FIRSTENERGY CORP

FORM 10-K
(Annual Report)

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

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2009
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________________ to ___________________

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
333-21011	FIRSTENERGY CORP. (An Ohio Corporation) 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-1843785
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	25-0718085

Akron, OH 44308
Telephone (800)736-3402

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
FirstEnergy Solutions Corp.	Common Stock, no 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 (X) No ( ) FirstEnergy Corp.
Yes ( ) No (X) 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 (X) 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 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 (X) 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.

(X) 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 (X)	FirstEnergy Corp.
Accelerated filer ( )	N/A
Non-accelerated filer (do not check if a smaller reporting company) (X)	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 (X)	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., $11,812,372,021 as of June 30, 2009; 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 JANUARY 31, 2010**
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, 2009	Part II
Proxy Statement for 2010 Annual Meeting of Stockholders to be held May 18, 2010	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 Pennsylvania.
- The impact of the regulatory process on the pending matters in Ohio, Pennsylvania and New Jersey.
- Business and regulatory impacts from ATSI's realignment into PJM.
- 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.
- Operation and maintenance costs being higher than anticipated.
- Other legislative and regulatory changes, and revised environmental requirements, including possible GHG 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 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 similar regulatory initiatives or actions.
- 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.
- Ultimate resolution of Met-Ed's and Penelec's TSC 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 and energy efficiency mandates.
- 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 amounts that are 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 their 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.
- The expected timing and likelihood of completion of the proposed merger with Allegheny Energy, Inc., including the timing, receipt and terms and conditions of any required governmental and regulatory approvals of the proposed merger that could reduce anticipated benefits or cause the parties to abandon the merger, the diversion of management's time and attention from our ongoing business during this time period, the ability to maintain relationships with customers, employees or suppliers as well as the ability to successfully integrate the businesses and realize cost savings and any other synergies and the risk that the credit ratings of the combined company or its subsidiaries may be different from what the companies expect.
- 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. A security rating is not a recommendation to buy, sell or hold securities that may be subject to revision or withdrawal at any time by the assigning rating organization. Each rating should be evaluated independently of any other rating. 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, Incorporated, owns and operates transmission facilities
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
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
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	FirstEnergy, 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
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:

AEP	American Electric Power Company, Inc.
ALJ	Administrative Law Judge
AMP-Ohio	American Municipal Power-Ohio, Inc.
AOCL	Accumulated Other Comprehensive Loss
AQC	Air Quality Control
ARO	Asset Retirement Obligation
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
CMEC	Capacity market Evolution Committee
CO_2	Carbon dioxide
CTC	Competitive Transition Charge
DOE	United States Department of Energy
DOJ	United States Department of Justice
DCPD	Deferred Compensation Plan for Outside Directors
DPA	Department of the Public Advocate, Division of Rate Counsel (New Jersey)
ECAR	East Central Area Reliability Coordination Agreement
EDCP	Executive Deferred Compensation Plan
EE&C	Energy Efficiency and Conservation
EMP	Energy Master Plan
EPA	United States Environmental Protection Agency
EPACT	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
ESOP	Employee Stock Ownership Plan
ESP	Electric Security Plan
FASB	Financial Accounting Standards Board

GLOSSARY OF TERMS, Cont'd.

FERC	Federal Energy Regulatory Commission
FMB	First Mortgage Bond
FPA	Federal Power Act
FRR	Fixed Resource Requirement
GAAP	Accounting Principles Generally Accepted in the United States
GHG	Greenhouse Gases
IBEW	International Brotherhood of Electrical Workers
IFRS	International Financial Reporting Standards
IRS	Internal Revenue Service
JCARR	Joint Committee on Agency Review
kV	Kilovolt
KWH	Kilowatt-hours
LED	Light-emitting Diode
LIBOR	London Interbank Offered Rate
LOC	Letter of Credit
LTIP	Long-Term Incentive Plan
MACT	Maximum Achievable Control Technology
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service, Inc.
MRO	Market Rate Offer
MW	Megawatts
MWH	Megawatt-hours
NAAQS	National Ambient Air Quality Standards
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NNSR	Non-Attainment New Source Review
NOPEC	Northeast Ohio Public Energy Council
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
OCC	Ohio Consumers' Counsel
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
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
PPUC	Pennsylvania Public Utility Commission
PSA	Power Supply Agreement
PSD	Prevention of Significant Deterioration
PUCO	Public Utilities Commission of Ohio
QSPE	Qualifying Special-Purpose Entity
RCP	Rate Certainty Plan
RECs	Renewable Energy Credits
RFP	Request for Proposal
RPM	Reliability Pricing Model
RTEP	Regional Transmission Expansion Plan
RTC	Regulatory Transition Charge
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Service
SB221	Amended Substitute Senate Bill 221
SBC	Societal Benefits Charge
SEC	U.S. Securities and Exchange Commission
SECA	Seams Elimination Cost Adjustment
SIP	State Implementation Plan(s) Under the Clean Air Act
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SRECs	Solar Renewable Energy Credits
TBC	Transition Bond Charge

GLOSSARY OF TERMS, Cont'd.

TMI-2	Three Mile Island Unit 2
TSC	Transmission Service Charge
VERO	Voluntary Enhanced Retirement Option
VIE	Variable Interest Entity

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PART I

ITEM 1. BUSINESS

Proposed Merger with Allegheny Energy, Inc.

On February 10, 2010, FirstEnergy entered into an Agreement and Plan of Merger (Merger Agreement) with Element Merger Sub, Inc., a Maryland corporation and its wholly-owned subsidiary (Merger Sub) and Allegheny Energy, Inc., a Maryland corporation (Allegheny). Upon the terms and subject to the conditions set forth in the Merger Agreement, Merger Sub will merge with and into Allegheny with Allegheny continuing as the surviving corporation and a wholly-owned subsidiary of FirstEnergy. Pursuant to the Merger Agreement, upon the closing of the merger, each issued and outstanding share of Allegheny common stock, including grants of restricted common stock, will automatically be converted into the right to receive 0.667 of a share of common stock of FirstEnergy. Completion of the merger is conditioned upon, among other things, shareholder approval of both companies as well as expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and approval by the FERC, the Maryland Public Service Commission, PPUC , the Virginia State Corporation Commission and the West Virginia Public Service Commission. FirstEnergy anticipates that the necessary approvals will be obtained within 12 to 14 months. The Merger Agreement contains certain termination rights for both FirstEnergy and Allegheny, and further provides for the payment of fees and expenses upon termination under specified circumstances. Further information concerning the proposed merger will be included in a joint proxy statement/prospectus contained in the registration statement on Form S-4 to be filed by FirstEnergy with the SEC in connection with the merger. See Note 21 to the consolidated financial statements.

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; and of its generating and marketing subsidiary, FES. 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., FEV, FENOC, FELHC, Inc., FirstEnergy Facilities Services Group, LLC, FirstEnergy Fiber Holdings Corp., GPU Power, Inc., GPU Nuclear, Inc., MARBEL Energy Corporation, 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 13,970 MW of diversified capacity (FES – 13,770 MW and JCP&L – 200 MW). Within FES' portfolio, approximately 7,469 MW, or 54.2%, consists of coal-fired capacity; 3,991 MW, or 29.0%, consists of nuclear capacity; 1,599 MW, or 11.6%, consists of oil and natural gas peaking units; 451 MW, or 3.3%, consists of hydroelectric capacity; and 260 MW, or 1.9%, consists of capacity from FGCO's current 11.5% 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. Additionally, see FERC Matters for RTO Consolidation.

FES, FGCO and NGC comply with the regulations, orders, policies and practices prescribed by the SEC and the FERC. 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. Additionally, see FERC Matters for RTO Consolidation.

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 PPUC.

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 PPUC.

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

Reference is made to Note 16, 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, New Jersey, 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. Additionally, see FERC Matters for RTO Consolidation.

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 regulatory accounting to those operations.

FirstEnergy accounts for the effects of regulation through the application of regulatory accounting 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 (regulatory assets) if the rate actions of its regulator make it probable that those costs will be recovered in future revenue. Regulatory accounting is applied only to the parts of the business that meet the above criteria. If a portion of the business applying regulatory accounting no longer meets those requirements, previously recorded net regulatory assets are removed from the balance sheet in accordance with GAAP.

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 2005, Congress amended the FPA 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 FPA 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 that could 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 found it to be in full compliance with all audited reliability standards. Our MISO facilities are next due for the periodic audit by Reliability *First* later this year.

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. On March 31, 2009, the NERC initiated a Compliance Violation Investigation in order to determine JCP&L's contribution to the electrical event and to review any potential violation of NERC Reliability Standards associated with the event. The initial phase of the investigation required JCP&L to respond to the NERC's request for factual data about the outage. JCP&L submitted its written response on May 1, 2009. The NERC conducted on site interviews with personnel involved in responding to the event on June 16-17, 2009. On July 7, 2009, the NERC issued additional questions regarding the event and JCP&L replied as requested on August 6, 2009. JCP&L is not able at this time to predict what actions, if any, that the NERC may take based on the data submittals or interview results.

On June 5, 2009, FirstEnergy self-reported to Reliability *First* a potential violation of NERC Standard PRC-005 resulting from its inability to validate maintenance records for 20 protection system relays (out of approximately 20,000 reportable relays) in JCP&L's and Penelec's transmission systems. These potential violations were discovered during a comprehensive field review of all FirstEnergy substations to verify equipment and maintenance database accuracy. FirstEnergy has completed all mitigation actions, including calibrations and maintenance records for the relays. Reliability *First* issued an Initial Notice of Alleged Violation on June 22, 2009. The NERC approved FirstEnergy's mitigation plan on August 19, 2009, and submitted it to the FERC for approval on August 19, 2009. FirstEnergy is not able at this time to predict what actions or penalties, if any, that Reliability *First* will propose for this self-reported violation.

Ohio Regulatory Matters

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. On January 21, 2009, the PUCO granted the Ohio Companies' application in part 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 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. The PUCO granted these applications for rehearing on March 18, 2009 for the purpose of further consideration. The PUCO has not yet issued a substantive Entry on Rehearing.

SB221, which became effective on July 31, 2008, required all electric utilities to file an ESP, and permitted the filing of an MRO. On July 31, 2008, the Ohio Companies filed with the PUCO a comprehensive ESP and a separate MRO. The PUCO denied the MRO application; however, the PUCO later granted the Ohio Companies' application for rehearing for the purpose of further consideration of the matter. The PUCO has not yet issued a substantive Entry on Rehearing. 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. In response to the PUCO's December 19, 2008 order, which significantly modified and approved the ESP as modified, the Ohio Companies notified the PUCO that they were withdrawing and terminating the ESP application in addition to continuing their rate plan then in effect as allowed by the terms of SB221. On December 31, 2008, the Ohio Companies conducted a CBP for the procurement of electric generation for retail customers from January 5, 2009 through March 31, 2009. The average winning bid price was equivalent to a retail rate of 6.98 cents per KWH. The power supply obtained through this process provided generation service to the Ohio Companies' retail customers who chose not to shop with alternative suppliers. On January 9, 2009, the Ohio Companies requested the implementation of a new fuel rider to recover the costs resulting from the December 31, 2008 CBP. The PUCO ultimately approved the Ohio Companies' request for a new fuel rider to recover increased costs resulting from the CBP but denied OE's and TE's request to continue collecting RTC and denied the request to allow the Ohio Companies to continue collections pursuant to the two existing fuel riders. The new fuel rider recovered the increased purchased power costs for OE and TE, and recovered a portion of those costs for CEI, with the remainder being deferred for future recovery.

On January 29, 2009, the PUCO ordered its Staff to develop a proposal to establish an ESP for the Ohio Companies. 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. Specifically, the Amended ESP provided that generation would be provided by FES at the average wholesale rate of the CBP described above for April and May 2009 to the Ohio Companies for their non-shopping customers; for the period of June 1, 2009 through May 31, 2011, retail generation prices would be based upon the outcome of a descending clock CBP on a slice-of-system basis. The Amended ESP further provided that the Ohio Companies will not seek a base distribution rate increase, subject to certain exceptions, with an effective date of such increase before January 1, 2012, that CEI would agree to write-off approximately $216 million of its Extended RTC regulatory asset, and that the Ohio Companies would 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. The Amended ESP also addressed a number of other issues, including but not limited to, rate design for various customer classes, and resolution of the prudence review and the collection of deferred costs that were approved in prior proceedings. On February 26, 2009, the Ohio Companies filed a Supplemental Stipulation, which was signed or not opposed by virtually all of the parties to the proceeding, that supplemented and modified certain provisions of the February 19, 2009 Stipulation and Recommendation. Specifically, the Supplemental Stipulation modified the provision relating to governmental aggregation and the Generation Service Uncollectible Rider, provided further detail on the allocation of the economic development funding contained in the Stipulation and Recommendation, and proposed additional provisions related to the collaborative process for the development of energy efficiency programs, among other provisions. The PUCO adopted and approved certain aspects of the Stipulation and Recommendation on March 4, 2009, and adopted and approved the remainder of the Stipulation and Recommendation and Supplemental Stipulation without modification on March 25, 2009. Certain aspects of the Stipulation and Recommendation and Supplemental Stipulation took effect on April 1, 2009 while the remaining provisions took effect on June 1, 2009.

The CBP auction occurred on May 13-14, 2009, and resulted in a weighted average wholesale price for generation and transmission of 6.15 cents per KWH. The bid was for a single, two-year product for the service period from June 1, 2009 through May 31, 2011. FES participated in the auction, winning 51% of the tranches (one tranche equals one percent of the load supply). Subsequent to the signing of the wholesale contracts, four winning bidders reached separate agreements with FES with the result that FES is now responsible for providing 77% of the Ohio Companies' total load supply. The results of the CBP were accepted by the PUCO on May 14, 2009. FES has also separately contracted with numerous communities to provide retail generation service through governmental aggregation programs.

On July 27, 2009, the Ohio Companies filed applications with the PUCO to recover three different categories of deferred distribution costs on an accelerated basis. In the Ohio Companies' Amended ESP, the PUCO approved the recovery of these deferrals, with collection originally set to begin in January 2011 and to continue over a 5 or 25 year period. The principal amount plus carrying charges through August 31, 2009 for these deferrals totaled $305.1 million. The applications were approved by the PUCO on August 19, 2009. Recovery of this amount, together with carrying charges calculated as approved in the Amended ESP, commenced on September 1, 2009, and will be collected in the 18 non-summer months from September 2009 through May 2011, subject to reconciliation until fully collected, with $165 million of the above amount being recovered from residential customers, and $140.1 million being recovered from non-residential customers.

SB221 also requires electric distribution utilities to implement energy efficiency programs. Under the provisions of SB221, the Ohio Companies are required to achieve a total annual energy savings equivalent of approximately 166,000 MWH in 2009, 290,000 MWH in 2010, 410,000 MWH in 2011, 470,000 MWH in 2012 and 530,000 MWH in 2013, with additional savings required through 2025. Utilities are also required to reduce peak demand in 2009 by 1%, with an additional .75% reduction each year thereafter through 2018. The PUCO may amend these benchmarks in certain, limited circumstances, and the Ohio Companies have filed an application with the PUCO seeking such amendments. As discussed below, on January 7, 2010, the PUCO amended the 2009 energy efficiency benchmarks to zero, contingent upon the Ohio Companies meeting the revised benchmarks in a period of not more than three years. The PUCO has not yet acted upon the application seeking a reduction of the peak demand reduction requirements. The Ohio Companies are presently involved in collaborative efforts related to energy efficiency, including filing applications for approval with the PUCO, as well as other implementation efforts arising out of the Supplemental Stipulation. On December 15, 2009, the Ohio Companies filed the required three year portfolio plan seeking approval for the programs they intend to implement to meet the energy efficiency and peak demand reduction requirements for the 2010-2012 period. The PUCO has set the matter for hearing on March 2, 2010. The Ohio Companies expect that all costs associated with compliance will be recoverable from customers.

In October 2009, the PUCO issued additional Entries, modifying certain of its previous rules that set out the manner in which electric utilities, including the Ohio Companies, will be required to comply with benchmarks contained in SB221 related to the employment of alternative energy resources, energy efficiency/peak demand reduction programs as well as greenhouse gas reporting requirements and changes to long term forecast reporting requirements. Applications for rehearing filed in mid-November 2009 were granted on December 9, 2009 for the sole purpose of further consideration of the matters raised in those applications. The PUCO has not yet issued a substantive Entry on Rehearing. The rules implementing the requirements of SB221 went into effect on December 10, 2009. The Ohio Companies, on October 27, 2009, submitted an application to amend their 2009 statutory energy efficiency benchmarks to zero. On January 7, 2010, the PUCO issued an Order granting the Companies' request to amend the energy efficiency benchmarks.

Additionally under SB221, electric utilities and electric service companies are required to serve part of their load from renewable energy resources equivalent to 0.25% of the KWH they serve in 2009. In August and October 2009, the Ohio Companies conducted RFPs to secure RECs. The RFPs sought renewable energy RECs, including solar RECs and RECs generated in Ohio in order to meet the Ohio Companies' alternative energy requirements set forth in SB221. The RECs acquired through these two RFPs will be used to help meet the renewable energy requirements established under SB221 for 2009, 2010 and 2011. On December 7, 2009, the Ohio Companies filed an application with the PUCO seeking a force majeure determination regarding the Ohio Companies' compliance with the 2009 solar energy resources benchmark, and seeking a reduction in the benchmark. The PUCO has not yet ruled on that application.

On October 20, 2009, the Ohio Companies filed an MRO to procure electric generation service for the period beginning June 1, 2011. The proposed MRO would establish a CBP to secure generation supply for customers who do not shop with an alternative supplier and would be similar, in all material respects, to the CBP conducted in May 2009 in that it would procure energy, capacity and certain transmission services on a slice of system basis. Enhancements to the May 2009 CBP, the MRO would include multiple bidding sessions and multiple products with different delivery periods for generation supply features which are designed to reduce potential price volatility and reduce supplier risk and encourage bidder participation. A technical conference was held on October 29, 2009. Hearings took place in December and the matter has been fully briefed. Pursuant to SB221, the PUCO has 90 days from the date of the application to determine whether the MRO meets certain statutory requirements. Although the Ohio Companies requested a PUCO determination by January 18, 2010, on February 3, 2010, the PUCO announced that its determination would be delayed. Under a determination that such statutory requirements are met, the Ohio Companies would be able to implement the MRO and conduct the CBP.

Pennsylvania Regulatory 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.

On February 20, 2009, Met-Ed and Penelec filed with the PPUC a generation procurement plan covering the period January 1, 2011 through May 31, 2013. The 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 proposed a staggered procurement schedule, which varies by customer class, through the use of a descending clock auction. On August 12, 2009, Met-Ed and Penelec filed a settlement agreement with the PPUC for the generation procurement plan covering the period January 1, 2011, through May 31, 2013, reflecting the settlement on all but two issues. The settlement plan is designed to provide adequate and reliable service as required by Pennsylvania law through a prudent mix of long-term, short-term and spot-market generation supply as required by Act 129. The settlement plan proposes a staggered procurement schedule, which varies by customer class. On September 2, 2009, the ALJ issued a Recommended Decision (RD) approving the settlement and adopted Met-Ed and Penelec's positions on two reserved issues. On November 6, 2009, the PPUC entered an Order approving the settlement and finding in favor of Met-Ed and Penelec on the two reserved issues. Generation procurement began in January 2010.

On May 22, 2008, the PPUC approved Met-Ed and Penelec annual updates to the TSC rider for the period June 1, 2008, through May 31, 2009. The TSCs included a component for under-recovery of actual transmission costs incurred during the prior period (Met-Ed - $144 million and Penelec - $4 million) and 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 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 Met-Ed and Penelec have concluded. On August 11, 2009, the ALJ issued a Recommended Decision to the PPUC approving Met-Ed's and Penelec's TSCs as filed and dismissing all complaints. Exceptions by various interveners were filed and reply exceptions were filed by Met-Ed and Penelec. On January 28, 2010, the PPUC adopted a motion which denies the recovery of marginal transmission losses through the TSC for the period of June 1, 2007 through March 31, 2008, and instructs Met-Ed and Penelec to work with the parties and file a petition to retain any over-collection, with interest, until 2011 for the purpose of providing mitigation of future rate increases starting in 2011 for their customers. Met-Ed and Penelec are now awaiting an order, which is expected to be consistent with the motion. If so, Met-Ed and Penelec plan to appeal such a decision to the Commonwealth Court of Pennsylvania. Although the ultimate outcome of this matter cannot be determined at this time, it is the belief of the companies that they should prevail in any such appeal and therefore expect to fully recover the approximately $170.5 million ($138.7 million for Met-Ed and $31.8 million for Penelec) in marginal transmission losses for the period prior to January 1, 2011.

On May 28, 2009, the PPUC approved Met-Ed's and Penelec's annual updates to their TSC rider for the period June 1, 2009 through May 31, 2010, subject to the outcome of the proceeding related to the 2008 TSC filing described above. For Penelec's customers the new TSC resulted in an approximate 1% decrease in monthly bills, reflecting projected PJM transmission costs as well as a reconciliation for costs already incurred. The TSC for Met-Ed's customers increased to recover the additional PJM charges paid by Met-Ed in the previous year and to reflect updated projected costs. In order to gradually transition customers to the higher rate, the PPUC approved Met-Ed's proposal to continue to recover the prior period deferrals allowed in the PPUC's May 2008 Order and defer $57.5 million of projected costs to a future TSC to be fully recovered by December 31, 2010. Under this proposal, monthly bills for Met-Ed's customers would increase approximately 9.4% for the period June 2009 through May 2010.

Act 129 became effective in 2008 and addresses issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters; and alternative energy. Among other things Act 129 requires each Pennsylvania utility to file with the PPUC an energy efficiency and peak load reduction plan by July 1, 2009, setting forth the utilities' plans to reduce energy consumption by a minimum of 1% and 3% by May 31, 2011 and May 31, 2013, respectively, and to reduce peak demand by a minimum of 4.5% by May 31, 2013. On July 1, 2009, Met-Ed, Penelec, and Penn filed EE&C Plans with the PPUC in accordance with Act 129. The Pennsylvania Companies submitted a supplemental filing on July 31, 2009, to revise the Total Resource Cost test items in the EE&C Plans pursuant to the PPUC's June 23, 2009 Order. Following an evidentiary hearing and briefing, the Pennsylvania Companies filed revised EE&C Plans on September 21, 2009. In an October 28, 2009 Order, the PPUC approved in part, and rejected in part, the Pennsylvania Companies' filing. Following additional filings related to the plans, including modifications as requested by the PPUC. The PPUC issued an order on January 28, 2010, approving, in part, and rejecting, in part the Pennsylvania Companies' modified plans. The Pennsylvania Companies filed final plans and tariff revisions on February 5, 2010 consistent with the minor revisions required by the PPUC. The PPUC must approve or reject the plans within 60 days.

