenues and transmission revenues. Wholesale revenues increased \$91 million in 2008 compared to the same period of 2007, primarily reflecting higher PJM spot market prices.

In 2008, retail generation revenues increased \$4 million primarily due to higher composite unit prices in all customer classes and higher KWH sales to residential and commercial customers, partially offset by a decrease in KWH sales to industrial customers due to the weakening economy.

Changes in retail generation sales and revenues in 2008 as compared to 2007 are summarized in the following tables:

Retail Generation KWH Sales	Increase (Decrease)
Residential	1.4%
Commercial	0.9%
Industrial	(1.9)%
Net Increase in Retail Generation Sales	0.2%

Retail Generation Revenues	Increase (Decrease)
	<i>(In millions)</i>
Residential	\$ 4
Commercial	2
Industrial	(2)
Net Increase in Retail Generation Revenues	\$ 4

Revenues from distribution throughput increased \$15 million in 2008 compared to 2007. Higher usage in the residential and commercial sectors along with an increase in transmission rates, resulting from the annual update of Penelec's TSC rider effective June 1, 2008 (see Regulatory Matters) and a slight decrease in usage in the industrial sector.

Changes in distribution KWH deliveries and revenues in 2008 as compared to 2007 are summarized in the following tables:

Distribution KWH Deliveries	Increase (Decrease)
Residential	1.4%
Commercial	0.9%
Industrial	(0.3)%
Net Increase in Distribution Deliveries	0.6%

<u>Distribution Revenues</u>	<u>Increase</u>
	<i>(In millions)</i>
Residential	\$ 11
Commercial	3
Industrial	1
Increase in Distribution Revenues	\$ 15

Transmission revenues increased by \$5 million in 2008 compared to 2007, primarily due to higher financial transmission rights revenue in PJM. Penelec defers the difference between transmission revenues and net transmission costs incurred in PJM, resulting in no material effect to current period earnings.

Expenses

Total operating expenses increased by \$111 million in 2008 compared to 2007. The following table presents changes from the prior year by expense category:

<u>Expenses - Changes</u>	<u>Increase (Decrease)</u>
	<i>(In millions)</i>
Purchased power costs	\$ 85
Other operating costs	(7)
Provision for depreciation	5
Amortization of regulatory assets, net	24
General taxes	4
Net Increase in expenses	\$ 111

Purchased power costs increased by \$85 million, or 10.8%, in 2008 compared to 2007, primarily due to higher composite unit prices paid to non-affiliates in the PJM market. Other operating costs decreased by \$7 million in 2008, principally due to lower labor and contractor costs charged to operating expense, reflecting a higher level of capital-related projects in 2008, and reduced billings from FESC for employee benefits. Depreciation expense increased primarily due to an increase in depreciable property since December 31, 2007.

Amortization of regulatory assets (net of deferrals) increased in 2008 compared to 2007 primarily due to the absence of the 2007 deferral of previously expensed decommissioning costs (\$12 million) for the Saxton nuclear research facility and decreased transmission cost deferrals (\$20 million), partially offset by an increase in universal service charge deferrals (\$8 million).

General taxes increased in 2008 primarily due to higher gross receipts taxes resulting from increased sales revenues.

Other Expense

In 2008, other expense increased primarily due to higher interest expense associated with Penelec's \$300 million senior note issuance in August 2007 and reduced life insurance investment values.

Market Risk Information

Penelec uses various market risk sensitive instruments, including derivative contracts, 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.

Commodity Price Risk

Penelec 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, 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. Derivatives that fall within the scope of SFAS 133 must be recorded at their fair value and marked to market. Certain of Penelec'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 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 or regulatory liability for below-market costs. The change in the fair value of commodity derivative contracts related to energy production during 2008 is summarized in the following table:

Increase (Decrease) in the Fair Value of Derivative Contracts	Non-Hedge	Hedge	Total
	<i>(In millions)</i>		
Change in the Fair Value of Commodity Derivative Contracts			
Outstanding net liabilities as of January 1, 2008	\$ (16)	\$ -	\$ (16)
Additions/Changes in value of existing contracts	50	-	50
Settled contracts	9	-	9
Net Assets - Derivatives Contracts as of December 31, 2008 ⁽¹⁾	\$ 43	\$ -	\$ 43
Impact of Changes in Commodity Derivative Contracts ⁽²⁾			
Income Statement Effects (Pre-Tax)	\$ -	\$ -	\$ -
Balance Sheet Effects:			
Regulatory Liability (net)	\$ (59)	\$ -	\$ (59)

(1) Includes \$43 million in non-hedge commodity derivative contracts (primarily with NUGs) that are offset by a regulatory liability with no impact to earnings.

(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 December 31, 2008 as follows:

	Non-Hedge	Hedge	Total
	<i>(In millions)</i>		
Non-Current-			
Other deferred charges	\$ 127	\$ -	\$ 127
Other noncurrent liabilities	(84)	-	(84)
Net assets	\$ 43	\$ -	\$ 43

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 December 31, 2008 are summarized by year in the following table:

Source of Information - Fair Value by Contract Year	2009	2010	2011	2012	2013	Thereafter	Total
	<i>(In millions)</i>						
Broker quote sheets ⁽¹⁾	\$ (31)	\$ (22)	\$ (35)	\$ (36)	\$ -	\$ -	\$ (124)
Prices based on models	-	-	-	-	28	139	167
Total ⁽²⁾	\$ (31)	\$ (22)	\$ (35)	\$ (36)	\$ 28	\$ 139	\$ 43

(1) Validated by observable market transactions.

(2) Includes \$43 million in non-hedge commodity derivative contracts (primarily with NUGs) that are offset by a regulatory liability with no impact to earnings.

Penelec performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% adverse shift in quoted market prices in the near term on derivative instruments would not have had a material effect on Penelec's consolidated financial position or cash flows as of December 31, 2008. Based on derivative contracts held as of December 31, 2008, an adverse 10% change in commodity prices would not have a material effect on Penelec's net income for the next 12 months.

Interest Rate Risk

Penelec's exposure to fluctuations in market interest rates is reduced since a significant portion of its debt has fixed interest rates. The table below presents principal amounts and related weighted average interest rates by year of maturity for Penelec's investment portfolio and debt obligations.

Comparison of Carrying Value to Fair Value

Year of Maturity	2009	2010	2011	2012	2013	There- after	Total	Fair Value
<i>(Dollars in millions)</i>								
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income						\$ 179	\$ 179	\$ 179
Average interest rate						3.9%	3.9%	
Liabilities								
Long-term Debt:								
Fixed rate	\$ 100	\$ 59				\$ 575	\$ 734	\$ 676
Average interest rate	6.1%	6.8%				5.9%	6.0%	
Variable rate						\$ 45	\$ 45	\$ 45
Average interest rate						1.2%	1.2%	
Short-term Borrowings:	\$ 281						\$ 281	\$ 281
Average interest rate	0.9%						0.9%	

Equity Price Risk

Included in Penelec's nuclear decommissioning trusts are marketable equity securities carried at their market value of approximately \$53 million as of December 31, 2008. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a \$5 million reduction in fair value as of December 31, 2008 (see Note 5).

Legal Proceedings

See the "Regulatory Matters," "Environmental Matters" and "Other Legal Proceedings" sections within the Combined Management's Discussion and Analysis of Registrant Subsidiaries for discussion of legal proceedings applicable to Penelec.

New Accounting Standards and Interpretations

See the "New Accounting Standards and Interpretations" section within the Combined Management's Discussion and Analysis of Registrant Subsidiaries for discussion of new accounting standards and interpretations applicable to Penelec.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of Pennsylvania Electric Company (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2008 consolidated financial statements.

FirstEnergy Corp.'s internal auditors, who are responsible to the Audit Committee of FirstEnergy's Board of Directors, review the results and performance of the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

FirstEnergy's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held ten meetings in 2008.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2008.

This annual report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholder's equity, and cash flows present fairly, in all material respects, the financial position of Pennsylvania Electric Company and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in the notes to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions as of January 1, 2007 (Note 8) and defined benefit pension and other postretirement plans as of December 31, 2006 (Note 4).

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 24, 2009

PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	2008	2007	2006
	<i>(In thousands)</i>		
REVENUES:			
Electric sales	\$ 1,443,461	\$ 1,336,517	\$ 1,086,781
Gross receipts tax collections	70,168	65,508	61,679
Total revenues	<u>1,513,629</u>	<u>1,402,025</u>	<u>1,148,460</u>
EXPENSES (Note 3):			
Purchased power from affiliates	284,074	284,826	154,420
Purchased power from non-affiliates	591,487	505,528	471,947
Other operating costs	228,257	234,949	203,868
Provision for depreciation	54,643	49,558	48,003
Amortization of regulatory assets, net	71,091	46,761	21,887
General taxes	79,604	76,050	72,612
Total expenses	<u>1,309,156</u>	<u>1,197,672</u>	<u>972,737</u>
OPERATING INCOME	<u>204,473</u>	<u>204,353</u>	<u>175,723</u>
OTHER INCOME (EXPENSE):			
Miscellaneous income	1,359	6,501	8,986
Interest expense (Note 3)	(59,424)	(54,840)	(45,278)
Capitalized interest	(591)	939	1,290
Total other expense	<u>(58,656)</u>	<u>(47,400)</u>	<u>(35,002)</u>
INCOME BEFORE INCOME TAXES	145,817	156,953	140,721
INCOME TAXES	<u>57,647</u>	<u>64,015</u>	<u>56,539</u>
NET INCOME	<u>\$ 88,170</u>	<u>\$ 92,938</u>	<u>\$ 84,182</u>

The accompanying Combined 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

As of December 31,	2008	2007
	<i>(In thousands)</i>	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 23	\$ 46
Receivables-		
Customers (less accumulated provisions of \$3,121,000 and \$3,905,000, respectively, for uncollectible accounts)	146,831	137,455
Associated companies	65,610	22,014
Other	26,766	19,529
Notes receivable from associated companies	14,833	16,313
Prepaid taxes	16,310	1,796
Other	1,517	1,281
	<u>271,890</u>	<u>198,434</u>
UTILITY PLANT:		
In service	2,324,879	2,219,002
Less - Accumulated provision for depreciation	868,639	838,621
	1,456,240	1,380,381
Construction work in progress	25,146	24,251
	<u>1,481,386</u>	<u>1,404,632</u>
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	115,292	137,859
Non-utility generation trusts	116,687	112,670
Other	293	531
	<u>232,272</u>	<u>251,060</u>
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	768,628	777,904
Pension assets (Note 4)	-	66,111
Power purchase contract asset	119,748	60,514
Other	18,658	33,893
	<u>907,034</u>	<u>938,422</u>
	<u>\$ 2,892,582</u>	<u>\$ 2,792,548</u>
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	\$ 145,000	\$ -
Short-term borrowings-		
Associated companies	31,402	214,893
Other	250,000	-
Accounts payable-		
Associated companies	63,692	83,359
Other	48,633	51,777
Accrued taxes	13,264	15,111
Accrued interest	13,131	13,167
Other	31,730	25,311
	<u>596,852</u>	<u>403,618</u>
CAPITALIZATION (See Consolidated Statements of Capitalization):		
Common stockholder's equity	949,109	1,072,057
Long-term debt and other long-term obligations	633,132	777,243
	<u>1,582,241</u>	<u>1,849,300</u>
NONCURRENT LIABILITIES:		
Regulatory liabilities	136,579	48,718
Accumulated deferred income taxes	169,807	210,776
Retirement benefits	172,718	41,298
Asset retirement obligations	87,089	81,849
Power purchase contract liability	83,600	85,355
Other	63,696	71,634
	<u>713,489</u>	<u>539,630</u>
COMMITMENTS AND CONTINGENCIES (Notes 6 and 13)		
	<u>\$ 2,892,582</u>	<u>\$ 2,792,548</u>

The accompanying Combined 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 CAPITALIZATION

As of December 31,	2008	2007
	<i>(In thousands)</i>	
COMMON STOCKHOLDER'S EQUITY:		
Common stock, \$20 par value, 5,400,000 shares authorized, 4,427,577 shares outstanding	\$ 88,552	\$ 88,552
Other paid-in capital	912,441	920,616
Accumulated other comprehensive income (loss) (Note 2(F))	(127,997)	4,946
Retained earnings (Note 10(A))	76,113	57,943
Total	<u>949,109</u>	<u>1,072,057</u>
LONG-TERM DEBT (Note 10(C)):		
First mortgage bonds-		
5.350% due 2010	12,310	12,310
5.350% due 2010	12,000	12,000
Total	<u>24,310</u>	<u>24,310</u>
Unsecured notes-		
6.125% due 2009	100,000	100,000
7.770% due 2010	35,000	35,000
5.125% due 2014	150,000	150,000
6.050% due 2017	300,000	300,000
6.625% due 2019	125,000	125,000
* 1.130% due 2020	20,000	20,000
* 1.210% due 2025	25,000	25,000
Total	<u>755,000</u>	<u>755,000</u>
Net unamortized discount on debt	(1,178)	(2,067)
Long-term debt due within one year	(145,000)	-
Total long-term debt	<u>633,132</u>	<u>777,243</u>
TOTAL CAPITALIZATION	<u>\$ 1,582,241</u>	<u>\$ 1,849,300</u>

* Denotes variable rate issue with applicable year-end interest rate shown.

The accompanying Combined Notes to Consolidated Financial Statements as they relate to Pennsylvania Electric Company are an integral part of these statements.

PENNSYLVANIA ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	<u>Comprehensive Income (Loss)</u>	<u>Common Stock</u>		<u>Other Paid-In Capital</u>	<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Retained Earnings</u>
		<u>Number of Shares</u>	<u>Par Value</u>			
<i>(Dollars in thousands)</i>						
Balance, January 1, 2006		5,290,596	\$ 105,812	\$ 1,202,551	\$ (309)	\$ 25,823
Net income	\$ 84,182					84,182
Net unrealized gain on investments, net						
of \$4,000 of income taxes	2				2	
Net unrealized gain on derivative instruments, net						
of \$27,000 of income taxes	38				38	
Comprehensive income	<u>\$ 84,222</u>					
Net liability for unfunded retirement benefits						
due to the implementation of SFAS 158, net						
of \$17,340,000 of income tax benefits (Note 4)					(6,924)	
Restricted stock units				46		
Stock-based compensation				21		
Cash dividends declared on common stock						(20,000)
Purchase accounting fair value adjustment				(13,184)		
Balance, December 31, 2006		5,290,596	105,812	1,189,434	(7,193)	90,005
Net income	\$ 92,938					92,938
Net unrealized gain on investments, net						
of \$12,000 of income tax benefits	21				21	
Net unrealized gain on derivative instruments, net						
of \$16,000 of income taxes	49				49	
Pension and other postretirement benefits, net						
of \$15,413,000 of income taxes (Note 4)	12,069				12,069	
Comprehensive income	<u>\$ 105,077</u>					
Restricted stock units				107		
Stock-based compensation				7		
Consolidated tax benefit allocation				1,261		
Repurchase of common stock		(863,019)	(17,260)	(182,740)		
Cash dividends declared on common stock						(125,000)
Purchase accounting fair value adjustment				(87,453)		
Balance, December 31, 2007		4,427,577	88,552	920,616	4,946	57,943
Net income	\$ 88,170					88,170
Net unrealized gain on investments, net						
of \$13,000 of income taxes	9				9	
Net unrealized gain on derivative instruments, net						
of \$4,000 of income tax benefits	69				69	
Pension and other postretirement benefits, net						
of \$90,822,000 of income tax benefits (Note 4)	(133,021)				(133,021)	
Comprehensive loss	<u>\$ (44,773)</u>					
Restricted stock units				35		
Stock-based compensation				1		
Consolidated tax benefit allocation				1,066		
Cash dividends declared on common stock						(70,000)

Purchase accounting fair value adjustment				(9,277)			
Balance, December 31, 2008	4,427,577	\$	88,552	\$	912,441	\$	(127,997) \$ 76,113

The accompanying Combined Notes to Consolidated Financial Statements as they relate to Pennsylvania Electric Company are an integral part of these statements.

PENNSYLVANIA ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2008	2007	2006
	<i>(In thousands)</i>		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	\$ 88,170	\$ 92,938	\$ 84,182
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	54,643	49,558	48,003
Amortization of regulatory assets, net	71,091	46,761	21,887
Deferred costs recoverable as regulatory assets	(35,898)	(71,939)	(80,942)
Deferred income taxes and investment tax credits, net	95,227	10,713	28,568
Accrued compensation and retirement benefits	(25,661)	(20,830)	5,125
Pension trust contribution	-	(13,436)	-
Decrease (increase) in operating assets-			
Receivables	(74,338)	18,771	14,299
Prepayments and other current assets	(16,313)	1,159	683
Increase (decrease) in operating liabilities-			
Accounts payable	(1,966)	(59,513)	67,602
Accrued taxes	(2,181)	4,743	(1,524)
Accrued interest	(36)	5,943	(638)
Other	17,815	13,125	8,363
Net cash provided from operating activities	<u>170,553</u>	<u>77,993</u>	<u>195,608</u>
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	45,000	299,109	-
Short-term borrowings, net	66,509	15,662	-
Redemptions and Repayments-			
Common Stock	-	(200,000)	-
Long-term debt	(45,556)	-	-
Short-term borrowings, net	-	-	(61,928)
Dividend Payments-			
Common stock	(90,000)	(70,000)	(20,000)
Other	-	(2,210)	-
Net cash provided from (used for) financing activities	<u>(24,047)</u>	<u>42,561</u>	<u>(81,928)</u>
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(126,672)	(94,991)	(106,980)
Loan repayments from (loans to) associated companies, net	1,480	3,235	(1,924)
Sales of investment securities held in trusts	117,751	175,222	99,469
Purchases of investment securities held in trusts	(134,621)	(199,375)	(99,469)
Other, net	(4,467)	(4,643)	(4,767)
Net cash used for investing activities	<u>(146,529)</u>	<u>(120,552)</u>	<u>(113,671)</u>
Net increase (decrease) in cash and cash equivalents	(23)	2	9
Cash and cash equivalents at beginning of year	46	44	35
Cash and cash equivalents at end of year	<u>\$ 23</u>	<u>\$ 46</u>	<u>\$ 44</u>
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	\$ 56,972	\$ 44,503	\$ 41,976
Income taxes	<u>\$ 44,197</u>	<u>\$ 2,996</u>	<u>\$ 29,189</u>

The accompanying Combined Notes to Consolidated Financial Statements as they relate to Pennsylvania Electric Company are an integral part of these statements.

COMBINED MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT SUBSIDIARIES

The following is a combined presentation of certain disclosures referenced in Management's Narrative Analysis of Results of Operations of FES and the Utilities. This information should be read in conjunction with FES' and the Utilities' respective Consolidated Financial Statements and Management's Narrative Analysis of Results of Operations and the Combined Notes to Consolidated Financial Statements.

Regulatory Matters (Applicable to each of the Utilities)

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

- restructuring the electric generation business and allowing the Utilities' customers to select a competitive electric generation supplier other than the Utilities;
- establishing or defining the PLR obligations to customers in the Utilities' service areas;
- providing the Utilities 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 Utilities' transmission and distribution systems; and
- requiring corporate separation of regulated and unregulated business activities.

The Utilities 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. As of December 31, 2008, regulatory assets that did not earn a current return totaled approximately \$61 million for JCP&L and \$72 million for Met-Ed. Regulatory assets not earning a current return (primarily for certain regulatory transition costs and employee postretirement benefits) will be recovered by 2014 for JCP&L and by 2020 for Met-Ed and Penelec. The following table discloses regulatory assets by company:

<u>Regulatory Assets*</u>	<u>December 31,</u> <u>2008</u>	<u>December 31,</u> <u>2007</u>	<u>Decrease</u>
	<i>(In millions)</i>		
OE	\$ 575	\$ 737	\$ (162)
CEI	784	871	(87)
TE	109	204	(95)
JCP&L	1,228	1,596	(368)
Met-Ed	413	523	(110)

* Penelec had net regulatory liabilities of approximately \$137 million and \$49 million as of December 31, 2008 and December 31, 2007, respectively.

Ohio (Applicable to OE, CEI, TE and FES)

On January 4, 2006, the PUCO issued an order authorizing the Ohio Companies to recover certain increased fuel costs through a fuel rider and to defer certain other increased fuel costs to be incurred from January 1, 2006 through December 31, 2008, including interest on the deferred balances. The order also provided for recovery of the deferred costs over a twenty-five-year period through distribution rates. On August 29, 2007, the Supreme Court of Ohio concluded that the PUCO violated a provision of the Ohio Revised Code by permitting the Ohio Companies "to collect deferred increased fuel costs through future distribution rate cases, or to alternatively use excess fuel-cost recovery to reduce deferred distribution-related expenses" and remanded the matter to the PUCO for further consideration. On September 10, 2007, the Ohio Companies filed an application with the PUCO that requested the implementation of two generation-related fuel cost riders to collect the increased fuel costs that were previously authorized to be deferred. On January 9, 2008, the PUCO approved the Ohio Companies' proposed fuel cost rider to recover increased fuel costs incurred during 2008, which was approximately \$185 million. In addition, the PUCO ordered the Ohio Companies to file a separate application for an alternate recovery mechanism to collect the 2006 and 2007 deferred fuel costs. On February 8, 2008, the Ohio Companies filed an application proposing to recover \$226 million of deferred fuel costs and carrying charges for 2006 and 2007 pursuant to a separate fuel rider. Recovery of the deferred fuel costs was also addressed in the Ohio Companies' comprehensive ESP filing, which was subsequently withdrawn on December 22, 2008, and also as a part of the stipulation and recommendation which was attached to the amended application for an ESP, both as described below.

On June 7, 2007, the Ohio Companies filed an application for an increase in electric distribution rates with the PUCO and, on August 6, 2007, updated their filing to support a distribution rate increase of \$332 million. On December 4, 2007, the PUCO Staff issued its Staff Reports containing the results of its investigation into the distribution rate request. In its reports, the PUCO Staff recommended a distribution rate increase in the range of \$161 million to \$180 million, with \$108 million to \$127 million for distribution revenue increases and \$53 million for recovery of costs deferred under prior cases. During the evidentiary hearings and filing of briefs, the PUCO Staff decreased their recommended revenue increase to a range of \$117 million to \$135 million. On January 21, 2009, the PUCO granted the Ohio Companies' application to increase electric distribution rates by \$136.6 million (OE - \$68.9 million, CEI - \$29.2 million and TE - \$38.5 million). These increases went into effect for OE and TE on January 23, 2009, and will go into effect for CEI on May 1, 2009. Applications for rehearing of this order were filed by the Ohio Companies and one other party on February 20, 2009.

On May 1, 2008, Governor Strickland signed SB221, which became effective on July 31, 2008. The bill requires all utilities to file an ESP with the PUCO, which must contain a proposal for the supply and pricing of retail generation. A utility may also file an MRO with the PUCO, in which it would have to prove the following objective market criteria: 1) the utility or its transmission service affiliate belongs to a FERC approved RTO, or there is comparable and nondiscriminatory access to the electric transmission grid; 2) the RTO has a market-monitor function and the ability to mitigate market power or the utility's market conduct, or a similar market monitoring function exists with the ability to identify and monitor market conditions and conduct; and 3) a published source of information is available publicly or through subscription that identifies pricing information for traded electricity products, both on- and off-peak, scheduled for delivery two years into the future.

On July 31, 2008, the Ohio Companies filed with the PUCO a comprehensive ESP and MRO. The MRO filing outlined a CBP for providing retail generation supply if the ESP is not approved and implemented. The CBP would use a "slice-of-system" approach where suppliers bid on tranches (approximately 100 MW) of the Ohio Companies' total customer load. If the Ohio Companies proceed with the MRO option, successful bidders (including affiliates) would be required to post independent credit requirements and could be subject to significant collateral calls depending upon power price movement. The PUCO denied the MRO application on November 26, 2008. The Ohio Companies filed an application for rehearing on December 23, 2008, which the PUCO granted on January 21, 2009, for the purpose of further consideration of the matter.

The ESP proposed to phase in new generation rates for customers beginning in 2009 for up to a three-year period and resolve the Ohio Companies' collection of fuel costs deferred in 2006 and 2007, and the distribution rate request described above. On December 19, 2008, the PUCO significantly modified and approved the ESP as modified. On December 22, 2008, the Ohio Companies notified the PUCO that they were withdrawing and terminating the ESP application as allowed by the terms of SB221. The Ohio Companies further notified the PUCO that, pursuant to SB221, the Ohio Companies would continue their current rate plan in effect and filed tariffs to continue those rates.

On December 31, 2008, the Ohio Companies conducted a CBP, using an RFP format administered by an independent third party, for the procurement of electric generation for retail customers from January 5, 2009 through March 31, 2009. Four qualified wholesale bidders were selected, including FES, for 97% of the tranches offered in the RFP. The average winning bid price was equivalent to a retail rate of 6.98 cents per kilowatt-hour. Subsequent to the RFP, the remaining 3% of the Ohio Companies' wholesale energy and capacity needs were obtained through a bilateral contract with the lowest bidder in the RFP procurement. The power supply obtained through the foregoing processes provides generation service to the Ohio Companies' retail customers who choose not to shop with alternative suppliers.

Following comments by other parties on the Ohio Companies' December 22, 2008, filing which continued the current rate plan, the PUCO issued an Order on January 7, 2009, that prevented OE and TE from collecting RTC and discontinued the collection of two fuel riders for the Ohio Companies. The Ohio Companies filed an application for rehearing on January 9, 2009, and also filed an application for a new fuel rider to recover the increased costs for purchasing power during the period January 1, 2009 through March 31, 2009. On January 14, 2009, the PUCO approved the Ohio Companies' request for the new fuel rider, subject to further review, allowed current recovery of those costs for OE and TE, and allowed CEI to collect a portion of those costs currently and defer the remainder. The PUCO also ordered the Ohio Companies to file additional information in order for it to determine that the costs incurred are prudent and whether the recovery of such costs is necessary to avoid a confiscatory result. The Ohio Companies filed an application for rehearing on that order on January 26, 2009. The applications for rehearing remain pending and the Ohio Companies are unable to predict the ultimate resolution of these issues.

On January 29, 2009, the PUCO ordered its Staff to develop a proposal to establish an ESP for the Ohio Companies and further ordered that a conference be held on February 5, 2009 to discuss the Staff's proposal. The Ohio Companies, PUCO Staff, and other parties participated in that conference, and in a subsequent conference held on February 17, 2009. Following discussions with the Staff and other parties regarding the Staff's proposal, on February 19, 2009, the Ohio Companies filed an amended ESP application, including an attached Stipulation and Recommendation that was signed by the Ohio Companies, the Staff of the PUCO, and many of the intervening parties representing a diverse range of interests, which substantially reflected the terms as proposed by the Staff as modified through the negotiations of the parties. Specifically, the stipulated ESP provides that generation will be provided by FES at the average wholesale rate of the RFP process described above for April and May 2009 to the Ohio Companies for their non-shopping customers and that for the period of June 1, 2009 through May 31, 2011, retail generation prices will be based upon the outcome of a descending clock CBP on a slice-of-system basis. The PUCO may, at its discretion, phase-in a portion of any increase resulting from this CBP process by authorizing deferral of related purchased power costs, subject to specified limits. The proposed ESP further provides that the Ohio Companies will not seek a base distribution rate increase with an effective date before January 1, 2012, that CEI will agree to write-off approximately \$215 million of its Extended RTC balance, and that the Ohio Companies will collect a delivery service improvement rider at an overall average rate of \$.002 per kWh for the period of April 1, 2009 through December 31, 2011. If the Stipulated ESP is approved, one-time after-tax charges associated with implementing the ESP would be approximately \$11.3 million for OE, \$145.7 million for CEI (including the CEI Extended RTC balance) and \$3.5 million for TE. The proposed ESP also addresses a number of other issues, including but not limited to, rate design for various customer classes, resolution of the prudence review described above and the collection of deferred costs that were approved in prior proceedings. On February 19, 2009, the PUCO attorney examiner issued an order setting this matter for hearing to begin on February 25, 2009.

Pennsylvania (Applicable to FES, Met-Ed, Penelec, OE and Penn)

Met-Ed and Penelec purchase a portion of their PLR and default service requirements from FES through a fixed-price partial requirements wholesale power sales agreement. The agreement allows Met-Ed and Penelec to sell the output of NUG energy to the market and requires FES to provide energy at fixed prices to replace any NUG energy sold to the extent needed for Met-Ed and Penelec to satisfy their PLR and default service obligations. The fixed price under the agreement is expected to remain below wholesale market prices during the term of the agreement. 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 their fixed income securities. If FES ultimately determines to terminate, reduce, or significantly modify the agreement prior to the expiration of Met-Ed's and Penelec's generation rate caps in 2010, timely regulatory relief is not likely to be granted by the PPUC. See FERC Matters below for a description of the Third Restated Partial Requirements Agreement, executed by the parties on October 31, 2008, that limits the amount of energy and capacity FES must supply to Met-Ed and Penelec. In the event of a third party supplier default, the increased costs to Met-Ed and Penelec could be material.

On May 22, 2008, the PPUC approved the Met-Ed and Penelec annual updates to the TSC rider for the period June 1, 2008, through May 31, 2009. Various intervenors filed complaints against those filings. In addition, the PPUC ordered an investigation to review the reasonableness of Met-Ed's TSC, while at the same time allowing Met-Ed to implement the rider June 1, 2008, subject to refund. On July 15, 2008, the PPUC directed the ALJ to consolidate the complaints against Met-Ed with its investigation and a litigation schedule was adopted. Hearings and briefing for both companies are expected to conclude by the end of February 2009. The TSCs include a component from under-recovery of actual transmission costs incurred during the prior period (Met-Ed - \$144 million and Penelec - \$4 million) and future transmission cost projections for June 2008 through May 2009 (Met-Ed - \$258 million and Penelec - \$92 million). Met-Ed received PPUC approval for a transition approach that would recover past under-recovered costs plus carrying charges through the new TSC over thirty-one months and defer a portion of the projected costs (\$92 million) plus carrying charges for recovery through future TSCs by December 31, 2010.

On February 1, 2007, the Governor of Pennsylvania proposed an EIS. The EIS includes four pieces of proposed legislation that, according to the Governor, is designed to reduce energy costs, promote energy independence and stimulate the economy. Elements of the EIS include the installation of smart meters, funding for solar panels on residences and small businesses, conservation and demand reduction programs to meet energy growth, a requirement that electric distribution companies acquire power that results in the “lowest reasonable rate on a long-term basis,” the utilization of micro-grids and a three year phase-in of rate increases. On July 17, 2007 the Governor signed into law two pieces of energy legislation. The first amended the Alternative Energy Portfolio Standards Act of 2004 to, among other things, increase the percentage of solar energy that must be supplied at the conclusion of an electric distribution company’s transition period. The second law allows electric distribution companies, at their sole discretion, to enter into long term contracts with large customers and to build or acquire interests in electric generation facilities specifically to supply long-term contracts with such customers. A special legislative session on energy was convened in mid-September 2007 to consider other aspects of the EIS. As part of the 2008 state budget negotiations, the Alternative Energy Investment Act was enacted in July 2008 creating a \$650 million alternative energy fund to increase the development and use of alternative and renewable energy, improve energy efficiency and reduce energy consumption.

On October 15, 2008, the Governor of Pennsylvania signed House Bill 2200 into law which became effective on November 14, 2008 as Act 129 of 2008. The bill addresses issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters and alternative energy. Act 129 requires utilities to file with the PPUC an energy efficiency and peak load reduction plan by July 1, 2009 and a smart meter procurement and installation plan by August 14, 2009. On January 15, 2009, in compliance with Act 129, the PPUC issued its guidelines for the filing of utilities’ energy efficiency and peak load reduction plans.

Major provisions of the legislation include:

- power acquired by utilities to serve customers after rate caps expire will be procured through a competitive procurement process that must include a mix of long-term and short-term contracts and spot market purchases;
- the competitive procurement process must be approved by the PPUC and may include auctions, RFPs, and/or bilateral agreements;
- utilities must provide for the installation of smart meter technology within 15 years;
- a minimum reduction in peak demand of 4.5% by May 31, 2013;
- minimum reductions in energy consumption of 1% and 3% by May 31, 2011 and May 31, 2013, respectively; and
- an expanded definition of alternative energy to include additional types of hydroelectric and biomass facilities.