Act 129 also required utilities to file by August 14, 2009 with the PPUC smart meter technology procurement and installation plan to provide for the installation of smart meter technology within 15 years. On August 14, 2009, Met-Ed, Penelec and Penn jointly filed a Smart Meter Technology Procurement and Installation Plan. Consistent with the PPUC's rules, this plan proposes a 24-month assessment period in which the Pennsylvania Companies will assess their needs, select the necessary technology, secure vendors, train personnel, install and test support equipment, and establish a cost effective and strategic deployment schedule, which currently is expected to be completed in fifteen years. Met-Ed, Penelec and Penn estimate assessment period costs at approximately $29.5 million, which the Pennsylvania Companies, in their plan, proposed to recover through an automatic adjustment clause. A Technical Conference and evidentiary hearings were held in November 2009. Briefs were filed on December 11, 2009, and Reply Briefs were filed on December 31, 2009. An Initial Decision was issued by the presiding ALJ on January 28, 2010. The ALJ's Initial Decision approved the Smart Meter Plan as modified by the ALJ, including: ensuring that the smart meters to be deployed include the capabilities listed in the Commission's Implementation Order; eliminating the provision of interest in the 1307(e) reconciliation; providing for the recovery of reasonable and prudent costs minus resulting savings from installation and use of smart meters; and reflecting that administrative start-up costs be expensed and the costs incurred for research and development in the assessment period be capitalized. Exceptions are due on February 17, 2010, and Reply Exceptions are due on March 1. The Pennsylvania Companies expect the PPUC to act on the plans in early 2010.

Legislation addressing rate mitigation and the expiration of rate caps has been introduced in both the 2008 and 2009 legislative sessions. The final form of such legislation and its possible impact on the Pennsylvania Companies' business and operations are uncertain.

On February 26, 2009, the PPUC approved a Voluntary Prepayment Plan requested by Met-Ed and Penelec that provides an opportunity for residential and small commercial customers to prepay an amount on their monthly electric bills during 2009 and 2010. Customer prepayments earn interest at 7.5% and will be used to reduce electricity charges in 2011 and 2012.

On March 31, 2009, Met-Ed and Penelec submitted their 5-year NUG Statement Compliance filing to the PPUC in accordance with their 1998 Restructuring Settlement originally entered into with the PPUC pursuant to comprehensive electric utility industry restructuring legislation (Customer Choice Act) adopted in Pennsylvania in 1996. In the compliance filing, Met-Ed proposed to reduce its CTC rate for the residential class with a corresponding increase in the generation rate and the shopping credit, and Penelec proposed to reduce its CTC rate to zero for all classes with a corresponding increase in the generation rate and the shopping credit. While these changes would result in additional annual generation revenue (Met-Ed - $27 million and Penelec - $59 million), overall rates would remain unchanged. On July 30, 2009, the PPUC entered an order approving the 5-year NUG Statement, approving the reduction of the CTC, and directing Met-Ed and Penelec to file a tariff supplement implementing this change. On July 31, 2009, Met-Ed and Penelec filed tariff supplements decreasing the CTC rate in compliance with the July 30, 2009 order, and increasing the generation rate in compliance with the companies' Restructuring Orders of 1998. On August 14, 2009, the PPUC approved Met-Ed and Penelec's compliance filings.

By Tentative Order entered September 17, 2009, the PPUC provided for an additional 30-day comment period on whether "the Restructuring Settlement allows NUG over-collection for select and isolated months to be used to reduce non-NUG stranded costs when a cumulative NUG stranded cost balance exists." In response to the Tentative Order, the Office of Small Business Advocate, Office of Consumer Advocate, York County Solid Waste and Refuse Authority, ARIPPA, the Met-Ed Industrial Users Group and Penelec Industrial Customer Alliance filed comments objecting to the above accounting method utilized by Met-Ed and Penelec. Met-Ed and Penelec filed reply comments on October 26, 2009. On November 5, 2009, the PPUC issued a Secretarial Letter allowing parties to file reply comments to Met-Ed and Penelec's reply comments by November 16, 2009, and reply comments were filed by the Office of Consumer Advocate, ARIPPA, and the Met-Ed Industrial Users Group and Penelec Industrial Customer Alliance. Met-Ed and Penelec are awaiting further action by the Commission.

On February 8, 2010, Penn filed with the PPUC a generation procurement plan covering the period June 1, 2011 through May 31, 2013. The plan is designed to provide adequate and reliable service through a prudent mix of long-term, short-term and spot market generation supply, as required by Act 129. The plan proposed a staggered procurement schedule, which varies by customer class, through the use of a descending clock auction. The PPUC is required to issue an order on the plan no later than November 8, 2010.

New Jersey Regulatory 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 30, 2009, the accumulated deferred cost balance totaled approximately $98 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. TMI-2 is a retired nuclear facility owned by JCP&L. 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 DPA 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 March 13, 2009, JCP&L filed its annual SBC Petition with the NJBPU that includes a request for a reduction in the level of recovery of TMI-2 decommissioning costs based on an updated TMI-2 decommissioning cost analysis dated January 2009. This matter is currently pending before the NJBPU.

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.

On January 28, 2009, the NJBPU adopted an order establishing the general process and contents of specific EMP plans that must be filed by New Jersey electric and gas utilities in order to achieve the goals of the EMP. Such utility specific plans are due to be filed with the NJBPU by July 1, 2010. At this time, FirstEnergy and JCP&L cannot determine the impact, if any, the EMP may have on their business or operations.

In support of former New Jersey Governor Corzine's Economic Assistance and Recovery Plan, JCP&L announced a proposal to spend approximately $98 million on infrastructure and energy efficiency projects in 2009. Under the proposal, an estimated $40 million would be spent on infrastructure projects, including substation upgrades, new transformers, distribution line re-closers and automated breaker operations. In addition, approximately $34 million would be spent implementing new demand response programs as well as expanding on existing programs. Another $11 million would be spent on energy efficiency, specifically replacing transformers and capacitor control systems and installing new LED street lights. The remaining $13 million would be spent on energy efficiency programs that would complement those currently being offered. The project relating to expansion of the existing demand response programs was approved by the NJBPU on August 19, 2009, and implementation began in 2009. Approval for the $11 million project related to energy efficiency programs intended to complement those currently being offered was denied by the NJBPU on December 1, 2009. Implementation of the remaining projects is dependent upon resolution of regulatory issues between the NJBPU and JCP&L including recovery of the costs associated with the proposal.

On February 11, 2010, S&P downgraded the senior unsecured debt of FirstEnergy Corp. to BB+. As a result, pursuant to the requirements of a pre-existing NJBPU order, JCP&L filed, on February 17, 2010, a plan addressing the mitigation of any effect of the downgrade and provided an assessment of present and future liquidity necessary to assure JCP&L's continued payment to BGS suppliers. The order also provides that the NJBPU should: 1) within 10 days of that filing, hold a public hearing to review the plan and consider the available options and 2) within 30 days of that filing issue an order with respect to the matter. At this time, the public hearing has not been scheduled and FirstEnergy and JCP&L cannot determine the impact, if any, these proceedings will have on their operations.

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. 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. On October 29, 2009, FirstEnergy, with another Company, filed an additional settlement agreement with FERC to resolve their outstanding claims. FirstEnergy is actively pursuing settlement agreements with other parties to the case. On December 8, 2009, certain parties sought a writ of mandamus from the DC Circuit Court of Appeals directing FERC to issue an order on the Initial Decision. The Court agreed to hold this matter in abeyance based upon FERC's representation to use good faith efforts to issue a substantive ruling on the initial decision no later than May 27, 2010. If FERC fails to act, the case will be submitted for briefing in June. The outcome of this matter cannot be predicted.

PJM Transmission Rate

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 on the content of the compliance filings 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. AEP's 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 (Opinion 494) 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, the FERC's April 19, 2007, and January 31, 2008, orders were appealed to the federal Court of Appeals for the D.C. Circuit. The Illinois Commerce Commission, the PUCO and another party have also appealed these orders to the Seventh Circuit Court of Appeals. The appeals of these parties and others were consolidated for argument in the Seventh Circuit and the Seventh Circuit Court of Appeals issued a decision on August 6, 2009. The court found that FERC had not marshaled enough evidence to support its decision to allocate cost for new 500+kV facilities on a postage-stamp basis and, based on this finding, remanded the rate design issue back to FERC. A request for rehearing and rehearing en banc by two companies was denied by the Seventh Circuit on October 20, 2009. On October 28, 2009, the Seventh Circuit closed its case dockets and returned the case to FERC for further action on the remand order. In an order dated January 21, 2010, FERC set the matter for "paper hearings" – meaning that FERC called for parties to submit comments or written testimony pursuant to the schedule described in the order. FERC identified nine separate issues for comments, and directed PJM to file the first round of comments on February 22, 2010, with other parties submitting responsive comments on April 8, 2010 and May 10, 2010.

The FERC's orders on PJM rate design prevented 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 postage-stamp basis reduces the cost 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. On November 14, 2008, PJM submitted revisions to its tariff to incorporate cost responsibility assignments for below 500 kV upgrades included in PJM's RTEP process in accordance with the settlement. The remaining merchant transmission cost allocation issues were the subject of a hearing at the FERC in May 2008. On November 19, 2009, FERC issued Opinion 503 agreeing that RTEP costs should be allocated on a pro-rata basis to merchant transmission companies. On December 22, 2009, a request for a rehearing of FERC's Opinion No. 503 was made. On January 19, 2010, the FERC issued a procedural order noting that FERC would address the rehearing requests in a future order.

RTO Consolidation

On August 17, 2009, FirstEnergy filed an application with the FERC requesting to consolidate its transmission assets and operations into PJM. Currently, FirstEnergy's transmission assets and operations are divided between PJM and MISO. The consolidation would make the transmission assets that are part of ATSI, whose footprint includes the Ohio Companies and Penn, part of PJM. Most of FirstEnergy's transmission assets in Pennsylvania and all of the transmission assets in New Jersey already operate as a part of PJM. Key elements of the filing include a Fixed Resource Requirement Plan (FRR Plan) that describes the means whereby capacity will be procured and administered as necessary to satisfy the PJM capacity requirements for the 2011-12 and 2012-13 delivery years; and also a request that ATSI's transmission customers be excused from the costs for regional transmission projects that were approved through PJM's RTEP process prior to ATSI's entry into PJM (legacy RTEP costs). The integration is expected to be complete on June 1, 2011, to coincide with delivery of power under the next competitive generation procurement process for the Ohio Companies and Penn. To ensure a definitive ruling at the same time the FERC rules on its request to integrate ATSI into PJM, on October 19, 2009, FirstEnergy filed a related complaint with the FERC on the issue of exempting the ATSI footprint from the legacy RTEP costs.

On September 4, 2009, the PUCO opened a case to take comments from Ohio's stakeholders regarding the RTO consolidation. FirstEnergy filed extensive comments in the PUCO case on September 25, 2009, and reply comments on October 13, 2009, and attended a public meeting on September 15, 2009 to answer questions regarding the RTO consolidation. Several parties have intervened in the regulatory dockets at the FERC and at the PUCO. Certain interveners have commented and protested particular elements of the proposed RTO consolidation, including an exit fee to MISO, integration costs to PJM, and cost-allocations of future transmission upgrades in PJM and MISO.

On December 17, 2009, FERC issued an order approving, subject to certain future compliance filings, ATSI's move to PJM. FirstEnergy's request to be exempted from legacy RTEP costs was rejected and its complaint dismissed.

On December 17, 2009, ATSI executed the PJM Consolidated Transmission Owners Agreement. On December 18, 2009, the Ohio Companies and Penn executed the PJM Operating Agreement and the PJM Reliability Assurance Agreement. Execution of these agreements committed ATSI and the Ohio Companies and Penn's load to moving into PJM on the schedule described in the application and approved in the FERC Order (June 1, 2011).

On January 15, 2010, the Ohio Companies and Penn submitted a compliance filing describing the process whereby ATSI-zone load serving entities (LSEs) can “opt out” of the Ohio Companies' and Penn's FRR Plan for the 2011-12 and 2012-13 Delivery Years. On January 16, 2010, FirstEnergy filed for clarification or rehearing of certain issues associated with implementing the FRR auctions on the proposed schedule. On January 19, 2010, FirstEnergy filed for rehearing of FERC's decision to impose the legacy RTEP costs on ATSI's transmission customers. Also on January 19, 2010, several parties, including the PUCO and the OCC asked for rehearing of parts of FERC's order. None of the rehearing parties asked FERC to rescind authorization for ATSI to enter PJM. Instead, parties focused on questions of cost and cost allocation or on alleged errors in implementing the move. On February 3, 2010, FirstEnergy filed an answer to the January 19, 2010 rehearing request of other parties. On February 16, 2010, FirstEnergy submitted a second compliance filing to FERC; the filing describes communications protocols and performance deficiency penalties for capacity suppliers that are taken in FRR auctions.

FirstEnergy will conduct FRR auctions on March 15-19, 2010, for the 2011-12 and 2012-13 delivery years. LSE's in the ATSI territory, including the Ohio Companies and Penn, will participate in PJM's next base residual auction for capacity resources for the 2013-2014 delivery years. This auction will be conducted in May of 2010. FirstEnergy expects to integrate into PJM effective June 1, 2011.

Changes ordered for PJM Reliability Pricing Model (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. 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 discussions. On February 9, 2009, PJM and a group of stakeholders submitted an offer of settlement, which used the PJM December 12, 2008 filing as its starting point, and stated that unless otherwise specified, provisions filed by PJM on December 12, 2008 apply.

On March 26, 2009, the FERC accepted in part, and rejected in part, tariff provisions submitted by PJM, revising certain parts of its RPM. It ordered changes included making incremental improvements to RPM and clarification on certain aspects of the March 26, 2009 Order. On April 27, 2009, PJM submitted a compliance filing addressing the changes the FERC ordered in the March 26, 2009 Order; subsequently, numerous parties filed requests for rehearing of the March 26, 2009 Order. On June 18, 2009, the FERC denied rehearing and request for oral argument of the March 26, 2009 Order.

PJM has reconvened the CMEC and has scheduled a CMEC Long-Term Issues Symposium to address near-term changes directed by the March 26, 2009 Order and other long-term issues not addressed in the February 2009 settlement. PJM made a compliance filing on September 1, 2009, incorporating tariff changes directed by the March 26, 2009 Order. The tariff changes were approved by the FERC in an order issued on October 30, 2009, and are effective November 1, 2009. The CMEC continues to work to address additional compliance items directed by the March 26, 2009 Order. On December 1, 2009, PJM informed FERC that PJM would file a scarcity-pricing design with the FERC on April 1, 2010.

MISO-PJM Billing Dispute

In September 2009, PJM reported that it had discovered a modeling error in the market-to-market power flow calculations between PJM and the MISO under the Joint Operating Agreement. The error, which dates back to 2005, was a result of the incorrect modeling of certain generation resources that have an impact on power flows across the PJM-MISO border. FERC settlement discussions on this issue have commenced, and FirstEnergy is participating in these discussions. The next settlement conference is set for February 25, 2010. Although the amount of the error is subject to dispute, PJM has estimated the magnitude of the error to be approximately $77 million in total to all parties. Should a payment by PJM to the MISO relating to the modeling error be required, the method by which PJM would collect such payments from PJM participants, and how MISO would allocate payments received to MISO participants, is uncertain at this time.

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 and FES. This requirement was 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. The FERC conditionally approved MISO's Resource Adequacy proposal on March 26, 2008. 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 April 16, 2009, the FERC issued an additional order on rehearing and compliance, approving MISO's proposed financial settlement provision for Resource Adequacy. The MISO Resource Adequacy program was implemented as planned and became effective on June 1, 2009, the beginning of the MISO planning year. On June 17, 2009, MISO submitted a compliance filing in response to the FERC's April 16, 2009 order directing it to address, among others, various market monitoring and mitigation issues. On July 8, 2009, various parties submitted comments on and protests to MISO's compliance filing. FirstEnergy submitted comments identifying specific aspects of the MISO's and Independent Market Monitor's proposals for market monitoring and mitigation and other issues that it believes the FERC should address and clarify. On October 23, 2009, FERC issued an order approving a MISO compliance filing that revised its tariff to provide for netting of demand resources, but prohibiting the netting of behind-the-meter generation.

FES Sales to Affiliates

FES supplied all of the power requirements for the Ohio Companies pursuant to a PSA that ended on December 31, 2008. On January 2, 2009, FES signed an agreement to provide 75% of the Ohio Companies' power requirements for the period January 5, 2009 through March 31, 2009. Subsequently, FES signed an agreement to provide 100% of the Ohio Companies' power requirements for the period April 1, 2009 through May 31, 2009. On March 4, 2009, the PUCO issued an order approving these two affiliate sales agreements. FERC authorization for these affiliate sales was by means of a December 23, 2008 waiver of restrictions on affiliate sales without prior approval of the FERC. Rehearing was denied on July 31, 2009. On October 19, 2009, the FERC accepted FirstEnergy's revised tariffs.

On May 13-14, 2009, FES participated in a descending clock auction for PLR service administered by the Ohio Companies and their consultant, CRA International. FES won 51 tranches in the auction, and entered into a Master SSO Supply Agreement to provide capacity, energy, ancillary services and transmission to the Ohio Companies for a two-year period beginning June 1, 2009. Other winning suppliers have assigned their Master SSO Supply Agreements to FES, five of which were effective in June, two more in July, four more in August and ten more in September, 2009. FES also supplies power used by Constellation to serve an additional five tranches. As a result of these arrangements, FES serves 77 tranches, or 77% of the PLR load of the Ohio Companies.

On November 3, 2009, FES, Met-Ed, Penelec and Waverly restated their partial requirements power purchase agreement for 2010. The Fourth Restated Partial Requirements Agreement (PRA) continues to limit the amount of capacity resources required to be supplied by FES to 3,544 MW, but requires FES to supply essentially all of Met-Ed, Penelec, and Waverly's energy requirements in 2010. Under the Fourth Restated Partial Requirements Agreement, Met-Ed, Penelec, and Waverly (Buyers) assigned 1,300 MW of existing energy purchases to FES to assist it in supplying Buyers' power supply requirements and managing congestion expenses. FES can either sell the assigned power from the third party into the market or use it to serve the Met-Ed/Penelec load. FES is responsible for obtaining additional power supplies in the event of failure of supply of the assigned energy purchase contracts. Prices for the power sold by FES under the Fourth Restated Partial Requirements Agreement were increased to $42.77 and $44.42, respectively for Met-Ed and Penelec. In addition, FES agreed to reimburse Met-Ed and Penelec, respectively, for congestion expenses and marginal losses in excess of $208 million and $79 million, respectively, as billed by PJM in 2010, and associated with delivery of power by FES under the Fourth Restated Partial Requirements Agreement. The Fourth Restated Partial Requirements Agreement terminates at the end of 2010.

The Yards Creek Pumped Storage Project is a 400 MW hydroelectric project located in Warren County, New Jersey. JCP&L owns an undivided 50% interest in the project, and JCP&L operates the project. PSEG Fossil, LLC, a subsidiary of Public Service Enterprise Group, owns the remaining interest in the plant. The project was constructed in the early 1960s, and became operational in 1965. Authorization to operate the project is by a license issued by the FERC. The existing license expires on February 28, 2013.

FirstEnergy and PSEG desire to renew the license and, to that end, on January 11, 2008, JCP&L and PSEG Fossil submitted the initial documents necessary to obtain a new license for the project. The process for relicensing (renewing the license for) a hydroelectric project is described in FERC's Integrated Licensing Process (ILP) regulations. The ILP regulations call for numerous environmental, operational, structural and safety and other studies to be conducted as part of the relicensing process. Although some of these studies were initiated in 2009, the bulk of the studies will be performed in 2010 – all for the purpose of submitting the application for a new license on February 28, 2011. The ILP regulations provide for opportunity for public notice and comment as part of many of these study processes; meaning that federal and state regulatory agencies, as well as members of the public, will have amply opportunity to participate in the relicensing process. The ILP regulations provide significant discretion for FERC to set a procedural schedule to act on the license application; meaning that FirstEnergy is not able at this time to predict when FERC will take final action in issuing the new license for the Yards Creek project. To the extent, however that the license proceedings extend beyond the February 28, 2013 expiration date for the current license, the current license will be extended as necessary to permit FERC to issue the new license.

Capital Requirements

Our capital spending for 2010 is expected to be approximately $1.65 billion (excluding nuclear fuel), of which $241 million relates to Sammis AQC system expenditures. Capital spending for 2011 and 2012 is expected to be approximately $1.0 billion to $1.2 billion each year. Our capital investments for additional nuclear fuel during 2010 are estimated to be approximately $203 million.

Anticipated capital expenditures for the Utilities, FES and FirstEnergy's other subsidiaries for 2010, 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.

	2009 Actual [1]	Capital Expenditures Forecast 2010
	(In millions)	
OE	$ 131	$ 116
Penn	23	19
CEI	111	108
TE	46	48
JCP&L	171	170
Met-Ed	100	102
Penelec	132	127
ATSI	34	49
FGCO	724	592
NGC	242	254
Other subsidiaries	56	66
Total	$ 1,770	$ 1,651

[1] Excludes nuclear fuel.

During the 2010-2014 period, maturities of, and sinking fund requirements for, long-term debt of FirstEnergy and its subsidiaries are:

	Long-Term Debt Redemption Schedule		
	2010	**2011-2014**	**Total**
		(In millions)	
FirstEnergy	$ 1	$ 256	$ 257
FES	52	300	352
OE	1	-	1
Penn	1	5	6
CEI [(1)]	-	300	300
JCP&L	31	140	171
Met-Ed	100	400	500
Penelec	24	150	174
Other [(2)]	58	(28)	30
Total	$ 268	$ 1,523	$ 1,791

[(1)] CEI has an additional $110 million due to associated companies in 2010-2014.

[(2)] Includes elimination of certain intercompany debt.

The following table displays operating lease commitments, net of capital trust cash receipts for the 2010-2014 period.

	Net Operating Lease Commitments		
	2010	**2011-2014**	**Total**
		(In millions)	
OE	$ 104	$ 403	$ 507
CEI [(1)]	(40)	(194)	(234)
TE	35	138	173
JCP&L	6	19	25
Met-Ed	7	13	20
Penelec	3	9	12
FESC	14	39	53
FGCO	199	888	1,087
NGC [(2)]	(103)	(414)	(517)
Total	$ 225	$ 901	$ 1,126

[(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 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 $1.2 billion of short-term indebtedness as of December 31, 2009, comprised of $1.1 billion in borrowings under the $2.75 billion revolving line of credit described below, $100 million of other bank borrowings and $31 million of currently payable notes. Total short-term bank lines of committed credit to FirstEnergy, FES and the Utilities as of January 31, 2010 were approximately $3.4 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, 2010, FES had a $100 million bank credit facility in addition to a $1 billion credit limit associated with FirstEnergy's $2.75 billion revolving credit facility. Also, an aggregate of $515 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, 2010, is described in the following table.

Company	Type	Maturity	Commitment	Available Liquidity as of January 31, 2010
			(In millions)	
FirstEnergy [1]	Revolving	Aug. 2012	$ 2,750	$ 1,387
FirstEnergy Solutions	Bank line	Mar. 2011	100	-
Ohio and Pennsylvania Companies	Receivables financing	Various [2]	515	308
		Subtotal	$ 3,365	$ 1,695
		Cash	-	764
		Total	**$ 3,365**	**$ 2,459**

(1) FirstEnergy Corp. and subsidiary borrowers.

(2) $370 million expires February 22, 2010; $145 million expires December 17, 2010. The Ohio and Pennsylvania Companies have typically renewed expiring receivables facilities on an annual basis and expect to continue that practice as market conditions and the continued quality of receivables permit.

FirstEnergy's primary source of cash for continuing operations as a holding company is cash from the operations of its subsidiaries. During 2009, the holding company received $972 million of cash dividends on common stock from its subsidiaries and paid $670 million in cash dividends to common shareholders.

As of December 31, 2009, the Ohio Companies and Penn had the aggregate capability to issue approximately $1.4 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 and CEI to incur additional secured debt not otherwise permitted by a specified exception of up to $127 million and $36 million, respectively, as of December 31, 2009. In April 2009, TE issued $300 million of new senior secured notes backed by FMBs. Concurrently with that issuance, and in order to satisfy the limitation on secured debt under its senior note indenture, TE issued an additional $300 million of FMBs to secure $300 million of its outstanding unsecured senior notes originally issued in November 2006. As a result, the provisions for TE to incur additional secured debt do not apply. In August 2009 CEI issued $300 million of FMBs. CEI restricted $150 million of the proceeds to fund the redemption of $150 million of secured notes that were paid in November 2009. Based upon FGCO's FMB indenture, net earnings and available bondable property additions as of December 31, 2009, FGCO had the capability to issue $2.2 billion of additional FMBs under the terms of that indenture. Met-Ed and Penelec had the capability to issue secured debt of approximately $379 million and $319 million, respectively, under provisions of their senior note indentures as of December 31, 2009.

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, 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

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. On November 5, 2009, the NRC issued a renewed operating license for Beaver Valley Power Station, Units 1 and 2. The operating licenses for these facilities were extended until 2036 and 2047 for Units 1 and 2, respectively.

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.

Station	In-Service Date	Current License Expiration
Beaver Valley Unit 1	1976	2036
Beaver Valley Unit 2	1987	2047
Perry	1986	2026
Davis-Besse	1977	2017

Nuclear Regulation

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2009, FirstEnergy had approximately $1.9 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 provided an additional $80 million parental guarantee associated with the funding of decommissioning costs for these units and indicated that it planned to contribute an additional $80 million to these trusts by 2010. As required by the NRC, FirstEnergy annually recalculates and adjusts the amount of its parental guarantee, as appropriate. The values of FirstEnergy's nuclear decommissioning trusts fluctuate based on market conditions. If the value of the trusts decline by a material amount, FirstEnergy's obligation to fund the trusts may increase. Disruptions in the capital markets and its effects on particular businesses and the economy in general also affects the values of the nuclear decommissioning trusts. On June 18, 2009, the NRC informed FENOC that its review tentatively concluded that a shortfall existed in the decommissioning trust fund for Beaver Valley Unit 1. On November 24, 2009, FENOC submitted a revised decommissioning funding calculation using the NRC formula method based on the renewed license for Beaver Valley Unit 1, which extended operations until 2036. FENOC's submittal demonstrated that there was a de minimis shortfall. On December 11, 2009, the NRC's review of FirstEnergy's methodology for the funding of decommissioning of this facility concluded that there was reasonable assurance of adequate decommissioning funding at the time permanent termination of operations is expected. FirstEnergy continues to evaluate the status of its funding obligations for the decommissioning of these nuclear facilities.

Nuclear Insurance

The Price-Anderson Act limits the public liability which can be assessed with respect to a nuclear power plant to $12.6 billion (assuming 104 units licensed to operate) for a single nuclear incident, which amount is covered by: (i) private insurance amounting to $375 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 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 $560 million (OE-$48 million, NGC-$486 million, TE-$26 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 $3 million (NGC-$3 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 $60 million (OE-$6 million, NGC-$51 million, TE-$2 million, Met Ed, Penelec and JCP&L- less than $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 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 SO_2 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 SO_2 regulations in Ohio that allows for compliance based on a 30-day averaging period. FirstEnergy believes it is currently in compliance with this policy, but cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

FirstEnergy complies with SO_2 reduction requirements under the Clean Air Act Amendments of 1990 by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NO_X reductions required by the 1990 Amendments are being achieved through combustion controls, the generation of more electricity at lower-emitting plants, and/or using emission allowances. 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 SO_2 emissions at the Sammis, Burger, Eastlake and Mansfield coal-fired plants through the installation of pollution control devices or repowering and provides for stipulated penalties for failure to install and operate such pollution controls or complete repowering in accordance with that agreement. Capital expenditures necessary to complete requirements of the Sammis NSR Litigation consent decree, including repowering Burger Units 4 and 5 for biomass fuel consumption, are currently estimated to be $399 million for 2010-2012.

In October 2007, PennFuture and three of its members filed a citizen suit under the federal CAA, alleging violations of air pollution laws at the Bruce Mansfield Plant, including opacity limitations, in the United States District Court for the Western District of Pennsylvania. In July 2008, three additional complaints were filed against FGCO in the U.S. 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 three 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 16, 2009, a settlement reached with PennFuture and one of the three individual complainants was approved by the Court, which dismissed the claims of PennFuture and of the settling individual. The other two non-settling individuals are now represented by counsel handling the three cases filed in July 2008. FGCO believes those claims are without merit and intends to defend itself against the allegations made in those three complaints. The Pennsylvania Department of Health, under a Cooperative Agreement with the Agency for Toxic Substances and Disease Registry, completed a Health Consultation regarding the Mansfield Plant and issued a report dated March 31, 2009, which concluded there is insufficient sampling data to determine if any public health threat exists for area residents due to emissions from the Mansfield Plant. The report recommended additional air monitoring and sample analysis in the vicinity of the Mansfield Plant, which the Pennsylvania Department of Environmental Protection has completed.

In December 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 and Met-Ed. On October 30, 2008, the state of Connecticut filed a Motion to Intervene, which the Court granted on March 24, 2009. Specifically, Connecticut and New Jersey allege that "modifications" at Portland Units 1 and 2 occurred between 1980 and 2005 without preconstruction NSR or permitting under the CAA's PSD program, and seek injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. The scope of Met-Ed’s indemnity obligation to and from Sithe Energy is disputed. Met-Ed filed a Motion to Dismiss the claims in New Jersey’s Amended Complaint and Connecticut’s Complaint in February and September of 2009, respectively. The Court granted Met-Ed's motion to dismiss New Jersey’s and Connecticut’s claims for injunctive relief against Met-Ed, but denied Met-Ed’s motion to dismiss the claims for civil penalties on statute of limitations grounds in order to allow the states to prove either that the application of the discovery rule or the doctrine of equitable tolling bars application of the statute of limitations.

In January 2009, the EPA issued a NOV to Reliant alleging NSR 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 2009, NOV also alleged NSR violations at the Keystone and Shawville Stations based on “modifications” dating back to 1984. JCP&L, as the former owner of 16.67% of the Keystone Station, and Penelec, as former owner and operator of the Shawville Station, are unable to predict the outcome of this matter.

In June 2008, the EPA issued a Notice and Finding of Violation to Mission Energy Westside, Inc. alleging that "modifications" at the Homer City Power Station occurred since 1988 to the present without preconstruction NSR or permitting under the CAA's PSD program. Mission Energy 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 Mission Energy is disputed. Penelec is unable to predict the outcome of this matter.

In August 2009, the EPA issued a Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, including the PSD, NNSR, and Title V regulations at the Eastlake, Lakeshore, Bay Shore, and Ashtabula generating plants. The EPA’s NOV alleges equipment replacements occurring during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. In September 2009, FGCO received an information request pursuant to Section 114(a) of the CAA requesting certain operating and maintenance information and planning information regarding the Eastlake, Lake Shore, Bay Shore and Ashtabula generating plants. On November 3, 2009, FGCO received a letter providing notification that the EPA is evaluating whether certain scheduled maintenance at the Eastlake generating plant may constitute a major modification under the NSR provision of the CAA. On December 23, 2009, FGCO received another information request regarding emission projections for the Eastlake generating plant pursuant to Section 114(a) of the CAA. FGCO intends to comply with the CAA, including EPA’s information requests, but, at this time, is unable to predict the outcome of this matter. A June 2006 finding of violation and NOV in which EPA alleged CAA violations at the Bay Shore Generating Plant remains unresolved and FGCO is unable to predict the outcome of such matter.

In August 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 its formerly-owned 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 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 SO_2 emissions in two phases (Phase I in 2009 for NO_X, 2010 for SO_2 and Phase II in 2015 for both NO_X and SO_2), ultimately capping SO_2 emissions in affected states to 2.5 million tons annually and NO_X emissions to 1.3 million tons annually. CAIR was challenged in the U.S. 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.” In September 2008, the EPA, utility, mining and certain environmental advocacy organizations petitioned the Court for a rehearing to reconsider its ruling vacating CAIR. In December 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. On July 10, 2009, the U.S. Court of Appeals for the District of Columbia ruled in a different case that a cap-and-trade program similar to CAIR, called the “NO_X SIP Call,” cannot be used to satisfy certain CAA requirements (known as reasonably available control technology) for areas in non-attainment under the "8-hour" ozone NAAQS. FGCO's 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 SO_2 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 U.S. 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 in May 2008. In October 2008, the EPA (and an industry group) petitioned the U.S. Supreme Court for review of the Court’s ruling vacating CAMR. On February 6, 2009, the EPA moved to dismiss its petition for certiorari. On February 23, 2009, the Supreme Court dismissed the EPA’s petition and denied the industry group’s petition. On October 21, 2009, the EPA opened a 30-day comment period on a proposed consent decree that would obligate the EPA to propose MACT regulations for mercury and other hazardous air pollutants by March 16, 2011, and to finalize the regulations by November 16, 2011. FGCO’s future cost of compliance with MACT regulations may be substantial and will depend on the action taken by the EPA and on how any future regulations 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 December 23, 2009, the Supreme Court of Pennsylvania affirmed the Commonwealth Court of Pennsylvania ruling that Pennsylvania’s mercury rule is “unlawful, invalid and unenforceable” and enjoined the Commonwealth from continued implementation or enforcement of that rule.

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, by 2012, the amount of man-made GHG, including CO_2, emitted by developed countries. The United States signed the Kyoto Protocol in 1998 but it was never submitted for ratification by the United States Senate. 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 used in the United States comes from renewable sources by 2012, increasing to 25% by 2025, and implementing an economy-wide cap-and-trade program to reduce GHG emissions by 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, the December 2009 U.N. Climate Change Conference in Copenhagen did not reach a consensus on a successor treaty to the Kyoto Protocol, but did take note of the Copenhagen Accord, a non-binding political agreement which recognized the scientific view that the increase in global temperature should be below two degrees Celsius, included a commitment by developed countries to provide funds, approaching $30 billion over the next three years with a goal of increasing to $100 billion by 2020, and established the “Copenhagen Green Climate Fund” to support mitigation, adaptation, and other climate-related activities in developing countries. Once they have become a party to the Copenhagen Accord, developed economies, such as the European Union, Japan, Russia, and the United States, would commit to quantified economy-wide emissions targets from 2020, while developing countries, including Brazil, China, and India, would agree to take mitigation actions, subject to their domestic measurement, reporting, and verification. At the federal level, members of Congress have introduced several bills seeking to reduce emissions of GHG in the United States, and the House of Representatives passed one such bill, the American Clean Energy and Security Act of 2009, on June 26, 2009. The Senate continues to consider a number of measures to regulate GHG emissions. 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 CO_2 emissions from automobiles as “air pollutants” under the CAA. Although this decision did not address CO_2 emissions from electric generating plants, the EPA has similar authority under the CAA to regulate “air pollutants” from those and other facilities. In December 2009, the EPA released its final “Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act.” The EPA’s finding concludes that the atmospheric concentrations of several key GHG threaten the health and welfare of future generations and that the combined emissions of these gases by motor vehicles contribute to the atmospheric concentrations of these key GHG and hence to the threat of climate change. Although the EPA’s finding does not establish emission requirements for motor vehicles, such requirements are expected to occur through further rulemakings. Additionally, while the EPA’s endangerment findings do not specifically address stationary sources, including electric generating plants EPA’s expected establishment of emission requirements for motor vehicles would be expected to support the establishment of future emission requirements by the EPA for stationary sources. In September 2009, the EPA finalized a national GHG emissions collection and reporting rule that will require FirstEnergy to measure GHG emissions commencing in 2010 and submit reports commencing in 2011. Also in September 2009, EPA proposed new thresholds for GHG emissions that define when CAA permits under the NSR and Title V operating permits programs would be required. EPA is proposing a major source emissions applicability threshold of 25,000 tons per year (tpy) of carbon dioxide equivalents (CO2e) for existing facilities under the Title V operating permits program and the Prevention of Significant Determination (PSD) portion of NSR. EPA is also proposing a significance level between 10,000 and 25,000 tpy CO2e to determine if existing major sources making modifications that result in an increase of emissions above the significance level would be required to obtain a PSD permit.

On September 21, 2009, the U.S. Court of Appeals for the Second Circuit and on October 16, 2009, the U.S. Court of Appeals for the Fifth Circuit, reversed and remanded lower court decisions that had dismissed complaints alleging damage from GHG emissions on jurisdictional grounds. These cases involve common law tort claims, including public and private nuisance, alleging that GHG emissions contribute to global warming and result in property damages. While FirstEnergy is not a party to either litigation, should the courts of appeals decisions be affirmed or not subjected to further review, FirstEnergy and/or one or more of its subsidiaries could be named in actions making similar allegations.

FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions, or litigation alleging damages from GHG emissions, could require significant capital and other expenditures or result in changes to its operations. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

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

On September 7, 2004, the EPA established new performance standards under Section 316(b) of the Clean Water Act for reducing impacts on fish and shellfish from cooling water intake structures at certain existing large electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic 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 1, 2009, the Supreme Court of the United States reversed one significant aspect of the Second Circuit Court’s opinion and decided that 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. EPA is developing a new regulation under Section 316(b) of the Clean Water Act consistent with the opinions of the Supreme Court and the Court of Appeals which have created significant uncertainty about the specific nature, scope and timing of the final performance standard. FirstEnergy is studying various control options and their costs and effectiveness. Depending on the results of such studies and 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 Waste Disposal

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. In February 2009, the EPA requested comments from the states on options for regulating coal combustion wastes, including regulation as non-hazardous waste or regulation as a hazardous waste. In March and June 2009, the EPA requested information from FGCO’s Bruce Mansfield Plant regarding the management of coal combustion wastes. In December 2009, EPA provided to FGCO the findings of its review of the Bruce Mansfield Plant’s coal combustion waste management practices. EPA observed that the waste management structures and the Plant “appeared to be well maintained and in good working order” and recommended only that FGCO “seal and maintain all asphalt surfaces.” On December 30, 2009, in an advanced notice of public rulemaking, the EPA said that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry. Additional regulations of fossil-fuel combustion waste products could have a significant impact on our management, beneficial use, and disposal, of coal ash. FGCO's future cost of compliance with any coal combustion waste regulations which may be promulgated could be substantial and would depend, in part, on the regulatory action taken by the EPA and implementation by the states.

The Utilities have been named as potentially responsible parties 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 potentially responsible parties for a particular site may be liable on a joint and several basis. Environmental liabilities that are considered probable have been recognized on the consolidated balance sheet as of December 31, 2009, 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 $101 million (JCP&L - $74 million, TE - $1 million, CEI - $1 million, FGCO - $1 million and FirstEnergy - $24 million) have been accrued through December 31, 2009. Included in the total are accrued liabilities of approximately $67 million for environmental remediation of former manufactured gas plants and gas holder facilities 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 acquire approximately 22.7 million tons of coal for the year 2010, approximately 109% of its 2010 coal requirements of 20.8 million tons. This contract coal is produced primarily from mines located in Ohio, Pennsylvania, Kentucky, West Virginia, Montana 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 joint venture 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, FGCO 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 began taking delivery of the coal in late 2009. 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 2011 and a portion of uranium material requirements through 2016. Conversion services contracts fully cover requirements through 2011 and partially fill requirements through 2016. Enrichment services are contracted for essentially all of the enrichment requirements for nuclear fuel through 2017. A portion of enrichment requirements is also contracted for through 2024. 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 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 2010; facilities at Beaver Valley Units 1 and 2 are expected to be adequate through 2015 and 2010, respectively. Davis-Besse has adequate storage through 2017. 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 were submitted to the NRC for approval during the second quarter of 2009. The NRC has requested additional information to complete the license review process and this information will be provided in early 2010. Dry fuel storage is also being pursued at Perry and Beaver Valley, with Perry implementation scheduled to complete by the end of 2010 and Beaver Valley to be complete by the end of 2014.

The Federal Nuclear Waste Policy Act of 1982 provided 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. However, the current Administration has stated the Yucca Mountain repository will not be completed and a Federal review of potential alternative strategies will be performed. FirstEnergy intends to make additional arrangements for storage capacity as a contingency for the continuing delays with the DOE acceptance of spent fuel for disposal.

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 currently consumed primarily by peaking units, and no natural gas demand is forecasted in 2010. First Energy purchased a partially completed combined cycle combustion turbine plant in Fremont Ohio. Construction is scheduled to be completed in late 2010 and generation is forecasted for 2011. 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 2009 net maximum hourly demand for each of the Utilities was:

- OE–5,156 MW on June 25, 2009;
- Penn–879 MW on June 25, 2009;
- CEI–3,843 MW on June 25, 2009;
- TE–2,009 MW on June 25, 2009;

- JCP&L–5,738 MW on August 10, 2009;
- Met-Ed–2,839 MW on August 10, 2009; and
- Penelec–2,679 MW on August 10, 2009.

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. The Ohio Utilities and Penn's default service supplies are provided through a competitive procurement process approved by the PUCO and PPUC, respectively. The default service supply for Met-Ed and Penelec is secured through a FERC-approved agreement with FES, but will move to a competitive procurement process in 2011. 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 2009, FES' generation was used to serve two main obligations. Affiliated companies utilized approximately 76% of FES' total generation. Direct retail customers utilized approximately 18% of FES' total generation. Geographically, approximately 67% of FES' obligation is located in the MISO market area and 33% 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) 14,346 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 FPA 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 Management's Discussion and Analysis). 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 generation 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. 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.

FirstEnergy remains focused on managing the transition to competitive markets for electricity in Pennsylvania. 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, FES, and FENOC participate in the funding of EPRI, which was formed for the purpose of expanding electric research and development (R&D) 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 participates in other initiatives with industry R&D consortiums and universities to address technology needs for its various business units. Participation in these consortiums helps the company address research needs in areas such as plant operations and maintenance, major component reliability, environmental controls, advanced energy technologies, and T&D System infrastructure to improve performance, and develop new technologies for advanced energy and grid applications.

Executive Officers

Name	Age	Positions Held During Past Five Years	Dates
A. J. Alexander (A)(G)	58	President and Chief Executive Officer	*-present
W. D. Byrd (B)	55	Vice President, Corporate Risk & Chief Risk Officer	2007-present
L. M. Cavalier (B)	58	Senior Vice President – Human Resources	2005-present
		Vice President	*-2005
M. T. Clark (A)(B)(C)(D)(F)(G)	59	Executive Vice President and Chief Financial Officer	2009-present
		Executive Vice President – Strategic Planning & Operations	2008-2009
		Senior Vice President – Strategic Planning & Operations	*-2008
D. S. Elliott (B)(D)	55	President – Pennsylvania Operations	2005-present
		Executive Vice President	2005-present
		Senior Vice President	*-2005
R. R. Grigg (A)(B)(C)(D)(H)	61	Executive Vice President and President-FirstEnergy Utilities	2008-present
		Executive Vice President and Chief Operating Officer	*-2008
J. J. Hagan (G)	59	President and Chief Nuclear Officer	2007-present
		Senior Vice President and Chief Operating Officer	2005-2007
		Senior Vice President	*-2005
C. E. Jones (B)(C)(D)(I)	54	Senior Vice President – Energy Delivery & Customer Service	2009-present
		President – FirstEnergy Solutions	2007-2009
		Senior Vice President – Energy Delivery & Customer Service	*-2007
C. D. Lasky (F)	47	Vice President – Fossil Operations	2008-present
		Vice President – Fossil Operations & Air Quality Compliance	2007-2008
		Vice President	*-2007
G. R. Leidich (A)(B)	59	Executive Vice President & President – FirstEnergy Generation	2008-present
		Senior Vice President – Operations (B)	2007-2008
		President and Chief Nuclear Officer (G)	*-2007
D. C. Luff (B)	62	Senior Vice President – Governmental Affairs	2007-present
		Vice President	*-2007
D. M. Lynch (E)	55	President – JCP&L	2009-present
		Regional President	*-2009
J. F. Pearson (A)(B)(C)(D)(F)(G)	55	Vice President and Treasurer	2006-present
		Treasurer	2005-2006
		Group Controller – Strategic Planning and Operations	*-2005
D. R. Schneider (F)	48	President	2009-present
		Senior Vice President – Energy Delivery & Customer Service (B)	2007-2009
		Vice President (B)	2006-2007
		Vice President (F)	*-2006
L.L. Vespoli (A)(B)(C)(D)(F)(G)	50	Executive Vice President and General Counsel	2008-present
		Senior Vice President and General Counsel	*-2008
H. L. Wagner (A)(B)(C)(D)(F)(G)	57	Vice President, Controller and Chief Accounting Officer	*-present

(A) Denotes executive officer of FE Corp.
(B) Denotes executive officer of FE Service
(C) Denotes executive officers of OE, CEI and TE.
(D) Denotes executive officer of Met-Ed, Penelec and Penn.
(E) Denotes executive officer of JCP&L
(F) Denotes executive officer of FES.
(G) Denotes executive officer of FENOC.
(H) Retiring March 31, 2010.
(I) Named Senior Vice President and President, FirstEnergy Utilities, effective April 1, 2010
* Indicates position held at least since January 1, 2005.