Legislation addressing rate mitigation and the expiration of rate caps was not enacted in 2008 but may be considered in the legislative session which began in January 2009. While the form and impact of such legislation is uncertain, several legislators and the Governor have indicated their intent to address these issues in 2009.

On September 25, 2008, Met-Ed and Penelec filed a Voluntary Prepayment Plan with the PPUC that would provide an opportunity for residential and small commercial customers to prepay an amount on their monthly electric bills during 2009 and 2010 that would earn interest at 7.5% and be used to reduce electric rates in 2011 and 2012. Met-Ed, Penelec, OCA and OSBA have reached a settlement agreement on the Voluntary Prepayment Plan and have jointly requested that the PPUC approve the settlement. The ALJ issued a decision on January 29, 2009, recommending approval and adoption of the settlement without modification.

On February 20, 2009, Met-Ed and Penelec filed a generation procurement plan covering the period January 1, 2011 through May 31, 2013, with the PPUC. The companies’ plan is designed to provide adequate and reliable service via a prudent mix of long-term, short-term and spot market generation supply, as required by Act 129. The plan proposes a staggered procurement schedule, which varies by customer class, through the use of a descending clock auction. Met-Ed and Penelec have requested PPUC approval of their plan by October 2009.

New Jersey (Applicable to JCP&L)

JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers, costs incurred under NUG agreements, and certain other stranded costs, exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of December 31, 2008, the accumulated deferred cost balance totaled approximately \$220 million.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004, supporting 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. JCP&L responded to additional NJBPU staff discovery requests in May and November 2007 and also submitted comments in the proceeding in November 2007. A schedule for further NJBPU proceedings has not yet been set.

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of the PUHCA pursuant to the EPACT. The NJBPU approved regulations effective October 2, 2006 that 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. These regulations are not expected to materially impact JCP&L. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. The NJBPU Staff circulated revised drafts of the proposal to interested stakeholders in November 2006 and again in February 2007. On February 1, 2008, the NJBPU accepted proposed rules for publication in the New Jersey Register on March 17, 2008. A public hearing on these proposed rules was held on April 23, 2008 and comments from interested parties were submitted by May 19, 2008.

New Jersey statutes require that the state periodically undertake a planning process, known as the EMP, to address energy related issues including energy security, economic growth, and environmental impact. The EMP is to be developed with involvement of the Governor's Office and the Governor's Office of Economic Growth, and is to be prepared by a Master Plan Committee, which is chaired by the NJBPU President and includes representatives of several State departments.

The EMP was issued on October 22, 2008, establishing five major goals:

- maximize energy efficiency to achieve a 20% reduction in energy consumption by 2020;
- reduce peak demand for electricity by 5,700 MW by 2020;
- meet 30% of the state's electricity needs with renewable energy by 2020;
- examine smart grid technology and develop additional cogeneration and other generation resources consistent with the state's greenhouse gas targets; and
- invest in innovative clean energy technologies and businesses to stimulate the industry's growth in New Jersey.

The EMP will be followed by appropriate legislation and regulation as necessary. At this time, JCP&L cannot determine the impact, if any, the EMP may have on its operations.

In support of the New Jersey Governor's Economic Assistance and Recovery Plan, JCP&L announced its intent to spend approximately \$98 million on infrastructure and energy efficiency projects in 2009. An estimated \$40 million will be spent on infrastructure projects, including substation upgrades, new transformers, distribution line re-closers and automated breaker operations. Approximately \$34 million will be spent implementing new demand response programs as well as expanding on existing programs. Another \$11 million will be spent on energy efficiency, specifically replacing transformers and capacitor control systems and installing new LED street lights. The remaining \$13 million will be spent on energy efficiency programs that will complement those currently being offered. Completion of the projects is dependent upon regulatory approval for full recovery of the costs associated with plan implementation.

FERC Matters (Applicable to FES and each of the Utilities)

Transmission Service between MISO and PJM

On November 18, 2004, the FERC issued an order eliminating the through and out rate for transmission service between the MISO and PJM regions. The FERC's intent was to eliminate multiple transmission charges for a single transaction between the MISO and PJM regions. The FERC also ordered MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a rate mechanism to recover lost transmission revenues created by elimination of this charge (referred to as the Seams Elimination Cost Adjustment or "SECA") during a 16-month transition period. The FERC issued orders in 2005 setting the SECA for hearing. The presiding judge issued an initial decision on August 10, 2006, rejecting the compliance filings made by MISO, PJM, and the transmission owners, and directing new compliance filings. This decision is subject to review and approval by the FERC. Briefs addressing the initial decision were filed on September 11, 2006 and October 20, 2006. A final order is pending before the FERC, and in the meantime, FirstEnergy affiliates have been negotiating and entering into settlement agreements with other parties in the docket to mitigate the risk of lower transmission revenue collection associated with an adverse order. On September 26, 2008, the MISO and PJM transmission owners filed a motion requesting that the FERC approve the pending settlements and act on the initial decision. On November 20, 2008, FERC issued an order approving uncontested settlements, but did not rule on the initial decision. On December 19, 2008, an additional order was issued approving two contested settlements.

PJM Transmission Rate Design

On January 31, 2005, certain PJM transmission owners made 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. Hearings were held and numerous parties appeared and litigated various issues concerning PJM rate design; notably AEP, which proposed to create a "postage stamp", or average rate for all high voltage transmission facilities across PJM and a zonal transmission rate for facilities below 345 kV. This proposal would have the effect of shifting recovery of the costs of high voltage transmission lines to other transmission zones, including those where JCP&L, Met-Ed, and Penelec serve load. On April 19, 2007, the FERC issued an order finding that the PJM transmission owners' existing "license plate" or zonal rate design was just and reasonable and ordered that the current license plate rates for existing transmission facilities be retained. On the issue of rates for new transmission facilities, the FERC directed that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp rate. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a "beneficiary pays" basis. The FERC found that PJM's current beneficiary-pays cost allocation methodology is not sufficiently detailed and, in a related order that also was issued on April 19, 2007, directed that hearings be held for the purpose of establishing a just and reasonable cost allocation methodology for inclusion in PJM's tariff.

On May 18, 2007, certain parties filed for rehearing of the FERC's April 19, 2007 order. On January 31, 2008, the requests for rehearing were denied. On February 11, 2008, AEP appealed the FERC's April 19, 2007, and January 31, 2008, orders to the federal Court of Appeals for the D.C. Circuit. The Illinois Commerce Commission, the PUCO and Dayton Power & Light have also appealed these orders to the Seventh Circuit Court of Appeals. The appeals of these parties and others have been consolidated for argument in the Seventh Circuit.

The FERC's orders on PJM rate design will prevent the allocation of a portion of the revenue requirement of existing transmission facilities of other utilities to JCP&L, Met-Ed and Penelec. In addition, the FERC's decision to allocate the cost of new 500 kV and above transmission facilities on a PJM-wide basis will reduce the costs of future transmission to be recovered from the JCP&L, Met-Ed and Penelec zones. A partial settlement agreement addressing the "beneficiary pays" methodology for below 500 kV facilities, but excluding the issue of allocating new facilities costs to merchant transmission entities, was filed on September 14, 2007. The agreement was supported by the FERC's Trial Staff, and was certified by the Presiding Judge to the FERC. On July 29, 2008, the FERC issued an order conditionally approving the settlement subject to the submission of a compliance filing. The compliance filing was submitted on August 29, 2008, and the FERC issued an order accepting the compliance filing on October 15, 2008. The remaining merchant transmission cost allocation issues were the subject of a hearing at the FERC in May 2008. An initial decision was issued by the Presiding Judge on September 18, 2008. PJM and FERC trial staff each filed a Brief on Exceptions to the initial decision on October 20, 2008. Briefs Opposing Exceptions were filed on November 10, 2008.

Post Transition Period Rate Design

The FERC had directed MISO, PJM, and the respective transmission owners to make filings on or before August 1, 2007 to reevaluate transmission rate design within MISO, and between MISO and PJM. On August 1, 2007, filings were made by MISO, PJM, and the vast majority of transmission owners, including FirstEnergy affiliates, which proposed to retain the existing transmission rate design. These filings were approved by the FERC on January 31, 2008. As a result of the FERC's approval, the rates charged to FirstEnergy's load-serving affiliates for transmission service over existing transmission facilities in MISO and PJM are unchanged. In a related filing, MISO and MISO transmission owners requested that the current MISO pricing for new transmission facilities that spreads 20% of the cost of new 345 kV and higher transmission facilities across the entire MISO footprint (known as the RECB methodology) be retained.

On September 17, 2007, AEP filed a complaint under Sections 206 and 306 of the Federal Power Act seeking to have the entire transmission rate design and cost allocation methods used by MISO and PJM declared unjust, unreasonable, and unduly discriminatory, and to have the FERC fix a uniform regional transmission rate design and cost allocation method for the entire MISO and PJM "Super Region" that recovers the average cost of new and existing transmission facilities operated at voltages of 345 kV and above from all transmission customers. Lower voltage facilities would continue to be recovered in the local utility transmission rate zone through a license plate rate. AEP requested a refund effective October 1, 2007, or alternatively, February 1, 2008. On January 31, 2008, the FERC issued an order denying the complaint. The effect of this order is to prevent the shift of significant costs to the FirstEnergy zones in MISO and PJM. A rehearing request by AEP was denied by the FERC on December 19, 2008. On February 17, 2009, AEP appealed the FERC's January 31, 2008, and December 19, 2008, orders to the U.S. Court of Appeals for the Seventh Circuit.

Interconnection Agreement with AMP-Ohio

On May 29, 2008, TE filed with the FERC a proposed Notice of Cancellation effective midnight December 31, 2008, of the Interconnection Agreement with AMP-Ohio. AMP-Ohio protested this filing. TE also filed a Petition for Declaratory Order seeking a FERC ruling, in the alternative if cancellation is not accepted, of TE's right to file for an increase in rates effective January 1, 2009, for power provided to AMP-Ohio under the Interconnection Agreement. AMP-Ohio filed a pleading agreeing that TE may seek an increase in rates, but arguing that any increase is limited to the cost of generation owned by TE affiliates. On August 18, 2008, the FERC issued an order that suspended the cancellation of the Agreement for five months, to become effective on June 1, 2009, and established expedited hearing procedures on issues raised in the filing and TE's Petition for Declaratory Order. On October 14, 2008, the parties filed a settlement agreement and mutual notice of cancellation of the Interconnection Agreement effective midnight December 31, 2008. On October 24, 2008 the presiding judge certified the settlement agreement as uncontested and on December 22, 2008, the FERC issued an order approving the uncontested settlement agreement. This latest action terminates the litigation and the Interconnection Agreement.

Duquesne's Request to Withdraw from PJM

On November 8, 2007, Duquesne Light Company (Duquesne) filed a request with the FERC to exit PJM and to join MISO. Duquesne's proposed move would affect numerous FirstEnergy interests, including but not limited to the terms under which FirstEnergy's Beaver Valley Plant would continue to participate in PJM's energy markets. FirstEnergy, therefore, intervened and participated fully in all of the FERC dockets that were related to Duquesne's proposed move.

In November, 2008, Duquesne and other parties, including FirstEnergy, negotiated a settlement that would, among other things, allow for Duquesne to remain in PJM and provide for a methodology for Duquesne to meet the PJM capacity obligations for the 2011-2012 auction that excluded the Duquesne load. The settlement agreement was filed on December 10, 2008 and approved by the FERC in an order issued on January 29, 2009. The MISO opposed the settlement agreement pending resolution of exit fees alleged to be owed by Duquesne. The FERC did not resolve this issue in its order.

Complaint against PJM RPM Auction

On May 30, 2008, a group of PJM load-serving entities, state commissions, consumer advocates, and trade associations (referred to collectively as the RPM Buyers) filed a complaint at the FERC against PJM alleging that three of the four transitional RPM auctions yielded prices that are unjust and unreasonable under the Federal Power Act. On September 19, 2008, the FERC denied the RPM Buyers' complaint. However, the FERC did grant the RPM Buyers' request for a technical conference to review aspects of the RPM. The FERC also ordered PJM to file on or before December 15, 2008, a report on potential adjustments to the RPM program as suggested in a Brattle Group report. On December 12, 2008, PJM filed proposed tariff amendments that would adjust slightly the RPM program. PJM also requested that the FERC conduct a settlement hearing to address changes to the RPM and suggested that the FERC should rule on the tariff amendments only if settlement could not be reached in January, 2009. The request for settlement hearings was granted. Settlement had not been reached by January 9, 2009 and, accordingly, FirstEnergy and other parties submitted comments on PJM's proposed tariff amendments. On January 15, 2009, the Chief Judge issued an order terminating settlement talks. On February 9, 2009, PJM and a group of stakeholders submitted an offer of settlement.

On October 20, 2008, the RPM Buyers filed a request for rehearing of the FERC's September 19, 2008 order. The FERC has not yet ruled on the rehearing request.

MISO Resource Adequacy Proposal

MISO made a filing on December 28, 2007 that would create an enforceable planning reserve requirement in the MISO tariff for load-serving entities such as the Ohio Companies, Penn Power, and FES. This requirement is proposed to become effective for the planning year beginning June 1, 2009. The filing would permit MISO to establish the reserve margin requirement for load-serving entities based upon a one day loss of load in ten years standard, unless the state utility regulatory agency establishes a different planning reserve for load-serving entities in its state. FirstEnergy believes the proposal promotes a mechanism that will result in commitments from both load-serving entities and resources, including both generation and demand side resources that are necessary for reliable resource adequacy and planning in the MISO footprint. Comments on the filing were filed on January 28, 2008. The FERC conditionally approved MISO's Resource Adequacy proposal on March 26, 2008, requiring MISO to submit to further compliance filings. Rehearing requests are pending on the FERC's March 26 Order. On May 27, 2008, MISO submitted a compliance filing to address issues associated with planning reserve margins. On June 17, 2008, various parties submitted comments and protests to MISO's compliance filing. FirstEnergy submitted comments identifying specific issues that must be clarified and addressed. On June 25, 2008, MISO submitted a second compliance filing establishing the enforcement mechanism for the reserve margin requirement which establishes deficiency payments for load-serving entities that do not meet the resource adequacy requirements. Numerous parties, including FirstEnergy, protested this filing.

On October 20, 2008, the FERC issued three orders essentially permitting the MISO Resource Adequacy program to proceed with some modifications. First, the FERC accepted MISO's financial settlement approach for enforcement of Resource Adequacy subject to a compliance filing modifying the cost of new entry penalty. Second, the FERC conditionally accepted MISO's compliance filing on the qualifications for purchased power agreements to be capacity resources, load forecasting, loss of load expectation, and planning reserve zones. Additional compliance filings were directed on accreditation of load modifying resources and price responsive demand. Finally, the FERC largely denied rehearing of its March 26 order with the exception of issues related to behind the meter resources and certain ministerial matters. On November 19, 2008, MISO made various compliance filings pursuant to these orders. Issuance of orders on these compliance filings is not expected to delay the June 1, 2009, start date for MISO Resource Adequacy.

FES Sales to Affiliates

On October 24, 2008, FES, on its own behalf and on behalf of its generation-controlling subsidiaries, filed an application with the FERC seeking a waiver of the affiliate sales restrictions between FES and the Ohio Companies. The purpose of the waiver is to ensure that FES will be able to continue supplying a material portion of the electric load requirements of the Ohio Companies in January 2009 pursuant to either an ESP or MRO as filed with the PUCO. FES previously obtained a similar waiver for electricity sales to its affiliates in New Jersey, New York, and Pennsylvania. On December 23, 2008, the FERC issued an order granting the waiver request and the Ohio Companies made the required compliance filing on December 30, 2008.

On October 31, 2008, FES executed a Third Restated Partial Requirements Agreement with Met-Ed, Penelec, and Waverly effective November 1, 2008. The Third Restated Partial Requirements Agreement limits the amount of capacity and energy required to be supplied by FES in 2009 and 2010 to roughly two-thirds of these affiliates' power supply requirements. Met-Ed, Penelec, and Waverly have committed resources in place for the balance of their expected power supply during 2009 and 2010. Under the Third Restated Partial Requirements Agreement, Met-Ed, Penelec, and Waverly are responsible for obtaining additional power supply requirements created by the default or failure of supply of their committed resources. Prices for the power provided by FES were not changed in the Third Restated Partial Requirements Agreement.

Environmental Matters

Various federal, state and local authorities regulate FES and the Utilities with regard to air and water quality and other environmental matters. The effects of compliance on FES and the Utilities with regard to environmental matters could have a material adverse effect on their earnings and competitive position to the extent that they compete with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

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

FES is required to meet federally-approved SO₂ emissions regulations. Violations of such regulations can result in the shutdown of the generating unit involved and/or civil or criminal penalties of up to \$37,500 for each day the unit is in violation. The EPA has an interim enforcement policy for SO₂ regulations in Ohio that allows for compliance based on a 30-day averaging period. FES believes it is currently in compliance with this policy, but cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The EPA Region 5 issued a Finding of Violation and NOV to the Bay Shore Power Plant dated June 15, 2006, alleging violations to various sections of the CAA. FES has disputed those alleged violations based on its CAA permit, the Ohio SIP and other information provided to the EPA at an August 2006 meeting with the EPA. The EPA has several enforcement options (administrative compliance order, administrative penalty order, and/or judicial, civil or criminal action) and has indicated that such option may depend on the time needed to achieve and demonstrate compliance with the rules alleged to have been violated. On June 5, 2007, the EPA requested another meeting to discuss "an appropriate compliance program" and a disagreement regarding emission limits applicable to the common stack for Bay Shore Units 2, 3 and 4.

FES complies with SO₂ reduction requirements under the Clean Air Act Amendments of 1990 by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NO_x reductions required by the 1990 Amendments are being achieved through combustion controls and the generation of more electricity at lower-emitting plants. In September 1998, the EPA finalized regulations requiring additional NO_x reductions at FES' 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. FES believes its facilities are also complying with the NO_x budgets established under SIPs through combustion controls and post-combustion controls, including Selective Catalytic Reduction and SNCR systems, and/or using emission allowances.

In 1999 and 2000, the EPA issued an NOV and the DOJ filed a civil complaint against OE and Penn based on operation and maintenance of the W. H. Sammis Plant (Sammis NSR Litigation) and filed similar complaints involving 44 other U.S. power plants. This case and seven other similar cases are referred to as the NSR cases. OE's and Penn's settlement with the EPA, the DOJ and three states (Connecticut, New Jersey and New York) that resolved all issues related to the Sammis NSR litigation was approved by the Court on July 11, 2005. This settlement agreement, in the form of a consent decree, requires reductions of NO_x and SO₂ emissions at the Sammis, Burger, Eastlake and Mansfield 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. Capital expenditures necessary to complete requirements of the Sammis NSR Litigation consent decree are currently estimated to be \$506 million for 2009-2010 (with \$414 million expected to be spent in 2009). This amount excludes the potential AQC expenditures related to Burger Units 4 and 5 described below. On September 8, 2008, the Environmental Enforcement Section of the DOJ sent a letter to OE regarding its view that the company was not in compliance with the Sammis NSR Litigation consent decree because the installation of an SNCR at Eastlake Unit 5 was not completed by December 31, 2006. However, the DOJ acknowledged that stipulated penalties could not apply under the terms of the Sammis NSR Litigation consent decree because Eastlake Unit 5 was idled on December 31, 2006 pending installation of the SNCR and advised that it had exercised its discretion not to seek any other penalties for this alleged non-compliance. OE disputed the DOJ's interpretation of the consent decree in a letter dated September 22, 2008. Although the Eastlake Unit 5 issue is no longer active, OE filed a dispute resolution petition on October 23, 2008, with the United States District Court for the Southern District of Ohio, due to potential impacts on its compliance decisions with respect to Burger Units 4 and 5. On December 23, 2008, OE withdrew its dispute resolution petition and subsequently filed a motion to extend the date (from December 31, 2008 to April 15, 2009), under the Sammis NSR Litigation consent decree, to elect for Burger Units 4 and 5 to permanently shut down those units by December 31, 2010, or to repower them or to install flue gas desulfurization (FGD) by later dates. On January 30, 2009, the Court issued an order extending the election date from December 31, 2008 to March 31, 2009.

On April 2, 2007, the United States Supreme Court ruled that changes in annual emissions (in tons/year) rather than changes in hourly emissions rate (in kilograms/hour) must be used to determine whether an emissions increase triggers NSR. Subsequently, on May 8, 2007, the EPA proposed to revise the NSR regulations to utilize changes in the hourly emission rate (in kilograms/hour) to determine whether an emissions increase triggers NSR. On December 10, 2008, the EPA announced it would not finalize this proposed change to the NSR regulations.

On May 22, 2007, FirstEnergy and FGCO received a notice letter, required 60 days prior to the filing of a citizen suit under the federal CAA, alleging violations of air pollution laws at the Bruce Mansfield Plant, including opacity limitations. Prior to the receipt of this notice, the Plant was subject to a Consent Order and Agreement with the Pennsylvania Department of Environmental Protection concerning opacity emissions under which efforts to achieve compliance with the applicable laws will continue. On October 18, 2007, PennFuture filed a complaint, joined by three of its members, in the United States District Court for the Western District of Pennsylvania. On January 11, 2008, FirstEnergy filed a motion to dismiss claims alleging a public nuisance. On April 24, 2008, the Court denied the motion to dismiss, but also ruled that monetary damages could not be recovered under the public nuisance claim. In July 2008, three additional complaints were filed against FGCO in the United States District Court for the Western District of Pennsylvania seeking damages based on Bruce Mansfield Plant air emissions. In addition to seeking damages, two of the complaints seek to enjoin the Bruce Mansfield Plant from operating except in a "safe, responsible, prudent and proper manner", one being a complaint filed on behalf of twenty-one individuals and the other being a class action complaint, seeking certification as a class action with the eight named plaintiffs as the class representatives. On October 14, 2008, the Court granted FGCO's motion to consolidate discovery for all four complaints pending against the Bruce Mansfield Plant. FGCO believes the claims are without merit and intends to defend itself against the allegations made in these complaints.

On December 18, 2007, the state of New Jersey filed a CAA citizen suit alleging NSR violations at the Portland Generation Station against Reliant (the current owner and operator), Sithe Energy (the purchaser of the Portland Station from Met-Ed in 1999), GPU, Inc. and Met-Ed. Specifically, New Jersey alleges that "modifications" at Portland Units 1 and 2 occurred between 1980 and 1995 without preconstruction NSR or permitting under the CAA's prevention of significant deterioration program, and seeks injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. On March 14, 2008, Met-Ed filed a motion to dismiss the citizen suit claims against it and a stipulation in which the parties agreed that GPU, Inc. should be dismissed from this case. On March 26, 2008, GPU, Inc. was dismissed by the United States District Court. The scope of Met-Ed's indemnity obligation to and from Sithe Energy is disputed. On October 30, 2008, the state of Connecticut filed a Motion to Intervene, but the Court has yet to rule on Connecticut's Motion. On December 5, 2008, New Jersey filed an amended complaint, adding claims with respect to alleged modifications that occurred after GPU's sale of the plant. On January 14, 2009, the EPA issued a NOV to Reliant alleging new source review violations at the Portland Generation Station based on "modifications" dating back to 1986. Met-Ed is unable to predict the outcome of this matter. The EPA's January 14, 2009, NOV also alleged new source review violations at the Keystone and Shawville Stations based on "modifications" dating back to 1984. JCP&L, as the former owner of 16.67% of Keystone Station and Penelec, as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter.

On June 11, 2008, the EPA issued a Notice and Finding of Violation to MEW alleging that "modifications" at the Homer City Power Station occurred since 1988 to the present without preconstruction NSR or permitting under the CAA's prevention of significant deterioration program. MEW is seeking indemnification from Penelec, the co-owner (along with New York State Electric and Gas Company) and operator of the Homer City Power Station prior to its sale in 1999. The scope of Penelec's indemnity obligation to and from MEW is disputed. Penelec is unable to predict the outcome of this matter.

On May 16, 2008, FGCO received a request from the EPA for information pursuant to Section 114(a) of the CAA for certain operating and maintenance information regarding the Eastlake, Lakeshore, Bay Shore and Ashtabula generating plants to allow the EPA to determine whether these generating sources are complying with the NSR provisions of the CAA. On July 10, 2008, FGCO and the EPA entered into an ACO modifying that request and setting forth a schedule for FGCO's response. On October 27, 2008, FGCO received a second request from the EPA for information pursuant to Section 114(a) of the CAA for additional operating and maintenance information regarding the Eastlake, Lakeshore, Bay Shore and Ashtabula generating plants. FGCO intends to fully comply with the EPA's information requests, but, at this time, is unable to predict the outcome of this matter.

On August 18, 2008, FirstEnergy received a request from the EPA for information pursuant to Section 114(a) of the CAA for certain operating and maintenance information regarding the Avon Lake and Niles generating plants, as well as a copy of a nearly identical request directed to the current owner, Reliant Energy, to allow the EPA to determine whether these generating sources are complying with the NSR provisions of the CAA. FirstEnergy intends to fully comply with the EPA's information request, but, at this time, is unable to predict the outcome of this matter.

National Ambient Air Quality Standards (Applicable to FES)

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 requires reductions of NO_x and SO₂ emissions in two phases (Phase I in 2009 for NO_x, 2010 for SO₂ and Phase II in 2015 for both NO_x and SO₂), ultimately capping SO₂ emissions in affected states to just 2.5 million tons annually and NO_x emissions to just 1.3 million tons annually. CAIR was challenged in the United States Court of Appeals for the District of Columbia and on July 11, 2008, the Court vacated CAIR "in its entirety" and directed the EPA to "redo its analysis from the ground up." On September 24, 2008, the EPA, utility, mining and certain environmental advocacy organizations petitioned the Court for a rehearing to reconsider its ruling vacating CAIR. On December 23, 2008, the Court reconsidered its prior ruling and allowed CAIR to remain in effect to "temporarily preserve its environmental values" until the EPA replaces CAIR with a new rule consistent with the Court's July 11, 2008 opinion. The future cost of compliance with these regulations may be substantial and will depend, in part, on the action taken by the EPA in response to the Court's ruling.

Mercury Emissions (Applicable to FES)

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, capping national mercury emissions at 38 tons by 2010 (as a "co-benefit" from implementation of SO₂ and NO_x emission caps under the EPA's CAIR program) and 15 tons per year by 2018. Several states and environmental groups appealed the CAMR to the United States Court of Appeals for the District of Columbia. On February 8, 2008, the Court vacated the CAMR, ruling that the EPA failed to take the necessary steps to "de-list" coal-fired power plants from its hazardous air pollutant program and, therefore, could not promulgate a cap-and-trade program. The EPA petitioned for rehearing by the entire Court, which denied the petition on May 20, 2008. On October 17, 2008, the EPA (and an industry group) petitioned the United States Supreme Court for review of the Court's ruling vacating CAMR. On February 6, 2009, the United States moved to dismiss its petition for certiorari. On February 23, 2009, the Supreme Court dismissed the United States' petition and denied the industry group's petition. Accordingly, the EPA could take regulatory action to promulgate new mercury emission standards for coal-fired power plants. FGCO's future cost of compliance with mercury regulations may be substantial and will depend on the action taken by the EPA and on how they are ultimately implemented.

Pennsylvania has submitted a new mercury rule for EPA approval that does not provide a cap-and-trade approach as in the CAMR, but rather follows a command-and-control approach imposing emission limits on individual sources. On January 30, 2009, the Commonwealth Court of Pennsylvania declared Pennsylvania's mercury rule "unlawful, invalid and unenforceable" and enjoined the Commonwealth from continued implementation or enforcement of that rule. It is anticipated that compliance with these regulations, if the Commonwealth Court's rulings were reversed on appeal and Pennsylvania's mercury rule was implemented, would not require the addition of mercury controls at the Bruce Mansfield Plant, FES' only Pennsylvania coal-fired power plant, until 2015, if at all.

Climate Change (Applicable to FES)

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, including CO₂, emitted by developed countries by 2012. The United States signed the Kyoto Protocol in 1998 but it was never submitted for ratification by the United States Senate. However, the Bush administration had 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. Also, in an April 16, 2008 speech, former President Bush set a policy goal of stopping the growth of GHG emissions by 2025, as the next step beyond the 2012 strategy. In addition, 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. President Obama has announced his Administration's "New Energy for America Plan" that includes, among other provisions, ensuring that 10% of electricity in the United States comes from renewable sources by 2012, and 25% by 2025; and implementing an economy-wide cap-and-trade program to reduce GHG emissions 80% by 2050.

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. At the international level, efforts to reach a new global agreement to reduce GHG emissions post-2012 have begun with the Bali Roadmap, which outlines a two-year process designed to lead to an agreement in 2009. At the federal level, members of Congress have introduced several bills seeking to reduce emissions of GHG in the United States, and the Senate Environment and Public Works Committee has passed one such bill. State activities, primarily the northeastern states participating in the Regional Greenhouse Gas Initiative and western states led by California, have coordinated efforts to develop regional strategies to control emissions of certain GHGs.

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate CO₂ emissions from automobiles as “air pollutants” under the CAA. Although this decision did not address CO₂ emissions from electric generating plants, the EPA has similar authority under the CAA to regulate “air pollutants” from those and other facilities. On July 11, 2008, the EPA released an Advance Notice of Proposed Rulemaking, soliciting input from the public on the effects of climate change and the potential ramifications of regulation of CO₂ under the CAA.

FES cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO₂ emissions could require significant capital and other expenditures. The CO₂ emissions per KWH of electricity generated by FES is lower than many regional competitors due to its diversified generation sources, which include low or non-CO₂ emitting gas-fired and nuclear generators.

Clean Water Act (Applicable to FES)

Various water quality regulations, the majority of which are the result of the federal Clean Water Act and its amendments, apply to FES' plants. In addition, Ohio, New Jersey and Pennsylvania have water quality standards applicable to FES' 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 life is drawn into a facility's cooling water system). On January 26, 2007, the United States Court of Appeals for the Second Circuit remanded portions of the rulemaking dealing with impingement mortality and entrainment back to the EPA for further rulemaking and eliminated the restoration option from the EPA's regulations. On July 9, 2007, the EPA suspended this rule, noting that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. On April 14, 2008, the Supreme Court of the United States granted a petition for a writ of certiorari to review one significant aspect of the Second Circuit Court's opinion which is whether Section 316(b) of the Clean Water Act authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. Oral argument before the Supreme Court occurred on December 2, 2008 and a decision is anticipated during the first half of 2009. FES is studying various control options and their costs and effectiveness. Depending on the results of such studies, the outcome of the Supreme Court's review of the Second Circuit's decision, the EPA's further rulemaking and any action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

The U.S. Attorney's Office in Cleveland, Ohio has advised FGCO that it is considering prosecution under the Clean Water Act and the Migratory Bird Treaty Act for three petroleum spills at the Edgewater, Lakeshore and Bay Shore plants which occurred on November 1, 2005, January 26, 2007 and February 27, 2007. FGCO is unable to predict the outcome of this matter.

Regulation of Hazardous Waste (Applicable to FES and each of the Utilities)

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 non-hazardous waste.

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2008, FirstEnergy had approximately \$1.7 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. As part of the application to the NRC to transfer the ownership of Davis-Besse, Beaver Valley and Perry to NGC in 2005, FirstEnergy agreed to contribute another \$80 million to these trusts by 2010. Consistent with NRC guidance, utilizing a “real” rate of return on these funds of approximately 2% over inflation, these trusts are expected to exceed the minimum decommissioning funding requirements set by the NRC. Conservatively, these estimates do not include any rate of return that the trusts may earn over the 20-year plant useful life extensions that FirstEnergy (and Exelon for TMI-1 as it relates to the timing of the decommissioning of TMI-2) seeks for these facilities.

The Utilities 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 may be liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2008, based on estimates of the total costs of cleanup, the Utilities' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately \$90 million (JCP&L - \$64 million, CEI - \$1 million, TE - \$1 million and FirstEnergy Corp. - \$24 million) have been accrued through December 31, 2008. Included in the total are accrued liabilities of approximately \$56 million for environmental remediation of former manufactured gas plants in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC.