Employees

As of December 31, 2009, FirstEnergy's subsidiaries had a total of 13,379 employees located in the United States as follows:

	Total Employees	Bargaining Unit Employees
FESC	2,910	284
OE	1,191	709
CEI	873	584
TE	396	294
Penn	200	147
JCP&L	1,432	1,092
Met-Ed	706	509
Penelec	902	632
ATSI	38	-
FES	247	-
FGCO	1,784	1,154
FENOC	2,700	1,014
Total	13,379	6,419

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. On September 9, 2005, the arbitration panel issued an opinion to award approximately $16 million to the bargaining unit employees. A final order identifying the individual damage amounts was issued on October 31, 2007 and 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. On February 25, 2009, the federal district court denied JCP&L's motion to vacate the arbitration decision and granted the union's motion to confirm the award. JCP&L filed a Notice of Appeal to the Third Circuit and a Motion to Stay Enforcement of the Judgment on March 6, 2009. The appeal process could take as long as 24 months. The parties are participating in the federal court's mediation programs and have held private settlement discussions. JCP&L recognized a liability for the potential $16 million award in 2005. Post-judgment interest began to accrue as of February 25, 2009, and the liability will be adjusted accordingly.

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. Additionally, we routinely post important information on our Web site and recognize our Web site is a channel of distribution to reach public investors and as a means of disclosing material non-public information for complying with disclosure obligations under SEC Regulation FD. 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. Management of each Registrant regularly evaluates the most significant risks of the Registrant’s businesses and reviews those risks with the FirstEnergy Board of Directors or appropriate Committees of the Board. 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 risk of potential breakdown or failure of equipment or processes, due to aging infrastructure, 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;
- changes in legislation and regulation; 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 Reliability Standards Set by NERC/FERC or Changes in the Rules of Organized Markets and the States in Which we do Business

As a result of the EPACT, owners, operators, and users of the bulk electric system are subject to mandatory reliability standards promulgated by the NERC and approved by FERC as well as mandatory reliability standards imposed by each of the states in which we operate. The standards are based on the functions that need to be performed to ensure that the bulk electric system operates reliably. Compliance with modified or 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 and the states, 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. In addition, the RTOs may direct our transmission owning affiliates to build new transmission facilities to meet the reliability requirements of the RTO or to provide new or expanded transmission service under the RTO tariffs.

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 required to pay for congestion costs if we schedule delivery of power between congestion zones during periods of high demand. If we are unable to hedge or 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 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 Regional and General Economic Cycles and also Related to Heavy Manufacturing Industries such as Automotive and Steel

Our business follows the economic cycles of our customers. As our retail strategy is centered around the sale of output from our generating plants generally where that power will reach, therefore, we are more directly impacted by the economic conditions in our primary markets (i.e., Western Pennsylvania, Ohio, Maryland, New Jersey, Michigan and Illinois). Declines in demand for electricity as a result of a regional economic downturn would be expected to reduce overall electricity sales and reduce our revenues. 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 operations are impacted by the economic conditions in our service territories and those conditions could negatively impact the rate of delinquent customer accounts and 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, environmental regulations 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 must 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 cost pressures could increase as we continue to implement our retail sales strategy. We expect to continue to face increased cost pressures in the areas of 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' inabilities 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.

Ability of Certain FirstEnergy Companies to Meet Their Obligations to Other FirstEnergy Companies

Certain of the FirstEnergy companies have obligations to other FirstEnergy companies because of transactions involving energy, coal, other commodities, services, and because of hedging transactions. If one FirstEnergy entity failed to perform under any of these arrangements, other FirstEnergy entities could incur losses. Their results of operations, financial position, or liquidity could be adversely affected, resulting in the nondefaulting FirstEnergy entity being unable to meet its obligations to unrelated third parties. Our hedging activities are generally undertaken with a view to overall FirstEnergy exposures. Some FirstEnergy companies may therefore be more or less hedged than if they were to engage in such transactions alone.

Risks Associated With our Proposed Merger With Allegheny

We May be Unable to Obtain the Approvals Required to Complete our Merger with Allegheny or, in Order to do so, the Combined Company May be Required to Comply With Material Restrictions or Conditions.

On February 11, 2010, we announced the execution of a merger agreement with Allegheny. Before the merger may be completed, shareholder approval will have to be obtained by us and by Allegheny. In addition, various filings must be made with the FERC and various state utility, regulatory, antitrust and other authorities in the United States. These governmental authorities may impose conditions on the completion, or require changes to the terms, of the merger, including restrictions or conditions on the business, operations, or financial performance of the combined company following completion of the merger. These conditions or changes could have the effect of delaying completion of the merger or imposing additional costs on or limiting the revenues of the combined company following the merger, which could have a material adverse effect on the financial results of the combined company and/or cause either us or Allegheny to abandon the merger.

If Completed, Our Merger with Allegheny May Not Achieve Its Intended Results.

We and Allegheny entered into the merger agreement with the expectation that the merger would result in various benefits, including, among other things, cost savings and operating efficiencies relating to both the regulated utility operations and the generation business. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the business of Allegheny is integrated in an efficient and effective manner. Failure to achieve these anticipated benefits could result in increased costs, decreases in the amount of expected revenues generated by the combined company and diversion of management's time and energy and could have an adverse effect on the combined company's business, financial results and prospects.

We Will be Subject to Business Uncertainties and Contractual Restrictions While the Merger with Allegheny is Pending That Could Adversely Affect Our Financial Results.

Uncertainty about the effect of the merger with Allegheny on employees and customers may have an adverse effect on us. Although we intend to take steps designed to reduce any adverse effects, these uncertainties may impair our ability to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, and could cause customers, suppliers and others that deal with us to seek to change existing business relationships.

Employee retention and recruitment may be particularly challenging prior to the completion of the merger, as employees and prospective employees may experience uncertainty about their future roles with the combined company. If, despite our retention and recruiting efforts, key employees depart or fail to accept employment with us because of issues relating to the uncertainty and difficulty of integration or a desire not to remain with the combined company, our financial results could be affected.

The pursuit of the merger and the preparation for the integration of Allegheny into our company may place a significant burden on management and internal resources. The diversion of management attention away from day-to-day business concerns and any difficulties encountered in the transition and integration process could affect our financial results.

In addition, the merger agreement restricts us, without Allegheny's consent, from making certain acquisitions and taking other specified actions until the merger occurs or the merger agreement terminates. These restrictions may prevent us from pursuing otherwise attractive business opportunities and making other changes to our business prior to completion of the merger or termination of the merger agreement.

Failure to Complete Our Merger with Allegheny Could Negatively Impact Our Stock Price and Our Future Business and Financial Results

If our merger with Allegheny is not completed, our ongoing business and financial results may be adversely affected and we will be subject to a number of risks, including the following:

- We may be required, under specified circumstances set forth in the Merger Agreement, to pay Allegheny a termination fee of $350 million and/or Allegheny's reasonable out-of-pocket transaction expenses up to $45 million;

- we will be required to pay costs relating to the merger, including legal, accounting, financial advisory, filing and printing costs, whether or not the merger is completed; and

- matters relating to our merger with Allegheny (including integration planning) may require substantial commitments of time and resources by our management, which could otherwise have been devoted to other opportunities that may have been beneficial to us.

We could also be subject to litigation related to any failure to complete our merger with Allegheny. If our merger is not completed, these risks may materialize and may adversely affect our business, financial results and stock price.

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. For example, we may be unable to timely recover the costs for our energy efficiency investments, expenses and additional capital or lost revenues resulting from the implementation of aggressive energy efficiency programs. 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. For example, our utility subsidiaries' ability to timely recover rates and charges associated with integration of the ATSI footprint into PJM is uncertain.

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 impose rate cap extensions or otherwise 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 and MISO in 2009. FES, FGCO, NGC and the Utilities must file to renew this authority for PJM in 2010. If any of these companies were to lose their market-based rate authority, they 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 cost based, 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.

A Significant Delay in or Challenges to Various Elements of ATSI's Consolidation into PJM, including but not Limited to, the Intervention of Parties to the Regulatory Proceedings, Could have a Negative Impact on Our Results of Operations and Financial Condition

On December 17, 2009, FERC authorized, subject to certain conditions, FirstEnergy to consolidate its transmission assets and operations that currently are located in MISO into PJM; such consolidation to be effective on June 1, 2011. The consolidation will make the transmission assets that are part of ATSI, whose footprint includes the Ohio Companies and Penn, part of PJM. Consolidation on June 1, 2011 will coincide with delivery of power under the next competitive generation procurement process for the Ohio Companies. On December 17, 2009, and after FERC issued the order, ATSI executed and delivered to PJM those legal documents necessary to implement its consolidation into PJM. On December 18, 2009, the Ohio Companies and Penn executed and delivered to PJM those legal documents necessary to follow ATSI into PJM. Currently, ATSI, the Ohio Companies and Penn are expected to consolidate into PJM as planned on June 1, 2011

Certain parties have objected to various aspects of the planned consolidation into PJM. On September 4, 2009, the PUCO opened a case to take comments from Ohio's stakeholders regarding the RTO consolidation. Certain parties have intervened and filed comments or protests in the FERC and PUCO dockets regarding particular elements of the proposed RTO consolidation. The disputed elements include, but are not limited to, recovery of integration costs to PJM and exit fees to MISO and cost-allocations of transmission upgrades that originate under the PJM and MISO tariffs. A ruling by FERC or the PUCO or any other regulator with jurisdiction in favor of one or more of the intervening or protesting parties (and against FirstEnergy) on one or more of the disputed issues could result in a negative impact on our results of operations and financial condition.

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. While we currently have energy efficiency riders in place to recover the cost of these programs either at or near a current recovery timeframe in all three states, currently only Ohio allows us to recover lost revenues. 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. Our results could be affected if we are unable to increase our customer's participation in our energy efficiency programs. 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.

The EPA is Conducting NSR Investigations at a Number of our Generating Plants, the Results of Which Could Negatively Impact our Results of Operations and Financial Condition

In August 2009, the EPA issued a Finding of Violation and NOV alleging violations of the CAA and Ohio regulations, including the PSD, NNSR, and Title V regulations at the Eastlake, Lakeshore, Bay Shore, and Ashtabula generating plants. The EPA's NOV alleges equipment replacements occurring during maintenance outages dating back to 1990 triggered the pre-construction permitting requirements under the PSD and NNSR programs. In September 2009, FGCO received an information request pursuant to Section 114(a) of the CAA requesting certain operating and maintenance information and planning information regarding the Eastlake, Lake Shore, Bay Shore and Ashtabula generating plants. On November 3, 2009, FGCO received a letter providing notification that the EPA is evaluating whether certain scheduled maintenance at the Eastlake generating plant may constitute a major modification under the NSR provision of the CAA. On December 23, 2009, FGCO received another information request regarding emission projections for the Eastlake generating plant pursuant to Section 114(a) of the CAA. FGCO intends to comply with the CAA, including EPA's information requests, but, at this time, is unable to predict the outcome of this matter. A June 2006 finding of violation and NOV in which EPA alleged CAA violations at the Bay Shore Generating Plant remains unresolved and FGCO is unable to predict the outcome of such matter.

In August 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 its formerly-owned 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 Section 114(a) information request An adverse result in the above referenced matters could have a negative impact on our results of operations and financial condition.

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. Also, claims have been made alleging that CO2 emissions from power generating facilities constitute a public nuisance under federal and/or state common law. Private individuals may seek to enforce environmental laws and regulations against us and could allege personal injury or property damage from exposure to hazardous materials. Recently the courts have begun to acknowledge these claims and may order us to reduce GHG emissions in the future. 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. In December 2009, the EPA issued an “endangerment and cause or contributing finding” for GHG under the CAA, which will allow the EPA to craft rules that directly regulate GHG. 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. Due to the uncertainty of control technologies available to reduce greenhouse gas emissions including CO_2, 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 21, 2009, the EPA opened a 30-day comment period on a proposed consent decree that would obligate the EPA to propose MACT regulations for mercury and other hazardous air pollutants by March 16, 2011, and to finalize the regulations by November 16, 2011. FGCO’s future cost of compliance with MACT regulations may be substantial 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 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 1, 2009, the Supreme Court of the United States reversed one significant aspect of the Second Circuit Court's opinion and decided that 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. The EPA is developing a new regulation under Section 316(b) of the Clean Water Act consistent with the opinions of the Supreme Court and the Court of Appeals which have created significant uncertainty about the specific nature, scope and timing of the final performance standard. 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.

Certain fossil-fuel combustion waste products, such as coal ash, have been exempt from hazardous waste disposal requirements pending the EPA's evaluation of the need for future regulation. In February 2009, the EPA requested comments from the states on options for regulating coal combustion wastes, including regulation as non-hazardous waste or regulation as a hazardous waste. On December 30, 2009, in an advanced notice of public rulemaking, the EPA said that the large volumes of coal combustion residuals produced by electric utilities pose significant financial risk to the industry. Additional regulation of fossil-fuel combustion waste products could have a significant impact on our management, beneficial use, and disposal of coal ash and our cost of compliance could increase significantly which could have a material adverse effect on future results of operations, cash flows and financial condition.

The Physical Risks Associated with Climate Change May Impact Our Results of Operations and Cash Flows.

Physical risks of climate change, such as more frequent or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, and other related phenomena, could affect some, or all, of our operations. Severe weather or other natural disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within the Utilities' service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. Finally, climate change could affect the availability of a secure and economical supply of water in some locations, which is essential for FirstEnergy's and FES's continued operation, particularly the cooling of generating units.

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. Laws and regulations such as CAIR may, and are, being revised and as CAIR is being rewritten it is creating uncertainty in many areas, including but not limited to, the annual NOx emission allowances beyond 2010.

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 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.

Increases in Taxes and Fees.

Due to the revenue needs of the United States and the states and jurisdictions in which we operate, various tax and fee increases may be proposed or considered. We cannot predict whether legislation or regulation will be introduced, the form of any legislation or regulation, whether any such legislation or regulation will be passed by the state legislatures or regulatory bodies. If enacted, these changes could increase tax costs and could have a negative impact on our results of operations, financial condition and cash flows.

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. On February 11, 2010, S&P issued a report lowering FirstEnergy's and its subsidiaries' credit ratings by one notch, while maintaining its stable outlook. As a result, FirstEnergy may be required to post up to $48 million of collateral. Moody's and Fitch affirmed the ratings and stable outlook of FirstEnergy and its subsidiaries on February 11, 2010.

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 15(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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The Utilities' (other than ATSI and JCP&L) and FGCO's respective first mortgage indentures constitute, in the opinion of their counsel, direct first liens on substantially all of the respective Utilities', FGCO's and NGC'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', FGCO's and NGC's properties.

FirstEnergy has access, either through ownership or lease, to the following generation sources as of January 31, 2010, 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).

Plant-Location	Unit	Net Demonstrated Capacity (MW)
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	118(d)
Clifty Creek - Madison, IN	1-6	142(d)
Total		7,729
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		3,991
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		2,250
Total		13,970

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 11.5% entitlement based on its participation in OVEC.
(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 15,065 pole miles.

The Utilities' electric distribution systems include 119,024 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 91,048,000 kV-amperes.

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The transmission facilities that are owned by ATSI are currently operated on an integrated basis as part of MISO and are interconnected with facilities operated by PJM. In December 2009, however, the FERC approved ATSI's realignment into PJM, subject to certain conditions. 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, 2009, consist of the following:

	Distribution Lines	Transmission Lines	Substation Transformer Capacity
	(Miles)		*(kV-amperes)*
OE	30,465	550	9,503,000
Penn	5,945	44	1,057,000
CEI	25,366	2,144	7,830,000
TE	2,122	223	2,973,000
JCP&L	19,775	2,160	21,967,000
Met-Ed	15,128	1,422	10,353,000
Penelec	20,223	2,701	13,978,000
ATSI*	-	5,821	23,387,000
Total	119,024	15,065	91,048,000

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

ITEM 3. LEGAL PROCEEDINGS

On February 16, 2010, a class action lawsuit was filed in Geauga County Court of Common Pleas against FirstEnergy, CEI and OE seeking declaratory judgment and injunctive relief, as well as compensatory, incidental and consequential damages, on behalf of a class of customers related to the reduction of a discount that had previously been in place for residential customers with electric heating, electric water heating, or load management systems. The reduction in the discount was approved by the PUCO. The named-defendant companies intend to assert all applicable defenses, including the lack of jurisdiction of the court of common pleas, and to challenge any class certification.

Reference is made to Note 15, 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 2009 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 2010 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 2009.

	Period			
	October	November	December	Fourth Quarter
Total Number of Shares Purchased [(a)]	15,928	29,860	388,426	434,214
Average Price Paid per Share	$ 45.84	$ 42.99	$ 43.28	$ 43.36
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 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 under the 2007 Incentive Plan and the Executive Deferred Compensation Plan, and any shares that may have been purchased as part of publicly announced plans.

ITEM 6. SELECTED FINANCIAL DATA

FIRSTENERGY CORP.

SELECTED FINANCIAL DATA

For the Years Ended December 31,	2009	2008	2007	2006	2005
	(In millions, except per share amounts)				
Revenues	$ 12,967	$ 13,627	$ 12,802	$ 11,501	$ 11,358
Income From Continuing Operations	$ 1,006	$ 1,342	$ 1,309	$ 1,258	$ 879
Earnings Available to FirstEnergy Corp.	$ 1,006	$ 1,342	$ 1,309	$ 1,254	$ 861
Basic Earnings per Share of Common Stock:					
Income from continuing operations	$ 3.31	$ 4.41	$ 4.27	$ 3.85	$ 2.68
Earnings per basic share	$ 3.31	$ 4.41	$ 4.27	$ 3.84	$ 2.62
Diluted Earnings per Share of Common Stock:					
Income from continuing operations	$ 3.29	$ 4.38	$ 4.22	$ 3.82	$ 2.67
Earnings per diluted share	$ 3.29	$ 4.38	$ 4.22	$ 3.81	$ 2.61
Dividends Declared per Share of Common Stock [(1)]	$ 2.20	$ 2.20	$ 2.05	$ 1.85	$ 1.705
Total Assets	$ 34,304	$ 33,521	$ 32,311	$ 31,196	$ 31,841
Capitalization as of December 31:					
Total Equity	$ 8,557	$ 8,315	$ 9,007	$ 9,069	$ 9,225
Preferred Stock	-	-	-	-	184
Long-Term Debt and Other Long-Term Obligations	11,908	9,100	8,869	8,535	8,155
Total Capitalization	$ 20,465	$ 17,415	$ 17,876	$ 17,604	$ 17,564
Weighted Average Number of Basic Shares Outstanding	304	304	306	324	328
Weighted Average Number of Diluted Shares Outstanding	306	307	310	327	330

(1) Dividends declared in 2009 and 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

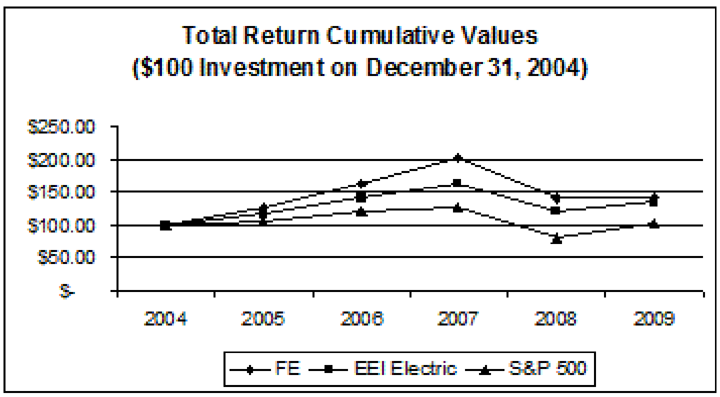
The common stock of FirstEnergy Corp. is listed on the New York Stock Exchange under the symbol "FE" and is traded on other registered exchanges.

	2009		2008	
First Quarter High-Low	$ 53.63	$ 35.63	$ 78.51	$ 64.44
Second Quarter High-Low	$ 43.29	$ 35.26	$ 83.49	$ 69.20
Third Quarter High-Low	$ 47.82	$ 36.73	$ 84.00	$ 63.03
Fourth Quarter High-Low	$ 47.77	$ 41.57	$ 66.69	$ 41.20
Yearly High-Low	$ 53.63	$ 35.26	$ 84.00	$ 41.20

Prices are from http://finance.yahoo.com.

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2004 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 110,712 and 110,365 holders of 304,835,407 shares of FirstEnergy's common stock as of December 31, 2009 and January 31, 2010, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 12 to the consolidated financial statements.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF REGISTRANT AND SUBSIDIARIES

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 Pennsylvania.
- The impact of the regulatory process on the pending matters in Ohio, Pennsylvania and New Jersey.
- Business and regulatory impacts from ATSI's realignment into PJM.
- 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.
- Operation and maintenance costs being higher than anticipated.
- Other legislative and regulatory changes, and revised environmental requirements, including possible GHG 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.
- 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.
- Ultimate resolution of Met-Ed's and Penelec's TSC 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 and energy efficiency mandates.
- 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 amounts that are 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 their 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.
- The expected timing and likelihood of completion of the proposed merger with Allegheny Energy, Inc., including the timing, receipt and terms and conditions of any required governmental and regulatory approvals of the proposed merger that could reduce anticipated benefits or cause the parties to abandon the merger, the diversion of management's time and attention from our ongoing business during this time period, the ability to maintain relationships with customers, employees or suppliers as well as the ability to successfully integrate the businesses and realize cost savings and any other synergies and the risk that the credit ratings of the combined company or its subsidiaries may be different from what the companies expect.
- 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. A security rating is not a recommendation to buy, sell or hold securities that may be subject to revision or withdrawal at any time by the assigning rating organization. Each rating should be evaluated independently of any other rating. 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 CORP.

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

EXECUTIVE SUMMARY

Earnings available to FirstEnergy Corp. in 2009 were $1.01 billion, or basic earnings of $3.31 per share of common stock ($3.29 diluted), compared with earnings available to FirstEnergy Corp. of $1.34 billion, or basic earnings of $4.41 per share of common stock ($4.38 diluted), in 2008 and $1.31 billion, or basic earnings of $4.27 per share ($4.22 diluted), in 2007.

Change in Basic Earnings Per Share From Prior Year	2009	2008
Basic Earnings Per Share – Prior Year	$ 4.41	$ 4.27
Non-core asset sales/impairments	0.47	0.02
Litigation settlement	(0.03)	0.03
Trust securities impairment	0.16	(0.20)
Saxton decommissioning regulatory asset – 2007	-	(0.05)
Regulatory charges	(0.55)	-
Derivative mark-to-market adjustment	(0.42)	-
Organizational restructuring	(0.14)	-
Debt redemption premiums	(0.31)	-
Income tax resolution	0.68	-
Revenues	(1.85)	1.61
Fuel and purchased power	(0.09)	(1.24)
Amortization of regulatory assets, net	(0.02)	(0.44)
Investment income	0.20	0.08
Interest expense	(0.14)	0.04
Reduced common shares outstanding	-	0.03
Transmission expenses	0.73	(0.02)
Other expenses	0.21	0.28
Basic Earnings Per Share	$ 3.31	$ 4.41

Financial Matters

Proposed Merger with Allegheny Energy, Inc.

On February 10, 2010, we entered into a Merger Agreement with Allegheny the consummation of which will result, among other things, in our becoming an electric utility holding company for:

- generation subsidiaries owning or controlling approximately 24,000 MWs of generating capacity from a diversified mix of regional coal, nuclear, natural gas, oil and renewable power,
- ten regulated electric distribution subsidiaries providing electric service to more than six million customers in Pennsylvania, Ohio, Maryland, New Jersey, New York, Virginia and West Virginia, and
- transmission subsidiaries owning over 20,000 miles of high-voltage lines connecting the Midwest and Mid-Atlantic.

Upon the terms and subject to the conditions set forth in the Merger Agreement, Merger Sub will merge with and into Allegheny with Allegheny continuing as the surviving corporation and a wholly-owned subsidiary of FirstEnergy. Pursuant to the Merger Agreement, upon the closing of the merger, each issued and outstanding share of Allegheny common stock, including grants of restricted common stock, will automatically be converted into the right to receive 0.667 of a share of common stock of FirstEnergy. Completion of the merger is conditioned upon, among other things, shareholder approval of both companies as well as expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and approval by the FERC, the Maryland Public Service Commission, PPUC, the Virginia State Corporation Commission and the West Virginia Public Service Commission. We anticipate that the necessary approvals will be obtained within 12 to 14 months. The Merger Agreement contains certain termination rights for both us and Allegheny, and further provides for the payment of fees and expenses upon termination under specified circumstances. Further information concerning the proposed merger will be included in a joint proxy statement/prospectus contained in the registration statement on Form S-4 to be filed by us with the SEC in connection with the merger.

Financing Activities

In 2009, we issued approximately $3.7 billion of long-term debt (excluding PCRBs) -- $2.2 billion for our Energy Delivery Services Segment and $1.5 billion for our Competitive Energy Services Segment. The primary use of the proceeds related to the repayment of long-term debt of $1.9 billion and short-term borrowings of $1.2 billion (primarily from the $2.75 billion revolver), to finance capital expenditures and for other general corporate purposes, including the Utilities' and ATSI's voluntary contribution of $500 million to the pension plan. As a result, we extended the maturity schedule of long-term debt to an average of 14.5 years, an increase of two years from 2008. Additionally, throughout 2009, FGCO and NGC remarketed and issued $940 million of PCRBs, of which $776 million was placed in fixed rate modes.

Rating Agency Actions

On February 11, 2010, S&P issued a report lowering FirstEnergy's and its subsidiaries' credit ratings by one notch, while maintaining its stable outlook. As a result, FirstEnergy may be required to post up to $48 million of collateral (see Note 15(B)). Moody's and Fitch affirmed the ratings and stable outlook of FirstEnergy and its subsidiaries on February 11, 2010. These rating agency actions were taken in response to the announcement of the proposed merger with Allegheny.

Previously, on June 17, 2009, Moody's had issued a report affirming FirstEnergy's Baa3 and FES' Baa2 credit ratings and maintained its stable outlook and, on July 9, 2009, S&P had reaffirmed its since-lowered ratings on FirstEnergy and its subsidiaries, including a BBB corporate credit rating, and maintained its then current stable outlook.

In addition, on August 3, 2009, Moody's upgraded the senior secured debt ratings of FirstEnergy's seven regulated utilities as follows: CEI and TE were each upgraded to Baa1 from Baa2, and JCP&L, Met-Ed, OE, Penelec and Penn were each upgraded to A3 from Baa1.

Sumpter Plant Sale

On December 17, 2009, FirstEnergy announced that its FGCO subsidiary reached an agreement in principle to sell its 340 MW Sumpter Plant in Sumpter, Michigan, resulting in an impairment charge in 2009 of approximately $6 million ($4 million, after tax). The sale is expected to close in first quarter of 2010 **.** The plant, built in 2002 by FGCO, consists of four 85-MW natural gas combustion turbines.

OVEC Participation Interest Sale

On May 1, 2009, FGCO sold a 9% interest in the output from OVEC for $252 million (214 MW from OVEC's generating facilities in southern Indiana and Ohio). FGCO's remaining interest in OVEC was reduced to 11.5%. This transaction increased 2009 net income by $159 million.

Legacy Power Contracts

During 2008, in anticipation of certain regulatory actions, FES entered into purchased power contracts representing approximately 4.4 million MWH per year for MISO delivery in 2010 and 2011. These contracts, which represented less than 10% of FES's estimated Ohio load, were intended to cover potential short positions that were anticipated in those years and qualified for the normal purchase normal sale scope exception under accounting for derivatives and hedging. In the fourth quarter of 2009, as FES determined that the short positions in 2010 and 2011 were not expected to materialize based on reductions in PLR obligations and decreased demand due to economic conditions, the contracts were modified to financially settle to avoid congestion and transmission expenses associated with physical delivery. As a result of the modification, the fair value of the contracts was recorded, resulting in a mark-to-market charge of approximately $205 million ($129 million, after tax) to purchased power expense. For all other purchased power contracts qualifying for the normal purchase normal sale scope exception, FES expects to take physical delivery of the power over the remaining term of the contracts.

Operational Matters

Recessionary Market Conditions and Weather Impacts

Customers' demand for electricity produced and sold by FirstEnergy's competitive subsidiary, FES, along with the value of that electricity, has been impacted by conditions in competitive power markets, macro and micro economic conditions, and weather conditions in FirstEnergy's service territories. Recessionary economic conditions, particularly in the automotive and steel industries, compounded by unusually mild regional summertime temperatures, adversely affected FirstEnergy's operations and revenues in 2009. Generation output for 2009 was 65.9 million MWH versus 2008 output of 82.4 million MWH.

Customers' demand for electricity affects FirstEnergy's distribution, transmission and generation revenues, the quantity of electricity produced, purchased power expense and fuel expense. FirstEnergy has taken various actions and instituted a number of changes in operating practices designed to mitigate the impact of these external influences. These actions included employee severances, wage reductions, employee and retiree benefit changes, reduced levels of overtime and the use of fewer contractors. Any continuing recessionary economic conditions, coupled with unusually mild weather patterns and the resulting impact on electricity prices and demand could also adversely affect FirstEnergy's results of operations and financial condition and could require further changes in FirstEnergy's operations.

FirstEnergy Reorganization and Voluntary Enhanced Retirement Option

Beginning March 3, 2009, FirstEnergy reduced its management and support staff by 348 employees during 2009. This staffing reduction resulted from an effort to enhance efficiencies in response to the economic downturn. The reduction represented approximately 4.5% of FirstEnergy's non-union workforce. Total one-time charges associated with the reorganization were approximately $66 million ($41 million, after tax), or $0.14 per share of common stock.

In June 2009, FirstEnergy offered a VERO, which provided additional benefits for qualified employees who elected to retire. The VERO was accepted by 397 non-represented employees and 318 union employees.

PJM Regional Transmission Organization (RTO) Integration

On August 17, 2009, FirstEnergy filed an application with the FERC to consolidate its transmission assets and operations into PJM. Currently, FirstEnergy's transmission assets and operations are divided between PJM and MISO. The consolidation would move the transmission assets that are part of FirstEnergy's ATSI subsidiary and are located within the footprint of the Ohio Companies and Penn - into PJM. On December 17, 2009, a FERC order approving the integration and outlining the terms required for the move was issued and on December 18, 2009, ATSI announced that it signed an agreement to join PJM. FirstEnergy plans to integrate its operations into PJM by June 1, 2011.

Beaver Valley Power Station License Renewal

On November 5, 2009, FENOC announced that the NRC approved a 20-year license extension for Beaver Valley Power Station Units 1 and 2 until 2036 and 2047, respectively. Beaver Valley is located in Shippingport, Pennsylvania and is capable of generating 1,815 MW and is the 56th out of 104 nuclear reactors in the United States to receive a license extension from the NRC.

Refueling Outages

On February 23, 2009, the Perry Plant began its 12th scheduled refueling and maintenance outage, in which 280 of the plant's 748 fuel assemblies were exchanged, safety inspections were conducted, and several maintenance projects were completed, including replacement of the plant's recirculation pump motor. On May 13, 2009, the Perry Plant returned to service.

On April 20, 2009, Beaver Valley Unit 1 began its 19th scheduled refueling and maintenance outage. During the outage, 62 of the 157 fuel assemblies were exchanged and safety inspections were conducted. Also, several projects were completed to ensure continued safe and reliable operations, including maintenance on the cooling tower and the replacement of a pump motor. On May 21, 2009, Beaver Valley Unit 1 returned to service.

On October 12, 2009, Beaver Valley Unit 2 began a scheduled refueling and maintenance outage. During the outage, 60 of the 157 fuel assemblies were exchanged and safety inspections were conducted. In addition, numerous improvement projects were completed to ensure continued safe and reliable operations. On November 27, 2009, Beaver Valley Unit 2 returned to service.

R. E. Burger Plant

On April 1, 2009, FirstEnergy announced plans to retrofit Units 4 and 5 at its R.E. Burger Plant to repower the units with biomass. Retrofitting the Burger Plant is expected to help meet the renewable energy goals set forth in Ohio SB221, will utilize much of the existing infrastructure currently in place, preserve approximately 100 jobs and continue positive economic support to Belmont County, Ohio. Once complete, the Burger Plant will be one of the largest biomass facilities in the United States. The capital cost for retrofitting the Burger Plant is estimated to be approximately $200 million, and once completed, is expected to be capable of producing up to 312 MW of electricity.

Fremont Energy Center

On September 22, 2009, FirstEnergy announced that it expects to complete construction of the Fremont Energy Center by the end of 2010. Originally acquired by FGCO in January 2008, the Fremont Energy Center includes two natural gas combined-cycle combustion turbines and a steam turbine capable of producing 544 MW of load-following capacity and 163 MW of peaking capacity. With the accelerated construction schedule, the remaining cost to complete the project is estimated to be approximately $150 million.

Norton Energy Storage Project

On November 23, 2009, FGCO announced that it purchased a 92-acre site in Norton, Ohio, for approximately $35 million to develop a compressed-air electric generating plant. The transaction includes rights to a 600-acre underground cavern ideal for energy storage technology. With 9.6 million cubic meters of storage, the Norton Energy Storage Project has the potential to be expanded to up to 2,700 MW of capacity. The Norton Energy Storage Project is part of FirstEnergy's overall environmental strategy, which includes continued investment in renewable and low-emitting energy resources.

Labor Agreements

On May 21, 2009, 517 Penelec employees, represented by the IBEW Local 459, elected to strike. In response, on May 22, 2009, Penelec implemented its work-continuation plan to use nearly 400 non-represented employees with previous line experience and training drawn from Penelec and other FirstEnergy operations to perform service reliability and priority maintenance work in Penelec's service territory. Penelec's IBEW Local 459 employees ratified a three-year contract agreement on July 19, 2009, and returned to work on July 20, 2009.

On June 26, 2009, FirstEnergy announced that seven of its union locals, representing about 2,600 employees, ratified contract extensions. The unions included employees from Penelec, Penn, CEI, OE and TE, along with certain power plant employees. On July 8, 2009, FirstEnergy announced that employees of Met-Ed represented by IBEW Local 777 ratified a two-year contract. Union members had been working without a contract since the previous agreement expired on April 30, 2009. On December 7, 2009, FirstEnergy announced that employees of its FGCO subsidiary represented by the IBEW Local 272 voted to ratify a thirty-nine month labor agreement that runs through February of 2013. IBEW Local 272 represents 374 of 513 employees at the Bruce Mansfield Plant in Shippingport, Pennsylvania.

Smart Grid Proposal

On August 6, 2009, FirstEnergy filed an application for economic stimulus funding with the DOE under the American Recovery and Reinvestment Act that proposed investing $114 million on smart grid technologies to improve the reliability and interactivity of its electric distribution infrastructure in its three-state service area. The application requested $57 million, which represents half of the funding needed for targeted projects in communities served by the Utilities. On October 27, 2009, FirstEnergy received notice from the DOE that its application was selected for award negotiations. However, no assurance can be given that we will receive such an award. The remaining investment would be expected to be recovered through customer rates. The project was approved by the NJBPU on August 6, 2009. Approval by the PPUC and the PUCO for the Pennsylvania portion and the Ohio portion, respectively, of the project is pending.

Powering our Communities Program

In September 2009, FES introduced Powering Our Communities, an innovative program that offers economic support to communities in the OE, CEI and TE service areas. The program provides up-front economic support to Ohio residents and businesses that agree to purchase electric generation supply from FES through governmental aggregation programs. As of February 1, 2010, FES signed agreements with 57 area communities.

In January 2010, FES, NOPEC and GEXA Energy, NOPEC's former generation supplier, finalized agreements making FES the generation supplier for approximately 425,000 customers in the 160 Northeast Ohio communities served by NOPEC from January 1, 2010 through December 31, 2019.

Regulatory Matters - Ohio

Ohio Regulatory Update

In August 2009, the PUCO approved the applications to accelerate the recovery of deferred costs, primarily for distribution investments, from up to 25 years to 18 months. The principal amount plus carrying charges through August 31, 2009, for these deferrals was approximately $305 million. Accelerated recovery began September 1, 2009, and will be collected in the 18 non-summer months through May 31, 2011, which is expected to save customers approximately $320 million in carrying costs.

On December 10, 2009, rules went into effect that set out the manner in which Ohio's electric utilities will be required to comply with benchmarks contained in SB221 related to the employment of alternative energy resources, energy efficiency/peak demand reduction programs, greenhouse gas reporting requirements and changes to long term forecast reporting requirements. The rules restrict the types of renewable energy resources and energy efficiency and peak reduction programs that may be included toward meeting the statutory goals, which is expected to significantly increase the cost of compliance for the Ohio companies' customers. The Ohio Companies submitted an application to amend their 2009 statutory energy efficiency benchmarks to zero. In January 2010, the PUCO approved the Ohio Companies' request contingent upon their meeting energy efficiency programs in 2010 – 2012.

On December 15, 2009, FirstEnergy's Ohio Utilities filed three-year plans with the PUCO to offer energy efficiency programs to their customers. The filing outlined specific programs to make homes and businesses more energy efficient and reduce peak energy use. The PUCO has set the matter for hearing on March 2, 2010.

In October 2009, the Ohio Companies filed an MRO to procure electric generation for the period beginning June 1, 2011, that would establish a CBP to secure generation supply for customers who do not shop with an alternative supplier.

In late 2009 the Ohio Companies conducted RFPs and secured RECs including solar RECs and RECs generated in Ohio, in order to meet the Ohio Companies' alternative energy requirements established under SB221 for 2009, 2010 and 2011. As the Ohio Companies were only able to procure a portion of their solar energy resource requirements for 2009, on December 7, 2009, they filed an application with the PUCO seeking approval for a force majeure determination to reduce the 2009 solar energy resources requirement to the level of the RECs received through the RFPs. Absent this regulatory relief, the Ohio Companies may not be able to meet their 2009 statutory renewable energy benchmarks, which may result in the assessment of forfeiture by the PUCO. The PUCO has not yet ruled on that application.

Regulatory Matters - Pennsylvania

NUG Statement Compliance Filing

On March 31, 2009, Met-Ed and Penelec submitted their 5-year NUG Statement Compliance filing to the PPUC. Both Met-Ed and Penelec proposed to reduce their CTC rate for certain customer classes with a corresponding increase in the generation rate and shopping credit. While these changes would result in additional annual generation revenue (Met-Ed - $27 million and Penelec - $59 million), overall rates would remain unchanged. The PPUC approved the compliance filings and the reduction in the CTC rate.

By Tentative Order entered September 17, 2009, the PPUC provided for an additional 30-day comment period on whether "the Restructuring Settlement allows NUG over-collection for select and isolated months to be used to reduce non-NUG stranded costs when a cumulative NUG stranded cost balance exists." In response to the Tentative Order, the Office of Small Business Advocate, Office of Consumer Advocate, York County Solid Waste and Refuse Authority, and others filed comments objecting to the above accounting method utilized by Met-Ed and Penelec. After Met-Ed and Penelec filed reply comments, the PPUC issued a Secretarial Letter on November 5, 2009 allowing parties to file reply comments to Met-Ed and Penelec's reply comments by November 16, 2009. Reply comments were filed and the companies are awaiting further action by the PPUC.

Act 129

In 2009, the PPUC approved the company-specific energy consumption and peak demand reductions that must be achieved under Act 129, which requires electric distribution companies to reduce electricity consumption by 1% by May 31, 2011 and by 3% by May 31, 2013, and an annual system peak demand reduction of 4.5% by May 31, 2013. Costs associated with achieving the reduction will be recovered from customers. On July 1, 2009, Met-Ed, Penelec and Penn filed energy efficiency and conservation plans, which approval is pending.

Act 129 also required utilities to file with the PPUC a smart meter technology procurement and installation plan to provide for the installation of smart meter technology within 15 years. The plan filed by Met-Ed, Penelec, and Penn proposed a 24-month period to assess their needs, select technology, secure vendors, train personnel, install and test support equipment, and establish a cost effective and strategic deployment schedule, which currently is expected to be completed in 15 years. Met-Ed, Penelec and Penn estimate assessment period costs at approximately $29.5 million, which the Pennsylvania Companies proposed to recover through an automatic adjustment clause. A decision is pending by the presiding ALJ.

Transmission Cost Recovery

In 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. The TSCs included a component for under-recovery of actual transmission costs incurred during the prior period (Met-Ed - $144 million and Penelec - $4 million) and 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 future TSCs by December 31, 2010. Various intervenors filed complaints against those filings and the PPUC ordered an investigation to review the reasonableness of Met-Ed's TSC, while allowing Met-Ed to implement the June 1, 2008 rider, subject to refund. In August 2009, the ALJ issued a Recommend Decision to the PPUC approving Met-Ed's and Penelec's TSCs as filed and dismissing all complaints. On January 28, 2010, the PPUC adopted a motion which denies the recovery of marginal transmission losses through the TSC for the period of June 1, 2007 through March 31, 2008, and instructs Met-Ed and Penelec to work with the parties and file a petition to retain any over-collection, with interest, until 2011 for the purpose of providing mitigation of future rate increases starting in 2011 for their customers. The Companies are now awaiting an order, which is expected to be consistent with the motion. If so, Met-Ed and Penelec plan to appeal such a decision to the Commonwealth Court of Pennsylvania. Although the ultimte outcome of this matter cannot be determined at this time, it is the belief of the Companies that they should prevail in any such appeal and therefore expect to fully recover the approximately $170.5 million ($138.7 million for Met-Ed and $31.8 million for Penelec) in marginal transmission losses for the period prior to January 1, 2011.

On May 28, 2009, the PPUC approved Met-Ed's and Penelec's annual updates to their TSC rider for the period June 1, 2009 through May 31, 2010, subject to the outcome of the preceding related to the 2008 TSC filing described above. Although the new TSC resulted in an approximate 1% decrease in monthly bills for Penelec customers, the TSC for Met-Ed's customers increased to recover the additional PJM charges paid by Met-Ed in the previous year and to reflect updated projected costs. Under the proposal, monthly bills for Met-Ed's customers would increase approximately 9.4% for the period June 2009 through May 2010.

Default Service Plan

On February 20, 2009, Met-Ed and Penelec filed with the PPUC a generation procurement plan covering the period January 1, 2011 through May 31, 2013. A settlement agreement was later filed on all but two issues and on November 6, 2009, the PPUC entered an Order approving the settlement and finding in favor of Met-Ed and Penelec on the two issues reserved for litigation. Generation procurement began in January 2010.

On February 8, 2010, Penn filed with the PPUC a generation procurement plan covering the period June 1, 2011 through May 31, 2013. The 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 proposed a staggered procurement schedule, which varies by customer class, through the use of a descending clock auction. The PPUC must issue an order on the plan no later than November 8, 2010.

Regulatory Matters – New Jersey

Solar Renewable Energy Proposal

On March 27, 2009, the NJBPU approved JCP&L's proposal to help increase the pace of solar energy project development by establishing long-term agreements to purchase and sell SRECs, which will provide a stable basis for financing solar generation projects. In 2009, JCP&L, in collaboration with another New Jersey electric utility, announced an RFP to secure SRECs. A total of 61 MW of solar generating capacity (42 for JCP&L) will be solicited to help meet New Jersey Renewable Portfolio Standards. The first solicitation was conducted in August 2009; subsequent solicitations will occur over the next three years. The costs of this program are expected to be fully recoverable through a per KWH rate approved by the NJBPU and applied to all customers.