Other Legal Proceedings

Power Outages and Related Litigation (Applicable to JCP&L)

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 in July 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, NJ, based on a common incident involving the failure of the bushings of two large transformers in the Red Bank substation resulting in planned and unplanned outages in the area during a 2-3 day period. In 2005, JCP&L renewed its motion to decertify the class based on a very limited number of class members who incurred damages and also filed a motion for summary judgment on the remaining plaintiffs' claims for negligence, breach of contract and punitive damages. In July 2006, the New Jersey Superior Court dismissed the punitive damage claim and again decertified the class based on the fact that a vast majority of the class members did not suffer damages and those that did would be more appropriately addressed in individual actions. Plaintiffs appealed this ruling to the New Jersey Appellate Division which, in March 2007, reversed the decertification of the Red Bank class and remanded this matter back to the Trial Court to allow plaintiffs sufficient time to establish a damage model or individual proof of damages. JCP&L filed a petition for allowance of an appeal of the Appellate Division ruling to the New Jersey Supreme Court which was denied in May 2007. Proceedings are continuing in the Superior Court and a case management conference with the presiding Judge was held on June 13, 2008. At that conference, the plaintiffs stated their intent to drop their efforts to create a class-wide damage model and, instead of dismissing the class action, expressed their desire for a bifurcated trial on liability and damages. The judge directed the plaintiffs to indicate, on or before August 22, 2008, how they intend to proceed under this scenario. Thereafter, the judge expects to hold another pretrial conference to address plaintiffs' proposed procedure. JCP&L has received the plaintiffs' proposed plan of action, and intends to file its objection to the proposed plan, and also file a renewed motion to decertify the class. JCP&L is defending this action but is unable to predict the outcome. No liability has been accrued as of December 31, 2008.

On December 9, 2008, a transformer at JCP&L's Oceanview substation failed, resulting in an outage on certain bulk electric system (transmission voltage) lines out of the Oceanview and Atlantic substations, with customers in the affected area losing power. Power was restored to most customers within a few hours, and to all customers within eleven hours. On December 16, 2008, JCP&L provided preliminary information about the event to certain regulatory agencies, including the NERC. In a letter dated January 30, 2009, the NERC submitted a written "Notice of Request for Information" (NOI) to JCP&L. The NOI asked for additional factual details about the December 9 event, which JCP&L provided in its response. JCP&L is not able to predict what actions, if any, the NERC may take in response to JCP&L's NOI submittal.

Nuclear Plant Matters (Applicable to FES)

On May 14, 2007, the Office of Enforcement of the NRC issued a DFI to FENOC, following FENOC's reply to an April 2, 2007 NRC request for information about two reports prepared by expert witnesses for an insurance arbitration (the insurance claim was subsequently withdrawn by FirstEnergy in December 2007) related to Davis-Besse. The NRC indicated that this information was needed for the NRC "to determine whether an Order or other action should be taken pursuant to 10 CFR 2.202, to provide reasonable assurance that FENOC will continue to operate its licensed facilities in accordance with the terms of its licenses and the Commission's regulations." FENOC was directed to submit the information to the NRC within 30 days. On June 13, 2007, FENOC filed a response to the NRC's DFI reaffirming that it accepts full responsibility for the mistakes and omissions leading up to the damage to the reactor vessel head and that it remains committed to operating Davis-Besse and FirstEnergy's other nuclear plants safely and responsibly. FENOC submitted a supplemental response clarifying certain aspects of the DFI response to the NRC on July 16, 2007. On August 15, 2007, the NRC issued a confirmatory order imposing these commitments. FENOC must inform the NRC's Office of Enforcement after it completes the key commitments embodied in the NRC's order. FENOC has conducted the employee training required by the confirmatory order and a consultant has performed follow-up reviews to ensure the effectiveness of that training. The NRC continues to monitor FENOC's compliance with all the commitments made in the confirmatory order.

In August 2007, FENOC submitted an application to the NRC to renew the operating licenses for the Beaver Valley Power Station (Units 1 and 2) for an additional 20 years. The NRC is required by statute to provide an opportunity for members of the public to request a hearing on the application. No members of the public, however, requested a hearing on the Beaver Valley license renewal application. On September 24, 2008, the NRC issued a draft supplemental Environmental Impact Statement for Beaver Valley. FENOC will continue to work with the NRC Staff as it completes its environmental and technical reviews of the license renewal application, and expects to obtain renewed licenses for the Beaver Valley Power Station in 2009. If renewed licenses are issued by the NRC, the Beaver Valley Power Station's licenses would be extended until 2036 and 2047 for Units 1 and 2, respectively.

Other Legal Matters (Applicable to FES and each of the Utilities)

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

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 also sought injunctive relief to eliminate harmful emissions and repair property damage and the institution of a medical monitoring program for class members. On April 5, 2007, the Court rejected the plaintiffs' request to certify this case as a class action and, accordingly, did not appoint the plaintiffs as class representatives or their counsel as class counsel. On July 30, 2007, plaintiffs' counsel voluntarily withdrew their request for reconsideration of the April 5, 2007 Court order denying class certification and the Court heard oral argument on the plaintiffs' motion to amend their complaint, which OE opposed. On August 2, 2007, the Court denied the plaintiffs' motion to amend their complaint. Plaintiffs appealed the Court's denial of the motion for certification as a class action which the Ohio Court of Appeals (7th District) denied on December 11, 2008. The period to file a notice of appeal to the Ohio Supreme Court has expired.

JCP&L's bargaining unit employees filed a grievance challenging JCP&L's 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties' collective bargaining agreement. At the conclusion of the June 1, 2005 hearing, the arbitration panel decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the arbitration panel issued an opinion to award approximately \$16 million to the bargaining unit employees. On February 6, 2006, a federal district Court granted a union motion to dismiss, as premature, a JCP&L appeal of the award filed on October 18, 2005. A final order identifying the individual damage amounts was issued on October 31, 2007. The award appeal process was initiated. The union filed a motion with the federal Court to confirm the award and JCP&L filed its answer and counterclaim to vacate the award on December 31, 2007. JCP&L and the union filed briefs in June and July of 2008 and oral arguments were held in the fall. The Court has yet to render its decision. JCP&L recognized a liability for the potential \$16 million award in 2005.

The union employees at the Bruce Mansfield Plant have been working without a labor contract since February 15, 2008. The parties are continuing to bargain with the assistance of a federal mediator. FES has a strike mitigation plan ready in the event of a strike.

FES and the Utilities accrue legal liabilities only when they conclude that it is probable that they have an obligation for such costs and can reasonably estimate the amount of such costs. If it were ultimately determined that FES and the Utilities have legal liability or are otherwise made subject to liability based on the above matters, it could have a material adverse effect on their financial condition, results of operations and cash flows.

New Accounting Standards and Interpretations (Applicable to FES and each of the Utilities)

SFAS 141(R) – “Business Combinations”

In December 2007, the FASB issued SFAS 141(R), which: (i) requires the acquiring entity in a business combination to recognize all assets acquired and liabilities assumed in the transaction; (ii) establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and (iii) requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. The Standard includes both core principles and pertinent application guidance, eliminating the need for numerous EITF issues and other interpretative guidance. SFAS 141(R) will affect business combinations entered into by FES and the Utilities that close after January 1, 2009. In addition, the Standard also affects the accounting for changes in deferred tax valuation allowances and income tax uncertainties made after January 1, 2009, that were established as part of a business combination prior to the implementation of this Standard. Under SFAS 141(R), adjustments to the acquired entity's deferred tax assets and uncertain tax position balances occurring outside the measurement period will be recorded as a component of income tax expense, rather than goodwill. The impact of the application of this Standard in periods after implementation will be dependent upon the nature of acquisitions at that time.

SFAS 160 - “Non-controlling Interests in Consolidated Financial Statements – an Amendment of ARB No. 51”

In December 2007, the FASB issued SFAS 160 that establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. This Statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is prohibited. The Statement is not expected to have a material impact on financial statements of FES or the Utilities.

SFAS 161 - “Disclosures about Derivative Instruments and Hedging Activities – an Amendment of FASB Statement No. 133”

In March 2008, the FASB issued SFAS 161 that enhances the current disclosure framework for derivative instruments and hedging activities. The Statement requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. The FASB believes that additional required disclosure of the fair values of derivative instruments and their gains and losses in a tabular format will provide a more complete picture of the location in an entity's financial statements of both the derivative positions existing at period end and the effect of using derivatives during the reporting period. Disclosing information about credit-risk-related contingent features is designed to provide information on the potential effect on an entity's liquidity from using derivatives. This Statement also requires cross-referencing within the footnotes to help users of financial statements locate important information about derivative instruments. The Statement is effective for reporting periods beginning after November 15, 2008. FES expects this Standard to increase its disclosure requirements for derivative instruments and hedging activities.

EITF Issue No. 08-6 – “Equity Method Investment Accounting Considerations”

In November 2008, the FASB issued EITF 08-6, which clarifies how to account for certain transactions involving equity method investments. It provides guidance in determining the initial carrying value of an equity method investment, accounting for a change in an investment from equity method to cost method, assessing the impairment of underlying assets of an equity method investment, and accounting for an equity method investee's issuance of shares. This statement is effective for transactions occurring in fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is not permitted. The impact of the application of this Standard in periods after implementation will be dependent upon the nature of future investments accounted for under the equity method.

FSP SFAS 132 (R)-1 – “Employers’ Disclosures about Postretirement Benefit Plan Assets”

In December 2008, the FASB issued Staff Position (FSP) SFAS 132(R)-1, which provides guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement plan. Requirements of this FSP include disclosures about investment policies and strategies, categories of plan assets, fair value measurements of plan assets, and significant categories of risk. This FSP is effective for fiscal years ending after December 15, 2009. FES and the Utilities expect this Staff Position to increase their disclosure requirements for postretirement benefit plan assets.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

FES and the Utilities are wholly owned subsidiaries of FirstEnergy. FES' consolidated financial statements include its wholly owned subsidiaries, FGCO and NGC. OE's consolidated financial statements include its wholly owned subsidiary, Penn.

On December 28, 2006, the NRC approved the transfer of ownership in NGC from FirstEnergy to FES. Effective December 31, 2006, NGC is a wholly owned subsidiary of FES. FENOC continues to operate and maintain the nuclear generation assets. FES' consolidated financial statements assume that this corporate restructuring occurred as of December 31, 2003, with FES' and NGC's financial position, results of operations and cash flows combined at the end of 2003 and associated company transactions and balances eliminated in consolidation.

FES and the Utilities follow GAAP and comply with the regulations, orders, policies and practices prescribed by the SEC, FERC and, as applicable, the 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.

FES and the Utilities 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. FES and the Utilities consolidate a VIE (see Note 7) when they are determined to be the VIE's primary beneficiary. Investments in non-consolidated affiliates over which FES and the Utilities have the ability to exercise significant influence, but not control (20-50% 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 Sheets and the percentage share of the entity's earnings is reported in the Consolidated Statements of Income.

Certain prior year amounts have been reclassified to conform to the current year presentation. In the fourth quarter of 2008, Met-Ed and Penelec determined that certain NUG contracts should be reflected at fair value, with offsetting regulatory assets or liabilities. The December 31, 2007, balance sheet has been revised for Met-Ed and Penelec to record derivative assets of \$141 million and \$61 million, respectively, offset by a regulatory liability. Unless otherwise indicated, defined terms used herein have the meanings set forth in the accompanying Glossary of Terms.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(A) ACCOUNTING FOR THE EFFECTS OF REGULATION

The Utilities account for the effects of regulation through the application of SFAS 71 since their rates:

- are established by a third-party regulator with the authority to set rates that bind customers;
- are cost-based; and
- can be charged to and collected from customers.

An enterprise meeting all of these criteria capitalizes costs that would otherwise be charged to expense if the rate actions of its regulator make it probable that those costs will be recovered in future revenue. SFAS 71 is applied only to the parts of the business that meet the above criteria. If a portion of the business applying SFAS 71 no longer meets those requirements, previously recorded net regulatory assets are removed from the balance sheet in accordance with the guidance in SFAS 101.

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

- restructuring the electric generation business and allowing the Utilities' customers to select a competitive electric generation supplier other than the Utilities;
- establishing or defining the PLR obligations to customers in the Utilities' service areas;
- providing the Utilities 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 Utilities' transmission and distribution systems; and
- requiring corporate separation of regulated and unregulated business activities.

Regulatory Assets

The Utilities 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 expense as incurred. Regulatory assets that do not earn a current return as of December 31, 2008 (primarily for certain regulatory transition costs and employee postretirement benefits) totaled approximately \$61 million for JCP&L and \$72 million for Met-Ed, which will be recovered by 2014 and 2020, respectively.

Regulatory assets on the Utilities' Consolidated Balance Sheets are comprised of the following:

Regulatory Assets *	OE	CEI	TE	JCP&L	Met-Ed
December 31, 2008			<i>(In millions)</i>		
Regulatory transition costs	\$ 112	\$ 80	\$ 12	\$ 1,236	\$ 12
Customer shopping incentives	-	420	-	-	-
Customer receivables for future income taxes	68	4	1	59	113
Loss (Gain) on reacquired debt	20	1	(3)	24	9
Employee postretirement benefit costs	-	7	3	13	8
Nuclear decommissioning, decontamination and spent fuel disposal costs	-	-	-	(2)	(55)
Asset removal costs	(15)	(36)	(16)	(148)	-
Property losses and unrecovered plant costs	-	-	-	8	-
MISO/PJM transmission costs	31	19	20	-	319
Fuel costs – RCP	109	75	30	-	-
Distribution costs – RCP	222	198	55	-	-
Other	28	16	7	38	7
Total	<u>\$ 575</u>	<u>\$ 784</u>	<u>\$ 109</u>	<u>\$ 1,228</u>	<u>\$ 413</u>
December 31, 2007					
Regulatory transition costs	\$ 197	\$ 227	\$ 71	\$ 1,630	\$ 279
Customer shopping incentives	91	393	32	-	-
Customer receivables (payables) for future income taxes	101	18	(1)	51	126
Loss (Gain) on reacquired debt	23	2	(3)	25	10
Employee postretirement benefit costs	-	8	4	17	10
Nuclear decommissioning, decontamination and spent fuel disposal costs	-	-	-	-	(129)
Asset removal costs	(6)	(18)	(11)	(148)	-
Property losses and unrecovered plant costs	-	-	-	9	-
MISO/PJM transmission costs	56	34	24	-	226
Fuel costs – RCP	111	77	33	-	-
Distribution costs – RCP	148	122	51	-	-
Other	16	8	4	12	1
Total	<u>\$ 737</u>	<u>\$ 871</u>	<u>\$ 204</u>	<u>\$ 1,596</u>	<u>\$ 523</u>

* Penn had net regulatory liabilities of approximately \$11 million and \$67 million as of December 31, 2008 and 2007, respectively. Penelec had net regulatory liabilities of approximately \$137 million and \$49 million as of December 31, 2008 and 2007, respectively.

In accordance with the Ohio Companies' RCP, recovery of the aggregate of the regulatory transition costs and the Extended RTC (deferred customer shopping incentives and interest costs) amounts were completed by OE and TE as of December 31, 2008. CEI's recovery of regulatory transition costs is projected to be complete by April 2009, at which time recovery of its Extended RTC will begin, with recovery estimated to be complete as of December 31, 2010. At the end of its recovery period, any of CEI's remaining unamortized Extended RTC balances will be reduced by applying any remaining cost of removal regulatory liability balances; any further remaining Extended RTC balances will be written off. The RCP allowed the Ohio Companies to defer and capitalize certain distribution costs during the period January 1, 2006 through December 31, 2008, not to exceed \$150 million in each of the years 2006, 2007 and 2008. In addition, the Ohio Companies deferred certain fuel costs through December 31, 2007 that were incurred above the amount collected through a fuel recovery mechanism in accordance with the RCP (see Note 9 (B)).

Transition Cost Amortization

CEI amortizes transition costs using the effective interest method. Extended RTC amortization, beginning in mid-2009, will be equal to the related revenue recovery that is recognized. CEI's estimated net amortization of regulatory transition costs and Extended RTC amounts (including associated carrying charges) under the RCP is expected to be \$216 million in 2009 and \$273 million in 2010.

JCP&L's and Met-Ed's regulatory transition costs include the deferral of above-market costs for power supplied from NUGs of \$555 million for JCP&L (recovered through BGS and NUGC revenues) and \$67 million for Met-Ed (recovered through CTC revenues). Projected above-market NUG costs are adjusted to fair value at the end of each quarter, with a corresponding offset to regulatory assets. Recovery of the remaining regulatory transition costs is expected to continue pursuant to various regulatory proceedings in New Jersey and Pennsylvania (See Note 9).

(B) REVENUES AND RECEIVABLES

Electric service provided to FES' and the Utilities' retail customers is metered on a cycle basis. Electric revenues are recorded based on energy delivered through the end of the calendar month. An estimate of unbilled revenues is calculated to recognize electric service provided between the last meter reading and the end of the month. This estimate includes many factors including historical customer usage, load profiles, estimated weather impacts, customer shopping activity and prices in effect for each class of customer. In each accounting period, FES and the Utilities accrue the estimated unbilled amount receivable as revenue and reverse the related prior period estimate.

Receivables from customers include sales to residential, commercial and industrial customers and sales to wholesale customers. There was no material concentration of receivables as of December 31, 2008 with respect to any particular segment of customers. Billed and unbilled customer receivables for FES and the Utilities as of December 31, 2008 and 2007 are shown below.

Customer Receivables	FES	OE	CEI	TE ⁽¹⁾	JCP&L	Met-Ed	Penelec
December 31, 2008				<i>(In millions)</i>			
Billed	\$ 84	\$ 143	\$ 150	\$ 1	\$ 179	\$ 93	\$ 86
Unbilled	2	134	126	-	161	67	61
Total	\$ 86	\$ 277	\$ 276	\$ 1	\$ 340	\$ 160	\$ 147
December 31, 2007							
Billed	\$ 107	\$ 143	\$ 144	\$ -	\$ 162	\$ 80	\$ 75
Unbilled	27	106	107	-	159	63	62
Total	\$ 134	\$ 249	\$ 251	\$ -	\$ 321	\$ 143	\$ 137

⁽¹⁾ See Note 12 for a discussion of TE's accounts receivable financing arrangement with Centerior Funding Corporation.

(C) EMISSION ALLOWANCES

FES holds emission allowances for SO₂ and NO_x in order to comply with programs implemented by the EPA designed to regulate emissions of SO₂ and NO_x produced by power plants. Emission allowances are either granted by the EPA at zero cost or are purchased at fair value as needed to meet emission requirements. Emission allowances are not purchased with the intent of resale. Emission allowances eligible to be used in the current year are recorded in materials and supplies inventory at the lesser of weighted average cost or market value. Emission allowances eligible for use in future years are recorded as other investments. FES recognizes emission allowance costs as fuel expense during the periods that emissions are produced by its generating facilities. Excess emission allowances that are not needed to meet emission requirements may be sold, with any pre-tax gain or loss included in other operating expenses.

(D) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (except for nuclear generating assets which were adjusted to fair value in accordance with SFAS 144), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. FES' accounting policy for planned major maintenance projects is to recognize liabilities as they are incurred.

FES and the Utilities provide for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The respective annual composite rates for FES' and the Utilities' electric plant in 2008, 2007 and 2006 are shown in the following table:

	Annual Composite Depreciation Rate		
	2008	2007	2006
OE	3.1%	2.9%	2.8%
CEI	3.5	3.6	3.2
TE	3.6	3.9	3.8
Penn	2.4	2.3	2.6
JCP&L	2.3	2.1	2.1
Met-Ed	2.3	2.3	2.3
Penelec	2.5	2.3	2.3
FGCO	4.7	4.0	4.1
NGC	2.8	2.8	2.7

Jointly-Owned Generating Stations

JCP&L holds a 50% ownership interest in Yards Creek Pumped Storage Facility having a net book value of approximately \$18.9 million as of December 31, 2008.

Asset Retirement Obligations

FES and the Utilities recognize liabilities for retirement obligations associated with tangible assets in accordance with SFAS 143 and FIN 47. These standards require recognition of the fair value of a liability for an ARO in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying value of the long-lived asset and depreciated over time, as described further in Note 11.

Nuclear Fuel

FES' property, plant and equipment includes nuclear fuel recorded at original cost, which includes material, enrichment, fabrication and interest costs incurred prior to reactor load. Nuclear fuel is amortized based on the units of production method.

(E) ASSET IMPAIRMENTS

Long-Lived Assets

FES and the Utilities evaluate the carrying value of their long-lived assets when events or circumstances indicate that the carrying amount may not be recoverable. In accordance with SFAS 144, the carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If an impairment exists, a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. Fair value is estimated by using available market valuations or the long-lived asset's expected future net discounted cash flows. The calculation of expected cash flows is based on estimates and assumptions about future events.

Goodwill

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

The forecasts used in FES' and the Utilities' evaluation of goodwill reflect operations consistent with their general business assumptions. Unanticipated changes in those assumptions could have a significant effect on future evaluations of goodwill. The impairment analysis includes a significant source of cash representing the Utilities' recovery of transition costs as described in Note 9.

FES' and the Utilities' 2008 annual review was completed in the third quarter of 2008 with no impairment indicated. Due to the significant downturn in the U.S. economy during the fourth quarter of 2008, goodwill was tested for impairment as of an interim date (December 31, 2008). No impairment was indicated for Penelec, Met-Ed and JCP&L. As discussed in Note 10(B) on February 19, 2009, the Ohio Companies filed an application for an amended ESP, which substantially reflects terms proposed by the PUCO Staff on February 2, 2009. Goodwill for CEI and TE was tested as of December 31, 2008, reflecting the projected results associated with the amended ESP. No impairment was indicated for CEI or TE. If the PUCO's final decision authorizes less revenue recovery than the amounts assumed, an additional impairment analysis will be performed at that time that could result in future goodwill impairment. During 2008, JCP&L, Met-Ed and Penelec adjusted goodwill due to the realization of tax benefits that had been reserved under purchase accounting.

FES' and the Utilities' 2007 annual review was completed in the third quarter of 2007, with no impairment indicated. In the third quarter of 2007, JCP&L, Met-Ed and Penelec adjusted goodwill due to the realization of tax benefits that had been reserved in purchase accounting.

FES' and the Utilities' 2006 annual review was completed in the third quarter of 2006 with no impairment indicated. On January 11, 2007, the PPUC issued its order related to the comprehensive rate filing made by Met-Ed and Penelec on April 10, 2006. Prior to issuing the order, the PPUC conducted an informal, nonbinding polling of Commissioners at its public meeting on December 21, 2006 that indicated the rate increase ultimately granted would be substantially below the amounts requested. As a result of the polling, Met-Ed and Penelec determined that an interim review of goodwill would be required. As a result, Met-Ed recognized an impairment charge of \$355 million in the fourth quarter of 2006. No impairment was indicated for Penelec.

A summary of the changes in FES' and the Utilities' goodwill for the three years ended December 31, 2008 is shown below.

<u>Goodwill</u>	<u>FES</u>	<u>CEI</u>	<u>TE</u>	<u>JCP&L</u>	<u>Met-Ed</u>	<u>Penelec</u>
	<i>(In millions)</i>					
Balance as of January 1, 2006	\$ 24	\$ 1,689	\$ 501	\$ 1,986	\$ 864	\$ 882
Impairment charges	-	-	-	-	(355)	-
Adjustments related to GPU acquisition	-	-	-	(24)	(13)	(21)
Balance as of December 31, 2006	24	1,689	501	1,962	496	861
Adjustments related to GPU acquisition	-	-	-	(136)	(72)	(83)
Balance as of December 31, 2007	24	1,689	501	1,826	424	778
Adjustments related to GPU acquisition	-	-	-	(15)	(8)	(9)
Balance as of December 31, 2008	<u>\$ 24</u>	<u>\$ 1,689</u>	<u>\$ 501</u>	<u>\$ 1,811</u>	<u>\$ 416</u>	<u>\$ 769</u>

Investments

At the end of each reporting period, FES and the Utilities evaluate their investments for impairment. In accordance with SFAS 115, FSP SFAS 115-1 and SFAS 124-1, investments classified as available-for-sale securities are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. FES and the Utilities first consider their intent and ability to hold the investment until recovery and then consider, among other factors, the duration and the extent to which the security's fair value has been less than cost and the near-term financial prospects of the security issuer when evaluating investments for impairment. If the decline in fair value is determined to be other-than-temporary, the cost basis of the investment is written down to fair value. Upon adoption of FSP SFAS 115-1 and SFAS 124-1, FES, OE and TE began recognizing in earnings the unrealized losses on available-for-sale securities held in their nuclear decommissioning trusts since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of other-than-temporary impairment. The fair value and unrealized gains and losses of FES' and the Utilities' investments are disclosed in Note 5.

(F) COMPREHENSIVE INCOME

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholder's equity except those resulting from transactions with stockholders and from the adoption of SFAS 158 in December 2006. Accumulated other comprehensive income (loss), net of tax, included on FES' and the Utilities' Consolidated Balance Sheets as of December 31, 2008 and 2007 is comprised of the following components:

<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>FES</u>	<u>OE</u>	<u>CEI</u>	<u>TE</u>	<u>JCP&L</u>	<u>Met-Ed</u>	<u>Penelec</u>
	<i>(In millions)</i>						
Net liability for unfunded retirement benefits including the implementation of SFAS 158	\$ (97)	\$ (190)	\$ (135)	\$ (43)	\$ (215)	\$ (140)	\$ (128)
Unrealized gain on investments	30	6	-	10	-	-	-
Unrealized loss on derivative hedges	(25)	-	-	-	(2)	(1)	-
AOCL (AOCL) Balance, December 31, 2008	<u>\$ (92)</u>	<u>\$ (184)</u>	<u>\$ (135)</u>	<u>\$ (33)</u>	<u>\$ (217)</u>	<u>\$ (141)</u>	<u>\$ (128)</u>
Net liability for unfunded retirement benefits including the implementation of SFAS 158	\$ (11)	\$ 32	\$ (69)	\$ (18)	\$ (18)	\$ (14)	\$ 5
Unrealized gain on investments	168	16	-	7	-	-	-
Unrealized loss on derivative hedges	(16)	-	-	-	(2)	(1)	-
AOCL (AOCL) Balance, December 31, 2007	<u>\$ 141</u>	<u>\$ 48</u>	<u>\$ (69)</u>	<u>\$ (11)</u>	<u>\$ (20)</u>	<u>\$ (15)</u>	<u>\$ 5</u>

Other comprehensive income (loss) reclassified to net income in the three years ended December 31, 2008 is as follows:

2008	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
<i>(In millions)</i>							
Pension and other postretirement benefits	\$ 7	\$ 16	\$ 1	\$ -	\$ 14	\$ 9	\$ 14
Gain on investments	31	9	-	1	-	-	-
Loss on derivative hedges	(3)	-	-	-	-	-	-
Reclassification to net income	35	25	1	1	14	9	14
Income taxes related to reclassification to net income	14	10	-	-	6	4	6
Reclassification to net income, net of income taxes	<u>\$ 21</u>	<u>15</u>	<u>1</u>	<u>1</u>	<u>8</u>	<u>5</u>	<u>8</u>
2007							
Pension and other postretirement benefits	\$ 5	\$ 14	\$ (5)	\$ (2)	\$ 8	\$ 6	\$ 11
Gain on investments	10	-	-	-	-	-	-
Loss on derivative hedges	(12)	-	-	-	-	-	-
Reclassification to net income	3	14	(5)	(2)	8	6	11
Income taxes (benefits) related to reclassification to net income	1	6	(2)	(1)	4	3	5
Reclassification to net income, net of income taxes (benefits)	<u>\$ 2</u>	<u>\$ 8</u>	<u>\$ (3)</u>	<u>\$ (1)</u>	<u>\$ 4</u>	<u>\$ 3</u>	<u>\$ 6</u>
2006							
Gain (loss) on investments	\$ 28	\$ -	\$ -	\$ (1)	\$ -	\$ -	\$ -
Loss on derivative hedges	(9)	-	-	-	-	-	-
Reclassification to net income	19	-	-	(1)	-	-	-
Income taxes related to reclassification to net income	7	-	-	-	-	-	-
Reclassification to net income, net of income taxes	<u>\$ 12</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ (1)</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>

3. TRANSACTIONS WITH AFFILIATED COMPANIES

FES' and the Utilities' operating revenues, operating expenses, investment income and interest expense include transactions with affiliated companies. These affiliated company transactions include PSAs between FES and the Utilities, support service billings from FESC and FENOC, and interest on associated company notes.

Effective October 16, 2007 CEI and TE assigned their leasehold interests in the Bruce Mansfield Plant to FGCO and FGCO assumed all of CEI's and TE's obligations arising under those leases. FGCO subsequently transferred the Unit 1 portion of these leasehold interests, as well as FGCO's leasehold interests under its July 13, 2007 Bruce Mansfield Unit 1 sale and leaseback transaction, to a newly formed wholly-owned subsidiary on December 17, 2007. The subsidiary assumed all of the lessee obligations associated with the assigned interests. However, CEI and TE remain primarily liable on the 1987 leases and related agreements. FGCO remains primarily liable on the 2007 leases and related agreements, and FES remains primarily liable as a guarantor under the related 2007 guarantees, as to the lessors and other parties to the respective agreements.

During the second quarter of 2008, NGC purchased 56.8 MW of lessor equity interests in the OE 1987 sale and leaseback of the Perry Plant and approximately 43.5 MW of lessor equity interests in the OE 1987 sale and leaseback of Beaver Valley Unit 2. In addition, NGC purchased 158.5 MW of lessor equity interests in the TE and CEI 1987 sale and leaseback of Beaver Valley Unit 2. The Ohio Companies continue to lease these MW under their respective sale and leaseback arrangements and the related lease debt remains outstanding.

The Ohio Companies had a PSA with FES through December 31, 2008 to meet their PLR and default service obligations. Met-Ed and Penelec have a partial requirements PSA with FES to meet a portion of their PLR and default service obligations (see Note 9). FES is incurring interest expense through FGCO and NGC on associated company notes payable to the Ohio Companies and Penn related to the 2005 intra-system generation asset transfers. The primary affiliated company transactions for FES and the Utilities for the three years ended December 31, 2008 are as follows:

Affiliated Company Transactions - 2008	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
<i>(In millions)</i>							
Revenues:							
Electric sales to affiliates	\$ 2,968	\$ 70	\$ -	\$ 30	\$ -	\$ -	\$ -
Ground lease with ATSI	-	12	7	2	-	-	-
Expenses:							
Purchased power from affiliates	101	1,203	766	411	-	304	284
Support services	552	145	67	62	90	57	56
Investment Income:							
Interest income from affiliates	-	15	1	20	1	-	1
Interest income from FirstEnergy	13	13	-	-	-	-	-
Interest Expense:							
Interest expense to affiliates	4	3	19	1	3	2	2
Interest expense to FirstEnergy	26	-	7	2	5	4	5
Affiliated Company Transactions - 2007							
Revenues:							
Electric sales to affiliates	\$ 2,901	\$ 73	\$ 92	\$ 167	\$ -	\$ -	\$ -
Ground lease with ATSI	-	12	7	2	-	-	-
Expenses:							
Purchased power from affiliates	234	1,261	770	392	-	290	285
Support services	560	146	70	55	100	54	58
Investment Income:							
Interest income from affiliates	-	30	17	18	1	1	1
Interest income from FirstEnergy	28	29	2	-	-	-	-
Interest Expense:							
Interest expense to affiliates	31	1	1	-	1	1	1
Interest expense to FirstEnergy	34	-	1	10	11	10	11
Affiliated Company Transactions - 2006							
Revenues:							
Electric sales to affiliates	\$ 2,609	\$ 80	\$ 95	\$ 170	\$ 14	\$ -	\$ -
Ground lease with ATSI	-	12	7	2	-	-	-
Expenses:							
Purchased power from affiliates	257	1,264	727	363	25	178	154
Support services	602	143	63	63	93	51	55
Investment Income:							
Interest income from affiliates	-	75	58	32	1	1	1
Interest income from FirstEnergy	12	25	-	-	-	-	-
Interest Expense:							
Interest expense to affiliates	109	-	-	-	-	-	-
Interest expense to FirstEnergy	53	-	7	7	11	5	11

FirstEnergy does not bill directly or allocate any of its costs to any subsidiary company. Costs are allocated to FES and the Utilities from FESC and FENOC. The majority of costs are directly billed or assigned at no more than cost. The remaining costs are for services that are provided on behalf of more than one company, or costs that cannot be precisely identified and are allocated using formulas developed by FESC and FENOC. The current allocation or assignment formulas used and their bases include multiple factor formulas: each company's proportionate amount of FirstEnergy's aggregate direct payroll, number of employees, asset balances, revenues, number of customers, other factors and specific departmental charge ratios. Management believes that these allocation methods are reasonable. Intercompany transactions with FirstEnergy and its other subsidiaries are generally settled under commercial terms within thirty days.