On February 11, 2010, Standard and Poor's downgraded the senior unsecured debt of FirstEnergy Corp. to BB+. As a result, pursuant to the requirements of a pre-existing NJBPU order, JCP&L filed, on February 17, a plan addressing the mitigation of any effect of the downgrade and which provided an assessment of present and future liquidity necessary to assure JCP&L's continued payment to BGS suppliers. The order also provides that the NJBPU should: 1) within 10 days of that filing, hold a public hearing to review the plan and consider the available options and 2) within 30 days of that filing issue an order with respect to the matter. At this time, the public hearing has not been scheduled and FirstEnergy and JCP&L cannot determine the impact, if any, these proceedings will have on their operations.

FIRSTENERGY'S BUSINESS

We are a diversified energy company headquartered in Akron, Ohio, that operates primarily through two core business segments (see "Results of Operations"). Financial information for each of FirstEnergy's reportable segments is presented in the following table. With the completion of transition to a fully competitive generation market in Ohio in 2009, the former Ohio Transitional Generation Services segment was combined with the Energy Delivery Services segment, consistent with how management views the business. Disclosures for FirstEnergy's operating segments for 2008 and 2007 have been reclassified to conform to the 2009 presentation.

- **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 Ohio, Pennsylvania and New Jersey. Its revenues are primarily derived 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 Ohio, Pennsylvania and New Jersey franchise areas. Its results reflect the commodity costs of securing electric generation from FES and from non-affiliated power suppliers, the net PJM and MISO transmission expenses related to the delivery of the respective generation loads, and the deferral and amortization of certain fuel costs.

  The service areas of our utilities are summarized below:

Company	Area Served	Customers Served
OE	Central and Northeastern Ohio	1,038,000
Penn	Western Pennsylvania	160,000
CEI	Northeastern Ohio	754,000
TE	Northwestern Ohio	310,000
JCP&L	Northern, Western and East Central New Jersey	1,095,000
Met-Ed	Eastern Pennsylvania	551,000
Penelec	Western Pennsylvania	590,000
ATSI	Service areas of OE, Penn, CEI and TE	

- **Competitive Energy Services** supplies electric power to 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 and 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 energy to the segment's customers.

PROPOSED MERGER WITH ALLEGHENY

Proposed Merger with Allegheny Energy, Inc.

On February 10, 2010, we entered into a Merger Agreement with Allegheny the consummation of which will result, among other things, in our becoming an electric utility holding company for:

- generation subsidiaries owning or controlling approximately 24,000 MWs of generating capacity from a diversified mix of regional coal, nuclear, natural gas, oil and renewable power,

- ten regulated electric distribution subsidiaries providing electric service to more than six million customers in Pennsylvania, Ohio, Maryland, New Jersey, New York, Virginia and West Virginia, and

- transmission subsidiaries owning over 20,000 miles of high-voltage lines connecting the Midwest and Mid-Atlantic.

Upon the terms and subject to the conditions set forth in the Merger Agreement, Merger Sub will merge with and into Allegheny with Allegheny continuing as the surviving corporation and a wholly-owned subsidiary of FirstEnergy. Pursuant to the Merger Agreement, upon the closing of the merger, each issued and outstanding share of Allegheny common stock, including grants of restricted common stock, will automatically be converted into the right to receive 0.667 of a share of common stock of FirstEnergy. Completion of the merger is conditioned upon, among other things, shareholder approval of both companies as well as expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and approval by the FERC, the Maryland Public Service Commission, PPUC, the Virginia State Corporation Commission and the West Virginia Public Service Commission. We anticipate that the necessary approvals will be obtained within 12 to 14 months. The Merger Agreement contains certain termination rights for both us and Allegheny, and further provides for the payment of fees and expenses upon termination under specified circumstances. Further information concerning the proposed merger will be included in a joint proxy statement/prospectus contained in the registration statement on Form S-4 to be filed by us with the SEC in connection with the merger.

Prior to the merger, we and Allegheny will continue to operate as separate companies. Accordingly, except for specific references to the pending merger, the descriptions of our strategy and outlook and the risks and challenges we face, and the discussion and analysis of our results of operations and financial condition set forth below relate solely to FirstEnergy. Details regarding the pending merger are discussed in Note 21 to the consolidated financial statements.

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 generation market prices in Ohio and Pennsylvania;
- executing our direct-to-customer retail sales strategy;
- maintaining adequate and ready access to cash resources; and
- achieving our financial goals and commitments to shareholders.

2009 was a difficult year for the U.S. economy due to the ongoing effects of the recession. In the region FirstEnergy serves, this was evidenced by reduced sales, particularly in the industrial sector, and very soft wholesale market power prices when compared to 2008. We responded, in part, by making adjustments to both our operational and capital spending plans, as well as our financing plans. Despite these challenges, we continued to make solid progress toward achieving our overall operational and financial goals.

We began implementation of our long-term strategic plans during the past several years. 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:

2007 and 2008

In 2007, we successfully transitioned Penn to market-based retail rates for generation service through a competitive, wholesale power supply procurement process. During 2007 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. For generation service, Met-Ed and Penelec received partial requirements for their PLR service from FES. Also during 2007, the Ohio Companies filed an application for an increase in electric distribution rates with the PUCO to support a distribution rate increase. In 2009, the PUCO granted the Ohio Companies' application to increase electric distribution rates by $136.6 million. These increases went into effect during 2009.

We continued our successful “mining our assets” program, through which we increased the net-generating capacity at several facilities through cost-effective unit upgrades. In 2008, we achieved record generation output of 82.4 billion KWH. Our generation growth strategy is to continue to implement low cost, incremental upgrades to existing facilities, complemented by strategic asset purchases, rather than making substantial investments in new coal or nuclear baseload capacity with very long lead times to construct.

We made several strategic investments in 2008, including the purchase of the partially complete Fremont Energy Center, which includes two natural gas combined-cycle combustion turbines and a steam turbine capable of producing 544 MW of load-following capacity and 163 MW of peaking capacity. We expect to complete construction by the end of 2010.

In mid-2008, we also 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 MW and help support our incremental generation expansion plans. The burning of Signal Peak coal is also expected to improve the performance of some of our older generating units, which will factor into our decision making process regarding potential future plant shutdowns. Signal Peak began commercial operation in December 2009. Although, we have experienced some issues with the start-up of commercial operations, we believe those issues will be resolved and Signal Peak is expected to achieve its production goals for the year. 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 both a comprehensive ESP and MRO with the PUCO. In November 2008, the PUCO issued an order denying the 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).

2009 and 2010

In 2009, our total generation output of 65.9 billion KWH reflected the economic realities of the continued recession coupled with mild weather, particularly during the summer months. Due to the continued implementation of our retail strategy, which will concentrate on direct sales and governmental aggregation and de-emphasize the wholesale market, we expect a significant increase in our generation output in 2010. Distribution rate increases became effective for OE and TE in January 2009 and for CEI in May 2009, as a result of rate cases filed in 2007. Transition cost recovery related to the Ohio Companies' transition to a competitive generation market ended for OE and TE on December 31, 2008. Additionally, FES assumed their third party partial requirements contracts and now expects to provide Met-Ed and Penelec with their complete PLR and default service load through the end of 2010 when their current rate caps expire and they transition to procuring their generation requirements at competitive market prices.

On February 19, 2009, the Ohio Companies filed an amended ESP application, including a 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 and on February 26, 2009 filed a Supplemental Stipulation supported by nearly every party in the case, which the PUCO approved in March 2009 (see Regulatory Matters – Ohio). The Amended ESP included a May 2009 auction to secure full requirements generation supply and pricing for the Ohio Companies for the period June 1, 2009 through May 31, 2011. The auction resulted in an average weighted wholesale price for generation and transmission of 6.15 cents per KWH. FES was a successful bidder for 51% of the Ohio Companies PLR load.

Following the May 2009 auction, FES accelerated the execution of its retail strategy, described above, to directly acquire and serve customers of the Ohio Companies, including select large commercial and industrial customers. Through December 31, 2009, FES entered into agreements with 60 area communities under governmental aggregation programs, representing approximately 580,000 residential and small commercial customers inside of our Ohio franchise territories. As of December 31, 2009, FES supplied 77% of the PLR load.

In August 2009, we filed an application with the FERC for approval to consolidate our ATSI transmission assets and operations currently dedicated to MISO into PJM. On December 17, 2009, FERC issued an order approving the integration and outlining the terms required for the move, which is expected to be complete by June 1, 2011. On December 18, 2009, ATSI announced it had signed an agreement to join PJM. In December 2009, we also announced that an agreement in principle had been reached to sell the 340-MW Sumpter Plant which is located in MISO. The sale is expected to close in the first quarter of 2010.

Total distribution sales in 2009 were 102 million MWH, down from 112 million MWH in 2008. This decrease was due to the effects of the recession, primarily in reduced industrial sales, coupled with mild weather.

As we look to 2010 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 during the next phase of the market recovery. 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 expected to expire. Beginning in 2011, Met-Ed and Penelec have approval from the PPUC to obtain their power supply from the competitive wholesale market and fully recover their generation costs through retail rates. As a result, FES plans to redeploy the power currently sold to Met-Ed and Penelec primarily to retail customers located in and near our generation footprint and into local regional auctions and RFPs for PLR service, with the remainder available for sale in the wholesale market.

In Ohio, we filed an application for an MRO with the PUCO in October 2009, which would establish generation rates for the Ohio Companies beginning June 1, 2011, using a descending clock-style auction similar in all material respects to that used in the May 2009 auction process. Pursuant to SB221, the PUCO has 90 days from the date of the application to determine whether the MRO meets certain statutory requirements. Although the Ohio Companies requested a PUCO determination by January 18, 2010, on February 3, 2010, the PUCO announced that its determination would be delayed. Under a determination that such statutory requirements are met, the Ohio Companies would be able to implement the MRO and conduct the CBP.

We will 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 thrive in the competitive marketplace.

As discussed above, our strategy is focused on maximizing the earnings potential from our unregulated FES operations and maintaining stable earnings growth from our regulated utility operations. In addition, if approvals for the pending merger with Allegheny have been obtained and the merger is consummated in early to mid-2011 as we currently expect, the work of integrating Allegheny and its operations and generation, transmission and distribution assets with our own will begin in earnest. We expect that those efforts will enhance our ability to achieve our strategic goals as discussed above.

Financial Outlook

In response to the unprecedented volatility in the capital and credit markets that began in late 2008 and our increased risk exposure to the commodity markets that resulted from the outcome of the Ohio CBP, we carefully assessed 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 steps to strengthen our liquidity position and provide additional flexibility to meet our anticipated obligations and those of our subsidiaries.

These actions included spending reductions of more than $600 million in 2009 compared to 2008 levels through measured and appropriate changes in capital and operation and maintenance expenditures. In addition, we adjusted the construction schedule for the $1.8 billion AQC project at our W.H. Sammis Plant in order to delay certain costs from our 2009 budget while still targeting our completion deadline by the end of 2010.

We completed significant financing activities at our regulated utilities of $2.2 billion as well as issuing 5, 12 and 30-year unsecured senior notes totaling $1.5 billion at FES. We also completed refinancing $518 million of variable rate debt to fixed rate debt, and made a voluntary contribution of $500 million in September 2009 to our pension plan. 2009 cash flow from operations was strong at $2.5 billion

On February 11, 2010, S&P issued a report lowering FirstEnergy's and its subsidiaries' credit ratings by one notch, while maintaining its stable outlook. As a result, FirstEnergy may be required to post up to $48 million of collateral (see Note 15(B)). Moody's and Fitch affirmed the ratings and stable outlook of FirstEnergy and its subsidiaries on February 11, 2010.

Our financial strategy focuses on reducing debt, a minimum of $500 million during 2010. We are also focusing on delivering consistent financial results, improving financial strength and flexibility, deploying cash as effectively as possible, and improving our current credit metrics.

Positive earnings drivers in 2010 are expected to include:

- Increased FES commodity margin from implementation of the retail strategy and the restructuring of the PJM PLR contracts;
- Increased distribution revenues from projected sales of 110 million MWH in 2010 vs. 102 million MWH in 2009, and a full year of both the distribution rate increase and Delivery Service Improvement Rider in Ohio;

- A full year of operation and maintenance cost savings that resulted from 2009 staffing adjustments, changes in our compensation structure, fossil plant outage schedule changes and general cost-saving measures; and
- Reduced costs from one less nuclear refueling outage in 2010 vs. 2009.

Negative earnings drivers in 2010 are expected to include:

- Reduced gains from sale of nuclear decommissioning trust investments in 2009;
- Reduced RTC margin for CEI:
- The absence of significant favorable tax settlements in 2010 compared to 2009; and
- Increased benefit and financing costs, general taxes and depreciation expense.

Our liquidity position remains strong, with access to more than $ 3.3 billion of liquidity, of which approximately $2.5 billion was available as of January 31, 2010. We intend to continue to fund our capital requirements through cash generated from operations **.**

A driver for longer-term earnings growth is our continued effort to improve the utilization and output of our generation fleet. During 2010 we plan to invest approximately $646 million in our regulated energy delivery services business

Positive earnings drivers for 2011 could include:

- The December 31, 2010 expiration of FES' contracts to serve Met-Ed and Penelec's generation requirements. In 2011, 100% of the generation output at FES will be priced at market;
- Potentially increased distribution deliveries tied to an economic recovery; and
- Incremental Signal Peak coal production and price improvement

Negative earnings drivers for 2011 could include:

- Increased nuclear fuel costs and coal contract pricing adjustments;
- Pressure to maintain O&M cost reductions vs. 2010 with a potentially improving economy
- Increased depreciation and general taxes and lower capitalized interest resulting from completion of our Sammis AQC and Fremont construction projects

Capital Expenditures Outlook

Our capital expenditure forecast for 2010 is approximately $1.65 billion.

Capital expenditures for our competitive energy services business are expected to hold steady from 2009 to 2010 at $467 million exclusive of Sammis AQC project, the Burger Biomass conversion and Norton, and the Fremont facility. That level spending plan includes $65 million for the Davis-Besse steam generator replacement, expected to be completed in 2014. Other planned expenditures provide for maintaining of critical generation assets, delivering operational improvements to enhance reliability, and supporting our generation to market strategy.

This is the final year for work on the Sammis AQC project, which is expected to go in service at the end of 2010 . To date, this initiative has cost just under $1.58 billion, with an additional $241 million planned in 2010. Expenditures on the Burger Biomass conversion project get underway in 2010 with $16 million planned. The project is expected to be completed by December 2012. We plan to spend $150 million in 2010 on the Fremont facility and anticipate that work will be completed by the end of the year.

For our regulated operations, capital expenditures are forecast to be $646 million in 2010, primarily in support of transmission and distribution reliability **.** The spending plan also includes projects in Ohio and Pennsylvania for Energy Efficiency and Advanced Metering initiatives, which are expected to be partially reimbursed through federal stimulus funding.

The anticipated 2010 capital spend for the Regional Transmission Expansion initiative is $78 million. This initiative is focused on meeting NERC, Reliability First Corporation, PJM and FirstEnergy planning criteria . In addition, there are projects associated with the connection of new retail and wholesale load delivery points, transition to PJM market, and projects connecting new wholesale generation connection points.

For 2011 through 2014, we anticipate average annual capital expenditures of approximately $1.2 billion, exclusive of any additional opportunities or new mandated spending. Planned capital initiatives promote reliability, improve operations, and support current environmental and energy efficiency proposals.

Actual capital spending for 2009 and projected capital spending for 2010 is as follows:

Projected Capital Spending by Business Unit	**2009**	**2010**
	(In millions)	
Energy Delivery	$ 687	$ 646
Nuclear	259	265
Fossil	199	186
FES Other	9	16
Corporate	46	52
Sammis AQC	437	241
Subtotal	$ 1,637	$ 1,406
Fremont Facility	51	150
Burger Biomass and Norton	38	17
Transmission Expansion	44	78
Total Capital	**$ 1,770**	**$ 1,651**

Environmental Outlook

At FirstEnergy, we continually strive to enhance environmental protection and remain good stewards of our natural resources. We allocate significant resources to support our environmental compliance efforts, and our employees share both a commitment to and accountability for our environmental performance. Our corporate focus on continuous improvement is integral to our environmental performance.

Recent action underscores our commitment to enhancing our environmental stewardship throughout our entire organization as well as mitigating the company’s exposure to existing and anticipated environmental laws and regulations.

In April, 2009, we announced our intention to convert our R.E. Burger Plant in Shadyside, Ohio from a facility that generates electricity by burning coal to one that will utilize renewable biomass. When completed, Burger will be one of the largest renewable facilities of its kind in the world. In September 2009, we announced plans to complete construction of the Fremont Energy Center, a 707-MW natural-gas fired peaking plant located in Fremont, Ohio, by the end of 2010. And in November 2009, we purchased the rights to develop a compressed-air electric generating plant in Norton, Ohio. This technology would essentially operate like a large battery with the ability to store energy when there is low demand and then use it when needed. This is especially important for the storage of energy generated from intermittent renewable sources of energy – such as wind and solar – as they do not always produce energy when demand is high. Together, these three low-emitting projects (Burger, Fremont, and Norton) are part of our overall environmental strategy, which includes continued investment in renewable and low-emitting energy resources.

We have spent more than $7 billion on environmental protection efforts since the Clean Air Act became law in 1970, and these investments are making a difference. Since 1990, we have reduced emissions of nitrogen oxides (NOx) by more than 72% sulfur dioxide (SO2) by more than 69% and mercury by about 47%. Also, our CO2 emission rate, in pounds of CO2 per kWh, has dropped by 19 percent through this period. Based on this progress, emission rates for our power plants are significantly lower than the regional average.

To further enhance our environmental performance, we have implemented 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 NOx SO2 and particulate. It also fulfills the requirements imposed by the 2005 Sammis Consent Decree that resolved Sammis NSR litigation. At the end of 2010, we will have invested approximately $1.8 billion at our W.H. Sammis Plant in Stratton, Ohio, to further reduce emissions of SO2 and NOx. This multi-year environmental retrofit project, which began in 2006 and is expected to be completed in 2010, is designed to reduce the plant’s SO2 emissions by 95% and NOx by at least 64%. This is one of the largest environmental retrofit projects in the nation.

By yearend, we expect approximately 70% of our generation fleet to be non emitting or low emitting generation. Over 52% of our coal-fired generating fleet will have full NOx and SO2 equipment controls thus significantly decreasing our exposure to the volatile emission allowance market for NOx and SO2 and potential future environmental requirements.

One of the key issues facing our company and industry is global climate change related mandates. Lawmakers at the state and federal level are exploring and implementing a wide range of responses. We believe our generation fleet is very well positioned to be successfully competitive in a carbon-constrained economy. In addition, we believe the proposed merger with Allegheny, if consummated, will enhance our environmental profile as it will result in our having an even more diverse mix of fully-scrubbed baseload fossil, non-emitting nuclear and renewable generation, including large-scale storage.

We have taken aggressive steps over the past two decades that have increased our generating capacity without adding to overall CO2 emissions. For example, since 1990, we have reconfigured our fleet by retiring nearly 700 megawatts of older, coal-based generation and adding more than 1,800 megawatts of non-emitting nuclear capacity. Through these and other actions, we have increased our generating capacity by nearly 15% over the same period while avoiding some 350 million metric tons of CO2 emissions. Today, nearly 40% of our electricity is generated without emitting CO2 – a key advantage that will help us meet the challenge of future government climate change mandates. And with recent announcements in 2009, including the expanded use of renewable energy, energy storage and natural gas, our CO2 emission rate will decline even further in the future.

Moreover, we have taken a leadership role in pursuing new ventures and testing and developing new technologies that show promise in achieving additional reductions in CO2 emissions. These include:

- Bringing online 132.5 MW of wind generation in 2009 and we now sell over 1 million MWh per year of wind generation.
- Testing of CO2 sequestration at our R.E. Burger Plant. The results of this testing will help us gain a better understanding of the potential for geological storage of CO2.
- Supporting afforestation – growing forests on non-forested land – and other efforts designed to remove CO2 from the environment.
- Participating in the U.S. EPA's SF6 (sulfur hexafluoride) Emissions Reduction Partnership for Electric Power Systems since its inception in 1998. Since then, we have reduced emissions of SF6 by nearly 20 metric tons, resulting in an equivalent reduction of nearly 430,000 tons of CO2.
- Supporting research to develop and evaluate cost effective sorbent materials for CO2 capture including work by Powerspan at the Burger Plant and the University of Akron.

In addition, we will remain actively engaged in the federal and state debate over future environmental requirements and legislation, especially those dealing with global climate change. We are committed to working with policy makers to develop fair and reasonable legislation, with the goal of reducing global emissions while minimizing the economic impact on our customers. Due to the significant uncertainty as to the final form of any such legislation at both the federal and state levels, it makes it difficult to determine the potential impact and risks associated with GHG emissions requirements.

We also have a long history of supporting research in distributed energy resources. Distributed energy resources include fuel cells, solar and wind systems or energy storage technologies located close to the customer or direct control of customer loads to provide alternatives or enhancements to the traditional electric power system. Through a partnership with EPRI, the Cuyahoga Valley National Park, the Department of Defense and Case Western Reserve University, two solid-oxide fuel cells were installed as part of a test program to explore the technology and the environmental benefits of distributed generation. We are also evaluating the impact of distributed energy storage on the distribution system through analysis and field demonstrations of advanced battery technologies. Integrated direct load control technology with two-way communication capability is being installed on customers' non-critical equipment such as air conditioners in New Jersey and Pennsylvania to help manage peak loading on the electric distribution system.

We are equally committed internally to environmental performance throughout our entire organization, including our newest facility, a "green" office building in Akron that incorporates a wide range of innovative, environmentally sound features (pictured below). In December, this building was awarded Gold Level certification by the U.S. Green Building Council's Leadership in Energy and Environmental Design (LEED) program, making this campus the largest office building in northeast Ohio to receive this highly-prized designation.

Our efforts to protect the environment combine innovative technologies with proven and effective work processes. For example, we are expanding an environmental management system that tracks thousands of environmental commitments and provides up-to-date information to responsible parties on compliance issues and deadlines. This system allows us to more efficiently maintain our compliance with environmental standards.

The company also uses a rigorous compliance assistance program. Company personnel continually audit all of our facilities, from generating plants to office buildings, and conduct a top-to-bottom review of the entire operation to check on compliance with company environmental policy and environmental regulation in addition to identifying best environmental practices.

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 reliability standards set by NERC/FERC or changes in the rules of organized markets and the states in which we do business;
- 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 regional and 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;
- ability of certain FirstEnergy companies to meet their obligations to other FirstEnergy companies;
- ability to obtain the approvals required to complete our merger with Allegheny or, in order to do so, the combined company may be required to comply with material restrictions or conditions;
- if completed, our merger with Allegheny may not achieve its intended results;
- we will be subject to business uncertainties and contractual restrictions while the merger with Allegheny is pending that could adversely affect our financial results;
- failure to complete the merger with Allegheny could negatively impact our stock price and our future business and financial results;
- 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 regional transmission organizations;
- a significant delay in or challenges to various elements of ATSI's consolidation into PJM, including but not limited to, the intervention of parties to the regulatory proceedings, could have a negative impact on our results of operations and financial condition;
- energy conservation and energy price increases could negatively impact our financial results;
- the EPA is conducting NSR investigations at a number of our generating plants, the results of which could negatively impact our results of operations and financial condition;
- 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;

- the physical risks associated with climate change may impact our results of operations and cash flows;
- 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;
- increases in taxes and fees;
- 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 effectively hedge our generation portfolio, and the competitiveness and liquidity of energy markets; each could adversely affect our results of operations, cash flows and financial condition; and
- questions regarding the soundness of financial institutions or counterparties could adversely affect us.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among our business segments. With the completion of transition to a fully competitive generation market in Ohio in 2009, the former Ohio Transitional Generation Services segment was combined with the Energy Delivery Services segment, consistent with how management views the business. Disclosures for FirstEnergy's operating segments for 2008 and 2007 have been reclassified to conform to the 2009 presentation. A reconciliation of segment financial results is provided in Note 16 to the consolidated financial statements. Earnings available to FirstEnergy Corp. by major business segment were as follows:

				Increase (Decrease)	
	2009	**2008**	**2007**	**2009 vs 2008**	**2008 vs 2007**
	(In millions, except per share amounts)				
Earnings Available to FirstEnergy Corp.					
By Business Segment:					
Energy delivery services	$ 435	$ 916	$ 965	$ (481)	$ (49)
Competitive energy services	517	472	495	45	(23)
Other and reconciling adjustments*	54	(46)	(151)	100	105
Total	$ 1,006	$ 1,342	$ 1,309	$ (336)	$ 33
Basic Earnings Per Share:	$ 3.31	$ 4.41	$ 4.27	$ (1.10)	$ 0.14
Diluted Earnings Per Share:	$ 3.29	$ 4.38	$ 4.22	$ (1.09)	$ 0.16

* 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 – 2009 Compared with 2008

Financial results for our major business segments in 2009 and 2008 were as follows:

2009 Financial Results	**Energy Delivery Services**	**Competitive Energy Services**	**Other and Reconciling Adjustments**	**FirstEnergy Consolidated**
		(In millions)		
Revenues:				
External				
Electric	$ 10,585	$ 1,447	$ -	$ 12,032
Other	559	441	(82)	918
Internal*	-	2,843	(2,826)	17
Total Revenues	11,144	4,731	(2,908)	12,967
Expenses:				
Fuel	-	1,153	-	1,153
Purchased power	6,560	996	(2,826)	4,730
Other operating expenses	1,424	1,357	(84)	2,697
Provision for depreciation	445	270	21	736
Amortization of regulatory assets	1,155	-	-	1,155
Deferral of new regulatory assets	(136)	-	-	(136)
General taxes	641	108	4	753
Total Expenses	10,089	3,884	(2,885)	11,088
Operating Income	1,055	847	(23)	1,879
Other Income (Expense):				
Investment income	139	121	(56)	204
Interest expense	(472)	(166)	(340)	(978)
Capitalized interest	3	60	67	130
Total Other Income (Expense)	(330)	15	(329)	(644)
Income Before Income Taxes	725	862	(352)	1,235
Income taxes	290	345	(390)	245
Net Income	435	517	38	990
Less: Noncontrolling interest income (loss)	-	-	(16)	(16)
Earnings available to FirstEnergy Corp.	$ 435	$ 517	$ 54	$ 1,006

* Consistent with the accounting for the effects of certain types of regulation, internal revenues do not fully eliminate representing sales of RECs by FES to the Ohio Companies.

2008 Financial Results	**Energy Delivery Services**	**Competitive Energy Services**	**Other and Reconciling Adjustments**	**FirstEnergy Consolidated**
		(In millions)		
Revenues:				
External				
Electric	$ 11,360	$ 1,333	$ -	$ 12,693
Other	708	238	(12)	934
Internal	-	2,968	(2,968)	-
Total Revenues	12,068	4,539	(2,980)	13,627
Expenses:				
Fuel	2	1,338	-	1,340
Purchased power	6,480	779	(2,968)	4,291
Other operating expenses	2,022	1,142	(119)	3,045
Provision for depreciation	417	243	17	677
Amortization of regulatory assets, net	1,053	-	-	1,053
Deferral of new regulatory assets	(316)	-	-	(316)
General taxes	646	109	23	778
Total Expenses	10,304	3,611	(3,047)	10,868
Operating Income	1,764	928	67	2,759
Other Income (Expense):				
Investment income	171	(34)	(78)	59
Interest expense	(411)	(152)	(191)	(754)
Capitalized interest	3	44	5	52
Total Other Expense	(237)	(142)	(264)	(643)
Income Before Income Taxes	1,527	786	(197)	2,116
Income taxes	611	314	(148)	777
Net Income	916	472	(49)	1,339
Less: Noncontrolling interest income (loss)	-	-	(3)	(3)
Earnings available to FirstEnergy Corp.	$ 916	$ 472	$ (46)	$ 1,342

Changes Between 2009 and 2008 Financial Results Increase (Decrease)				
Revenues:				
External				
Electric	$ (775)	$ 114	$ -	$ (661)
Other	(149)	203	(70)	(16)
Internal*	-	(125)	142	17
Total Revenues	(924)	192	72	(660)
Expenses:				
Fuel	(2)	(185)	-	(187)
Purchased power	80	217	142	439
Other operating expenses	(598)	215	35	(348)
Provision for depreciation	28	27	4	59
Amortization of regulatory assets	102	-	-	102
Deferral of new regulatory assets	180	-	-	180
General taxes	(5)	(1)	(19)	(25)
Total Expenses	(215)	273	162	220
Operating Income	(709)	(81)	(90)	(880)
Other Income (Expense):				
Investment income	(32)	155	22	145
Interest expense	(61)	(14)	(149)	(224)
Capitalized interest	-	16	62	78
Total Other Income (Expense)	(93)	157	(65)	(1)
Income Before Income Taxes	(802)	76	(155)	(881)
Income taxes	(321)	31	(242)	(532)
Net Income	(481)	45	87	(349)
Less: Noncontrolling interest income (loss)	-	-	(13)	(13)
Earnings available to FirstEnergy Corp.	$ (481)	$ 45	$ 100	$ (336)

* Consistent with the accounting for the effects of certain types of regulation, internal revenues do not fully eliminate representing sales of RECs by FES to the Ohio Companies.

Energy Delivery Services – 2009 Compared to 2008

Net income decreased $481 million to $435 million in 2009 compared to $916 million in 2008, primarily due to lower revenues, increased purchased power costs and decreased deferrals of new regulatory assets, partially offset by lower other operating expenses.

Revenues –

The decrease in total revenues resulted from the following sources:

Revenues by Type of Service	**2009**	**2008**	**Increase (Decrease)**
		(In millions)	
Distribution services	$ 3,420	$ 3,882	$ (462)
Generation sales:			
Retail	5,760	5,768	(8)
Wholesale	752	962	(210)
Total generation sales	6,512	6,730	(218)
Transmission	1,023	1,268	(245)
Other	189	188	1
Total Revenues	$ 11,144	$ 12,068	$ (924)

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

Electric Distribution KWH Deliveries	
Residential	(3.3)%
Commercial	(4.4)%
Industrial	(14.7)%
Total Distribution KWH Deliveries	(7.3)%

The lower revenues from distribution services were driven primarily by the reductions in sales volume associated with milder weather and economic conditions. The decrease in residential deliveries reflected reduced weather-related usage compared to 2008, as cooling degree days and heating degree days decreased by 17% and 1%, respectively. The decreases in distribution deliveries to commercial and industrial customers were primarily due to economic conditions in FirstEnergy's service territory. In the industrial sector, KWH deliveries declined to major automotive customers by 20.2% and to steel customers by 36.2%. Reduced revenues from transition charges for OE and TE that ceased with the full recovery of related costs effective January 1, 2009 and the transition rate reduction for CEI effective June 1, 2009, were offset by PUCO-approved distribution rate increases (see Regulatory Matters – Ohio).

The following table summarizes the price and volume factors contributing to the $218 million decrease in generation revenues in 2009 compared to 2008:

Sources of Change in Generation Revenues	**Increase (Decrease)**
	(In millions)
Retail:	
Effect of 10.5% decrease in sales volumes	$ (603)
Change in prices	595
	(8)
Wholesale:	
Effect of 14.9% decrease in sales volumes	(143)
Change in prices	(67)
	(210)
Net Decrease in Generation Revenues	$ (218)

The decrease in retail generation sales volumes from 2008 was primarily due to the weakened economic conditions and milder weather described above. Retail generation prices increased for JCP&L and Penn during 2009 as a result of their power procurement processes. For the Ohio Companies, average prices increased primarily due to the higher fuel cost recovery riders that were effective from January through May 2009. In addition, effective June 1, 2009, the Ohio Companies' transmission tariff ended and the recovery of transmission costs is included in the generation rate established under the CBP.

Wholesale generation sales decreased principally as a result of JCP&L selling less available power from NUGs due to the termination of a NUG purchase contract in October 2008. The decrease in wholesale prices reflected lower spot market prices in PJM.

Transmission revenues decreased $245 million primarily due to the termination of the Ohio Companies' current transmission tariff and lower MISO and PJM transmission revenues, partially offset by higher transmission rates for Met-Ed and Penelec resulting from the annual updates to their TSC riders (see Regulatory Matters). The difference between transmission revenues accrued and transmission costs incurred are deferred, resulting in no material effect on current period earnings.

Expenses –

Total expenses increased by $215 million due to the following:

- Purchased power costs were $80 million higher in 2009 due to higher unit costs, partially offset by an increase in volumes combined with higher NUG cost deferrals. The increased purchased power costs from non-affiliates was due primarily to increased volumes for the Ohio Companies as a result of their CBP, partially offset by lower volumes for Met-Ed and Penelec due to the termination of a third-party supply contract in December 2008 and for JCP&L due to the termination of a NUG purchase contract in October 2008. Decreased purchased power costs from FES were principally due to lower volumes for the Ohio Companies following their CBP, partially offset by increased volumes for Met-Ed and Penelec under their fixed-price partial requirements PSA with FES. Higher unit costs from FES, which included a component for transmission under the Ohio Companies' CBP, partially offset the decreased volumes.

  The following table summarizes the sources of changes in purchased power costs:

Source of Change in Purchased Power	**Increase (Decrease)**
	(In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 58
Change due to increased volumes	312
	370
Purchases from FES:	
Change due to increased unit costs	583
Change due to decreased volumes	(725)
	(142)
Increase in NUG costs deferred	(148)
Net Increase in Purchased Power Costs	$ 80

- Transmission expenses were lower by $481 million in 2009, reflecting the change in the transmission tariff under the Ohio Companies' CBP, reduced transmission volumes and lower congestion costs.

- Intersegment cost reimbursements related to the Ohio Companies' nuclear generation leasehold interests increased by $114 million in 2009. Prior to 2009, a portion of OE's and TE's leasehold costs were recovered through customer transition charges. Effective January 1, 2009, these leasehold costs are reimbursed from the competitive energy services segment.

- Labor and employee benefit expenses decreased by $39 million reflecting changes to Energy Delivery's organizational and compensation structure and increased resources dedicated to capital projects, partially offset by higher pension expenses resulting from reduced pension plan asset values at the end of 2008.

- Storm-related costs were $16 million lower in 2009 compared to the prior year.

- An increase in other operating expenses of $40 million resulted from the recognition of economic development and energy efficiency obligations in accordance with the PUCO-approved ESP.

- Uncollectible expenses were higher by $12 million in 2009 principally due to increased bankruptcies.

- A $102 million increase in the amortization of regulatory assets was due primarily to the ESP-related impairment of CEI's regulatory assets ($216 million) and MISO/PJM transmission cost amortization in 2009, partially offset by the cessation of transition cost amortization for OE and TE.

- A $180 million decrease in the deferral of new regulatory assets was principally due to the absence in 2009 of PJM transmission cost deferrals and RCP distribution cost deferrals, partially offset by the PUCO-approved deferral of purchased power costs for CEI.

- Depreciation expense increased $28 million due to property additions since 2008.

- General taxes decreased $5 million due primarily to lower revenue-related taxes in 2009.

Other Expense –

Other expense increased $93 million in 2009 compared to 2008. Lower investment income of $32 million resulted primarily from repaid notes receivable from affiliates. Higher interest expense (net of capitalized interest) of $61 million resulted from a net increase in debt of $1.8 billion by the Utilities and ATSI during 2009.

Competitive Energy Services – 2009 Compared to 2008

Net income increased to $517 million in 2009 compared to $472 million in the same period of 2008. The increase in net income includes FGCO's gain from the sale of a 9% participation interest in OVEC, increased sales margins, and an increase in investment income, offset by a mark-to-market adjustment relating to purchased power contracts for delivery in 2010 and 2011.

Revenues –

Total revenues increased $192 million in 2009 compared to the same period in 2008. This increase primarily resulted from the OVEC sale and higher unit prices on affiliated generation sales to the Ohio Companies and non-affiliated customers, partially offset by lower sales volumes.

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

Revenues by Type of Service	**2009**	**2008**	**Increase (Decrease)**
		(In millions)	
Non-Affiliated Generation Sales:			
Retail	$ 778	$ 615	$ 163
Wholesale	669	718	(49)
Total Non-Affiliated Generation Sales	1,447	1,333	114
Affiliated Generation Sales	2,843	2,968	(125)
Transmission	73	150	(77)
Sale of OVEC participation interest	252	-	252
Other	116	88	28
Total Revenues	$ 4,731	$ 4,539	$ 192

The increase in non-affiliated retail revenues of $163 million resulted from increased revenue in both the PJM and MISO markets. The increase in MISO retail revenue is primarily the result of the acquisition of new customers, higher unit prices and the inclusion of the transmission related component in retail rates previously reported as transmission revenues. The increase in PJM retail revenue resulted from the acquisition of new customers, higher sales volumes and unit prices. The acquisition of new customers in MISO is primarily due to new government aggregation contracts with 60 area communities in Ohio that will provide discounted generation prices to approximately 580,000 residential and small commercial customers. Lower non-affiliated wholesale revenues of $49 million resulted from decreased sales volumes in PJM partially offset by increased capacity prices, increased sales volumes in MISO, and favorable settlements on hedged transactions.

The lower affiliated company wholesale generation revenues of $125 million were due to lower sales volumes to the Ohio Companies combined with lower unit prices to the Pennsylvania companies, partially offset by higher unit prices to the Ohio Companies and increased sales volumes to the Pennsylvania Companies. The lower sales volumes and higher unit prices to the Ohio Companies reflected the results of the power procurement processes in the first half of 2009 (see Regulatory Matters – Ohio). The higher sales to the Pennsylvania Companies were due to increased Met-Ed and Penelec generation sales requirements supplied by FES partially offset by lower sales to Penn due to decreased default service requirements in 2009 compared to 2008. Additionally, 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 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)
	(In millions)
Retail:	
Effect of 8.6 % increase in sales volumes	$ 53
Change in prices	110
	163
Wholesale:	
Effect of 13.9 % decrease in sales volumes	(100)
Change in prices	51
	(49)
Net Increase in Non-Affiliated Generation Revenues	$ 114

Source of Change in Affiliated Generation Revenues	Increase (Decrease)
	(In millions)
Ohio Companies:	
Effect of 36.3 % decrease in sales volumes	$ (837)
Change in prices	645
	(192)
Pennsylvania Companies:	
Effect of 14.7 % increase in sales volumes	97
Change in prices	(30)
	67
Net Decrease in Affiliated Generation Revenues	$ (125)

Transmission revenues decreased $77 million due primarily to reduced loads following the expiration of the government aggregation programs in Ohio at the end of 2008 and to the inclusion of the transmission-related component in the retail rates in mid-2009. In 2009 FGCO sold 9% of its participation interest in OVEC resulting in a $252 million ($158 million, after tax) gain. Other revenue increased $28 million primarily due to income associated with NGC's acquisition of equity interests in the Perry and Beaver Valley Unit 2 leases.

Expenses -

Total expenses increased $273 million in 2009 due to the following factors:

- Fossil Fuel costs decreased $198 million due primarily to lower generation volumes ($307 million) partially offset by higher unit prices ($109 million). Nuclear Fuel costs increased $13 million as higher unit prices ($26 million) were partially offset by lower generation ($13 million).

- Purchased power costs increased $217 million due to a mark-to-market adjustment ($205 million) relating to purchased power contracts for delivery in 2010 and 2011 and higher unit prices ($33 million) that resulted primarily from higher capacity costs, partially offset by lower volumes purchased ($21 million) due to FGCO's reduced participation interest in OVEC.

- Fossil operating costs decreased $24 million due primarily to a reduction in contractor, material and labor costs and increased resources dedicated to capital projects, partially offset by higher employee benefits.

- Nuclear operating costs increased $45 million due to an additional refueling outage during the 2009 period and higher employee benefits, partially offset by lower labor costs.

- Transmission expense increased $121 million due to transmission services charges related to the load serving entity obligations in MISO, increased net congestion and higher loss expenses in MISO and PJM.

- Other expense increased $72 million due primarily to increased intersegment billings for leasehold costs from the Ohio Companies and higher pension costs.

- Depreciation expense increased $27 million due to NGC's increased ownership interest in Beaver Valley Unit 2 and Perry.

Other Income (Expense) –

Total other income in 2009 was $15 million compared to total other expense in 2008 of $142 million, resulting primarily from a $155 million increase from gains on the sale of nuclear decommissioning trust investments. During 2009, the majority of the nuclear decommissioning trust holdings were converted to more closely align with the liability being funded.

Other – 2009 Compared to 2008

Our financial results from other operating segments and reconciling items resulted in a $100 million increase in net income in 2009 compared to 2008. The increase resulted primarily from $200 million of favorable tax settlements, offset by debt redemption costs of $90 million and by the absence of the gain from the sale of telecommunication assets ($19 million, net of taxes) in 2008.

Summary of Results of Operations – 2008 Compared with 2007

Financial results for our major business segments in 2007 were as follows:

2007 Financial Results	Energy Delivery Services	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
		(In millions)		
Revenues:				
External				
Electric	$ 10,628	$ 1,316	$ -	$ 11,944
Other	694	152	12	858
Internal	-	2,901	(2,901)	-
Total Revenues	11,322	4,369	(2,889)	12,802
Expenses:				
Fuel	5	1,173	-	1,178
Purchased power	5,973	764	(2,901)	3,836
Other operating expenses	2,005	1,160	(82)	3,083
Provision for depreciation	404	204	30	638
Amortization of regulatory assets	1,019	-	-	1,019
Deferral of new regulatory assets	(524)	-	-	(524)
General taxes	627	107	20	754
Total Expenses	9,509	3,408	(2,933)	9,984
Operating Income	1,813	961	44	2,818
Other Income (Expense):				
Investment income	241	16	(137)	120
Interest expense	(457)	(172)	(146)	(775)
Capitalized interest	11	20	1	32
Total Other Expense	(205)	(136)	(282)	(623)
Income Before Income Taxes	1,608	825	(238)	2,195
Income taxes	643	330	(90)	883
Net Income	965	495	(148)	1,312
Less: Noncontrolling interest income	-	-	3	3
Earnings available to FirstEnergy Corp.	$ 965	$ 495	$ (151)	$ 1,309

Changes Between 2008 and 2007 Financial Results Increase (Decrease)	Energy Delivery Services	Competitive Energy Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
Revenues:				
External				
Electric	$ 732	$ 17	$ -	$ 749
Other	14	86	(24)	76
Internal	-	67	(67)	-
Total Revenues	746	170	(91)	825
Expenses:				
Fuel	(3)	165	-	162
Purchased power	507	15	(67)	455
Other operating expenses	17	(18)	(37)	(38)
Provision for depreciation	13	39	(13)	39
Amortization of regulatory assets	34	-	-	34
Deferral of new regulatory assets	208	-	-	208
General taxes	19	2	3	24
Total Expenses	795	203	(114)	884
Operating Income	(49)	(33)	23	(59)
Other Income (Expense):				
Investment income	(70)	(50)	59	(61)
Interest expense	46	20	(45)	21
Capitalized interest	(8)	24	4	20
Total Other Expense	(32)	(6)	18	(20)
Income Before Income Taxes	(81)	(39)	41	(79)
Income taxes	(32)	(16)	(58)	(106)
Net Income	(49)	(23)	99	27
Less: Noncontrolling interest income	-	-	(3)	(3)
Earnings available to FirstEnergy Corp.	$ (49)	$ (23)	$ 102	$ 30

Energy Delivery Services – 2008 Compared to 2007

Net income decreased $49 million to $916 million in 2008 compared to $965 million in 2007, primarily due to increased purchased power costs, decreased deferral of new regulatory assets 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)**
		(In millions)	
Distribution services	$ 3,882	$ 3,909	$ (27)
Generation sales:			
Retail	5,768	5,393	375
Wholesale	962	694	268
Total generation sales	6,730	6,087	643
Transmission	1,267	1,118	149
Other	189	208	(19)
Total Revenues	$ 12,068	$ 11,322	$ 746

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 $643 million increase in generation revenues in 2008 compared to 2007:

Sources of Change in Generation Revenues	**Increase (Decrease)**
	(In millions)
Retail:	
Effect of 1.9% decrease in sales volumes	$ (103)
Change in prices	478
	375
Wholesale:	
Effect of 0.1% increase in sales volumes	1
Change in prices	267
	268
Net Increase in Generation Revenues	$ 643

The decrease in retail generation sales volumes was primarily due to milder weather and economic conditions in the Utilities' service territories and an increase in customer shopping for Penn, Penelec and JCP&L. 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, and the Ohio Companies' fuel cost recovery riders that became effective in January 2008. The increase in wholesale prices reflected higher spot market prices for PJM market participants.