In 2007 and 2006, TE sold 150 MW of its Beaver Valley Unit 2 leased capacity entitlement to CEI (\$98 million in 2007 and \$102 million in 2006). This sale agreement was terminated at the end of 2007.

4. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

FirstEnergy provides a noncontributory qualified defined benefit pension plan that covers substantially all of its employees and non-qualified pension plans that cover certain employees. The plans provide defined benefits based on years of service and compensation levels. FirstEnergy's funding policy is based on actuarial computations using the projected unit credit method. On January 2, 2007, FirstEnergy made a \$300 million voluntary cash contribution to its qualified pension plan. In December 2008, The Worker, Retiree, and Employer Recovery Act of 2008 (WRERA) was enacted. Among other provisions, the WRERA provides temporary funding relief to defined benefit plans in light of the current economic crisis. It is expected that the WRERA will have a favorable impact on the level of minimum required contributions for years after 2009. The Company estimates that additional cash contributions will not be required before 2011.

FirstEnergy 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 also 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 and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. During 2006, FirstEnergy amended the OPEB plan effective in 2008 to cap the monthly contribution for many of the retirees and their spouses receiving subsidized health care coverage. During 2008, FirstEnergy further amended the OPEB plan effective in 2010 to limit the monthly contribution for pre-1990 retirees. In addition, FirstEnergy has obligations to former or inactive employees after employment, but before retirement, for disability-related benefits.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans and earnings on plan assets. Pension and OPEB costs may also be affected by changes in key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs. FirstEnergy uses a December 31 measurement date for its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of December 31, 2008.

Obligations and Funded Status As of December 31	FirstEnergy Pension Benefits		FirstEnergy Other Benefits	
	2008	2007	2008	2007
<i>(In millions)</i>				
Change in benefit obligation				
Benefit obligation as of January 1	\$ 4,750	\$ 5,031	\$ 1,182	\$ 1,201
Service cost	87	88	19	21
Interest cost	299	294	74	69
Plan participants' contributions	-	-	25	23
Plan amendments	6	-	(20)	-
Medicare retiree drug subsidy	-	-	2	-
Actuarial (gain) loss	(152)	(381)	12	(30)
Benefits paid	(289)	(282)	(105)	(102)
Benefit obligation as of December 31	<u>\$ 4,701</u>	<u>\$ 4,750</u>	<u>\$ 1,189</u>	<u>\$ 1,182</u>
Change in fair value of plan assets				
Fair value of plan assets as of January 1	\$ 5,285	\$ 4,818	\$ 618	\$ 607
Actual return on plan assets	(1,251)	438	(152)	43
Company contribution	8	311	54	47
Plan participants' contribution	-	-	25	23
Benefits paid	(289)	(282)	(105)	(102)
Fair value of plan assets as of December 31	<u>\$ 3,753</u>	<u>\$ 5,285</u>	<u>\$ 440</u>	<u>\$ 618</u>
Qualified plan	\$ (774)	\$ 700		
Non-qualified plans	(174)	(165)		
Funded status	<u>\$ (948)</u>	<u>\$ 535</u>	\$ (749)	\$ (564)
Accumulated benefit obligation	\$ 4,367	\$ 4,397		
Amounts Recognized in the Statement of				
Financial Position				
Noncurrent assets	\$ -	\$ 700	\$ -	\$ -
Current liabilities	(8)	(7)	-	-
Noncurrent liabilities	(940)	(158)	(749)	(564)
Net asset (liability) as of December 31	<u>\$ (948)</u>	<u>\$ 535</u>	<u>\$ (749)</u>	<u>\$ (564)</u>
Amounts Recognized in				
Accumulated Other Comprehensive Income				
Prior service cost (credit)	\$ 80	\$ 83	\$ (912)	\$ (1,041)
Actuarial loss	2,182	623	801	635
Net amount recognized	<u>\$ 2,262</u>	<u>\$ 706</u>	<u>\$ (111)</u>	<u>\$ (406)</u>
Assumptions Used to Determine				
Benefit Obligations As of December 31				
Discount rate	7.00%	6.50%	7.00%	6.50%
Rate of compensation increase	5.20%	5.20%		
Allocation of Plan Assets				
As of December 31				
Asset Category				
Equity securities	47%	61%	56%	69%
Debt securities	38	30	38	27
Real estate	9	7	2	2
Private equities	3	1	1	-
Cash	3	1	3	2
Total	<u>100%</u>	<u>100%</u>	<u>100%</u>	<u>100%</u>

FES' and the Utilities' shares of the net pension and OPEB asset (liability) as of December 31, 2008 and 2007 are as follows:

Net Pension and OPEB Asset (Liability)	Pension Benefits		Other Benefits	
	2008	2007	2008	2007
<i>(In millions)</i>				
FES	\$ (193)	\$ 42	\$ (124)	\$ (102)
OE	(38)	229	(167)	(178)
CEI	(27)	62	(93)	(93)
TE	(12)	29	(59)	(63)
JCP&L	(128)	93	(58)	8
Met-Ed	(89)	51	(52)	(8)
Penelec	(64)	66	(103)	(40)



Estimated Items to be Amortized in 2009 Net Periodic Pension Cost from Accumulated Other Comprehensive Income	FirstEnergy Pension Benefits	FirstEnergy Other Benefits
	(In millions)	
Prior service cost (credit)	\$ 13	\$ (151)
Actuarial loss	\$ 170	\$ 63

Components of Net Periodic Benefit Costs	FirstEnergy Pension Benefits			FirstEnergy Other Benefits		
	2008	2007	2006	2008	2007	2006
	(In millions)					
Service cost	\$ 87	\$ 88	\$ 87	\$ 19	\$ 21	\$ 34
Interest cost	299	294	276	74	69	105
Expected return on plan assets	(463)	(449)	(396)	(51)	(50)	(46)
Amortization of prior service cost	13	13	13	(149)	(149)	(76)
Recognized net actuarial loss	8	45	62	47	45	56
Net periodic cost	<u>\$ (56)</u>	<u>\$ (9)</u>	<u>\$ 42</u>	<u>\$ (60)</u>	<u>\$ (64)</u>	<u>\$ 73</u>

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31	FirstEnergy Pension Benefits			FirstEnergy Other Benefits		
	2008	2007	2006	2008	2007	2006
Discount rate	6.50%	6.00%	5.75%	6.50%	6.00%	5.75%
Expected long-term return on plan assets	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase	5.20%	3.50%	3.50%			

FES' and the Utilities' shares of the net periodic pension and OPEB costs for the three years ended December 31, 2008 are as follows:

Net Periodic Pension and OPEB Costs	Pension Benefits			Other Benefits		
	2008	2007	2006	2008	2007	2006
	(In millions)					
FES	\$ 15	\$ 21	\$ 40	\$ (7)	\$ (10)	\$ 14
OE	(26)	(16)	(6)	(7)	(11)	17
CEI	(5)	1	4	2	4	11
TE	(3)	-	1	4	5	8
JCP&L	(15)	(9)	(5)	(16)	(16)	2
Met-Ed	(10)	(7)	(7)	(10)	(10)	3
Penelec	(13)	(10)	(5)	(13)	(13)	7

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. The assumed rates of return on pension plan assets consider historical market returns and economic forecasts for the types of investments held by FirstEnergy's pension trusts. The long-term rate of return is developed considering the portfolio's asset allocation strategy.

FirstEnergy generally employs a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return on plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, and small and large capitalization funds. Other assets such as real estate and private equity are used to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives are not used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on a continuing basis through periodic investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

Assumed Health Care Cost Trend Rates As of December 31	2008	2007
Health care cost trend rate assumed for next year (pre/post-Medicare)	8.5-10%	9-11%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5%	5%
Year that the rate reaches the ultimate trend rate (pre/post-Medicare)	2015-2017	2015-2017

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects to FirstEnergy:

	<u>1-Percentage- Point Increase</u>	<u>1-Percentage- Point Decrease</u>
	<i>(In millions)</i>	
Effect on total of service and interest cost	\$ 4	\$ (3)
Effect on accumulated postretirement benefit obligation	\$ 36	\$ (32)

Taking into account estimated employee future service, FirstEnergy expects to make the following pension benefit payments from plan assets and other benefit payments, net of the Medicare subsidy and participant contributions:

<u>Year</u>	<u>Pension Benefits</u>	<u>Other Benefits</u>
	<i>(In millions)</i>	
2009	\$ 302	\$ 85
2010	309	89
2011	314	94
2012	325	96
2013	338	99
2014- 2018	1,906	524

5. FAIR VALUE OF FINANCIAL INSTRUMENTS

(A) LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

All borrowings with initial maturities of less than one year are defined as short-term financial instruments under GAAP and are reported on the Consolidated Balance Sheets at cost, which approximates their fair market value, in the caption "short-term borrowings." The following table provides the approximate fair value and related carrying amounts of long-term debt and other long-term obligations as shown in the Consolidated Statements of Capitalization as of December 31:

	<u>2008</u>		<u>2007</u>	
	<u>Carrying Value</u>	<u>Fair Value</u>	<u>Carrying Value</u>	<u>Fair Value</u>
	<i>(In millions)</i>			
FES	\$ 2,552	\$ 2,528	\$ 1,975	\$ 1,971
OE	1,232	1,223	1,182	1,197
CEI	1,741	1,618	1,666	1,706
TE	300	244	304	283
JCP&L	1,569	1,520	1,597	1,560
Met-Ed	542	519	542	535
Penelec	779	721	779	779

The fair values of long-term debt and other long-term obligations reflect the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective year. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to those of FES and the Utilities.

(B) INVESTMENTS

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value. Investments other than cash and cash equivalents include held-to-maturity securities and available-for-sale securities. FES and the Utilities periodically evaluate their investments for other-than-temporary impairment. They first consider their intent and ability to hold the investment until recovery and then consider, among other factors, the duration and the extent to which the security's fair value has been less than cost and the near-term financial prospects of the security issuer when evaluating investments for impairment.

Available-For-Sale Securities

FES and the Utilities hold debt and equity securities within their nuclear decommissioning trusts, nuclear fuel disposal trusts and NUG trusts. These trust investments are classified as available-for-sale with the fair value representing quoted market prices. FES and the Utilities have no securities held for trading purposes.

The following table provides the fair value of investments in available-for-sale securities as of December 31, 2008 and 2007. The fair value was determined using the specific identification method.

	2008 ⁽¹⁾		2007 ⁽²⁾	
	Debt Securities	Equity Securities	Debt Securities	Equity Securities
	(In millions)			
FES	\$ 429	\$ 380	\$ 417	\$ 916
OE	95	18	45	82
TE	74	-	67	-
JCP&L	258	66	248	102
Met-Ed	115	110	115	172
Penelec	167	53	167	83

(1) Excludes cash balances of \$225 million at FES, \$12 million at Penelec, \$4 million at OE and \$1 million at Met-Ed.

(2) Excludes cash balances of \$2 million at JCP&L and \$1 million at Penelec.

The following table summarizes the amortized cost basis, unrealized gains and losses and fair values of investments in available-for-sale securities as of December 31:

	2008				2007			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(In millions)							
Debt securities								
FES	\$ 401	\$ 28	\$ -	\$ 429	\$ 402	\$ 15	\$ -	\$ 417
OE	86	9	-	95	43	2	-	45
TE	66	8	-	74	63	4	-	67
JCP&L	253	9	4	258	249	3	4	248
Met-Ed	111	4	-	115	112	3	-	115
Penelec	164	3	-	167	166	1	-	167
Equity securities								
FES	\$ 355	\$ 25	\$ -	\$ 380	\$ 631	\$ 285	\$ -	\$ 916
OE	17	1	-	18	59	23	-	82
JCP&L	64	2	-	66	89	13	-	102
Met-Ed	101	9	-	110	136	36	-	172
Penelec	51	2	-	53	80	3	-	83

Proceeds from the sale of investments in available-for-sale securities, realized gains and losses on those sales, and interest and dividend income for the three years ended December 31, 2008 were as follows:

	FES	OE	TE	JCP&L	Met-Ed	Penelec
	(In millions)					
2008						
Proceeds from sales	\$ 951	\$ 121	\$ 38	\$ 248	\$ 181	\$ 118
Realized gains	99	11	1	1	2	1
Realized losses	184	9	-	17	17	10
Interest and dividend income	37	5	3	14	9	8
2007						
Proceeds from sales	\$ 656	\$ 38	\$ 45	\$ 196	\$ 185	\$ 175
Realized gains	29	1	1	23	30	19
Realized losses	42	4	1	3	2	1
Interest and dividend income	42	4	3	13	8	10
2006						
Proceeds from sales	\$ 1,066	\$ 39	\$ 53	\$ 217	\$ 176	\$ 99
Realized gains	118	1	-	1	1	-
Realized losses	90	1	1	5	4	4
Interest and dividend income	36	3	3	13	7	7

Unrealized gains applicable to the decommissioning trusts of OE, TE and FES (except for those formerly owned by Penn) are recognized in OCI in accordance with SFAS 115, as fluctuations in fair value will eventually impact earnings. The decommissioning trusts of JCP&L, Met-Ed and Penelec are subject to regulatory accounting in accordance with SFAS 71. Net unrealized gains and losses are recorded as regulatory assets or liabilities since the difference between investments held in trust and the decommissioning liabilities will be recovered from or refunded to customers.

The investment policy for the nuclear decommissioning trust funds restricts or limits the ability to hold certain types of assets including private or direct placements, warrants, securities of FirstEnergy, investments in companies owning nuclear power plants, financial derivatives, preferred stocks, securities convertible into common stock and securities of the trust fund's custodian or managers and their parents or subsidiaries.

Held-To-Maturity Securities

The following table provides the amortized cost basis (carrying value), unrealized gains and losses and fair values of investments in held-to-maturity securities with maturity dates ranging from 2009 to 2017 excluding: restricted funds, whose carrying values are assumed to approximate market value, notes receivable, whose fair value represents the present value of the cash inflows based on the yield to maturity, and other investments of \$161 million and \$87 million in 2008 and 2007, respectively, excluded by SFAS 107, "Disclosures about Fair Values of Financial Instruments," as of December 31:

	2008				2007			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
Debt securities	<i>(In millions)</i>							
OE	\$ 240	\$ -	\$ 13	\$ 227	\$ 254	\$ 28	\$ -	\$ 282
CEI	426	9	-	435	463	68	-	531
JCP&L	1	-	-	1	1	-	-	1
Equity securities								
OE	\$ 2	\$ -	\$ -	\$ 2	\$ 2	\$ -	\$ -	\$ 2

The following table provides the approximate fair value and related carrying amounts of notes receivable as of December 31:

	2008		2007	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Notes receivable	<i>(In millions)</i>			
FES	\$ 75	\$ 74	\$ 65	\$ 63
OE	257	294	259	299
CEI	-	-	1	1
TE	180	189	192	223

The fair value of notes receivable represents the present value of the cash inflows based on the yield to maturity. The yields assumed were based on financial instruments with similar characteristics and terms. The maturity dates range from 2009 to 2040.

(C) SFAS 157 ADOPTION

Effective January 1, 2008, FES and the Utilities adopted SFAS 157, which provides a framework for measuring fair value under GAAP and, among other things, requires enhanced disclosures about assets and liabilities recognized at fair value. FES and the Utilities also adopted SFAS 159 on January 1, 2008, which provides the option to measure certain financial assets and financial liabilities at fair value. FES and the Utilities have analyzed their financial assets and financial liabilities within the scope of SFAS 159 and, as of December 31, 2008, have elected not to record eligible assets and liabilities at fair value.

As defined in SFAS 157, fair value is the price that would be received for an asset or paid to transfer a liability (exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between willing market participants on the measurement date. SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy defined by SFAS 157 are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those where transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. FES' and the Utilities' Level 1 assets and liabilities primarily consist of exchange-traded derivatives and equity securities listed on active exchanges that are held in various trusts.

Level 2 – Pricing inputs are either directly or indirectly observable in the market as of the reporting date, other than quoted prices in active markets included in Level 1. FES' and the Utilities' Level 2 assets and liabilities consist primarily of investments in debt securities held in various trusts and commodity forwards. Additionally, Level 2 includes those financial instruments that are valued using models or other valuation methodologies based on assumptions that are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Instruments in this category include non-exchange-traded derivatives such as forwards and certain interest rate swaps.

Level 3 – Pricing inputs include inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. FES and the Utilities develop their view of the future market price of key commodities through a combination of market observation and assessment (generally for the short term) and fundamental modeling (generally for the longer term). Key fundamental electricity model inputs are generally directly observable in the market or derived from publicly available historic and forecast data. Some key inputs reflect forecasts published by industry leading consultants who generally employ similar fundamental modeling approaches. Fundamental model inputs and results, as well as the selection of consultants, reflect the consensus of appropriate management. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. The Level 3 instruments of JCP&L, Met-Ed and Penelec consist of NUG contracts.

FES and the Utilities utilize market data and assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. FES and the Utilities primarily apply the market approach for recurring fair value measurements using the best information available. Accordingly, FES and the Utilities maximize the use of observable inputs and minimize the use of unobservable inputs.

The following table sets forth FES' and the Utilities' financial assets and financial liabilities that are accounted for at fair value by level within the fair value hierarchy as of December 31, 2008. As required by SFAS 157, assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. FES' and the Utilities' assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Level 1 - Assets				Level 1 - Liabilities		
	<i>(In millions)</i>				<i>(In millions)</i>		
	Derivatives	Nuclear Decommissioning Trusts ⁽¹⁾	Other Investments	Total	Derivatives	NUG Contracts ⁽²⁾	Total
FES	\$ -	\$ 290	\$ -	\$ 290	\$ 25	\$ -	\$ 25
OE	-	18	-	18	-	-	-
JCP&L	-	67	-	67	-	-	-
Met-Ed	-	104	-	104	-	-	-
Penelec	-	58	-	58	-	-	-

	Level 2 - Assets				Level 2 - Liabilities		
	<i>(In millions)</i>				<i>(In millions)</i>		
	Derivatives	Nuclear Decommissioning Trusts ⁽¹⁾	Other Investments	Total	Derivatives	NUG Contracts ⁽²⁾	Total
FES	\$ 12	\$ 744	\$ -	\$ 756	\$ 28	\$ -	\$ 28
OE	-	98	-	98	-	-	-
TE	-	73	-	73	-	-	-
JCP&L	7	74	181	262	-	-	-
Met-Ed	14	121	-	135	-	-	-
Penelec	7	57	117	181	-	-	-

	Level 3 - Assets				Level 3 - Liabilities		
	<i>(In millions)</i>				<i>(In millions)</i>		
	Derivatives	Nuclear Decommissioning Trusts ⁽¹⁾	NUG Contracts ⁽²⁾	Total	Derivatives	NUG Contracts ⁽²⁾	Total
JCP&L	\$ -	\$ -	\$ 14	\$ 14	\$ -	\$ 532	\$ 532
Met-Ed	-	-	300	300	-	150	150
Penelec	-	-	120	120	-	84	84

(1) Balance excludes \$4 million of net receivables, payables and accrued income.

(2) NUG contract assets and liabilities are subject to regulatory accounting.

The determination of the above fair value measures takes into consideration various factors required under SFAS 157. These factors include nonperformance risk, including counterparty credit risk and the impact of credit enhancements (such as cash deposits, LOCs and priority interests). The impact of nonperformance risk was immaterial in the fair value measurements.

Exchange-traded derivative contracts, which include some futures and options, are generally based on unadjusted quoted market prices in active markets and are classified within Level 1. Forwards, options and swap contracts that are not exchange-traded are classified as Level 2 as the fair values of these items are based on Intercontinental Exchange quotes or market transactions in the OTC markets. In addition, complex or longer-term structured transactions can introduce the need for internally-developed model inputs that may not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is classified as Level 3.

Nuclear decommissioning trusts consist of equity securities listed on active exchanges classified as Level 1 and various debt securities and collective trusts classified as Level 2. Other investments represent the NUG trusts, spent nuclear fuel trusts and rabbi trust investments, which primarily consist of various debt securities and collective trusts classified as Level 2.

The following tables provide a reconciliation of changes in the fair value of NUG contracts classified as Level 3 in the fair value hierarchy during 2008 (in millions):

	<u>JCP&L</u>	<u>Met-Ed</u>	<u>Penelec</u>
Balance as of January 1, 2008	\$ (750)	\$ (28)	\$ (25)
Settlements ⁽¹⁾	232	34	12
Unrealized gains (losses) ⁽¹⁾	-	144	49
Net transfers to (from) Level 3	-	-	-
Balance as of December 31, 2008	<u>\$ (518)</u>	<u>\$ 150</u>	<u>\$ 36</u>
Change in unrealized gains (losses) relating to instruments held as of December 31, 2008	<u>\$ -</u>	<u>\$ 144</u>	<u>\$ 49</u>

⁽¹⁾ Changes in the fair value of NUG contracts are completely offset by regulatory assets and do not impact earnings

Under FSP FAS 157-2, "Effective Date of FASB Statement No. 157", FES and the Utilities deferred until January 1, 2009, the election of SFAS 157 for financial assets and financial liabilities measured at fair value on a non-recurring basis and are currently evaluating the impact of SFAS 157 on those financial assets and financial liabilities.

(D) DERIVATIVES

FES and the Utilities are 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, they use a variety of 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 for risk management activities throughout FES and the Utilities. 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.

FES and the Utilities account for derivative instruments on their Consolidated Balance Sheets at fair value unless they meet the normal purchase and normal sales criteria. Derivatives that meet that criteria are accounted for using traditional accrual accounting. The changes in the fair value of derivative instruments that do not meet the normal purchase and normal sales criteria are recorded as other expense, as 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.

FES hedges anticipated transactions using cash flow hedges. Such transactions include hedges of anticipated electricity and natural gas purchases. FES' maximum hedge terms are typically two years. 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. Gains and losses from any ineffective portion of cash flow hedges are included directly in earnings. The ineffective portion of cash flow hedges was immaterial during 2008.

FES' net deferred losses of \$25 million included in AOCL as of December 31, 2008, for derivative hedging activity, as compared to \$16 million as of December 31, 2007, resulted from a net \$11 million increase related to current hedging activity and a \$2 million decrease due to net hedge losses reclassified to earnings during 2008. Based on current estimates, approximately \$20 million (after tax) of the net deferred losses on derivative instruments in AOCL as of December 31, 2008 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.

6. LEASES

FES and the Utilities lease certain generating facilities, office space and other property and equipment under cancelable and noncancelable leases.

In 1987, OE sold portions of its ownership interests in Perry Unit 1 and Beaver Valley Unit 2 and entered into operating leases on the portions sold for basic lease terms of approximately 29 years. In that same year, CEI and TE also sold portions of their ownership interests in Beaver Valley Unit 2 and Bruce Mansfield Units 1, 2 and 3 and entered into similar operating leases for lease terms of approximately 30 years. During the terms of their respective leases, OE, CEI and TE are responsible, to the extent of their leasehold interests, for costs associated with the units including construction expenditures, operation and maintenance expenses, insurance, nuclear fuel, property taxes and decommissioning. They have the right, at the expiration of the respective basic lease terms, to renew their respective leases. They also have the right to purchase the facilities at the expiration of the basic lease term or any renewal term at a price equal to the fair market value of the facilities. The basic rental payments are adjusted when applicable federal tax law changes.

On July 13, 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1, representing 779 MW of net demonstrated capacity. The purchase price of approximately \$1.329 billion (net after-tax proceeds of approximately \$1.2 billion) for the undivided interest was funded through a combination of equity investments by affiliates of AIG Financial Products Corp. and Union Bank of California, N.A. in six lessor trusts and proceeds from the sale of \$1.135 billion aggregate principal amount of 6.85% pass through certificates due 2034. A like principal amount of secured notes maturing June 1, 2034 were issued by the lessor trusts to the pass through trust that issued and sold the certificates. The lessor trusts leased the undivided interest back to FGCO for a term of approximately 33 years under substantially identical leases. FES has unconditionally and irrevocably guaranteed all of FGCO's obligations under each of the leases. This transaction is classified as an operating lease under GAAP for FES and FirstEnergy.

Effective October 16, 2007 CEI and TE assigned their leasehold interests in the Bruce Mansfield Plant to FGCO and FGCO assumed all of CEI's and TE's obligations arising under those leases. FGCO subsequently transferred the Unit 1 portion of these leasehold interests, as well as FGCO's leasehold interests under its July 13, 2007 Bruce Mansfield Unit 1 sale and leaseback transaction, to a newly formed wholly-owned subsidiary on December 17, 2007. The subsidiary assumed all of the lessee obligations associated with the assigned interests. However, CEI and TE remain primarily liable on the 1987 leases and related agreements. FGCO remains primarily liable on the 2007 leases and related agreements, and FES remains primarily liable as a guarantor under the related 2007 guarantees, as to the lessors and other parties to the respective agreements. These assignments terminate automatically upon the termination of the underlying leases.

During the second quarter of 2008, NGC purchased 56.8 MW of lessor equity interests in the OE 1987 sale and leaseback of the Perry Plant and approximately 43.5 MW of lessor equity interests in the OE 1987 sale and leaseback of Beaver Valley Unit 2. In addition, NGC purchased 158.5 MW of lessor equity interests in the TE and CEI 1987 sale and leaseback of Beaver Valley Unit 2. The Ohio Companies continue to lease these MW under their respective sale and leaseback arrangements and the related lease debt remains outstanding.

The rentals for capital and operating leases are charged to operating expenses on the Consolidated Statements of Income. Such costs for the three years ended December 31, 2008 are summarized as follows:

	<u>FES</u>	<u>OE</u>	<u>CEI</u>	<u>TE</u>	<u>JCP&L</u>	<u>Met-Ed</u>	<u>Penelec</u>
	<i>(In millions)</i>						
2008							
Operating leases							
Interest element	\$ 110	\$ 77	\$ 1	\$ 23	\$ 3	\$ 2	\$ 1
Other	63	69	4	42	5	2	3
Capital leases							
Interest element	1	-	-	-	-	-	-
Other ⁽¹⁾	8	-	1	-	-	-	-
Total rentals	<u>\$ 182</u>	<u>\$ 146</u>	<u>\$ 6</u>	<u>\$ 65</u>	<u>\$ 8</u>	<u>\$ 4</u>	<u>\$ 4</u>
2007							
Operating leases							
Interest element	\$ 30	\$ 83	\$ 24	\$ 38	\$ 3	\$ 2	\$ 1
Other	15	62	38	63	5	2	4
Capital leases							
Interest element	-	-	-	-	-	-	-
Other	-	-	1	-	-	-	-
Total rentals	<u>\$ 45</u>	<u>\$ 145</u>	<u>\$ 63</u>	<u>\$ 101</u>	<u>\$ 8</u>	<u>\$ 4</u>	<u>\$ 5</u>
2006							
Operating leases							
Interest element	\$ -	\$ 87	\$ 26	\$ 41	\$ 3	\$ 2	\$ 1
Other	-	58	48	68	4	1	3
Capital leases							
Interest element	-	-	-	-	-	-	-
Other	-	1	1	-	-	-	-
Total rentals	<u>\$ -</u>	<u>\$ 146</u>	<u>\$ 75</u>	<u>\$ 109</u>	<u>\$ 7</u>	<u>\$ 3</u>	<u>\$ 4</u>

⁽¹⁾ Includes \$5 million in 2008 of wind purchased power agreements classified as capital leases in accordance with EITF 01-8.

Established by OE in 1996, PNBV purchased a portion of the lease obligation bonds issued on behalf of lessors in OE's Perry Unit 1 and Beaver Valley Unit 2 sale and leaseback transactions. Similarly, CEI and TE established Shippingport in 1997 to purchase the lease obligation bonds issued on behalf of lessors in their Bruce Mansfield Units 1, 2 and 3 sale and leaseback transactions. The PNBV and Shippingport arrangements effectively reduce lease costs related to those transactions (see Note 7).

The future minimum capital lease payments as of December 31, 2008 are as follows:

<u>Capital Leases</u>	<u>FES</u>	<u>OE</u>	<u>CEI</u>
	<i>(In millions)</i>		
2009	\$ 6	\$ 1	\$ 1
2010	6	-	1
2011	6	1	1
2012	5	-	1
2013	5	1	1
Years thereafter	24	5	5
Total minimum lease payments	<u>52</u>	<u>8</u>	<u>10</u>
Executory costs	-	-	-
Net minimum lease payments	<u>52</u>	<u>8</u>	<u>10</u>
Interest portion	<u>8</u>	<u>3</u>	<u>7</u>
Present value of net minimum lease payments	44	5	3
Less current portion	5	1	1
Noncurrent portion	<u>\$ 39</u>	<u>\$ 4</u>	<u>\$ 2</u>

The future minimum operating lease payments as of December 31, 2008 are as follows:

<u>Operating Leases</u>	<u>FES</u>	<u>OE</u>	<u>CEI</u>	<u>TE</u>	<u>JCP&L</u>	<u>Met-Ed</u>	<u>Penelec</u>
	<i>(In millions)</i>						
2009	\$ 176	\$ 145	\$ 4	\$ 64	\$ 8	\$ 4	\$ 5
2010	177	141	-	62	4	2	1
2011	172	141	-	62	4	2	1
2012	215	141	-	62	4	2	1
2013	224	142	-	62	3	2	-
Years thereafter	2,320	441	-	203	50	34	1
Total minimum lease payments	<u>\$ 3,284</u>	<u>\$ 1,151</u>	<u>\$ 4</u>	<u>\$ 515</u>	<u>\$ 73</u>	<u>\$ 46</u>	<u>\$ 9</u>

FirstEnergy has been notified by the lessor of certain vehicle and equipment leases of its election to terminate the lease arrangements effective November 2009. FirstEnergy is currently pursuing replacement lease arrangements with alternative lessors. In the event that replacement lease arrangements are not secured, FES and the Utilities would be required to purchase the vehicles and equipment under lease at their aggregate unamortized value of approximately \$100 million upon termination of the leases.

CEI and TE had recorded above-market lease liabilities for Beaver Valley Unit 2 and the Bruce Mansfield Plant associated with the 1997 merger between OE and Centerior. The unamortized above-market lease liability for Beaver Valley Unit 2 of \$310 million as of December 31, 2008, of which \$37 million is classified as current, is being amortized by TE on straight-line basis through the end of the lease term in 2017. Effective October 16, 2007, CEI and TE assigned their leasehold interests in the Bruce Mansfield Plant to FGCO. The unamortized above-market lease liability for the Bruce Mansfield Plant of \$353 million as of December 31, 2008, of which \$46 million is classified as current, is being amortized by FGCO on straight-line basis through the end of the lease term in 2016.

7. 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. FES and the Utilities consolidate VIEs when they are determined to be the VIE's primary beneficiary as defined by FIN 46R.

Trusts

PNBV and Shippingport were 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.

Loss Contingencies

FES and the Ohio Companies are exposed to losses under their applicable sale-leaseback agreements upon the occurrence of certain contingent events that each company considers unlikely to occur. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events that render the applicable plant worthless. Net discounted lease payments would not be payable if the casualty loss payments are made. The following table shows each company's net exposure to loss based upon the casualty value provisions mentioned above:

	<u>Maximum Exposure</u>	<u>Discounted Lease Payments, net</u>	<u>Net Exposure</u>
	<i>(in millions)</i>		
FES	\$ 1,349	\$ 1,182	\$ 167
OE	778	574	204
CEI	713	81	632
TE	713	419	294

See Note 6 for a discussion of CEI's and TE's assignment of their leasehold interests in the Bruce Mansfield Plant to FGCO.

Power Purchase Agreements

In accordance with FIN 46R, FES and the Utilities evaluated their 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 FES and the Utilities and the contract price for power is correlated with the plant's variable costs of production. JCP&L, Met-Ed and Penelec maintain 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. JCP&L, Met-Ed, and Penelec were not involved in the creation of, and have no equity or debt invested in, these entities.

Management 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, management 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. Management has been unable to obtain the requested information, which in most cases was deemed by the requested entity to be proprietary. As such, JCP&L, Met-Ed and Penelec applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities under FIN 46R.

Since JCP&L, Met-Ed and Penelec have 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. JCP&L, Met-Ed and Penelec expect any above-market costs they incur to be recovered from customers. Purchased power costs from these entities during the three years ended December 31, 2008 are shown in the following table:

	<u>2008</u>	<u>2007</u>	<u>2006</u>
		<i>(In millions)</i>	
JCP&L	\$ 84	\$ 90	\$ 81
Met-Ed	61	56	60
Penelec	33	30	29

8. TAXES

Income Taxes

FES and the Utilities record income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and loss carryforwards and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to temporary tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled. Details of income taxes for the three years ended December 31, 2008 are shown below:

PROVISION FOR INCOME TAXES	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
				<i>(In millions)</i>			
2008							
Currently payable-							
Federal	\$ 156	\$ 79	\$ 119	\$ 46	\$ 101	\$ 5	\$ (34)
State	20	4	6	-	34	6	(3)
	<u>176</u>	<u>83</u>	<u>125</u>	<u>46</u>	<u>135</u>	<u>11</u>	<u>(37)</u>
Deferred, net-							
Federal	109	22	16	(12)	9	47	84
State	12	(2)	(2)	(4)	4	4	12
	<u>121</u>	<u>20</u>	<u>14</u>	<u>(16)</u>	<u>13</u>	<u>51</u>	<u>96</u>
Investment tax credit amortization	(4)	(4)	(2)	-	-	(1)	(1)
Total provision for income taxes	<u>\$ 293</u>	<u>\$ 99</u>	<u>\$ 137</u>	<u>\$ 30</u>	<u>\$ 148</u>	<u>\$ 61</u>	<u>\$ 58</u>
2007							
Currently payable-							
Federal	\$ 528	\$ 105	\$ 166	\$ 73	\$ 138	\$ 26	\$ 41
State	111	(4)	20	7	42	7	12
	<u>639</u>	<u>101</u>	<u>186</u>	<u>80</u>	<u>180</u>	<u>33</u>	<u>53</u>
Deferred, net-							
Federal	(288)	-	(23)	(27)	(25)	30	10
State	(42)	4	2	2	(5)	6	1
	<u>(330)</u>	<u>4</u>	<u>(21)</u>	<u>(25)</u>	<u>(30)</u>	<u>36</u>	<u>11</u>
Investment tax credit amortization	(4)	(4)	(2)	(1)	(1)	(1)	-
Total provision for income taxes	<u>\$ 305</u>	<u>\$ 101</u>	<u>\$ 163</u>	<u>\$ 54</u>	<u>\$ 149</u>	<u>\$ 68</u>	<u>\$ 64</u>
2006							
Currently payable-							
Federal	\$ 102	\$ 162	\$ 174	\$ 83	\$ 79	\$ 21	\$ 21
State	18	30	32	14	24	6	7
	<u>120</u>	<u>192</u>	<u>206</u>	<u>97</u>	<u>103</u>	<u>27</u>	<u>28</u>
Deferred, net-							
Federal	110	(58)	(14)	(35)	34	40	26
State	11	(7)	1	(1)	11	11	3
	<u>121</u>	<u>(65)</u>	<u>(13)</u>	<u>(36)</u>	<u>45</u>	<u>51</u>	<u>29</u>
Investment tax credit amortization	(5)	(4)	(4)	(1)	(1)	(1)	-
Total provision for income taxes	<u>\$ 236</u>	<u>\$ 123</u>	<u>\$ 189</u>	<u>\$ 60</u>	<u>\$ 147</u>	<u>\$ 77</u>	<u>\$ 57</u>

FES and the Utilities are party to an intercompany income tax allocation agreement with FirstEnergy and its other subsidiaries that provides for the allocation of consolidated tax liabilities. Net tax benefits attributable to FirstEnergy, excluding any tax benefits derived from interest expense associated with acquisition indebtedness from the merger with GPU, is reallocated to the subsidiaries of FirstEnergy that have taxable income. That allocation is accounted for as a capital contribution to the company receiving the tax benefit.

The following tables provide a reconciliation of federal income tax expense at the federal statutory rate to the total provision for income taxes for the three years ended December 31, 2008.

	<u>FES</u>	<u>OE</u>	<u>CEI</u>	<u>TE</u>	<u>JCP&L</u>	<u>Met-Ed</u>	<u>Penelec</u>
	<i>(In millions)</i>						
2008							
Book income before provision for income taxes	\$ 800	\$ 310	\$ 421	\$ 105	\$ 335	\$ 149	\$ 146
Federal income tax expense at statutory rate	\$ 280	\$ 109	\$ 147	\$ 37	\$ 117	\$ 52	\$ 51
Increases (reductions) in taxes resulting from-							
Amortization of investment tax credits	(4)	(4)	(2)	-	-	(1)	(1)
State income taxes, net of federal tax benefit	21	1	2	(2)	25	7	5
Manufacturing deduction	(15)	(3)	(8)	(2)	-	-	-
Other, net	11	(4)	(2)	(3)	6	3	3
Total provision for income taxes	<u>\$ 293</u>	<u>\$ 99</u>	<u>\$ 137</u>	<u>\$ 30</u>	<u>\$ 148</u>	<u>\$ 61</u>	<u>\$ 58</u>
2007							
Book income before provision for income taxes	\$ 833	\$ 298	\$ 440	\$ 145	\$ 335	\$ 164	\$ 157
Federal income tax expense at statutory rate	\$ 292	\$ 104	\$ 154	\$ 51	\$ 117	\$ 57	\$ 55
Increases (reductions) in taxes resulting from-							
Amortization of investment tax credits	(4)	(4)	(2)	(1)	(1)	(1)	-
State income taxes, net of federal tax benefit	45	-	14	6	24	9	8
Manufacturing deduction	(6)	(2)	(1)	-	-	-	-
Other, net	(22)	3	(2)	(2)	9	3	1
Total provision for income taxes	<u>\$ 305</u>	<u>\$ 101</u>	<u>\$ 163</u>	<u>\$ 54</u>	<u>\$ 149</u>	<u>\$ 68</u>	<u>\$ 64</u>
2006							
Book income before provision for income taxes	\$ 655	\$ 335	\$ 495	\$ 159	\$ 337	\$ (163)	\$ 141
Federal income tax expense at statutory rate	\$ 229	\$ 117	\$ 173	\$ 56	\$ 118	\$ (57)	\$ 49
Increases (reductions) in taxes resulting from-							
Amortization of investment tax credits	(5)	(4)	(4)	(1)	(1)	(1)	-
State income taxes, net of federal tax benefit	18	15	22	8	23	11	6
Goodwill impairment	-	-	-	-	-	124	-
Other, net	(6)	(5)	(2)	(3)	7	-	2
Total provision for income taxes	<u>\$ 236</u>	<u>\$ 123</u>	<u>\$ 189</u>	<u>\$ 60</u>	<u>\$ 147</u>	<u>\$ 77</u>	<u>\$ 57</u>

Accumulated deferred income taxes as of December 31, 2008 and 2007 are as follows:

	<u>FES</u>	<u>OE</u>	<u>CEI</u>	<u>TE</u>	<u>JCP&L</u>	<u>Met-Ed</u>	<u>Penelec</u>
	<i>(In millions)</i>						
AS OF DECEMBER 31, 2008							
Property basis differences	\$ 434	\$ 494	\$ 428	\$ 172	\$ 436	\$ 275	\$ 329
Regulatory transition charge	-	40	29	4	190	29	-
Customer receivables for future income taxes	-	22	1	-	24	49	48
Deferred customer shopping incentive	-	-	151	-	-	-	-
Deferred MISO/PJM transmission costs	-	11	7	7	-	137	4
Other regulatory assets - RCP	-	121	100	32	-	-	-
Deferred sale and leaseback gain	(438)	(45)	-	-	(10)	(12)	-
Nonutility generation costs	-	-	-	-	-	30	(82)
Unamortized investment tax credits	(23)	(5)	(5)	(2)	(2)	(6)	(5)
Unrealized losses on derivative hedges	(15)	-	-	-	(1)	(1)	-
Pension and other postretirement obligations	(68)	(94)	(47)	(25)	(90)	(72)	(89)
Lease market valuation liability	(124)	-	-	(122)	-	-	-
Oyster Creek securitization (Note 10(C))	-	-	-	-	137	-	-
Nuclear decommissioning activities	14	2	-	13	(34)	(65)	(55)
Deferred gain for asset sales - affiliated companies	-	41	27	9	-	-	-
Allowance for equity funds used during construction	-	20	1	-	-	-	-
All other	(48)	46	12	(9)	39	24	20
Net deferred income tax liability (asset)	<u>\$ (268)</u>	<u>\$ 653</u>	<u>\$ 704</u>	<u>\$ 79</u>	<u>\$ 689</u>	<u>\$ 388</u>	<u>\$ 170</u>
AS OF DECEMBER 31, 2007							
Property basis differences	\$ 275	\$ 484	\$ 404	\$ 173	\$ 439	\$ 266	\$ 319
Regulatory transition charge	-	70	77	26	235	60	-
Customer receivables for future income taxes	-	22	1	-	14	49	62
Deferred customer shopping incentive	-	34	142	13	-	-	-
Deferred MISO/PJM transmission costs	-	20	12	9	-	97	13
Other regulatory assets - RCP	-	92	71	30	-	-	-
Deferred sale and leaseback gain	(455)	(49)	-	-	(20)	(11)	-
Nonutility generation costs	-	-	-	-	-	22	(112)
Unamortized investment tax credits	(23)	(6)	(7)	(4)	(2)	(6)	(5)
Unrealized losses on derivative hedges	(10)	-	-	-	(1)	(1)	-
Pension and other postretirement obligations	(21)	8	(15)	(17)	20	1	(18)
Lease market valuation liability	(148)	-	-	(135)	-	-	-
Oyster Creek securitization (Note 10(C))	-	-	-	-	149	-	-
Nuclear decommissioning activities	142	7	-	11	(48)	(57)	(65)
Deferred gain for asset sales - affiliated companies	-	45	30	10	-	-	-
Allowance for equity funds used during construction	-	21	-	-	-	-	-
All other	(37)	33	11	(13)	14	19	17
Net deferred income tax liability (asset)	<u>\$ (277)</u>	<u>\$ 781</u>	<u>\$ 726</u>	<u>\$ 103</u>	<u>\$ 800</u>	<u>\$ 439</u>	<u>\$ 211</u>

On January 1, 2007, FES and the Utilities adopted FIN 48, which provides guidance for accounting for uncertainty in income taxes in a company's financial statements in accordance with SFAS 109. This interpretation prescribes a financial statement recognition threshold and measurement attribute for tax positions taken or expected to be taken on a company's tax return. FIN 48 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 is a two-step process. The first step is to determine if it is more likely than not that a tax position will be sustained upon examination, based on the merits of the position, and should therefore be recognized. The second step is to measure a tax position that meets the more likely than not recognition threshold to determine the amount of income tax benefit to recognize in the financial statements.

As of January 1, 2007, the total amount of unrecognized tax benefits for FES and the Utilities was \$59 million (see table below for amounts included for FES and the Utilities) and recorded a cumulative effect adjustment (OE - \$0.6 million, CEI - \$0.2 million and FES - \$0.5 million) to the January 1, 2007 balance of retained earnings to increase reserves for uncertain tax positions.

A reconciliation of the change in the unrecognized tax benefits for the years 2008 and 2007 are as follows:

	<u>FES</u>	<u>OE</u>	<u>CEI</u>	<u>TE</u>	<u>JCP&L</u>	<u>Met-Ed</u>	<u>Penelec</u>
	<i>(In millions)</i>						
Balance as of January 1, 2008	\$ 14	\$ (12)	\$ (17)	\$ (1)	\$ 38	\$ 24	\$ 16
Increase for tax positions related to the current year	-	1	-	-	-	-	-
Increase for tax positions related to prior years	1	1	-	-	6	5	9
Decrease for tax positions of prior years	(10)	(14)	(8)	(3)	(2)	(1)	(1)
Decrease for settlement	-	(6)	(1)	-	-	-	-
Balance as of December 31, 2008	<u>\$ 5</u>	<u>\$ (30)</u>	<u>\$ (26)</u>	<u>\$ (4)</u>	<u>\$ 42</u>	<u>\$ 28</u>	<u>\$ 24</u>

	<u>FES</u>	<u>OE</u>	<u>CEI</u>	<u>TE</u>	<u>JCP&L</u>	<u>Met-Ed</u>	<u>Penelec</u>
	<i>(In millions)</i>						
Balance as of January 1, 2007	\$ 14	\$ (19)	\$ (15)	\$ (3)	\$ 44	\$ 18	\$ 20
Increase for tax positions related to the current year	-	1	-	-	-	-	-
Increase for tax positions related to prior years	4	10	2	2	-	6	-
Decrease for tax positions of prior years	(4)	(4)	(4)	-	(6)	-	(4)
Balance as of December 31, 2007	<u>\$ 14</u>	<u>\$ (12)</u>	<u>\$ (17)</u>	<u>\$ (1)</u>	<u>\$ 38</u>	<u>\$ 24</u>	<u>\$ 16</u>

As of December 31, 2008, FES and the Utilities expect that \$44 million of the unrecognized benefits will be resolved within the next twelve months and are included in the captions "Prepayments and other" and "Accrued taxes," with the remaining amount included in "Other non-current liabilities" on the Consolidated Balance Sheets as follows:

<u>Balance Sheet Classifications</u>	<u>FES</u>	<u>OE</u>	<u>CEI</u>	<u>TE</u>	<u>JCP&L</u>	<u>Met-Ed</u>	<u>Penelec</u>
	<i>(In millions)</i>						
Current-							
Prepayments and other	\$ -	\$ (52)	\$ (33)	\$ (9)	\$ -	\$ -	\$ -
Accrued taxes	-	-	-	-	26	13	11
Non-Current-							
Other non-current liabilities	5	22	7	5	16	15	13
Net liabilities (assets)	<u>\$ 5</u>	<u>\$ (30)</u>	<u>\$ (26)</u>	<u>\$ (4)</u>	<u>\$ 42</u>	<u>\$ 28</u>	<u>\$ 24</u>

FIN 48 also requires companies to recognize interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized in accordance with FIN 48 and the amount previously taken or expected to be taken on the tax return. FES and the Utilities include net interest and penalties in the provision for income taxes, consistent with their policy prior to implementing FIN 48.

The following table summarizes the net interest expense (income) recognized by FES and the Utilities for the three years ended December 31, 2008 and the cumulative net interest payable (receivable) as of December 31, 2008 and 2007:

	<u>Net Interest Expense (Income)</u>			<u>Net Interest Payable (Receivable)</u>	
	<u>For the Years Ended</u>			<u>As of December 31,</u>	
	<u>December 31,</u>			<u>2008</u>	<u>2007</u>
	<u>2008</u>	<u>2007</u>	<u>2006</u>	<u>(In millions)</u>	
FES	\$ -	\$ -	\$ 1	\$ 1	\$ 2
OE	(4)	1	1	(9)	(5)
CEI	(2)	(1)	1	(7)	(3)
TE	-	-	1	(1)	-
JCP&L	1	1	(2)	11	10
Met-Ed	1	2	-	6	5
Penelec	2	-	(1)	6	4

FES and the Utilities have tax returns that are under review at the audit or appeals level by the IRS and state tax authorities. All state jurisdictions are open from 2001-2008. The IRS began reviewing returns for the years 2001-2003 in July 2004 and several items are under appeal. The federal audit for years 2004-2006 were completed in the third quarter of 2008 and several items are under appeals. The IRS began auditing the year 2007 in February 2007 and the year 2008 in February 2008 under its Compliance Assurance Process program. Both audits are expected to close before December 2009. Management believes that adequate reserves have been recognized and final settlement of these audits is not expected to have a material adverse effect on FES' or the Utilities' financial condition or results of operations.

On July 13, 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1, representing 779 MW of net demonstrated capacity (see Note 6). This transaction generated tax capital gains of approximately \$815 million, all of which were offset by existing tax capital loss carryforwards. Accordingly, FirstEnergy reduced its tax loss carryforward valuation allowance in the third quarter of 2007, with a corresponding reduction to goodwill (see Note 2(E)).

FES and Penelec have pre-tax net operating loss carryforwards for state and local income tax purposes. These losses expire as follows:

Expiration Period	FES	Penelec
	<i>(In millions)</i>	
2009-2013	\$ 2	\$ -
2014-2018	1	-
2019-2023	27	216
2024-2028	38	17
	\$ 68	\$ 233

General Taxes

Details of general taxes for the three years ended December 31, 2008 are shown below:

	FES	OE	CEI	TE	JCP&L	Met-Ed	Penelec
	<i>(In millions)</i>						
2008							
Kilowatt-hour excise	\$ 1	\$ 97	\$ 70	\$ 30	\$ 51	\$ -	\$ -
State gross receipts	16	17	-	-	-	79	70
Real and personal property	53	61	67	19	5	3	2
Social security and unemployment	14	9	6	3	10	5	6
Other	4	2	-	-	1	(1)	2
Total general taxes	\$ 88	\$ 186	\$ 143	\$ 52	\$ 67	\$ 86	\$ 80

2007							
Kilowatt-hour excise	\$ 1	\$ 99	\$ 69	\$ 29	\$ 52	\$ -	\$ -
State gross receipts	18	17	-	-	-	73	66
Real and personal property	53	59	65	19	5	2	2
Social security and unemployment	14	8	6	3	9	5	5
Other	1	(2)	2	-	-	-	3
Total general taxes	\$ 87	\$ 181	\$ 142	\$ 51	\$ 66	\$ 80	\$ 76

2006							
Kilowatt-hour excise	\$ -	\$ 95	\$ 68	\$ 28	\$ 50	\$ -	\$ -
State gross receipts	10	19	-	-	-	67	62
Real and personal property	49	55	61	20	5	2	1
Social security and unemployment	13	7	5	2	9	4	5
Other	1	4	1	1	-	4	5
Total general taxes	\$ 73	\$ 180	\$ 135	\$ 51	\$ 64	\$ 77	\$ 73

Commercial Activity Tax

On June 30, 2005, tax legislation was enacted in the State of Ohio that created a new CAT tax, which is based on qualifying "taxable gross receipts" and does not consider any expenses or costs incurred to generate such receipts, except for items such as cash discounts, returns and allowances, and bad debts. The CAT tax was effective July 1, 2005, and replaced the Ohio income-based franchise tax and the Ohio personal property tax. The CAT tax is phased-in while the current income-based franchise tax is phased-out over a five-year period at a rate of 20% annually, beginning with the year ended 2005, and the personal property tax is phased-out over a four-year period at a rate of approximately 25% annually, beginning with the year ended 2005. During the phase-out period the Ohio income-based franchise tax was computed consistent with the prior tax law, except that the tax liability as computed was multiplied by 80% in 2005; 60% in 2006; 40% in 2007 and 20% in 2008, therefore eliminating the current income-based franchise tax over a five-year period. As a result of the new tax structure, all net deferred tax benefits that were not expected to reverse during the five-year phase-in period were written-off as of June 30, 2005.

9. REGULATORY MATTERS

(A) 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 (the PUCO, the FERC, the NERC and the U.S. – Canada Power System Outage Task Force) regarding enhancements to regional reliability. The proposed enhancements were divided into two groups: enhancements that were to be completed in 2004; and enhancements that were to be completed after 2004. In 2004, FirstEnergy completed all of the enhancements that were recommended for completion in 2004. 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 that could require additional material expenditures.

In 2005, Congress amended the Federal Power Act to provide for federally-enforceable mandatory reliability standards. The mandatory reliability standards apply to the bulk power system and impose certain operating, record-keeping and reporting requirements on the Utilities and ATSI. The NERC is charged with establishing and enforcing these reliability standards, although it has delegated day-to-day implementation and enforcement of its responsibilities to eight regional entities, including Reliability *First* Corporation. All of FirstEnergy's facilities are located within the Reliability *First* region. FirstEnergy actively participates in the NERC and Reliability *First* stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, it is clear that the NERC, Reliability *First* and the FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. The financial impact of complying with new or amended standards cannot be determined at this time. However, the 2005 amendments to the Federal Power Act provide that all prudent costs incurred to comply with the new reliability standards be recovered in rates. Still, any future inability on FirstEnergy's part to comply with the reliability standards for its bulk power system could result in the imposition of financial penalties and thus have a material adverse effect on its financial condition, results of operations and cash flows.

In April 2007, Reliability *yFirst* performed a routine compliance audit of FirstEnergy's bulk-power system within the Midwest ISO region and found it to be in full compliance with all audited reliability standards. Similarly, in October 2008, Reliability *First* performed a routine compliance audit of FirstEnergy's bulk-power system within the PJM region and a final report is expected in early 2009. FES and the Utilities currently do not expect any material adverse financial impact as a result of these audits.

(B) OHIO

On January 4, 2006, the PUCO issued an order authorizing the Ohio Companies to recover certain increased fuel costs through a fuel rider and to defer certain other increased fuel costs to be incurred from January 1, 2006 through December 31, 2008, including interest on the deferred balances. The order also provided for recovery of the deferred costs over a twenty-five-year period through distribution rates. On August 29, 2007, the Supreme Court of Ohio concluded that the PUCO violated a provision of the Ohio Revised Code by permitting the Ohio Companies "to collect deferred increased fuel costs through future distribution rate cases, or to alternatively use excess fuel-cost recovery to reduce deferred distribution-related expenses" and remanded the matter to the PUCO for further consideration. On September 10, 2007, the Ohio Companies filed an application with the PUCO that requested the implementation of two generation-related fuel cost riders to collect the increased fuel costs that were previously authorized to be deferred. On January 9, 2008, the PUCO approved the Ohio Companies' proposed fuel cost rider to recover increased fuel costs incurred during 2008, which was approximately \$185 million. In addition, the PUCO ordered the Ohio Companies to file a separate application for an alternate recovery mechanism to collect the 2006 and 2007 deferred fuel costs. On February 8, 2008, the Ohio Companies filed an application proposing to recover \$226 million of deferred fuel costs and carrying charges for 2006 and 2007 pursuant to a separate fuel rider. Recovery of the deferred fuel costs was also addressed in the Ohio Companies' comprehensive ESP filing, which was subsequently withdrawn on December 22, 2008, and also as a part of the stipulation and recommendation which was attached to the amended application for an ESP, both as described below.

On June 7, 2007, the Ohio Companies filed an application for an increase in electric distribution rates with the PUCO and, on August 6, 2007, updated their filing to support a distribution rate increase of \$332 million. On December 4, 2007, the PUCO Staff issued its Staff Reports containing the results of its investigation into the distribution rate request. In its reports, the PUCO Staff recommended a distribution rate increase in the range of \$161 million to \$180 million, with \$108 million to \$127 million for distribution revenue increases and \$53 million for recovery of costs deferred under prior cases. During the evidentiary hearings and filing of briefs, the PUCO Staff decreased their recommended revenue increase to a range of \$117 million to \$135 million. On January 21, 2009, the PUCO granted the Ohio Companies' application to increase electric distribution rates by \$136.6 million (OE - \$68.9 million, CEI - \$29.2 million and TE - \$38.5 million). These increases went into effect for OE and TE on January 23, 2009, and will go into effect for CEI on May 1, 2009. Applications for rehearing of this order were filed by the Ohio Companies and one other party on February 20, 2009.

On May 1, 2008, Governor Strickland signed SB221, which became effective on July 31, 2008. The bill requires all utilities to file an ESP with the PUCO, which must contain a proposal for the supply and pricing of retail generation. A utility may also file an MRO with the PUCO, in which it would have to prove the following objective market criteria: 1) the utility or its transmission service affiliate belongs to a FERC approved RTO, or there is comparable and nondiscriminatory access to the electric transmission grid; 2) the RTO has a market-monitor function and the ability to mitigate market power or the utility's market conduct, or a similar market monitoring function exists with the ability to identify and monitor market conditions and conduct; and 3) a published source of information is available publicly or through subscription that identifies pricing information for traded electricity products, both on- and off-peak, scheduled for delivery two years into the future.

On July 31, 2008, the Ohio Companies filed with the PUCO a comprehensive ESP and MRO. The MRO filing outlined a CBP for providing retail generation supply if the ESP is not approved and implemented. The CBP would use a "slice-of-system" approach where suppliers bid on tranches (approximately 100 MW) of the Ohio Companies' total customer load. If the Ohio Companies proceed with the MRO option, successful bidders (including affiliates) would be required to post independent credit requirements and could be subject to significant collateral calls depending upon power price movement. The PUCO denied the MRO application on November 26, 2008. The Ohio Companies filed an application for rehearing on December 23, 2008, which the PUCO granted on January 21, 2009, for the purpose of further consideration of the matter.

The ESP proposed to phase in new generation rates for customers beginning in 2009 for up to a three-year period and resolve the Ohio Companies' collection of fuel costs deferred in 2006 and 2007, and the distribution rate request described above. On December 19, 2008, the PUCO significantly modified and approved the ESP as modified. On December 22, 2008, the Ohio Companies notified the PUCO that they were withdrawing and terminating the ESP application as allowed by the terms of SB221. The Ohio Companies further notified the PUCO that, pursuant to SB221, the Ohio Companies would continue their current rate plan in effect and filed tariffs to continue those rates.

On December 31, 2008, the Ohio Companies conducted a CBP, using an RFP format administered by an independent third party, for the procurement of electric generation for retail customers from January 5, 2009 through March 31, 2009. Four qualified wholesale bidders were selected, including FES, for 97% of the tranches offered in the RFP. The average winning bid price was equivalent to a retail rate of 6.98 cents per kilowatt-hour. Subsequent to the RFP, the remaining 3% of the Ohio Companies' wholesale energy and capacity needs were obtained through a bilateral contract with the lowest bidder in the RFP procurement. The power supply obtained through the foregoing processes provides generation service to the Ohio Companies' retail customers who choose not to shop with alternative suppliers.

Following comments by other parties on the Ohio Companies' December 22, 2008, filing which continued the current rate plan, the PUCO issued an Order on January 7, 2009, that prevented OE and TE from collecting RTC and discontinued the collection of two fuel riders for the Ohio Companies. The Ohio Companies filed an application for rehearing on January 9, 2009, and also filed an application for a new fuel rider to recover the increased costs for purchasing power during the period January 1, 2009 through March 31, 2009. On January 14, 2009, the PUCO approved the Ohio Companies' request for the new fuel rider, subject to further review, allowed current recovery of those costs for OE and TE, and allowed CEI to collect a portion of those costs currently and defer the remainder. The PUCO also ordered the Ohio Companies to file additional information in order for it to determine that the costs incurred are prudent and whether the recovery of such costs is necessary to avoid a confiscatory result. The Ohio Companies filed an application for rehearing on that order on January 26, 2009. The applications for rehearing remain pending and the Ohio Companies are unable to predict the ultimate resolution of these issues.

On January 29, 2009, the PUCO ordered its Staff to develop a proposal to establish an ESP for the Ohio Companies and further ordered that a conference be held on February 5, 2009 to discuss the Staff's proposal. The Ohio Companies, PUCO Staff, and other parties participated in that conference, and in a subsequent conference held on February 17, 2009. Following discussions with the Staff and other parties regarding the Staff's proposal, on February 19, 2009, the Ohio Companies filed an amended ESP application, including an attached Stipulation and Recommendation that was signed by the Ohio Companies, the Staff of the PUCO, and many of the intervening parties representing a diverse range of interests, which substantially reflected the terms as proposed by the Staff as modified through the negotiations of the parties. Specifically, the stipulated ESP provides that generation will be provided by FES at the average wholesale rate of the RFP process described above for April and May 2009 to the Ohio Companies for their non-shopping customers and that for the period of June 1, 2009 through May 31, 2011, retail generation prices will be based upon the outcome of a descending clock CBP on a slice-of-system basis. The PUCO may, at its discretion, phase-in a portion of any increase resulting from this CBP process by authorizing deferral of related purchased power costs, subject to specified limits. The proposed ESP further provides that the Ohio Companies will not seek a base distribution rate increase with an effective date before January 1, 2012, that CEI will agree to write-off approximately \$215 million of its Extended RTC balance, and that the Ohio Companies will collect a delivery service improvement rider at an overall average rate of \$.002 per kWh for the period of April 1, 2009 through December 31, 2011. If the Stipulated ESP is approved, one-time after-tax charges associated with implementing the ESP would be approximately \$11.3 million for OE, \$145.7 million for CEI (including the CEI Extended RTC balance) and \$3.5 million for TE. The proposed ESP also addresses a number of other issues, including but not limited to, rate design for various customer classes, resolution of the prudence review described above and the collection of deferred costs that were approved in prior proceedings. On February 19, 2009, the PUCO attorney examiner issued an order setting this matter for hearing to begin on February 25, 2009.

(C) PENNSYLVANIA

Met-Ed and Penelec purchase a portion of their PLR and default service requirements from FES through a fixed-price partial requirements wholesale power sales agreement. The agreement allows Met-Ed and Penelec to sell the output of NUG energy to the market and requires FES to provide energy at fixed prices to replace any NUG energy sold to the extent needed for Met-Ed and Penelec to satisfy their PLR and default service obligations. The fixed price under the agreement is expected to remain below wholesale market prices during the term of the agreement. 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 their fixed income securities. If FES ultimately determines to terminate, reduce, or significantly modify the agreement prior to the expiration of Met-Ed's and Penelec's generation rate caps in 2010, timely regulatory relief is not likely to be granted by the PPUC. See FERC Matters below for a description of the Third Restated Partial Requirements Agreement, executed by the parties on October 31, 2008, that limits the amount of energy and capacity FES must supply to Met-Ed and Penelec. In the event of a third party supplier default, the increased costs to Met-Ed and Penelec could be material.

On May 22, 2008, the PPUC approved the Met-Ed and Penelec annual updates to the TSC rider for the period June 1, 2008, through May 31, 2009. Various intervenors filed complaints against those filings. In addition, the PPUC ordered an investigation to review the reasonableness of Met-Ed's TSC, while at the same time allowing Met-Ed to implement the rider June 1, 2008, subject to refund. On July 15, 2008, the PPUC directed the ALJ to consolidate the complaints against Met-Ed with its investigation and a litigation schedule was adopted. Hearings and briefing for both companies are expected to conclude by the end of February 2009. The TSCs include a component from under-recovery of actual transmission costs incurred during the prior period (Met-Ed - \$144 million and Penelec - \$4 million) and future transmission cost projections for June 2008 through May 2009 (Met-Ed - \$258 million and Penelec - \$92 million). Met-Ed received PPUC approval for a transition approach that would recover past under-recovered costs plus carrying charges through the new TSC over thirty-one months and defer a portion of the projected costs (\$92 million) plus carrying charges for recovery through future TSCs by December 31, 2010.

On February 1, 2007, the Governor of Pennsylvania proposed an EIS. The EIS includes four pieces of proposed legislation that, according to the Governor, is designed to reduce energy costs, promote energy independence and stimulate the economy. Elements of the EIS include the installation of smart meters, funding for solar panels on residences and small businesses, conservation and demand reduction programs to meet energy growth, a requirement that electric distribution companies acquire power that results in the "lowest reasonable rate on a long-term basis," the utilization of micro-grids and a three year phase-in of rate increases. On July 17, 2007 the Governor signed into law two pieces of energy legislation. The first amended the Alternative Energy Portfolio Standards Act of 2004 to, among other things, increase the percentage of solar energy that must be supplied at the conclusion of an electric distribution company's transition period. The second law allows electric distribution companies, at their sole discretion, to enter into long term contracts with large customers and to build or acquire interests in electric generation facilities specifically to supply long-term contracts with such customers. A special legislative session on energy was convened in mid-September 2007 to consider other aspects of the EIS. As part of the 2008 state budget negotiations, the Alternative Energy Investment Act was enacted in July 2008 creating a \$650 million alternative energy fund to increase the development and use of alternative and renewable energy, improve energy efficiency and reduce energy consumption.

On October 15, 2008, the Governor of Pennsylvania signed House Bill 2200 into law which became effective on November 14, 2008 as Act 129 of 2008. The bill addresses issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters and alternative energy. Act 129 requires utilities to file with the PPUC an energy efficiency and peak load reduction plan by July 1, 2009 and a smart meter procurement and installation plan by August 14, 2009. On January 15, 2009, in compliance with Act 129, the PPUC issued its guidelines for the filing of utilities' energy efficiency and peak load reduction plans.

Major provisions of the legislation include:

- power acquired by utilities to serve customers after rate caps expire will be procured through a competitive procurement process that must include a mix of long-term and short-term contracts and spot market purchases;
- the competitive procurement process must be approved by the PPUC and may include auctions, RFPs, and/or bilateral agreements;
- utilities must provide for the installation of smart meter technology within 15 years;
- a minimum reduction in peak demand of 4.5% by May 31, 2013;
- minimum reductions in energy consumption of 1% and 3% by May 31, 2011 and May 31, 2013, respectively; and
- an expanded definition of alternative energy to include additional types of hydroelectric and biomass facilities.

Legislation addressing rate mitigation and the expiration of rate caps was not enacted in 2008 but may be considered in the legislative session which began in January 2009. While the form and impact of such legislation is uncertain, several legislators and the Governor have indicated their intent to address these issues in 2009.

On September 25, 2008, Met-Ed and Penelec filed a Voluntary Prepayment Plan with the PPUC that would provide an opportunity for residential and small commercial customers to prepay an amount on their monthly electric bills during 2009 and 2010 that would earn interest at 7.5% and be used to reduce electric rates in 2011 and 2012. Met-Ed, Penelec, OCA and OSBA have reached a settlement agreement on the Voluntary Prepayment Plan and have jointly requested that the PPUC approve the settlement. The ALJ issued a decision on January 29, 2009, recommending approval and adoption of the settlement without modification.

On February 20, 2009, Met-Ed and Penelec filed a generation procurement plan covering the period January 1, 2011 through May 31, 2013, with the PPUC. The companies' plan is designed to provide adequate and reliable service via a prudent mix of long-term, short-term and spot market generation supply, as required by Act 129. The plan proposes a staggered procurement schedule, which varies by customer class, through the use of a descending clock auction. Met-Ed and Penelec have requested PPUC approval of their plan by October 2009.

(D) 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, costs incurred under NUG agreements, and certain other stranded costs, exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of December 31, 2008, the accumulated deferred cost balance totaled approximately \$220 million.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004, supporting 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. JCP&L responded to additional NJBPU staff discovery requests in May and November 2007 and also submitted comments in the proceeding in November 2007. A schedule for further NJBPU proceedings has not yet been set.

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of the PUHCA pursuant to the EPACT. The NJBPU approved regulations effective October 2, 2006 that 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. These regulations are not expected to materially impact JCP&L. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. The NJBPU Staff circulated revised drafts of the proposal to interested stakeholders in November 2006 and again in February 2007. On February 1, 2008, the NJBPU accepted proposed rules for publication in the New Jersey Register on March 17, 2008. A public hearing on these proposed rules was held on April 23, 2008 and comments from interested parties were submitted by May 19, 2008.

New Jersey statutes require that the state periodically undertake a planning process, known as the EMP, to address energy related issues including energy security, economic growth, and environmental impact. The EMP is to be developed with involvement of the Governor's Office and the Governor's Office of Economic Growth, and is to be prepared by a Master Plan Committee, which is chaired by the NJBPU President and includes representatives of several State departments.

The EMP was issued on October 22, 2008, establishing five major goals:

- maximize energy efficiency to achieve a 20% reduction in energy consumption by 2020;
- reduce peak demand for electricity by 5,700 MW by 2020;
- meet 30% of the state's electricity needs with renewable energy by 2020;
- examine smart grid technology and develop additional cogeneration and other generation resources consistent with the state's greenhouse gas targets; and
- invest in innovative clean energy technologies and businesses to stimulate the industry's growth in New Jersey.

The EMP will be followed by appropriate legislation and regulation as necessary. At this time, JCP&L cannot determine the impact, if any, the EMP may have on its operations.

In support of the New Jersey Governor's Economic Assistance and Recovery Plan, JCP&L announced its intent to spend approximately \$98 million on infrastructure and energy efficiency projects in 2009. An estimated \$40 million will be spent on infrastructure projects, including substation upgrades, new transformers, distribution line re-closers and automated breaker operations. Approximately \$34 million will be spent implementing new demand response programs as well as expanding on existing programs. Another \$11 million will be spent on energy efficiency, specifically replacing transformers and capacitor control systems and installing new LED street lights. The remaining \$13 million will be spent on energy efficiency programs that will complement those currently being offered. Completion of the projects is dependent upon regulatory approval for full recovery of the costs associated with plan implementation.

(E) FERC MATTERS

Transmission Service between MISO and PJM

On November 18, 2004, the FERC issued an order eliminating the through and out rate for transmission service between the MISO and PJM regions. The FERC's intent was to eliminate multiple transmission charges for a single transaction between the MISO and PJM regions. The FERC also ordered MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a rate mechanism to recover lost transmission revenues created by elimination of this charge (referred to as the Seams Elimination Cost Adjustment or "SECA") during a 16-month transition period. The FERC issued orders in 2005 setting the SECA for hearing. The presiding judge issued an initial decision on August 10, 2006, rejecting the compliance filings made by MISO, PJM, and the transmission owners, and directing new compliance filings. This decision is subject to review and approval by the FERC. Briefs addressing the initial decision were filed on September 11, 2006 and October 20, 2006. A final order is pending before the FERC, and in the meantime, FirstEnergy affiliates have been negotiating and entering into settlement agreements with other parties in the docket to mitigate the risk of lower transmission revenue collection associated with an adverse order. On September 26, 2008, the MISO and PJM transmission owners filed a motion requesting that the FERC approve the pending settlements and act on the initial decision. On November 20, 2008, FERC issued an order approving uncontested settlements, but did not rule on the initial decision. On December 19, 2008, an additional order was issued approving two contested settlements.

PJM Transmission Rate Design

On January 31, 2005, certain PJM transmission owners made 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. Hearings were held and numerous parties appeared and litigated various issues concerning PJM rate design; notably AEP, which proposed to create a "postage stamp", or average rate for all high voltage transmission facilities across PJM and a zonal transmission rate for facilities below 345 kV. This proposal would have the effect of shifting recovery of the costs of high voltage transmission lines to other transmission zones, including those where JCP&L, Met-Ed, and Penelec serve load. On April 19, 2007, the FERC issued an order finding that the PJM transmission owners' existing "license plate" or zonal rate design was just and reasonable and ordered that the current license plate rates for existing transmission facilities be retained. On the issue of rates for new transmission facilities, the FERC directed that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp rate. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a "beneficiary pays" basis. The FERC found that PJM's current beneficiary-pays cost allocation methodology is not sufficiently detailed and, in a related order that also was issued on April 19, 2007, directed that hearings be held for the purpose of establishing a just and reasonable cost allocation methodology for inclusion in PJM's tariff.

On May 18, 2007, certain parties filed for rehearing of the FERC's April 19, 2007 order. On January 31, 2008, the requests for rehearing were denied. On February 11, 2008, AEP appealed the FERC's April 19, 2007, and January 31, 2008, orders to the federal Court of Appeals for the D.C. Circuit. The Illinois Commerce Commission, the PUCO and Dayton Power & Light have also appealed these orders to the Seventh Circuit Court of Appeals. The appeals of these parties and others have been consolidated for argument in the Seventh Circuit.

The FERC's orders on PJM rate design will prevent the allocation of a portion of the revenue requirement of existing transmission facilities of other utilities to JCP&L, Met-Ed and Penelec. In addition, the FERC's decision to allocate the cost of new 500 kV and above transmission facilities on a PJM-wide basis will reduce the costs of future transmission to be recovered from the JCP&L, Met-Ed and Penelec zones. A partial settlement agreement addressing the "beneficiary pays" methodology for below 500 kV facilities, but excluding the issue of allocating new facilities costs to merchant transmission entities, was filed on September 14, 2007. The agreement was supported by the FERC's Trial Staff, and was certified by the Presiding Judge to the FERC. On July 29, 2008, the FERC issued an order conditionally approving the settlement subject to the submission of a compliance filing. The compliance filing was submitted on August 29, 2008, and the FERC issued an order accepting the compliance filing on October 15, 2008. The remaining merchant transmission cost allocation issues were the subject of a hearing at the FERC in May 2008. An initial decision was issued by the Presiding Judge on September 18, 2008. PJM and FERC trial staff each filed a Brief on Exceptions to the initial decision on October 20, 2008. Briefs Opposing Exceptions were filed on November 10, 2008.

Post Transition Period Rate Design

The FERC had directed MISO, PJM, and the respective transmission owners to make filings on or before August 1, 2007 to reevaluate transmission rate design within MISO, and between MISO and PJM. On August 1, 2007, filings were made by MISO, PJM, and the vast majority of transmission owners, including FirstEnergy affiliates, which proposed to retain the existing transmission rate design. These filings were approved by the FERC on January 31, 2008. As a result of the FERC's approval, the rates charged to FirstEnergy's load-serving affiliates for transmission service over existing transmission facilities in MISO and PJM are unchanged. In a related filing, MISO and MISO transmission owners requested that the current MISO pricing for new transmission facilities that spreads 20% of the cost of new 345 kV and higher transmission facilities across the entire MISO footprint (known as the RECB methodology) be retained.

On September 17, 2007, AEP filed a complaint under Sections 206 and 306 of the Federal Power Act seeking to have the entire transmission rate design and cost allocation methods used by MISO and PJM declared unjust, unreasonable, and unduly discriminatory, and to have the FERC fix a uniform regional transmission rate design and cost allocation method for the entire MISO and PJM "Super Region" that recovers the average cost of new and existing transmission facilities operated at voltages of 345 kV and above from all transmission customers. Lower voltage facilities would continue to be recovered in the local utility transmission rate zone through a license plate rate. AEP requested a refund effective October 1, 2007, or alternatively, February 1, 2008. On January 31, 2008, the FERC issued an order denying the complaint. The effect of this order is to prevent the shift of significant costs to the FirstEnergy zones in MISO and PJM. A rehearing request by AEP was denied by the FERC on December 19, 2008. On February 17, 2009, AEP appealed the FERC's January 31, 2008, and December 19, 2008, orders to the U.S. Court of Appeals for the Seventh Circuit.

Interconnection Agreement with AMP-Ohio

On May 29, 2008, TE filed with the FERC a proposed Notice of Cancellation effective midnight December 31, 2008, of the Interconnection Agreement with AMP-Ohio. AMP-Ohio protested this filing. TE also filed a Petition for Declaratory Order seeking a FERC ruling, in the alternative if cancellation is not accepted, of TE's right to file for an increase in rates effective January 1, 2009, for power provided to AMP-Ohio under the Interconnection Agreement. AMP-Ohio filed a pleading agreeing that TE may seek an increase in rates, but arguing that any increase is limited to the cost of generation owned by TE affiliates. On August 18, 2008, the FERC issued an order that suspended the cancellation of the Agreement for five months, to become effective on June 1, 2009, and established expedited hearing procedures on issues raised in the filing and TE's Petition for Declaratory Order. On October 14, 2008, the parties filed a settlement agreement and mutual notice of cancellation of the Interconnection Agreement effective midnight December 31, 2008. On October 24, 2008 the presiding judge certified the settlement agreement as uncontested and on December 22, 2008, the FERC issued an order approving the uncontested settlement agreement. This latest action terminates the litigation and the Interconnection Agreement.

Duquesne's Request to Withdraw from PJM

On November 8, 2007, Duquesne Light Company (Duquesne) filed a request with the FERC to exit PJM and to join MISO. Duquesne's proposed move would affect numerous FirstEnergy interests, including but not limited to the terms under which FirstEnergy's Beaver Valley Plant would continue to participate in PJM's energy markets. FirstEnergy, therefore, intervened and participated fully in all of the FERC dockets that were related to Duquesne's proposed move.

In November, 2008, Duquesne and other parties, including FirstEnergy, negotiated a settlement that would, among other things, allow for Duquesne to remain in PJM and provide for a methodology for Duquesne to meet the PJM capacity obligations for the 2011-2012 auction that excluded the Duquesne load. The settlement agreement was filed on December 10, 2008 and approved by the FERC in an order issued on January 29, 2009. The MISO opposed the settlement agreement pending resolution of exit fees alleged to be owed by Duquesne. The FERC did not resolve this issue in its order.

Complaint against PJM RPM Auction

On May 30, 2008, a group of PJM load-serving entities, state commissions, consumer advocates, and trade associations (referred to collectively as the RPM Buyers) filed a complaint at the FERC against PJM alleging that three of the four transitional RPM auctions yielded prices that are unjust and unreasonable under the Federal Power Act. On September 19, 2008, the FERC denied the RPM Buyers' complaint. However, the FERC did grant the RPM Buyers' request for a technical conference to review aspects of the RPM. The FERC also ordered PJM to file on or before December 15, 2008, a report on potential adjustments to the RPM program as suggested in a Brattle Group report. On December 12, 2008, PJM filed proposed tariff amendments that would adjust slightly the RPM program. PJM also requested that the FERC conduct a settlement hearing to address changes to the RPM and suggested that the FERC should rule on the tariff amendments only if settlement could not be reached in January, 2009. The request for settlement hearings was granted. Settlement had not been reached by January 9, 2009 and, accordingly, FirstEnergy and other parties submitted comments on PJM's proposed tariff amendments. On January 15, 2009, the Chief Judge issued an order terminating settlement talks. On February 9, 2009, PJM and a group of stakeholders submitted an offer of settlement.

On October 20, 2008, the RPM Buyers filed a request for rehearing of the FERC's September 19, 2008 order. The FERC has not yet ruled on the rehearing request.

MISO Resource Adequacy Proposal

MISO made a filing on December 28, 2007 that would create an enforceable planning reserve requirement in the MISO tariff for load-serving entities such as the Ohio Companies, Penn Power, and FES. This requirement is proposed to become effective for the planning year beginning June 1, 2009. The filing would permit MISO to establish the reserve margin requirement for load-serving entities based upon a one day loss of load in ten years standard, unless the state utility regulatory agency establishes a different planning reserve for load-serving entities in its state. FirstEnergy believes the proposal promotes a mechanism that will result in commitments from both load-serving entities and resources, including both generation and demand side resources that are necessary for reliable resource adequacy and planning in the MISO footprint. Comments on the filing were filed on January 28, 2008. The FERC conditionally approved MISO's Resource Adequacy proposal on March 26, 2008, requiring MISO to submit to further compliance filings. Rehearing requests are pending on the FERC's March 26 Order. On May 27, 2008, MISO submitted a compliance filing to address issues associated with planning reserve margins. On June 17, 2008, various parties submitted comments and protests to MISO's compliance filing. FirstEnergy submitted comments identifying specific issues that must be clarified and addressed. On June 25, 2008, MISO submitted a second compliance filing establishing the enforcement mechanism for the reserve margin requirement which establishes deficiency payments for load-serving entities that do not meet the resource adequacy requirements. Numerous parties, including FirstEnergy, protested this filing.

On October 20, 2008, the FERC issued three orders essentially permitting the MISO Resource Adequacy program to proceed with some modifications. First, the FERC accepted MISO's financial settlement approach for enforcement of Resource Adequacy subject to a compliance filing modifying the cost of new entry penalty. Second, the FERC conditionally accepted MISO's compliance filing on the qualifications for purchased power agreements to be capacity resources, load forecasting, loss of load expectation, and planning reserve zones. Additional compliance filings were directed on accreditation of load modifying resources and price responsive demand. Finally, the FERC largely denied rehearing of its March 26 order with the exception of issues related to behind the meter resources and certain ministerial matters. On November 19, 2008, MISO made various compliance filings pursuant to these orders. Issuance of orders on these compliance filings is not expected to delay the June 1, 2009, start date for MISO Resource Adequacy.

FES Sales to Affiliates

On October 24, 2008, FES, on its own behalf and on behalf of its generation-controlling subsidiaries, filed an application with the FERC seeking a waiver of the affiliate sales restrictions between FES and the Ohio Companies. The purpose of the waiver is to ensure that FES will be able to continue supplying a material portion of the electric load requirements of the Ohio Companies in January 2009 pursuant to either an ESP or MRO as filed with the PUCO. FES previously obtained a similar waiver for electricity sales to its affiliates in New Jersey, New York, and Pennsylvania. On December 23, 2008, the FERC issued an order granting the waiver request and the Ohio Companies made the required compliance filing on December 30, 2008.

On October 31, 2008, FES executed a Third Restated Partial Requirements Agreement with Met-Ed, Penelec, and Waverly effective November 1, 2008. The Third Restated Partial Requirements Agreement limits the amount of capacity and energy required to be supplied by FES in 2009 and 2010 to roughly two-thirds of these affiliates' power supply requirements. Met-Ed, Penelec, and Waverly have committed resources in place for the balance of their expected power supply during 2009 and 2010. Under the Third Restated Partial Requirements Agreement, Met-Ed, Penelec, and Waverly are responsible for obtaining additional power supply requirements created by the default or failure of supply of their committed resources. Prices for the power provided by FES were not changed in the Third Restated Partial Requirements Agreement.

10. CAPITALIZATION

(A) RETAINED EARNINGS (ACCUMULATED DEFICIT)

There are no restrictions on retained earnings for payment of cash dividends on OE's, CEI's, TE's, JCP&L's and FES' common stock. In general, Met-Ed's and Penelec's respective first mortgage indentures restrict the payment of dividends or distributions on or with respect to each of the company's common stock to amounts credited to earned surplus since the date of its indenture. As of December 31, 2008, Penelec had retained earnings available to pay common stock dividends of \$66 million, net of amounts restricted under its first mortgage indenture. Met-Ed had an accumulated deficit of \$51 million as of December 31, 2008, and is therefore currently precluded from making cash dividend distributions to FirstEnergy.

(B) PREFERRED AND PREFERENCE STOCK

The Utilities' preferred stock and preference stock authorizations are as follows:

	Preferred Stock		Preference Stock	
	Shares Authorized	Par Value	Shares Authorized	Par Value
OE	6,000,000	\$100	8,000,000	no par
OE	8,000,000	\$25		
Penn	1,200,000	\$100		
CEI	4,000,000	no par	3,000,000	no par
TE	3,000,000	\$100	5,000,000	\$25
TE	12,000,000	\$25		
JCP&L	15,600,000	no par		
Met-Ed	10,000,000	no par		
Penelec	11,435,000	no par		

No preferred shares or preference shares are currently outstanding. The following table details the change in preferred shares outstanding for OE, TE and JCP&L during 2006. No shares were issued in 2007 or 2008.

	Not Subject to Mandatory Redemption	
	Number of Shares	Par or Stated Value
	<i>(Dollars in thousands)</i>	
OE		
Balance, January 1, 2006	750,699	\$ 75,070
Redemptions-		
3.90% Series	(152,510)	(15,251)
4.40% Series	(176,280)	(17,628)
4.44% Series	(136,560)	(13,656)
4.56% Series	(144,300)	(14,430)
4.24% Series	(40,000)	(4,000)
4.25% Series	(41,049)	(4,105)
4.64% Series	(60,000)	(6,000)
Balance, December 31, 2006	-	\$ -
TE		
Balance, January 1, 2006	2,910,000	\$ 96,000
Redemptions-		
\$4.25 Series	(160,000)	(16,000)
\$4.56 Series	(50,000)	(5,000)
\$4.25 Series	(100,000)	(10,000)
\$2.365 Series	(1,400,000)	(35,000)
Adjustable Series B	(1,200,000)	(30,000)
Balance, December 31, 2006	-	\$ -
JCP&L		
Balance, January 1, 2006	125,000	\$ 12,649
Redemptions-		
4.00% Series	(125,000)	(12,649)
Balance, December 31, 2006	-	\$ -

(C) LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

Securitized Transition Bonds

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

JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt JCP&L's Consolidated Balance Sheets. As of December 31, 2008, \$369 million of the transition bonds were outstanding. The transition bonds are the sole obligations of JCP&L Transition Funding and JCP&L Transition Funding II and are collateralized by each company's equity and assets, which consist primarily of bondable transition property.

Bondable transition property represents the irrevocable right under New Jersey law of a utility company to charge, collect and receive from its customers, through a non-bypassable TBC, the principal amount and interest on transition bonds and other fees and expenses associated with their issuance. JCP&L sold its bondable transition property to JCP&L Transition Funding and JCP&L Transition Funding II and, as servicer, manages and administers the bondable transition property, including the billing, collection and remittance of the TBC, pursuant to separate servicing agreements with JCP&L Transition Funding and JCP&L Transition Funding II. For the two series of transition bonds, JCP&L is entitled to aggregate annual servicing fees of up to \$628,000 that are payable from TBC collections.

Other Long-term Debt

FGCO and each of the Utilities, except for JCP&L, have a first mortgage indenture under which they can issue FMBs secured by a direct first mortgage lien on substantially all of their property and franchises, other than specifically excepted property.

FES and the Utilities have various debt covenants under their respective financing arrangements. The most restrictive of the debt covenants relate to the nonpayment of interest and/or principal on debt and the maintenance of certain financial ratios. There also exist cross-default provisions in a number of the respective financing arrangements of FirstEnergy, FES, FGCO, NGC and the Utilities. These provisions generally trigger a default in the applicable financing arrangement of an entity if it or any of its significant subsidiaries defaults under another financing arrangement of a certain principal amount, typically \$50 million. Although such defaults by any of the Utilities will generally cross-default FirstEnergy financing arrangements containing these provisions, defaults by FirstEnergy will not generally cross-default applicable financing arrangements of any of the Utilities. Defaults by any of FES, FGCO or NGC will generally cross-default to applicable financing arrangements of FirstEnergy and, due to the existence of guarantees by FirstEnergy of certain financing arrangements of FES, FGCO and NGC, defaults by FirstEnergy will generally cross-default FES, FGCO and NGC financing arrangements containing these provisions. Cross-default provisions are not typically found in any of the senior note or FMBs of FirstEnergy or the Utilities.

Based on the amount of FMBs authenticated by the respective mortgage bond trustees through December 31, 2008, the Utilities' annual sinking fund requirement for all FMBs issued under the various mortgage indentures amounted to \$5 million for Penn, \$8 million for Met-Ed and \$21 million for Penelec. Penn expects to deposit funds with its mortgage bond trustee in 2009 that will then be withdrawn upon the surrender for cancellation of a like principal amount of FMBs, specifically authenticated for such purposes against unfunded property additions or against previously retired FMBs. This method can result in minor increases in the amount of the annual sinking fund requirement. Met-Ed and Penelec could fulfill their sinking fund obligations by providing bondable property additions, previously retired FMBs or cash to the respective mortgage bond trustees.

As of December 31, 2008, currently payable long-term debt includes variable interest rate PCRBs of \$2.0 billion for FES, \$100 million for OE, \$29 million for Met-Ed and \$45 million for Penelec, the bondholders of which are entitled to the benefit of irrevocable direct pay bank LOCs. The interest rates on the PCRBs are reset daily or weekly. Bondholders can tender their PCRBs for mandatory purchase prior to maturity with the purchase price payable from remarketing proceeds, or if the PCRBs are not successfully remarketed, by drawings on the irrevocable direct pay LOCs. The subsidiary obligor is required to reimburse the applicable LOC bank for any such drawings or, if the LOC bank fails to honor its LOC for any reason, must itself pay the purchase price.

Prior to the third quarter of 2008, FES and the Utilities had not experienced any unsuccessful remarketings of these variable-rate PCRBs. Coincident with recent disruptions in the variable-rate demand bond and capital markets generally, certain of the PCRBs had been tendered by bondholders to the trustee. As of January 31, 2009, all PCRBs that had been tendered were successfully remarketed.

In February 2009, holders of approximately \$434 million in principal of LOC-supported PCRBs of NGC were notified that the applicable Wachovia Bank LOCs expire on March 18, 2009. As a result, these PCRBs are subject to mandatory purchase at a price equal to the principal amount, plus accrued and unpaid interest, which FES and NGC expect to fund through short-term borrowings. Subject to market conditions, FES and NGC expect to remarket or refinance these PCRBs during the remainder of 2009.

The sinking fund requirements for FES and the Utilities for FMBs and maturing long-term debt (excluding capital leases) for the next five years are:

<u>Year</u>	<u>FES</u>	<u>OE</u>	<u>CEI</u>	<u>JCP&L</u>	<u>Met-Ed</u>	<u>Penelec</u>
	<i>(In millions)</i>					
2009	\$ 2,020	\$ 101	\$ 150	\$ 29	\$ 29	\$ 145
2010	68	65	18	31	100	59
2011	83	1	20	32	-	-
2012	124	1	22	34	-	-
2013	75	2	324	36	150	-

Included in the table above are amounts for the variable interest rate PCRBs described above. The following table classifies the outstanding PCRBs by year, representing the next time the debt holders may exercise their right to tender their PCRBs.

<u>Year</u>	<u>FES</u>	<u>OE</u>	<u>Met-Ed</u>	<u>Penelec</u>
	<i>(In millions)</i>			
2009	\$ 1,979	\$ 100	\$ 29	\$ 45
2010	15	-	-	-
2011	25	-	-	-
2012	56	-	-	-

Obligations to repay certain PCRBs are secured by several series of FMBs. Certain PCRBs are entitled to the benefit of irrevocable bank LOCs of \$2.1 billion as of December 31, 2008, or noncancelable municipal bond insurance of \$39 million as of December 31, 2008, to pay principal of, or interest on, the applicable PCRBs. To the extent that drawings are made under the LOCs or the policies, FGCO, NGC and the Utilities are entitled to a credit against their obligation to repay those bonds. FGCO, NGC and the Utilities pay annual fees of 0.35% to 1.70% of the amounts of the LOCs to the issuing banks and are obligated to reimburse the banks or insurers, as the case may be, for any drawings thereunder. The insurers hold FMBs as security for such reimbursement obligations. These amounts and percentages for FES and the Utilities are as follows:

	<u>FES</u>	<u>OE</u>	<u>Met-Ed</u>	<u>Penelec</u>
	<i>In millions</i>			
Amounts				
LOCs	\$ 1,916*	\$ 101	\$ 29	\$ 45
Insurance Policies	-	1	14	24
Fees				
LOCs	0.35% to 0.90%	1.70%	0.85%	0.85%

* Includes LOC of \$490 million issued for FirstEnergy on behalf of NGC

OE has LOCs of \$291 million and \$134 million in connection with the sale and leaseback of Beaver Valley Unit 2 and Perry Unit 1, respectively. OE entered into a Credit Agreement pursuant to which a standby LOC was issued in support of approximately \$236 million of the Beaver Valley Unit 2 LOCs and the issuer of the standby LOC obtained the right to pledge or assign participations in OE's reimbursement obligations under the credit agreement to a trust. The trust then issued and sold trust certificates to institutional investors that were designed to be the credit equivalent of an investment directly in OE.

11. ASSET RETIREMENT OBLIGATIONS

FES and the Utilities have 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, FES and the Utilities have recognized conditional retirement obligations (primarily for asbestos remediation) in accordance with FIN 47.

The ARO liabilities for FES, OE and TE primarily relate to the decommissioning of the Beaver Valley, Davis-Besse and Perry nuclear generating facilities (OE for its leasehold interest in Beaver Valley Unit 2 and Perry and TE for its leasehold interest in Beaver Valley Unit 2). The ARO liabilities for JCP&L, Met-Ed and Penelec primarily relate to the decommissioning of the TMI-2 nuclear generating facility. FES and the Utilities use an expected cash flow approach to measure the fair value of their nuclear decommissioning AROs.

FES and the Utilities maintain nuclear decommissioning trust funds that are legally restricted for purposes of settling the nuclear decommissioning ARO. The fair values of the decommissioning trust assets as of December 31, 2008 and 2007 were as follows:

	<u>2008</u>	<u>2007</u>
	<i>(In millions)</i>	
FES	\$ 1,034	\$ 1,333
OE	117	127
TE	74	67
JCP&L	143	176
Met-Ed	226	287
Penelec	115	138

FIN 47 provides accounting standards for conditional retirement obligations associated with tangible long-lived assets, requiring recognition of the fair value of a liability for an ARO in the period in which it is incurred if a reasonable estimate can be identified. FIN 47 states that an obligation exists even though there may be uncertainty about timing or method of settlement and further clarifies SFAS 143, stating that the uncertainty surrounding the timing and method of settlement when settlement is conditional on a future event occurring should be reflected in the measurement of the liability, not in the recognition of the liability. Accounting for conditional ARO under FIN 47 is the same as described above for SFAS 143.

The following table describes the changes to the ARO balances during 2008 and 2007.

<u>ARO Reconciliation</u>	<u>FES</u>	<u>OE</u>	<u>CEI</u>	<u>TE</u>	<u>JCP&L</u>	<u>Met-Ed</u>	<u>Penelec</u>
	<i>(In millions)</i>						
Balance as of January 1, 2007	\$ 760	\$ 88	\$ 2	\$ 27	\$ 84	\$ 151	\$ 77
Liabilities settled	(1)	-	-	-	-	-	-
Accretion	51	6	-	1	6	10	5
Balance as of December 31, 2007	810	94	2	28	90	161	82
Liabilities settled	(2)	-	-	-	-	-	-
Accretion	55	5	-	2	5	10	5
Revisions in estimated cash flows	-	(18) ⁽¹⁾	-	-	-	-	-
Balance as of December 31, 2008	<u>\$ 863</u>	<u>\$ 81</u>	<u>\$ 2</u>	<u>\$ 30</u>	<u>\$ 95</u>	<u>\$ 171</u>	<u>\$ 87</u>

⁽¹⁾ OE revised the estimated cash flows associated with the retired Gorge and Toronto plants based on an agreement to remediate asbestos at the sites within one year.

12. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

FirstEnergy, FES and the Utilities are parties to a \$2.75 billion five-year revolving credit facility. FirstEnergy has the ability to request an increase in the total commitments available under this facility up to a maximum of \$3.25 billion, subject to the discretion of each lender to provide additional commitments. Commitments under the facility are available until August 24, 2012, unless the lenders agree, at the request of the borrowers, to an unlimited number of additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each borrower are subject to a specified sub-limit, as well as applicable regulatory and other limitations. The annual facility fee is 0.125%

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 as of December 31, 2008:

<u>Borrower</u>	<u>Revolving Credit Facility Sub-Limit</u>	<u>Regulatory and Other Short-Term Debt Limitations</u>
	<i>(In millions)</i>	
FES	\$ 1,000	\$ -(1)
OE	500	500
Penn	50	39(2)
CEI	250(3)	500
TE	250(3)	500
JCP&L	425	428(2)
Met-Ed	250	300(2)
Penelec	250	300(2)

⁽¹⁾ No regulatory approvals, statutory or charter limitations applicable.

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

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

The regulated companies also have the ability to borrow from each other and FirstEnergy to meet their short-term working capital requirements. A similar but separate arrangement exists among the unregulated companies. FESC administers these two money pools and tracks FirstEnergy's surplus funds and those of 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 2008 was 2.93% for the regulated companies' money pool and 2.87% for the unregulated companies' money pool.

The Utilities, 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. The receivables financing commitment by company are shown in the following table. There were no outstanding borrowings as of December 31, 2008.

Subsidiary Company	Parent Company	Commitment	Annual Facility Fee	Maturity
<i>(In millions)</i>				
OES Capital, Incorporated	OE	\$ 170	0.20%	February 22, 2010
Centerior Funding Corporation	CEI	200	0.20	February 22, 2010
Penn Power Funding LLC	Penn	25	0.60	December 18, 2009
Met-Ed Funding LLC	Met-Ed	80	0.60	December 18, 2009
Penelec Funding LLC	Penelec	75	0.60	December 18, 2009
		\$ 550		

The weighted average interest rates on short-term borrowings outstanding as of December 31, 2008 and 2007 were as follows:

	2008	2007
FES	1.08%	5.23%
OE ⁽¹⁾	-	4.80%
CEI	1.77%	5.10%
TE	1.46%	5.04%
JCP&L	1.46%	5.04%
Met-Ed	0.92%	5.17%
Penelec	0.95%	5.04%

⁽¹⁾ In 2008, OE's short-term borrowings consisted of noninterest-bearing notes related to its investment in certain low-income housing limited partnerships.

13. COMMITMENTS, GUARANTEES AND CONTINGENCIES

(A) NUCLEAR INSURANCE

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to \$12.5 billion (assuming 104 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to \$300 million; and (ii) \$12.2 billion provided by an industry retrospective rating plan required by the NRC pursuant thereto. Under such retrospective rating plan, in the event of a nuclear incident at any unit in the United States resulting in losses in excess of private insurance, up to \$118 million (but not more than \$18 million per unit per year in the event of more than one incident) must be contributed for each nuclear unit licensed to operate in the country by the licensees thereof to cover liabilities arising out of the incident. Based on their present nuclear ownership and leasehold interests, FirstEnergy's maximum potential assessment under these provisions would be \$470 million (OE-\$40 million, NGC-\$408 million, and TE-\$22 million) per incident but not more than \$70 million (OE-\$6 million, NGC-\$61 million, and TE-\$3 million) in any one year for each incident.

In addition to the public liability insurance provided pursuant to the Price-Anderson Act, FirstEnergy has also obtained insurance coverage in limited amounts for economic loss and property damage arising out of nuclear incidents. FirstEnergy is a member of Nuclear Electric Insurance Limited (NEIL) which provides coverage (NEIL I) for the extra expense of replacement power incurred due to prolonged accidental outages of nuclear units. Under NEIL I, FirstEnergy's subsidiaries have policies, renewable yearly, corresponding to their respective nuclear interests, which provide an aggregate indemnity of up to approximately \$2.0 billion (OE-\$168 million, NGC-\$1.7 billion, TE-\$89 million) for replacement power costs incurred during an outage after an initial 20-week waiting period. Members of NEIL I pay annual premiums and are subject to assessments if losses exceed the accumulated funds available to the insurer. FirstEnergy's present maximum aggregate assessment for incidents at any covered nuclear facility occurring during a policy year would be approximately \$18 million (OE-\$1 million, NGC-\$16 million, and TE-\$1 million).

FirstEnergy is insured as to its respective nuclear interests under property damage insurance provided by NEIL to the operating company for each plant. Under these arrangements, up to \$2.8 billion of coverage for decontamination costs, decommissioning costs, debris removal and repair and/or replacement of property is provided. FirstEnergy pays annual premiums for this coverage and is liable for retrospective assessments of up to approximately \$61 million (OE-\$6 million, NGC-\$52 million, TE-\$2 million, Met Ed, Penelec and JCP&L-\$1 million in total) during a policy year.

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

(B) GUARANTEES AND OTHER ASSURANCES

FES' contracts, including power contracts with affiliates awarded through competitive bidding processes, typically contain margining provisions which require the posting of cash or LOCs in amounts determined by future power price movements. Based on FES' book of business as of December 31, 2008, and forward prices as of that date, FES had \$103 million outstanding in margining accounts. Under a hypothetical adverse change in forward prices (15% decrease in prices), FES would be required to post an additional \$98 million. Depending on the volume of forward contracts entered and future price movements, FES could be required to post significantly higher amounts for margining.

In July 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1. FES has unconditionally and irrevocably guaranteed all of FGCO's obligations under each of the leases (see Notes 6 and 14). The related lessor notes and pass through certificates are not guaranteed by FES or FGCO, but the notes are secured by, among other things, each lessor trust's undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES' lease guaranty.

On October 8, 2008, to enhance their liquidity position in the face of the turbulent credit and bond markets, FirstEnergy, FES and FGCO entered into a \$300 million secured term loan facility with Credit Suisse. Under the facility, FGCO is the borrower and FES and FirstEnergy are guarantors. Generally, the facility is available to FGCO until October 7, 2009, with a minimum borrowing amount of \$100 million and maturity 30 days from the date of the borrowing. This facility is currently unused.

Also in October 2008, FirstEnergy negotiated with the banks that have issued irrevocable direct pay LOCs in support of its outstanding variable interest rate PCRBs to extend the respective reimbursement obligations of the applicable FirstEnergy subsidiary obligors in the event that such LOCs are drawn upon. FirstEnergy's subsidiaries currently have approximately \$2.1 billion variable interest rate PCRBs outstanding (FES - \$1.9 billion, OE - \$100 million, Met-Ed - \$29 million and Penelec - \$45 million). The LOCs supporting these PCRBs may be drawn upon to pay the purchase price to bondholders that have exercised the right to tender their PCRBs for mandatory purchase. A total of approximately \$972 million of LOCs that previously required reimbursement within 30 days or less of a draw under the applicable LOC have now been modified to extend the reimbursement obligations to six months or June 2009, as applicable.

(C) ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FES and the Utilities with regard to air and water quality and other environmental matters. The effects of compliance on FES and the Utilities with regard to environmental matters could have a material adverse effect on their earnings and competitive position to the extent that they compete with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations.

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

Clean Air Act Compliance

FES is required to meet federally-approved SO₂ emissions regulations. Violations of such regulations can result in the shutdown of the generating unit involved and/or civil or criminal penalties of up to \$37,500 for each day the unit is in violation. The EPA has an interim enforcement policy for SO₂ regulations in Ohio that allows for compliance based on a 30-day averaging period. FES believes it is currently in compliance with this policy, but cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The EPA Region 5 issued a Finding of Violation and NOV to the Bay Shore Power Plant dated June 15, 2006, alleging violations to various sections of the CAA. FES has disputed those alleged violations based on its CAA permit, the Ohio SIP and other information provided to the EPA at an August 2006 meeting with the EPA. The EPA has several enforcement options (administrative compliance order, administrative penalty order, and/or judicial, civil or criminal action) and has indicated that such option may depend on the time needed to achieve and demonstrate compliance with the rules alleged to have been violated. On June 5, 2007, the EPA requested another meeting to discuss "an appropriate compliance program" and a disagreement regarding emission limits applicable to the common stack for Bay Shore Units 2, 3 and 4.

FES complies with SO₂ reduction requirements under the Clean Air Act Amendments of 1990 by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NO_x reductions required by the 1990 Amendments are being achieved through combustion controls and the generation of more electricity at lower-emitting plants. In September 1998, the EPA finalized regulations requiring additional NO_x reductions at FES' 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. FES believes its facilities are also complying with the NO_x budgets established under SIPs through combustion controls and post-combustion controls, including Selective Catalytic Reduction and SNCR systems, and/or using emission allowances.

In 1999 and 2000, the EPA issued an NOV and the DOJ filed a civil complaint against OE and Penn based on operation and maintenance of the W. H. Sammis Plant (Sammis NSR Litigation) and filed similar complaints involving 44 other U.S. power plants. This case and seven other similar cases are referred to as the NSR cases. OE's and Penn's settlement with the EPA, the DOJ and three states (Connecticut, New Jersey and New York) that resolved all issues related to the Sammis NSR litigation was approved by the Court on July 11, 2005. This settlement agreement, in the form of a consent decree, requires reductions of NO_x and SO₂ emissions at the Sammis, Burger, Eastlake and Mansfield 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. Capital expenditures necessary to complete requirements of the Sammis NSR Litigation consent decree are currently estimated to be \$506 million for 2009-2010 (with \$414 million expected to be spent in 2009). This amount excludes the potential AQC expenditures related to Burger Units 4 and 5 described below. On September 8, 2008, the Environmental Enforcement Section of the DOJ sent a letter to OE regarding its view that the company was not in compliance with the Sammis NSR Litigation consent decree because the installation of an SNCR at Eastlake Unit 5 was not completed by December 31, 2006. However, the DOJ acknowledged that stipulated penalties could not apply under the terms of the Sammis NSR Litigation consent decree because Eastlake Unit 5 was idled on December 31, 2006 pending installation of the SNCR and advised that it had exercised its discretion not to seek any other penalties for this alleged non-compliance. OE disputed the DOJ's interpretation of the consent decree in a letter dated September 22, 2008. Although the Eastlake Unit 5 issue is no longer active, OE filed a dispute resolution petition on October 23, 2008, with the United States District Court for the Southern District of Ohio, due to potential impacts on its compliance decisions with respect to Burger Units 4 and 5. On December 23, 2008, OE withdrew its dispute resolution petition and subsequently filed a motion to extend the date (from December 31, 2008 to April 15, 2009), under the Sammis NSR Litigation consent decree, to elect for Burger Units 4 and 5 to permanently shut down those units by December 31, 2010, or to repower them or to install flue gas desulfurization (FGD) by later dates. On January 30, 2009, the Court issued an order extending the election date from December 31, 2008 to March 31, 2009.

On April 2, 2007, the United States Supreme Court ruled that changes in annual emissions (in tons/year) rather than changes in hourly emissions rate (in kilograms/hour) must be used to determine whether an emissions increase triggers NSR. Subsequently, on May 8, 2007, the EPA proposed to revise the NSR regulations to utilize changes in the hourly emission rate (in kilograms/hour) to determine whether an emissions increase triggers NSR. On December 10, 2008, the EPA announced it would not finalize this proposed changes to the NSR.

On May 22, 2007, FirstEnergy and FGCO received a notice letter, required 60 days prior to the filing of a citizen suit under the federal CAA, alleging violations of air pollution laws at the Bruce Mansfield Plant, including opacity limitations. Prior to the receipt of this notice, the Plant was subject to a Consent Order and Agreement with the Pennsylvania Department of Environmental Protection concerning opacity emissions under which efforts to achieve compliance with the applicable laws will continue. On October 18, 2007, PennFuture filed a complaint, joined by three of its members, in the United States District Court for the Western District of Pennsylvania. On January 11, 2008, FirstEnergy filed a motion to dismiss claims alleging a public nuisance. On April 24, 2008, the Court denied the motion to dismiss, but also ruled that monetary damages could not be recovered under the public nuisance claim. In July 2008, three additional complaints were filed against FGCO in the United States District Court for the Western District of Pennsylvania seeking damages based on Bruce Mansfield Plant air emissions. In addition to seeking damages, two of the complaints seek to enjoin the Bruce Mansfield Plant from operating except in a "safe, responsible, prudent and proper manner", one being a complaint filed on behalf of twenty-one individuals and the other being a class action complaint, seeking certification as a class action with the eight named plaintiffs as the class representatives. On October 14, 2008, the Court granted FGCO's motion to consolidate discovery for all four complaints pending against the Bruce Mansfield Plant. FGCO believes the claims are without merit and intends to defend itself against the allegations made in these complaints.

On December 18, 2007, the state of New Jersey filed a CAA citizen suit alleging NSR violations at the Portland Generation Station against Reliant (the current owner and operator), Sithe Energy (the purchaser of the Portland Station from Met-Ed in 1999), GPU, Inc. and Met-Ed. Specifically, New Jersey alleges that "modifications" at Portland Units 1 and 2 occurred between 1980 and 1995 without preconstruction NSR or permitting under the CAA's prevention of significant deterioration program, and seeks injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. On March 14, 2008, Met-Ed filed a motion to dismiss the citizen suit claims against it and a stipulation in which the parties agreed that GPU, Inc. should be dismissed from this case. On March 26, 2008, GPU, Inc. was dismissed by the United States District Court. The scope of Met-Ed's indemnity obligation to and from Sithe Energy is disputed. On October 30, 2008, the state of Connecticut filed a Motion to Intervene, but the Court has yet to rule on Connecticut's Motion. On December 5, 2008, New Jersey filed an amended complaint, adding claims with respect to alleged modifications that occurred after GPU's sale of the plant. On January 14, 2009, the EPA issued a NOV to Reliant alleging new source review violations at the Portland Generation Station based on "modifications" dating back to 1986. Met-Ed is unable to predict the outcome of this matter. The EPA's January 14, 2009, NOV also alleged new source review violations at the Keystone and Shawville Stations based on "modifications" dating back to 1984. JCP&L, as the former owner of 16.67% of Keystone Station and Penelec, as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter.

On June 11, 2008, the EPA issued a Notice and Finding of Violation to MEW alleging that "modifications" at the Homer City Power Station occurred since 1988 to the present without preconstruction NSR or permitting under the CAA's prevention of significant deterioration program. MEW is seeking indemnification from Penelec, the co-owner (along with New York State Electric and Gas Company) and operator of the Homer City Power Station prior to its sale in 1999. The scope of Penelec's indemnity obligation to and from MEW is disputed. Penelec is unable to predict the outcome of this matter.

On May 16, 2008, FGCO received a request from the EPA for information pursuant to Section 114(a) of the CAA for certain operating and maintenance information regarding the Eastlake, Lakeshore, Bay Shore and Ashtabula generating plants to allow the EPA to determine whether these generating sources are complying with the NSR provisions of the CAA. On July 10, 2008, FGCO and the EPA entered into an ACO modifying that request and setting forth a schedule for FGCO's response. On October 27, 2008, FGCO received a second request from the EPA for information pursuant to Section 114(a) of the CAA for additional operating and maintenance information regarding the Eastlake, Lakeshore, Bay Shore and Ashtabula generating plants. FGCO intends to fully comply with the EPA's information requests, but, at this time, is unable to predict the outcome of this matter.

On August 18, 2008, FirstEnergy received a request from the EPA for information pursuant to Section 114(a) of the CAA for certain operating and maintenance information regarding the Avon Lake and Niles generating plants, as well as a copy of a nearly identical request directed to the current owner, Reliant Energy, to allow the EPA to determine whether these generating sources are complying with the NSR provisions of the CAA. FirstEnergy intends to fully comply with the EPA's information request, but, at this time, is unable to predict the outcome of this matter.

National Ambient Air Quality Standards

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 requires reductions of NO_x and SO₂ emissions in two phases (Phase I in 2009 for NO_x, 2010 for SO₂ and Phase II in 2015 for both NO_x and SO₂), ultimately capping SO₂ emissions in affected states to just 2.5 million tons annually and NO_x emissions to just 1.3 million tons annually. CAIR was challenged in the United States Court of Appeals for the District of Columbia and on July 11, 2008, the Court vacated CAIR "in its entirety" and directed the EPA to "redo its analysis from the ground up." On September 24, 2008, the EPA, utility, mining and certain environmental advocacy organizations petitioned the Court for a rehearing to reconsider its ruling vacating CAIR. On December 23, 2008, the Court reconsidered its prior ruling and allowed CAIR to remain in effect to "temporarily preserve its environmental values" until the EPA replaces CAIR with a new rule consistent with the Court's July 11, 2008 opinion. The future cost of compliance with these regulations may be substantial and will depend, in part, on the action taken by the EPA in response to the Court's ruling.

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, capping national mercury emissions at 38 tons by 2010 (as a "co-benefit" from implementation of SO₂ and NO_x emission caps under the EPA's CAIR program) and 15 tons per year by 2018. Several states and environmental groups appealed the CAMR to the United States Court of Appeals for the District of Columbia. On February 8, 2008, the Court vacated the CAMR, ruling that the EPA failed to take the necessary steps to "de-list" coal-fired power plants from its hazardous air pollutant program and, therefore, could not promulgate a cap-and-trade program. The EPA petitioned for rehearing by the entire Court, which denied the petition on May 20, 2008. On October 17, 2008, the EPA (and an industry group) petitioned the United States Supreme Court for review of the Court's ruling vacating CAMR. On February 6, 2009, the United States moved to dismiss its petition for certiorari. On February 23, 2009, the Supreme Court dismissed the United States' petition and denied the industry group's petition. Accordingly, the EPA could take regulatory action to promulgate new mercury emission standards for coal-fired power plants. FGCO's future cost of compliance with mercury regulations may be substantial and will depend on the action taken by the EPA and on how they are ultimately implemented.

Pennsylvania has submitted a new mercury rule for EPA approval that does not provide a cap-and-trade approach as in the CAMR, but rather follows a command-and-control approach imposing emission limits on individual sources. On January 30, 2009, the Commonwealth Court of Pennsylvania declared Pennsylvania's mercury rule "unlawful, invalid and unenforceable" and enjoined the Commonwealth from continued implementation or enforcement of that rule. It is anticipated that compliance with these regulations, if the Commonwealth Court's rulings were reversed on appeal and Pennsylvania's mercury rule was implemented, would not require the addition of mercury controls at the Bruce Mansfield Plant, FES' only Pennsylvania coal-fired power plant, until 2015, if at all.

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, including CO₂, emitted by developed countries by 2012. The United States signed the Kyoto Protocol in 1998 but it was never submitted for ratification by the United States Senate. However, the Bush administration had 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. Also, in an April 16, 2008 speech, former President Bush set a policy goal of stopping the growth of GHG emissions by 2025, as the next step beyond the 2012 strategy. In addition, 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. President Obama has announced his Administration's "New Energy for America Plan" that includes, among other provisions, ensuring that 10% of electricity in the United States comes from renewable sources by 2012, and 25% by 2025; and implementing an economy-wide cap-and-trade program to reduce GHG emissions 80% by 2050.

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. At the international level, efforts to reach a new global agreement to reduce GHG emissions post-2012 have begun with the Bali Roadmap, which outlines a two-year process designed to lead to an agreement in 2009. At the federal level, members of Congress have introduced several bills seeking to reduce emissions of GHG in the United States, and the Senate Environment and Public Works Committee has passed one such bill. State activities, primarily the northeastern states participating in the Regional Greenhouse Gas Initiative and western states led by California, have coordinated efforts to develop regional strategies to control emissions of certain GHGs.

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate CO₂ emissions from automobiles as "air pollutants" under the CAA. Although this decision did not address CO₂ emissions from electric generating plants, the EPA has similar authority under the CAA to regulate "air pollutants" from those and other facilities. On July 11, 2008, the EPA released an Advance Notice of Proposed Rulemaking, soliciting input from the public on the effects of climate change and the potential ramifications of regulation of CO₂ under the CAA.

FES cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO₂ emissions could require significant capital and other expenditures. The CO₂ emissions per KWH of electricity generated by FES is lower than many regional competitors due to its diversified generation sources, which include low or non-CO₂ 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 FES' plants. In addition, Ohio, New Jersey and Pennsylvania have water quality standards applicable to FES' 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 life is drawn into a facility's cooling water system). On January 26, 2007, the United States Court of Appeals for the Second Circuit remanded portions of the rulemaking dealing with impingement mortality and entrainment back to the EPA for further rulemaking and eliminated the restoration option from the EPA's regulations. On July 9, 2007, the EPA suspended this rule, noting that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment to minimize impacts on fish and shellfish from cooling water intake structures. On April 14, 2008, the Supreme Court of the United States granted a petition for a writ of certiorari to review one significant aspect of the Second Circuit Court's opinion which is whether Section 316(b) of the Clean Water Act authorizes the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. Oral argument before the Supreme Court occurred on December 2, 2008 and a decision is anticipated during the first half of 2009. FES is studying various control options and their costs and effectiveness. Depending on the results of such studies, the outcome of the Supreme Court's review of the Second Circuit's decision, the EPA's further rulemaking and any action taken by the states exercising best professional judgment, the future costs of compliance with these standards may require material capital expenditures.

The U.S. Attorney's Office in Cleveland, Ohio has advised FGCO that it is considering prosecution under the Clean Water Act and the Migratory Bird Treaty Act for three petroleum spills at the Edgewater, Lakeshore and Bay Shore plants which occurred on November 1, 2005, January 26, 2007 and February 27, 2007. FGCO is unable to predict the outcome of this matter.

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 non-hazardous waste.

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2008, FirstEnergy had approximately \$1.7 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley, Perry and TMI-2. As part of the application to the NRC to transfer the ownership of Davis-Besse, Beaver Valley and Perry to NGC in 2005, FirstEnergy agreed to contribute another \$80 million to these trusts by 2010. Consistent with NRC guidance, utilizing a "real" rate of return on these funds of approximately 2% over inflation, these trusts are expected to exceed the minimum decommissioning funding requirements set by the NRC. Conservatively, these estimates do not include any rate of return that the trusts may earn over the 20-year plant useful life extensions that FirstEnergy (and Exelon for TMI-1 as it relates to the timing of the decommissioning of TMI-2) seeks for these facilities.

The Utilities 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 may be liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2008, based on estimates of the total costs of cleanup, the Utilities' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately \$90 million (JCP&L - \$64 million, CEI - \$1 million, TE - \$1 million and FirstEnergy Corp. - \$24 million) have been accrued through December 31, 2008. Included in the total are accrued liabilities of approximately \$56 million for environmental remediation of former manufactured gas plants in New Jersey, which are being recovered by JCP&L through a non-bypassable SBC.

(D) 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 in July 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, NJ, based on a common incident involving the failure of the bushings of two large transformers in the Red Bank substation resulting in planned and unplanned outages in the area during a 2-3 day period. In 2005, JCP&L renewed its motion to decertify the class based on a very limited number of class members who incurred damages and also filed a motion for summary judgment on the remaining plaintiffs' claims for negligence, breach of contract and punitive damages. In July 2006, the New Jersey Superior Court dismissed the punitive damage claim and again decertified the class based on the fact that a vast majority of the class members did not suffer damages and those that did would be more appropriately addressed in individual actions. Plaintiffs appealed this ruling to the New Jersey Appellate Division which, in March 2007, reversed the decertification of the Red Bank class and remanded this matter back to the Trial Court to allow plaintiffs sufficient time to establish a damage model or individual proof of damages. JCP&L filed a petition for allowance of an appeal of the Appellate Division ruling to the New Jersey Supreme Court which was denied in May 2007. Proceedings are continuing in the Superior Court and a case management conference with the presiding Judge was held on June 13, 2008. At that conference, the plaintiffs stated their intent to drop their efforts to create a class-wide damage model and, instead of dismissing the class action, expressed their desire for a bifurcated trial on liability and damages. The judge directed the plaintiffs to indicate, on or before August 22, 2008, how they intend to proceed under this scenario. Thereafter, the judge expects to hold another pretrial conference to address plaintiffs' proposed procedure. JCP&L has received the plaintiffs' proposed plan of action, and intends to file its objection to the proposed plan, and also file a renewed motion to decertify the class. JCP&L is defending this action but is unable to predict the outcome. No liability has been accrued as of December 31, 2008.

On December 9, 2008, a transformer at JCP&L's Oceanview substation failed, resulting in an outage on certain bulk electric system (transmission voltage) lines out of the Oceanview and Atlantic substations, with customers in the affected area losing power. Power was restored to most customers within a few hours, and to all customers within eleven hours. On December 16, 2008, JCP&L provided preliminary information about the event to certain regulatory agencies, including the NERC. In a letter dated January 30, 2009, the NERC submitted a written "Notice of Request for Information" (NOI) to JCP&L. The NOI asked for additional factual details about the December 9 event, which JCP&L provided in its response. JCP&L is not able to predict what actions, if any, the NERC may take in response to JCP&L's NOI submittal.

Nuclear Plant Matters

On May 14, 2007, the Office of Enforcement of the NRC issued a DFI to FENOC, following FENOC's reply to an April 2, 2007 NRC request for information about two reports prepared by expert witnesses for an insurance arbitration (the insurance claim was subsequently withdrawn by FirstEnergy in December 2007) related to Davis-Besse. The NRC indicated that this information was needed for the NRC "to determine whether an Order or other action should be taken pursuant to 10 CFR 2.202, to provide reasonable assurance that FENOC will continue to operate its licensed facilities in accordance with the terms of its licenses and the Commission's regulations." FENOC was directed to submit the information to the NRC within 30 days. On June 13, 2007, FENOC filed a response to the NRC's DFI reaffirming that it accepts full responsibility for the mistakes and omissions leading up to the damage to the reactor vessel head and that it remains committed to operating Davis-Besse and FirstEnergy's other nuclear plants safely and responsibly. FENOC submitted a supplemental response clarifying certain aspects of the DFI response to the NRC on July 16, 2007. On August 15, 2007, the NRC issued a confirmatory order imposing these commitments. FENOC must inform the NRC's Office of Enforcement after it completes the key commitments embodied in the NRC's order. FENOC has conducted the employee training required by the confirmatory order and a consultant has performed follow-up reviews to ensure the effectiveness of that training. The NRC continues to monitor FENOC's compliance with all the commitments made in the confirmatory order.

In August 2007, FENOC submitted an application to the NRC to renew the operating licenses for the Beaver Valley Power Station (Units 1 and 2) for an additional 20 years. The NRC is required by statute to provide an opportunity for members of the public to request a hearing on the application. No members of the public, however, requested a hearing on the Beaver Valley license renewal application. On September 24, 2008, the NRC issued a draft supplemental Environmental Impact Statement for Beaver Valley. FENOC will continue to work with the NRC Staff as it completes its environmental and technical reviews of the license renewal application, and expects to obtain renewed licenses for the Beaver Valley Power Station in 2009. If renewed licenses are issued by the NRC, the Beaver Valley Power Station's licenses would be extended until 2036 and 2047 for Units 1 and 2, respectively.

Other Legal Matters

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

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 also sought injunctive relief to eliminate harmful emissions and repair property damage and the institution of a medical monitoring program for class members. On April 5, 2007, the Court rejected the plaintiffs' request to certify this case as a class action and, accordingly, did not appoint the plaintiffs as class representatives or their counsel as class counsel. On July 30, 2007, plaintiffs' counsel voluntarily withdrew their request for reconsideration of the April 5, 2007 Court order denying class certification and the Court heard oral argument on the plaintiffs' motion to amend their complaint, which OE opposed. On August 2, 2007, the Court denied the plaintiffs' motion to amend their complaint. Plaintiffs appealed the Court's denial of the motion for certification as a class action which the Ohio Court of Appeals (7th District) denied on December 11, 2008. The period to file a notice of appeal to the Ohio Supreme Court has expired.

JCP&L's bargaining unit employees filed a grievance challenging JCP&L's 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties' collective bargaining agreement. At the conclusion of the June 1, 2005 hearing, the arbitration panel decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the arbitration panel issued an opinion to award approximately \$16 million to the bargaining unit employees. On February 6, 2006, a federal district Court granted a union motion to dismiss, as premature, a JCP&L appeal of the award filed on October 18, 2005. A final order identifying the individual damage amounts was issued on October 31, 2007. The award appeal process was initiated. The union filed a motion with the federal Court to confirm the award and JCP&L filed its answer and counterclaim to vacate the award on December 31, 2007. JCP&L and the union filed briefs in June and July of 2008 and oral arguments were held in the fall. The Court has yet to render its decision. JCP&L recognized a liability for the potential \$16 million award in 2005.

The union employees at the Bruce Mansfield Plant have been working without a labor contract since February 15, 2008. The parties are continuing to bargain with the assistance of a federal mediator. FES has a strike mitigation plan ready in the event of a strike.

FES and the Utilities accrue legal liabilities only when they conclude that it is probable that they have an obligation for such costs and can reasonably estimate the amount of such costs. If it were ultimately determined that FES and the Utilities have legal liability or are otherwise made subject to liability based on the above matters, it could have a material adverse effect on their financial condition, results of operations and cash flows.

14. SUPPLEMENTAL GUARANTOR INFORMATION

As discussed in Note 6, on July 13, 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1. FES has fully and unconditionally guaranteed all of FGCO's obligations under each of the leases. The related lessor notes and pass through certificates are not guaranteed by FES or FGCO, but the notes are secured by, among other things, each lessor trust's undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES' lease guaranty. This transaction is classified as an operating lease under GAAP for FES and a financing for FGCO.

The consolidating statements of income for the three years ended December 31, 2008, consolidating balance sheets as of December 31, 2008, and December 31, 2007, and condensed consolidating statements of cash flows for the three years ended December 31, 2008, for FES (parent and guarantor), FGCO and NGC (non-guarantor) are presented below. Investments in wholly owned subsidiaries are accounted for by FES using the equity method. Results of operations for FGCO and NGC are, therefore, reflected in FES' investment accounts and earnings as if operating lease treatment was achieved (see Note 6). The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions and the entries required to reflect operating lease treatment associated with the 2007 Bruce Mansfield Unit 1 sale and leaseback transaction.

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME

<u>For the Year Ended December 31, 2008</u>	<u>FES</u>	<u>FGCO</u>	<u>NGC</u>	<u>Eliminations</u>	<u>Consolidated</u>
			<i>(In thousands)</i>		
REVENUES	\$ 4,470,112	\$ 2,275,451	\$ 1,204,534	\$ (3,431,744)	\$ 4,518,353
EXPENSES:					
Fuel	16,322	1,171,993	126,978	-	1,315,293
Purchased power from affiliates	3,417,126	14,618	101,409	(3,431,744)	101,409
Purchased power from non-affiliates	778,882	-	-	-	778,882
Other operating expenses	116,972	416,723	502,096	48,757	1,084,548
Provision for depreciation	5,986	119,763	111,529	(5,379)	231,899
General taxes	19,260	46,153	22,591	-	88,004
Total expenses	<u>4,354,548</u>	<u>1,769,250</u>	<u>864,603</u>	<u>(3,388,366)</u>	<u>3,600,035</u>
OPERATING INCOME	<u>115,564</u>	<u>506,201</u>	<u>339,931</u>	<u>(43,378)</u>	<u>918,318</u>
OTHER INCOME (EXPENSE):					
Miscellaneous income (expense), including net income from equity investees	449,167	(3,366)	(35,665)	(431,116)	(20,980)
Interest expense to affiliates	(314)	(20,342)	(9,173)	-	(29,829)
Interest expense - other	(24,674)	(95,926)	(56,486)	65,404	(111,682)
Capitalized interest	142	39,934	3,688	-	43,764
Total other income (expense)	<u>424,321</u>	<u>(79,700)</u>	<u>(97,636)</u>	<u>(365,712)</u>	<u>(118,727)</u>
INCOME BEFORE INCOME TAXES	539,885	426,501	242,295	(409,090)	799,591
INCOME TAXES	<u>33,475</u>	<u>155,100</u>	<u>90,247</u>	<u>14,359</u>	<u>293,181</u>
NET INCOME	<u>\$ 506,410</u>	<u>\$ 271,401</u>	<u>\$ 152,048</u>	<u>\$ (423,449)</u>	<u>\$ 506,410</u>

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME

<u>For the Year Ended December 31, 2007</u>	<u>FES</u>	<u>FGCO</u>	<u>NGC</u>	<u>Eliminations</u>	<u>Consolidated</u>
	<i>(In thousands)</i>				
REVENUES	\$ 4,345,790	\$ 1,982,166	\$ 1,062,026	\$ (3,064,955)	\$ 4,325,027
EXPENSES:					
Fuel	26,169	942,946	117,895	-	1,087,010
Purchased power from affiliates	3,038,786	186,415	73,844	(3,064,955)	234,090
Purchased power from non-affiliates	764,090	-	-	-	764,090
Other operating expenses	161,797	352,856	514,389	11,997	1,041,039
Provision for depreciation	2,269	99,741	92,239	(1,337)	192,912
General taxes	20,953	41,456	24,689	-	87,098
Total expenses	<u>4,014,064</u>	<u>1,623,414</u>	<u>823,056</u>	<u>(3,054,295)</u>	<u>3,406,239</u>
OPERATING INCOME	<u>331,726</u>	<u>358,752</u>	<u>238,970</u>	<u>(10,660)</u>	<u>918,788</u>
OTHER INCOME (EXPENSE):					
Miscellaneous income (expense), including net income from equity investees	341,978	4,210	14,880	(308,192)	52,876
Interest expense to affiliates	(1,320)	(48,536)	(15,645)	-	(65,501)
Interest expense - other	(9,503)	(59,412)	(39,458)	16,174	(92,199)
Capitalized interest	35	14,369	5,104	-	19,508
Total other income (expense)	<u>331,190</u>	<u>(89,369)</u>	<u>(35,119)</u>	<u>(292,018)</u>	<u>(85,316)</u>
INCOME BEFORE INCOME TAXES	662,916	269,383	203,851	(302,678)	833,472
INCOME TAXES	<u>134,052</u>	<u>90,801</u>	<u>77,467</u>	<u>2,288</u>	<u>304,608</u>
NET INCOME	<u>\$ 528,864</u>	<u>\$ 178,582</u>	<u>\$ 126,384</u>	<u>\$ (304,966)</u>	<u>\$ 528,864</u>

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF INCOME

<u>For the Year Ended December 31, 2006</u>	<u>FES</u>	<u>FGCO</u>	<u>NGC</u>	<u>Eliminations</u>	<u>Consolidated</u>
	<i>(In thousands)</i>				
REVENUES	\$ 4,023,752	\$ 1,767,549	\$ 1,028,159	\$ (2,808,107)	\$ 4,011,353
EXPENSES:					
Fuel	18,265	983,492	103,900	-	1,105,657
Purchased power from affiliates	2,804,110	180,759	80,239	(2,808,107)	257,001
Purchased power from non-affiliates	590,491	-	-	-	590,491
Other operating expenses	202,369	271,718	553,477	-	1,027,564
Provision for depreciation	1,779	93,728	83,656	-	179,163
General taxes	12,459	38,781	22,092	-	73,332
Total expenses	<u>3,629,473</u>	<u>1,568,478</u>	<u>843,364</u>	<u>(2,808,107)</u>	<u>3,233,208</u>
OPERATING INCOME	<u>394,279</u>	<u>199,071</u>	<u>184,795</u>	<u>-</u>	<u>778,145</u>
OTHER INCOME (EXPENSE):					
Miscellaneous income (expense), including net income from equity investees	184,267	(596)	35,571	(164,740)	54,502
Interest expense to affiliates	(241)	(117,639)	(44,793)	-	(162,673)
Interest expense - other	(720)	(9,125)	(16,623)	-	(26,468)
Capitalized interest	1	4,941	6,553	-	11,495
Total other income (expense)	<u>183,307</u>	<u>(122,419)</u>	<u>(19,292)</u>	<u>(164,740)</u>	<u>(123,144)</u>
INCOME BEFORE INCOME TAXES	577,586	76,652	165,503	(164,740)	655,001
INCOME TAXES	<u>158,933</u>	<u>17,605</u>	<u>59,810</u>	<u>-</u>	<u>236,348</u>
NET INCOME	<u>\$ 418,653</u>	<u>\$ 59,047</u>	<u>\$ 105,693</u>	<u>\$ (164,740)</u>	<u>\$ 418,653</u>

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING BALANCE SHEETS

As of December 31, 2008	FES	FGCO	NGC	Eliminations	Consolidated
	<i>(In thousands)</i>				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	\$ -	\$ 39	\$ -	\$ -	\$ 39
Receivables-					
Customers	86,123	-	-	-	86,123
Associated companies	363,226	225,622	113,067	(323,815)	378,100
Other	991	11,379	12,256	-	24,626
Notes receivable from associated companies	107,229	21,946	-	-	129,175
Materials and supplies, at average cost	5,750	303,474	212,537	-	521,761
Prepayments and other	76,773	35,102	660	-	112,535
	<u>640,092</u>	<u>597,562</u>	<u>338,520</u>	<u>(323,815)</u>	<u>1,252,359</u>
PROPERTY, PLANT AND EQUIPMENT:					
In service	134,905	5,420,789	4,705,735	(389,525)	9,871,904
Less - Accumulated provision for depreciation	13,090	2,702,110	1,709,286	(169,765)	4,254,721
	121,815	2,718,679	2,996,449	(219,760)	5,617,183
Construction work in progress	4,470	1,441,403	301,562	-	1,747,435
	<u>126,285</u>	<u>4,160,082</u>	<u>3,298,011</u>	<u>(219,760)</u>	<u>7,364,618</u>
INVESTMENTS:					
Nuclear plant decommissioning trusts	-	-	1,033,717	-	1,033,717
Long-term notes receivable from associated companies	-	-	62,900	-	62,900
Investment in associated companies	3,596,152	-	-	(3,596,152)	-
Other	1,913	59,476	202	-	61,591
	<u>3,598,065</u>	<u>59,476</u>	<u>1,096,819</u>	<u>(3,596,152)</u>	<u>1,158,208</u>
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income taxes	24,703	476,611	-	(233,552)	267,762
Lease assignment receivable from associated companies	-	71,356	-	-	71,356
Goodwill	24,248	-	-	-	24,248
Property taxes	-	27,494	22,610	-	50,104
Unamortized sale and leaseback costs	-	20,286	-	49,646	69,932
Other	59,642	59,674	21,743	(44,625)	96,434
	<u>108,593</u>	<u>655,421</u>	<u>44,353</u>	<u>(228,531)</u>	<u>579,836</u>
	<u>\$ 4,473,035</u>	<u>\$ 5,472,541</u>	<u>\$ 4,777,703</u>	<u>\$ (4,368,258)</u>	<u>\$ 10,355,021</u>
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	\$ 5,377	\$ 925,234	\$ 1,111,183	\$ (16,896)	\$ 2,024,898
Short-term borrowings-					
Associated companies	1,119	257,357	6,347	-	264,823
Other	1,000,000	-	-	-	1,000,000
Accounts payable-					
Associated companies	314,887	221,266	250,318	(314,133)	472,338
Other	35,367	119,226	-	-	154,593
Accrued taxes	8,272	60,385	30,790	(19,681)	79,766
Other	61,034	136,867	13,685	36,853	248,439
	<u>1,426,056</u>	<u>1,720,335</u>	<u>1,412,323</u>	<u>(313,857)</u>	<u>4,244,857</u>
CAPITALIZATION:					
Common stockholder's equity	2,944,423	1,832,678	1,752,580	(3,585,258)	2,944,423
Long-term debt and other long-term obligations	61,508	1,328,921	469,839	(1,288,820)	571,448
	<u>3,005,931</u>	<u>3,161,599</u>	<u>2,222,419</u>	<u>(4,874,078)</u>	<u>3,515,871</u>
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	-	-	-	1,026,584	1,026,584
Accumulated deferred income taxes	-	-	206,907	(206,907)	-
Accumulated deferred investment tax credits	-	39,439	23,289	-	62,728
Asset retirement obligations	-	24,134	838,951	-	863,085
Retirement benefits	22,558	171,619	-	-	194,177
Property taxes	-	27,494	22,610	-	50,104
Lease market valuation liability	-	307,705	-	-	307,705
Other	18,490	20,216	51,204	-	89,910
	<u>41,048</u>	<u>590,607</u>	<u>1,142,961</u>	<u>819,677</u>	<u>2,594,293</u>

\$ 4,473,035 \$ 5,472,541 \$ 4,777,703 \$ (4,368,258) \$ 10,355,021

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING BALANCE SHEETS

As of December 31, 2007	FES	FGCO	NGC	Eliminations	Consolidated
	<i>(In thousands)</i>				
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	\$ 2	\$ -	\$ -	\$ -	\$ 2
Receivables-					
Customers	133,846	-	-	-	133,846
Associated companies	327,715	237,202	98,238	(286,656)	376,499
Other	2,845	978	-	-	3,823
Notes receivable from associated companies	23,772	-	69,012	-	92,784
Materials and supplies, at average cost	195	215,986	210,834	-	427,015
Prepayments and other	67,981	21,605	2,754	-	92,340
	<u>556,356</u>	<u>475,771</u>	<u>380,838</u>	<u>(286,656)</u>	<u>1,126,309</u>
PROPERTY, PLANT AND EQUIPMENT:					
In service	25,513	5,065,373	3,595,964	(392,082)	8,294,768
Less - Accumulated provision for depreciation	7,503	2,553,554	1,497,712	(166,756)	3,892,013
	18,010	2,511,819	2,098,252	(225,326)	4,402,755
Construction work in progress	1,176	571,672	188,853	-	761,701
	<u>19,186</u>	<u>3,083,491</u>	<u>2,287,105</u>	<u>(225,326)</u>	<u>5,164,456</u>
INVESTMENTS:					
Nuclear plant decommissioning trusts	-	-	1,332,913	-	1,332,913
Long-term notes receivable from associated companies	-	-	62,900	-	62,900
Investment in associated companies	2,516,838	-	-	(2,516,838)	-
Other	2,732	37,071	201	-	40,004
	<u>2,519,570</u>	<u>37,071</u>	<u>1,396,014</u>	<u>(2,516,838)</u>	<u>1,435,817</u>
DEFERRED CHARGES AND OTHER ASSETS:					
Accumulated deferred income taxes	16,978	522,216	-	(262,271)	276,923
Lease assignment receivable from associated companies	-	215,258	-	-	215,258
Goodwill	24,248	-	-	-	24,248
Property taxes	-	25,007	22,767	-	47,774
Pension assets	3,217	13,506	-	-	16,723
Unamortized sale and leaseback costs	-	27,597	-	43,206	70,803
Other	22,956	52,971	6,159	(38,133)	43,953
	<u>67,399</u>	<u>856,555</u>	<u>28,926</u>	<u>(257,198)</u>	<u>695,682</u>
	<u>\$ 3,162,511</u>	<u>\$ 4,452,888</u>	<u>\$ 4,092,883</u>	<u>\$ (3,286,018)</u>	<u>\$ 8,422,264</u>
LIABILITIES AND CAPITALIZATION					
CURRENT LIABILITIES:					
Currently payable long-term debt	\$ -	\$ 596,827	\$ 861,265	\$ (16,896)	\$ 1,441,196
Short-term borrowings-					
Associated companies	-	238,786	25,278	-	264,064
Other	300,000	-	-	-	300,000
Accounts payable-					
Associated companies	287,029	175,965	268,926	(286,656)	445,264
Other	56,194	120,927	-	-	177,121
Accrued taxes	18,831	125,227	28,229	(836)	171,451
Other	57,705	131,404	11,972	36,725	237,806
	<u>719,759</u>	<u>1,389,136</u>	<u>1,195,670</u>	<u>(267,663)</u>	<u>3,036,902</u>
CAPITALIZATION:					
Common stockholder's equity	2,414,231	951,542	1,562,069	(2,513,611)	2,414,231
Long-term debt and other long-term obligations	-	1,597,028	242,400	(1,305,716)	533,712
	<u>2,414,231</u>	<u>2,548,570</u>	<u>1,804,469</u>	<u>(3,819,327)</u>	<u>2,947,943</u>
NONCURRENT LIABILITIES:					
Deferred gain on sale and leaseback transaction	-	-	-	1,060,119	1,060,119
Accumulated deferred income taxes	-	-	259,147	(259,147)	-
Accumulated deferred investment tax credits	-	36,054	25,062	-	61,116
Asset retirement obligations	-	24,346	785,768	-	810,114
Retirement benefits	8,721	54,415	-	-	63,136
Property taxes	-	25,328	22,767	-	48,095
Lease market valuation liability	-	353,210	-	-	353,210

Other	19,800	21,829	-	-	41,629
	<u>28,521</u>	<u>515,182</u>	<u>1,092,744</u>	<u>800,972</u>	<u>2,437,419</u>
	<u>\$ 3,162,511</u>	<u>\$ 4,452,888</u>	<u>\$ 4,092,883</u>	<u>\$ (3,286,018)</u>	<u>\$ 8,422,264</u>

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

<u>For the Year Ended December 31, 2008</u>	<u>FES</u>	<u>FGCO</u>	<u>NGC</u>	<u>Eliminations</u>	<u>Consolidated</u>
	<i>(In thousands)</i>				
NET CASH PROVIDED FROM OPERATING ACTIVITIES	\$ 40,791	\$ 350,986	\$ 478,047	\$ (16,896)	\$ 852,928
CASH FLOWS FROM FINANCING ACTIVITIES:					
New financing-					
Long-term debt	-	353,325	265,050	-	618,375
Equity contributions from parent	280,000	675,000	175,000	(850,000)	280,000
Short-term borrowings, net	701,119	18,571	-	(18,931)	700,759
Redemptions and repayments-					
Long-term debt	(2,955)	(293,349)	(183,132)	16,896	(462,540)
Short-term borrowings, net	-	-	(18,931)	18,931	-
Common stock dividend payment	(43,000)	-	-	-	(43,000)
Other	-	(3,107)	(2,040)	-	(5,147)
Net cash provided from financing activities	935,164	750,440	235,947	(833,104)	1,088,447
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(43,244)	(1,047,917)	(744,468)	-	(1,835,629)
Proceeds from asset sales	-	23,077	-	-	23,077
Sales of investment securities held in trusts	-	-	950,688	-	950,688
Purchases of investment securities held in trusts	-	-	(987,304)	-	(987,304)
Loans repayments from (loans to) associated companies	(83,457)	(21,946)	69,012	-	(36,391)
Investment in subsidiary	(850,000)	-	-	850,000	-
Other	744	(54,601)	(1,922)	-	(55,779)
Net cash used for investing activities	(975,957)	(1,101,387)	(713,994)	850,000	(1,941,338)
Net change in cash and cash equivalents	(2)	39	-	-	37
Cash and cash equivalents at beginning of year	2	-	-	-	2
Cash and cash equivalents at end of year	\$ -	\$ 39	\$ -	\$ -	\$ 39

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

<u>For the Year Ended December 31, 2007</u>	<u>FES</u>	<u>FGCO</u>	<u>NGC</u>	<u>Eliminations</u>	<u>Consolidated</u>
			<i>(In thousands)</i>		
NET CASH PROVIDED FROM (USED FOR)					
OPERATING ACTIVITIES	\$ (18,017)	\$ 55,172	\$ 263,468	\$ (6,306)	\$ 294,317
CASH FLOWS FROM FINANCING ACTIVITIES:					
New financing-					
Long-term debt	-	1,576,629	179,500	(1,328,919)	427,210
Equity contributions from parent	700,000	700,000	-	(700,000)	700,000
Short-term borrowings, net	300,000	-	25,278	(325,278)	-
Redemptions and repayments-					
Common stock	(600,000)	-	-	-	(600,000)
Long-term debt	-	(1,048,647)	(494,070)	6,306	(1,536,411)
Short-term borrowings, net	-	(783,599)	-	325,278	(458,321)
Common stock dividend payment	(117,000)	-	-	-	(117,000)
Other	-	(3,474)	(1,725)	-	(5,199)
Net cash provided from (used for) financing activities	<u>283,000</u>	<u>440,909</u>	<u>(291,017)</u>	<u>(2,022,613)</u>	<u>(1,589,721)</u>
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(10,603)	(502,311)	(225,795)	-	(738,709)
Proceeds from asset sales	-	12,990	-	-	12,990
Proceeds from sale and leaseback transaction	-	-	-	1,328,919	1,328,919
Sales of investment securities held in trusts	-	-	655,541	-	655,541
Purchases of investment securities held in trusts	-	-	(697,763)	-	(697,763)
Loans repayments from associated companies	441,966	-	292,896	-	734,862
Investment in subsidiary	(700,000)	-	-	700,000	-
Other	3,654	(6,760)	2,670	-	(436)
Net cash provided from (used for) investing activities	<u>(264,983)</u>	<u>(496,081)</u>	<u>27,549</u>	<u>2,028,919</u>	<u>1,295,404</u>
Net change in cash and cash equivalents	-	-	-	-	-
Cash and cash equivalents at beginning of year	2	-	-	-	2
Cash and cash equivalents at end of year	<u>\$ 2</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 2</u>

FIRSTENERGY SOLUTIONS CORP.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

<u>For the Year Ended December 31, 2006</u>	<u>FES</u>	<u>FGCO</u>	<u>NGC</u>	<u>Eliminations</u>	<u>Consolidated</u>
	<i>(In thousands)</i>				
NET CASH PROVIDED FROM OPERATING ACTIVITIES	<u>\$ 250,518</u>	<u>\$ 150,510</u>	<u>\$ 470,578</u>	<u>\$ (12,765)</u>	<u>\$ 858,841</u>
CASH FLOWS FROM FINANCING ACTIVITIES:					
New financing-					
Long-term debt	-	565,395	591,515	-	1,156,910
Short-term borrowings, net	-	46,402	-	-	46,402
Redemptions and repayments-					
Long-term debt	-	(539,395)	(591,515)	-	(1,130,910)
Common stock dividend payment	(8,454)	-	(12,765)	12,765	(8,454)
Other	-	(3,738)	(3,161)	-	(6,899)
Net cash provided from (used for) financing activities	<u>(8,454)</u>	<u>68,664</u>	<u>(15,926)</u>	<u>12,765</u>	<u>57,049</u>
CASH FLOWS FROM INVESTING ACTIVITIES:					
Property additions	(948)	(212,867)	(363,472)	-	(577,287)
Proceeds from asset sales	-	34,215	-	-	34,215
Sales of investment securities held in trusts	-	-	1,066,271	-	1,066,271
Purchases of investment securities held in trusts	-	-	(1,066,271)	-	(1,066,271)
Loans to associated companies	(242,597)	-	(90,433)	-	(333,030)
Other	1,481	(40,522)	(747)	-	(39,788)
Net cash used for investing activities	<u>(242,064)</u>	<u>(219,174)</u>	<u>(454,652)</u>	<u>-</u>	<u>(915,890)</u>
Net change in cash and cash equivalents	-	-	-	-	-
Cash and cash equivalents at beginning of year	2	-	-	-	2
Cash and cash equivalents at end of year	<u>\$ 2</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 2</u>

15. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

SFAS 141(R) – “Business Combinations”

In December 2007, the FASB issued SFAS 141(R), which: (i) requires the acquiring entity in a business combination to recognize all assets acquired and liabilities assumed in the transaction; (ii) establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and (iii) requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. The Standard includes both core principles and pertinent application guidance, eliminating the need for numerous EITF issues and other interpretative guidance. SFAS 141(R) will affect business combinations entered into by FES and the Utilities that close after January 1, 2009. In addition, the Standard also affects the accounting for changes in deferred tax valuation allowances and income tax uncertainties made after January 1, 2009, that were established as part of a business combination prior to the implementation of this Standard. Under SFAS 141(R), adjustments to the acquired entity's deferred tax assets and uncertain tax position balances occurring outside the measurement period will be recorded as a component of income tax expense, rather than goodwill. The impact of the application of this Standard in periods after implementation will be dependent upon the nature of acquisitions at that time.

SFAS 160 - “Non-controlling Interests in Consolidated Financial Statements – an Amendment of ARB No. 51”

In December 2007, the FASB issued SFAS 160 that establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. This Statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is prohibited. The Statement is not expected to have a material impact on financial statements of FES or the Utilities.

SFAS 161 - “Disclosures about Derivative Instruments and Hedging Activities – an Amendment of FASB Statement No. 133”

In March 2008, the FASB issued SFAS 161 that enhances the current disclosure framework for derivative instruments and hedging activities. The Statement requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. The FASB believes that additional required disclosure of the fair values of derivative instruments and their gains and losses in a tabular format will provide a more complete picture of the location in an entity's financial statements of both the derivative positions existing at period end and the effect of using derivatives during the reporting period. Disclosing information about credit-risk-related contingent features is designed to provide information on the potential effect on an entity's liquidity from using derivatives. This Statement also requires cross-referencing within the footnotes to help users of financial statements locate important information about derivative instruments. The Statement is effective for reporting periods beginning after November 15, 2008. FES expects this Standard to increase its disclosure requirements for derivative instruments and hedging activities.

EITF Issue No. 08-6 – “Equity Method Investment Accounting Considerations”

In November 2008, the FASB issued EITF 08-6, which clarifies how to account for certain transactions involving equity method investments. It provides guidance in determining the initial carrying value of an equity method investment, accounting for a change in an investment from equity method to cost method, assessing the impairment of underlying assets of an equity method investment, and accounting for an equity method investee's issuance of shares. This statement is effective for transactions occurring in fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is not permitted. The impact of the application of this Standard in periods after implementation will be dependent upon the nature of future investments accounted for under the equity method.

FSP SFAS 132 (R)-1 – “Employers’ Disclosures about Postretirement Benefit Plan Assets”

In December 2008, the FASB issued Staff Position (FSP) SFAS 132(R)-1, which provides guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement plan. Requirements of this FSP include disclosures about investment policies and strategies, categories of plan assets, fair value measurements of plan assets, and significant categories of risk. This FSP is effective for fiscal years ending after December 15, 2009. FES and the Utilities expect this Staff Position to increase their disclosure requirements for postretirement benefit plan assets.

16. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED)

The following summarizes certain consolidated operating results by quarter for 2008 and 2007.

Three Months Ended	Revenues	Operating Income (Loss)	Income (Loss) From Continuing Operations Before Income Taxes	Income Taxes	Net Income
<i>(In millions)</i>					
FES					
March 31, 2008	\$ 1,099.1	\$ 175.7	\$ 147.8	\$ 57.8	\$ 90.0
March 31, 2007	1,018.2	188.7	164.9	62.4	102.5
June 30, 2008	1,071.3	142.2	115.4	47.3	68.1
June 30, 2007	1,068.7	263.8	239.1	87.7	151.4
September 30, 2008	1,241.6	288.8	278.9	93.2	185.7
September 30, 2007	1,170.1	272.1	248.4	93.7	154.7
December 31, 2008	1,106.4	311.6	257.5	94.9	162.6
December 31, 2007	1,068.0	194.2	181.1	60.8	120.3
OE					
March 31, 2008	\$ 652.6	\$ 77.1	\$ 70.8	\$ 26.9	\$ 43.9
March 31, 2007	625.6	65.4	71.4	17.4	54.0
June 30, 2008	609.6	76.1	70.5	21.7	48.8
June 30, 2007	596.8	70.8	73.2	27.6	45.6
September 30, 2008	702.3	100.0	101.0	28.5	72.5
September 30, 2007	668.8	82.0	82.3	34.1	48.2
December 31, 2008	637.3	80.8	68.0	21.5	46.5
December 31, 2007	600.3	73.1	71.6	22.2	49.4
CEI					
March 31, 2008	\$ 437.3	\$ 110.8	\$ 88.2	\$ 30.3	\$ 57.9
March 31, 2007	440.8	115.5	98.3	34.8	63.5
June 30, 2008	434.4	123.4	100.4	33.8	66.6
June 30, 2007	449.5	128.6	111.0	42.1	68.9
September 30, 2008	524.1	159.9	136.4	43.0	93.4
September 30, 2007	529.1	154.4	133.3	54.6	78.7
December 31, 2008	420.1	120.5	96.3	29.7	66.6
December 31, 2007	403.5	113.7	97.2	31.9	65.3
TE					
March 31, 2008	\$ 211.7	\$ 26.1	\$ 25.1	\$ 8.1	\$ 17.0
March 31, 2007	240.5	40.3	37.0	11.1	25.9
June 30, 2008	221.5	30.9	28.7	7.4	21.3
June 30, 2007	240.3	40.8	37.3	15.4	21.9
September 30, 2008	251.1	45.1	43.4	12.2	31.2
September 30, 2007	269.7	47.5	43.5	18.4	25.1
December 31, 2008	211.2	10.8	7.5	2.1	5.4
December 31, 2007	213.4	28.8	27.2	8.8	18.4

Three Months Ended	Revenues	Operating Income (Loss)	Income (Loss) From Continuing Operations		Income Taxes	Net Income (Loss)
			Before Income Taxes			
<i>(In millions)</i>						
Met-Ed						
March 31, 2008	\$ 400.3	\$ 45.6	\$ 38.9	\$ 16.7	\$ 22.2	
March 31, 2007	370.3	57.9	55.2	23.6	31.6	
June 30, 2008	392.0	37.8	32.7	12.9	19.8	
June 30, 2007	361.7	38.0	34.3	14.8	19.5	
September 30, 2008	455.5	45.1	38.3	16.3	22.0	
September 30, 2007	410.6	43.8	39.4	14.7	24.7	
December 31, 2008	405.2	46.1	39.0	15.0	24.0	
December 31, 2007	367.9	45.3	34.9	15.2	19.7	
Penelec						
March 31, 2008	\$ 395.5	\$ 56.0	\$ 39.7	\$ 18.3	\$ 21.4	
March 31, 2007	355.9	65.7	56.0	24.3	31.7	
June 30, 2008	351.4	44.2	30.4	12.0	18.4	
June 30, 2007	331.4	44.5	33.9	14.4	19.5	
September 30, 2008	389.8	46.6	31.7	9.1	22.6	
September 30, 2007	353.4	45.8	33.4	10.4	23.0	
December 31, 2008	376.9	57.7	44.0	18.2	25.8	
December 31, 2007	361.3	48.4	33.6	14.9	18.7	
JCP&L						
March 31, 2008	\$ 794.2	\$ 86.9	\$ 62.4	\$ 28.4	\$ 34.0	
March 31, 2007	683.7	89.9	71.0	32.7	38.3	
June 30, 2008	834.7	97.4	74.4	31.5	42.9	
June 30, 2007	780.0	110.2	89.5	39.7	49.8	
September 30, 2008	1,102.6	157.7	131.7	55.8	75.9	
September 30, 2007	1,033.2	143.3	122.1	46.3	75.8	
December 31, 2008	740.8	92.5	66.7	32.5	34.2	
December 31, 2007	746.9	76.4	52.6	30.4	22.2	

FIRSTENERGY CORP.

LIST OF SUBSIDIARIES OF THE REGISTRANT
AT DECEMBER 31, 2008

Ohio Edison Company - Incorporated in Ohio

The Cleveland Electric Illuminating Company - Incorporated in Ohio

The Toledo Edison Company - Incorporated in Ohio

FirstEnergy Properties, Inc. - Incorporated in Ohio

FirstEnergy Ventures Corp. - Incorporated in Ohio

FirstEnergy Facilities Services Group, LLC - Formation in Ohio

FirstEnergy Securities Transfer Company - Incorporated in Ohio

FirstEnergy Service Company - Incorporated in Ohio

FirstEnergy Solutions Corp. - Incorporated in Ohio

MARBEL Energy Corporation - Incorporated in Ohio

FirstEnergy Nuclear Operating Company - Incorporated in Ohio

American Transmission Systems, Incorporated - Incorporated in Ohio

FELHC, Inc. - Incorporated in Ohio

Jersey Central Power & Light Company - Incorporated in New Jersey

Metropolitan Edison Company - Incorporated in Pennsylvania

Pennsylvania Electric Company - Incorporated in Pennsylvania

GPU Diversified Holdings, LLC - Formation in Delaware

GPU Nuclear, Inc. - Incorporated in New Jersey

GPU Power, Inc. - Incorporated in Delaware

FirstEnergy Foundation - Incorporated in Ohio

FirstEnergy Fiber Holdings Corp. - Incorporated in Delaware

FIRSTENERGY CORP.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-48587, 333-102074, 333-153131, and 333-153608) and Form S-8 (Nos. 333-56094, 333-58279, 333-67798, 333-72766, 333-72768, 333-81183, 333-89356, 333-101472, 333-110662, and 333-146170) of FirstEnergy Corp. of our report dated February 24, 2009 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in the Annual Report to Stockholders, which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report dated February 24, 2009 relating to the financial statement schedule, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

Cleveland, OH
February 24, 2009

OHIO EDISON COMPANY

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-153608-06) of Ohio Edison Company of our report dated February 24, 2009 relating to the financial statements, which appears in the Annual Report to Stockholders, which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report dated February 24, 2009 relating to the financial statement schedule, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

Cleveland, OH
February 24, 2009

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (Nos. 333-153608-05) of The Cleveland Illuminating Company of our report dated February 24, 2009 relating to the financial statements, which appears in the Annual Report to Stockholders, which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report dated February 24, 2009 relating to the financial statement schedule, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

Cleveland, OH
February 24, 2009

THE TOLEDO EDISON COMPANY

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (Nos. 333-153608-04) of The Toledo Edison Company of our report dated February 24, 2009 relating to the financial statements, which appears in the Annual Report to Stockholders, which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report dated February 24, 2009 relating to the financial statement schedule, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

Cleveland, OH
February 24, 2009

JERSEY CENTRAL POWER & LIGHT COMPANY

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (Nos. 333-153608-03) of Jersey Central Power & Light Company of our report dated February 24, 2009 relating to the financial statements, which appears in the Annual Report to Stockholders, which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report dated February 24, 2009 relating to the financial statement schedule, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

Cleveland, OH
February 24, 2009

METROPOLITAN EDISON COMPANY

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (Nos. 333-153608-02) of Metropolitan Edison Company of our report dated February 24, 2009 relating to the financial statements, which appears in the Annual Report to Stockholders, which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report dated February 24, 2009 relating to the financial statement schedule, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

Cleveland, OH
February 24, 2009

PENNSYLVANIA ELECTRIC COMPANY

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (Nos. 333-153608-01) of Pennsylvania Electric Company of our report dated February 24, 2009 relating to the financial statements, which appears in the Annual Report to Stockholders, which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report dated February 24, 2009 relating to the financial statement schedule, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

Cleveland, OH
February 24, 2009

Certification

I, Anthony J. Alexander, certify that:

1. I have reviewed this report on Form 10-K of FirstEnergy Corp.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Anthony J. Alexander

Anthony J. Alexander
Chief Executive Officer

Certification

I, Donald R. Schneider, certify that:

1. I have reviewed this report on Form 10-K of FirstEnergy Solutions Corp.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Donald R. Schneider

Donald R. Schneider
Chief Executive Officer

Certification

I, Richard R. Grigg, certify that:

1. I have reviewed this report on Form 10-K of Ohio Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Richard R. Grigg
Richard R. Grigg
Chief Executive Officer

Certification

I, Richard R. Grigg, certify that:

1. I have reviewed this report on Form 10-K of The Cleveland Electric Illuminating Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Richard R. Grigg
Richard R. Grigg
Chief Executive Officer

Certification

I, Richard R. Grigg, certify that:

1. I have reviewed this report on Form 10-K of The Toledo Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Richard R. Grigg
Richard R. Grigg
Chief Executive Officer

Certification

I, Stephen E. Morgan, certify that:

1. I have reviewed this report on Form 10-K of Jersey Central Power & Light Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Stephen E. Morgan
Stephen E. Morgan
Chief Executive Officer

Certification

I, Richard R. Grigg, certify that:

1. I have reviewed this report on Form 10-K of Metropolitan Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Richard R. Grigg
Richard R. Grigg
Chief Executive Officer

Certification

I, Richard R. Grigg, certify that:

1. I have reviewed this report on Form 10-K of Pennsylvania Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Richard R. Grigg
Richard R. Grigg
Chief Executive Officer

Certification

I, Richard H. Marsh, certify that:

1. I have reviewed this report on Form 10-K of FirstEnergy Corp.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Richard H. Marsh

Richard H. Marsh
Chief Financial Officer

Certification

I, Richard H. Marsh, certify that:

1. I have reviewed this report on Form 10-K of FirstEnergy Solutions Corp.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Richard H. Marsh
Richard H. Marsh
Chief Financial Officer

Certification

I, Richard H. Marsh, certify that:

1. I have reviewed this report on Form 10-K of Ohio Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Richard H. Marsh
Richard H. Marsh
Chief Financial Officer

Certification

I, Richard H. Marsh, certify that:

1. I have reviewed this report on Form 10-K of The Cleveland Electric Illuminating Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Richard H. Marsh

Richard H. Marsh
Chief Financial Officer

Certification

I, Richard H. Marsh, certify that:

1. I have reviewed this report on Form 10-K of The Toledo Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Richard H. Marsh

Richard H. Marsh
Chief Financial Officer

Certification

I, Paulette R. Chatman, certify that:

1. I have reviewed this report on Form 10-K of Jersey Central Power & Light Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Paulette R. Chatman
Paulette R. Chatman
Chief Financial Officer

Certification

I, Richard H. Marsh, certify that:

1. I have reviewed this report on Form 10-K of Metropolitan Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Richard H. Marsh

Richard H. Marsh
Chief Financial Officer

Certification

I, Richard H. Marsh, certify that:

1. I have reviewed this report on Form 10-K of Pennsylvania Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Richard H. Marsh

Richard H. Marsh
Chief Financial Officer

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350**

In connection with the Report of FirstEnergy Corp. (the "Company") on Form 10-K for the year ending December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each undersigned officer of the Company does hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of his knowledge:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Anthony J. Alexander

Anthony J. Alexander
Chief Executive Officer

/s/ Richard H. Marsh

Richard H. Marsh
Chief Financial Officer

Date: February 24, 2009

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350**

In connection with the Report of FirstEnergy Solutions Corp. (the "Company") on Form 10-K for the year ending December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each undersigned officer of the Company does hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of his knowledge:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Donald R. Schneider

Donald R. Schneider
President
(Chief Executive Officer)

/s/ Richard H. Marsh

Richard H. Marsh
Chief Financial Officer

Date: February 24, 2009

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350**

In connection with the Report of Jersey Central Power & Light Company (the "Company") on Form 10-K for the year ending December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each undersigned officer of the Company does hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of his knowledge:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Stephen E. Morgan

Stephen E. Morgan
President
(Chief Executive Officer)

/s/ Paulette R. Chatman

Paulette R. Chatman
Controller
(Chief Financial Officer)

Date: February 24, 2009