Transmission revenues increased $149 million due to higher transmission rates for Met-Ed and Penelec resulting from the annual update to their TSC riders in mid-2008 and the Ohio Companies' 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 –

The net revenue increase discussed above was more than offset by a $795 million increase in expenses due to the following:

- Purchased power costs were $507 million higher in 2008 due to higher unit costs and a decrease in the amount of NUG costs deferred. The increase in unit costs from non-affiliates was primarily due to higher costs for JCP&L 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. Higher unit costs from FES reflect the increases in the Ohio Companies' retail generation rates, as provided for under the PSA then in effect with FES. The decrease in purchase volumes was due to the lower retail generation sales requirements described above.

  The following table summarizes the sources of changes in purchased power costs:

Source of Change in Purchased Power	**Increase (Decrease)**
	(In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 456
Change due to decreased volumes	(128)
	328
Purchases from FES:	
Change due to increased unit costs	110
Change due to decreased volumes	(44)
	66
Decrease in NUG costs deferred	113
Net Increase in Purchased Power Costs	$ 507

- Other operating expenses increased $17 million due primarily to the net effect of the following:

  - a $69 million increase primarily for reduced intersegment credits associated with the Ohio Companies' nuclear generation leasehold interests and increased MISO transmission-related expenses;

  - 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 $34 million due primarily 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 $208 million lower than in 2007. MISO transmission deferrals and RCP fuel deferrals decreased $166 million, as more transmission and generation costs were recovered from customers through PUCO-approved riders. Also contributing to the decrease was 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), partially 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 $19 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, 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)**
		(In millions)	
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)**
	(In millions)
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)
	(In millions)
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.

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.

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. Adverse market conditions during 2008 increased 2009 costs, which were partially offset by the effects of a $500 million voluntary cash pension contribution and an OPEB plan amendment in 2009 (see Note 3). 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 increases discussed above for 2009. 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, 2009:

Postretirement Benefits Expense (Credits)	**2009**	**2008**	**2007**
		(In millions)	
Pension	$ 185	$ (23)	$ 6
OPEB	(40)	(37)	(41)
Total	$ 145	$ (60)	$ (35)

As of December 31, 2009, our pension plan was underfunded and we currently anticipate that additional cash contributions will be required in 2012 for the 2011 plan year. The overall actual investment result during 2009 was a gain of 13.6% compared to an assumed 9% return. Based on discount rates of 6% for pension and 5.75% for OPEB, 2010 pre-tax net periodic pension and OPEB expense will be approximately $89 million.

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. The Ohio Utilities and Penn's default service supplies are provided through a competitive procurement process approved by the PUCO and PPUC, respectively. The default service supply for Met-Ed and Penelec is secured 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 2009, FES' generation was used to serve two main obligations -- affiliated companies utilized approximately 76% of its total generation and direct retail customers utilized approximately 18% of FES' total generation. Geographically, approximately 67% of FES' obligation is located in the MISO market area and 33% 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) 14,346 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

As of January 31, 2010 we had commitments of approximately $3.4 billion of liquidity including a $2.75 billion revolving credit facility, a $100 million bank line available to FES and $515 million of accounts receivable financing facilities through our Ohio and Pennsylvania utilities. 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.

As of December 31, 2009, our net deficit in working capital (current assets less current liabilities) was principally due to short-term borrowings ($1.2 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, 2009, included the following (in millions):

Currently Payable Long-term Debt		
PCRBs supported by bank LOCs [1]	$	1,553
FGCO and NGC unsecured PCRBs [1]		15
Met-Ed unsecured notes [2]		100
Penelec FMBs [3]		24
NGC collateralized lease obligation bonds		45
Sinking fund requirements		34
Other notes [3]		63
	$	1,834

(1) Interest rate mode permits individual debt holders to put the respective debt back to the issuer prior to maturity.

(2) Mature in March 2010.

(3) Mature in November 2010.

Short-Term Borrowings

We had approximately $1.2 billion of short-term borrowings as of December 31, 2009 and $2.4 billion as of December 31, 2008. Our available liquidity as of January 31, 2010, is summarized in the following table:

Company	**Type**	**Maturity**	**Commitment**	**Available Liquidity as of January 31, 2010**
			(In millions)	
FirstEnergy [1]	Revolving	Aug. 2012	$ 2,750	$ 1,387
FirstEnergy Solutions	Bank line	Mar. 2011	100	-
Ohio and Pennsylvania Companies	Receivables financing	Various [2]	515	308
		Subtotal	$ 3,365	$ 1,695
		Cash	-	764
		Total	**$ 3,365**	**$ 2,459**

(1) FirstEnergy Corp. and subsidiary borrowers.

(2) $370 million expires February 22, 2010; $145 million expires December 17, 2010. The Ohio and Pennsylvania Companies have typically renewed expiring receivables facilities on an annual basis and expect to continue that practice as market conditions and the continued quality of receivables permit.

Revolving Credit Facility

We have the capability to request an increase in the total commitments available under the $2.75 billion revolving credit facility (included in the borrowing capability table above) 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, 2009:

Borrower	Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations
	(In millions)	
FirstEnergy	$ 2,750	$ -(1)
FES	1,000	-(1)
OE	500	500
Penn	50	33(2)
CEI	250(3)	500
TE	250(3)	500
JCP&L	425	411(2)
Met-Ed	250	300(2)
Penelec	250	300(2)
ATSI	50(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 ATSI has received regulatory approval to have short-term borrowings up to the same amount.

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, 2009, our debt to total capitalization ratios (as defined under the revolving credit facility) were as follows:

Borrower	
FirstEnergy (1)	61.5%
FES	54.8%
OE	51.3%
Penn	35.5%
CEI	59.7%
TE	60.8%
JCP&L	35.6%
Met-Ed	41.2%
Penelec	53.6%
ATSI	48.8%

(1) As of December 31, 2009, FirstEnergy could issue additional debt of approximately $2.5 billion, or recognize a reduction in equity of approximately $1.4 billion, 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.

FirstEnergy Money Pools

FirstEnergy's regulated companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among FirstEnergy's unregulated companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in 2009 was 0.72% for the regulated companies' money pool and 0.90% for the unregulated companies' money pool.

Pollution Control Revenue Bonds

As of December 31, 2009, our currently payable long-term debt included approximately $1.6 billion (FES - $1.5 billion, 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.

The LOCs for our variable interest rate PCRBs were issued by the following banks:

LOC Bank	Aggregate LOC Amount (3)	LOC Termination Date	Reimbursements of LOC Draws Due
	(In millions)		
CitiBank N.A.	$ 166	June 2014	June 2014
The Bank of Nova Scotia	284	Beginning April 2011	Multiple dates (4)
The Royal Bank of Scotland	131	June 2012	6 months
KeyBank (1)	237	June 2010	6 months
Wachovia Bank	153	March 2014	March 2014
Barclays Bank (2)	528	Beginning December 2010	30 days
PNC Bank	70	Beginning November 2010	180 days
Total	$ **1,569**		

(1) Supported by four participating banks, with the LOC bank having 58% of the total commitment.

(2) Supported by 18 participating banks, with no one bank having more than 14% of the total commitment.

(3) Includes approximately $16 million of applicable interest coverage.

(4) Shorter of 6 months or LOC termination date ($155 million) and shorter of one year or LOC termination date ($129 million).

In 2009, holders of approximately $434 million of LOC-supported PCRBs of OE and NGC were notified that the applicable Wachovia Bank LOCs were set to expire. As a result, these PCRBs were subject to mandatory purchase at a price equal to the principal amount plus accrued and unpaid interest, which OE and NGC funded through short-term borrowings. FGCO remarketed $100 million of those PCRBs, which were previously held by OE and NGC and remarketed the remaining $334 million of PCRBs, of which $170 million was remarketed in fixed interest rate modes and secured by FMBs, thereby eliminating the need for third-party credit support. Also during 2009, FGCO and NGC remarketed approximately $329 million of other PCRBs supported by LOCs set to expire in 2009. Those PCRBs were also remarketed in fixed interest rate modes and secured by FMBs, thereby eliminating the need for third-party credit support. FGCO and NGC delivered FMBs to certain LOC banks listed above in connection with amendments to existing LOC and reimbursement agreements supporting twelve other series of PCRBs as described below and pledged FMBs to the applicable trustee under six separate series of PCRBs. On August 14, 2009, $177 million of non-LOC supported fixed rate PCRBs were issued and sold on behalf of FGCO to pay a portion of the cost of acquiring, constructing and installing air quality facilities at its W.H. Sammis Generating Station.

Long-Term Debt Capacity

As of December 31, 2009, the Ohio Companies and Penn had the aggregate capability to issue approximately $1.4 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 and CEI to incur additional secured debt not otherwise permitted by a specified exception of up to $127 million and $36 million, respectively, as of December 31, 2009. In April 2009, TE issued $300 million of new senior secured notes backed by FMBs. Concurrently with that issuance, and in order to satisfy the limitation on secured debt under its senior note indenture, TE issued an additional $300 million of FMBs to secure $300 million of its outstanding unsecured senior notes originally issued in November 2006. As a result, the provisions for TE to incur additional secured debt do not apply.

Based upon FGCO's FMB indenture, net earnings and available bondable property additions as of December 31, 2009, FGCO had the capability to issue $2.2 billion of additional FMBs under the terms of that indenture. On June 16, 2009, FGCO issued a total of approximately $395.9 million principal amount of FMBs, of which $247.7 million related to three new refunding series of PCRBs and approximately $148.2 million related to amendments to existing LOC and reimbursement agreements supporting two other series of PCRBs. On June 30, 2009, FGCO issued a total of approximately $52.1 million principal amount of FMBs related to three existing series of PCRBs (repurchased in October 2009, as described above).

In June 2009, a new FMB indenture became effective for NGC. On June 16, 2009, NGC issued a total of approximately $487.5 million principal amount of FMBs, of which $107.5 million related to one new refunding series of PCRBs and approximately $380 million related to amendments to existing LOC and reimbursement agreements supporting seven other series of PCRBs. In addition, on June 16, 2009, NGC issued an FMB in a principal amount of up to $500 million in connection with NGC's delivery of a Surplus Margin Guaranty of FES' obligations to post and maintain collateral under the PSA entered into by FES with the Ohio Companies as a result of the May 13-14, 2009 CBP auction. On June 30, 2009, NGC issued a total of approximately $273.3 million principal amount of FMBs, of which approximately $92 million related to three existing series of PCRBs ($29.6 million repurchased in October 2009, as described above) and approximately $181.3 million related to amendments to existing LOC and reimbursement agreements supporting three other series of PCRBs. Based upon NGC's FMB indenture, net earnings and available bondable property additions, NGC had the capability to issue $294 million of additional FMBs as of December 31, 2009.

Met-Ed and Penelec had the capability to issue secured debt of approximately $379 million and $319 million, respectively, under provisions of their senior note indentures as of December 31, 2009.

FirstEnergy's access to capital markets and costs of financing are influenced by the ratings of its securities. The following table displays FirstEnergy's, FES' and the Utilities' securities ratings as of February 11, 2010. On February 11, 2010, S&P issued a report lowering FirstEnergy's and its subsidiaries' credit ratings by one notch, while maintaining its stable outlook. As a result, FirstEnergy may be required to post up to $48 million of collateral (see Note 15(B)). Moody's and Fitch affirmed the ratings and stable outlook of FirstEnergy and its subsidiaries on February 11, 2010.

	Senior Secured		**Senior Unsecured**	
Issuer	**S&P**	**Moodys**	**S&P**	**Moodys**
FirstEnergy Corp.	-	-	BB+	Baa3
FirstEnergy Solutions	-	-	BBB-	Baa2
Ohio Edison	BBB	A3	BBB-	Baa2
Cleveland Electric Illuminating	BBB	Baa1	BBB-	Baa3
Toledo Edison	BBB	Baa1	-	-
Pennsylvania Power	BBB+	A3	-	-
Jersey Central Power & Light	-	-	BBB-	Baa2
Metropolitan Edison	BBB	A3	BBB-	Baa2
Pennsylvania Electric	BBB	A3	BBB-	Baa2
ATSI	-	-	BBB-	Baa1

On September 22, 2008, FirstEnergy, 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 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 have utilized, and may in the future utilize, the shelf registration statement to offer and sell unsecured and, in some cases, secured debt securities.

Changes in Cash Position

As of December 31, 2009, we had $874 million in cash and cash equivalents compared to $545 million as of December 31, 2008. 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, 2009 and 2008, FirstEnergy had approximately $12 million and $17 million, respectively, of restricted cash included in other current assets on the Consolidated Balance Sheet.

During 2009, we received $972 million of cash dividends from our subsidiaries and paid $670 million in cash dividends to common shareholders. 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%. CEI and TE are the only utility subsidiaries currently precluded from that action.

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 $2.5 billion in 2009, $2.2 billion in 2008 and $1.7 billion in 2007, as summarized in the following table:

	2009	2008	2007
		(In millions)	
Net income	$ 990	$ 1,339	$ 1,312
Non-cash charges and other adjustments	2,281	1,405	670
Pension trust contribution	(500)	-	(300)
Working capital and other	(306)	(520)	17
	$ 2,465	$ 2,224	$ 1,699

Net cash provided from operating activities increased by $241 million in 2009 primarily due to an increase in non-cash charges and other adjustments of $876 million and an increase in working capital and other of $214, partially offset by a $500 million pension trust contribution in 2009 and a $349 million decrease in net income (see Results of Operations above).

The increase in non-cash charges and other adjustments is primarily due to higher net amortization of regulatory assets ($282 million), including CEI's $216 million regulatory asset impairment, an increase in the provision for depreciation ($59 million) and the modification of certain purchased power contracts that resulted in a mark-to-market charge of approximately $205 million (see Note 6). Also included in non-cash charges and other adjustments was a $146 million charge relating to debt redemptions in 2009, of which $123 million was related primarily to premiums paid and included as a cash outflow in financing activities. The changes in working capital and other primarily resulted from a $268 million decrease in prepaid taxes due to decreased tax payments.

Net cash provided from operating activities increased in 2008 compared to 2007 due to an increase in non-cash charges 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.

Cash Flows From Financing Activities

In 2009, net cash provided from financing activities was $49 million compared to $1.2 billion in 2008. The decrease was primarily due to increased long-term debt redemptions ($1.6 billion) and increased repayments on short-term borrowings ($2.7 billion), partially offset by increased long-term debt issuances in 2009 ($3.3 billion). The increased long-term debt redemptions were primarily due to the $1.2 billion tender offer for holding company notes completed by FirstEnergy in September 2009, including approximately $122 million of premiums and redemption expenses paid. The short-term repayments in 2009 were primarily due to net repayments on the $2.75 billion revolving credit facility (see Revolving Credit Facility above) compared to net borrowings on the facility in 2008. The following table summarizes security issuances (net of any discounts) and redemptions, including premiums paid to debt holders as a result of the tender offer.

Securities Issued or Redeemed / Repurchased	2009	2008	2007
		(In millions)	
New issues			
First mortgage bonds	$ 398	$ 592	$ -
Pollution control notes	940	692	427
Senior secured notes	297	-	-
Unsecured notes	2,997	83	1,093
	$ 4,632	$ 1,367	$ 1,520
Redemptions			
First mortgage bonds	$ 1	$ 126	$ 293
Pollution control notes	884	698	436
Senior secured notes	217	35	188
Unsecured notes	1,508	175	153
Common stock	-	-	969
	$ 2,610	$ 1,034	$ 2,039
Short-term borrowings (repayments), net	$ (1,246)	$ 1,494	$ (205)

The following table summarizes new debt issuances, excluding any premium or discounts, (excluding PCRB issuances and refinancings of $940 million) during 2009.

Issuing Company	Issue Date	Principal (in millions)	Type	Maturity
Met-Ed*	01/20/2009	$ 300	7.70% Senior Notes	2019
JCP&L*	01/27/2009	$ 300	7.35% Senior Notes	2019
TE*	04/24/2009	$ 300	7.25% Senior Secured Notes	2020
Penn	06/30/2009	$ 100	6.09% FMB	2022
FES	08/07/2009	$ 400	4.80% Senior Notes	2015
		$ 600	6.05% Senior Notes	2021
		$ 500	6.80% Senior Notes	2039
CEI*	08/18/2009	$ 300	5.50% FMB	2024
Penelec*	09/30/2009	$ 250	5.20% Senior Notes	2020
		$ 250	6.15% Senior Notes	2038
ATSI	12/15/2009	$ 400	5.25% Senior Notes	2022

* Issued under the shelf registration statement referenced above.

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, 2009 by business segment:

Summary of Cash Flows Provided from (Used for) Investing Activities	Property Additions	Investments	Other	Total
Sources (Uses)		(In millions)		
2009				
Energy delivery services	$ (750)	$ 39	$ (46)	$ (757)
Competitive energy services	(1,262)	(8)	(19)	(1,289)
Other	(149)	(3)	72	(80)
Inter-Segment reconciling items	(42)	(24)	7	(59)
Total	$ (2,203)	$ 4	$ 14	$ (2,185)
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)

Net cash used for investing activities in 2009 decreased by $798 million compared to 2008. The change was principally due to a $685 million decrease in property additions, which reflects lower AQC system expenditures and the absence in 2009 of the purchase of certain lessor equity interests in Beaver Valley Unit 2 and Perry and the purchase of the partially-completed Fremont Energy Center. Net cash used for other investing activities decreased primarily due to the liquidation of restricted funds used for debt redemptions in 2009 combined with decreased cash investments in the Signal Peak coal mining project in 2009 as compared to 2008.

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.

Our capital spending for 2010 is expected to be approximately $1.7 billion (excluding nuclear fuel), of which $241 million relates to AQC system expenditures. Capital spending for 2011 and 2012 is expected to be approximately $1.0 billion to $1.2 billion each year. Our capital spending investments for additional nuclear fuel during 2010 is estimated to be approximately $170 million.

CONTRACTUAL OBLIGATIONS

As of December 31, 2009, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	Total	2010	2011-2012	2013-2014	Thereafter
			(In millions)		
Long-term debt	$ 13,753	$ 264	$ 433	$ 1,084	$ 11,972
Short-term borrowings	1,181	1,181	-	-	-
Interest on long-term debt (1)	11,663	785	1,537	1,473	7,868
Operating leases (2)	3,485	225	442	459	2,359
Fuel and purchased power (3)	18,422	3,217	4,753	4,245	6,207
Capital expenditures	999	335	376	245	43
Pension funding	972	-	63	557	352
Other (4)	283	232	3	2	46
Total	$ 50,758	$ 6,239	$ 7,607	$ 8,065	$ 28,847

(1) Interest on variable-rate debt based on rates as of December 31, 2009.
(2) See Note 7 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 7) and contingent tax liabilities (see Note 10).

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, 2009, our maximum exposure to potential future payments under outstanding guarantees and other assurances approximated $4.2 billion, as summarized below:

Guarantees and Other Assurances	Maximum Exposure
	(In millions)
FirstEnergy Guarantees of Subsidiaries:	
Energy and energy-related contracts (1)	$ 382
LOC (long-term debt) – interest coverage (2)	6
FirstEnergy guarantee of OVEC obligations	300
Other (3)	296
	984
Subsidiaries' Guarantees:	
Energy and energy-related contracts	54
LOC (long-term debt) – interest coverage (2)	6
FES' guarantee of NGC's nuclear property insurance	77
FES' guarantee of FGCO's sale and leaseback obligations	2,464
	2,601
Surety Bonds:	101
LOC (long-term debt) – interest coverage (2)	3
LOC (non-debt) (4)(5)	502
	606
Total Guarantees and Other Assurances	$ 4,191

(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 $1.6 billion is reflected as currently payable long-term debt on FirstEnergy's consolidated balance sheets.

(3) Includes guarantees of $80 million for nuclear decommissioning funding assurances and $161 million supporting OE's sale and leaseback arrangement.

(4) Includes $167 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facility.

(5) Includes approximately $200 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, an acceleration of payment or funding obligation, or "material adverse event," the immediate posting of cash collateral, provision of an LOC or accelerated payments may be required of the subsidiary. On February 11, 2010, S&P issued a report lowering FirstEnergy's and its subsidiaries' credit ratings by one notch, while maintaining its stable outlook. As a result, FirstEnergy may be required to post up to $48 million of collateral. Moody's and Fitch affirmed the ratings and stable outlook of FirstEnergy and its subsidiaries on February 11, 2010. As of December 31, 2009, our maximum exposure under these collateral provisions was $648 million, including the $48 million related to the credit rating downgrade by S&P on February 11, 2010, as shown below:

Collateral Provisions	FES	Utilities	Total
		(In millions)	
Credit rating downgrade to below investment grade	$ 392	$ 115	$ 507
Acceleration of payment or funding obligation	45	53	98
Material adverse event	43	-	43
Total	$ 480	$ 168	$ 648

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 $807 million, consisting of $51 million due to "material adverse event" contractual clauses, $98 million due to an acceleration of payment or funding obligation, and $658 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, 2009, and forward prices as of that date, FES had $179 million outstanding in margining accounts. Under a hypothetical adverse change in forward prices (95% confidence level change in forward prices over a one year time horizon), FES would be required to post an additional $129 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 connection with FES' obligations to post and maintain collateral under the two-year PSA entered into by FES and the Ohio Companies following the CBP auction on May 13-14, 2009, NGC entered into a Surplus Margin Guaranty in an amount up to $500 million. The Surplus Margin Guaranty is secured by an NGC FMB issued in favor of the Ohio Companies.

FES' debt obligations are generally guaranteed by its subsidiaries, FGCO and NGC, pursuant to guarantees entered into on March 26, 2007. Similar guarantees were entered into on that date pursuant to which FES guaranteed the debt obligations of each of FGCO and NGC. Accordingly, present and future holders of indebtedness of FES, FGCO and NGC will have claims against each of FES, FGCO and NGC regardless of whether their primary obligor is FES, FGCO or NGC.

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, was $1.7 billion as of December 31, 2009, and December 31, 2008.

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

FirstEnergy is exposed to financial and market risks resulting from the fluctuation of interest rates and commodity prices associated with electricity, energy transmission, natural gas, coal, nuclear fuel and emission allowances. To manage the volatility relating to these exposures, FirstEnergy uses a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes. Certain derivatives must be recorded at their fair value and marked to market. The majority of FirstEnergy's derivative hedging contracts qualify for the normal purchase and normal sale exception 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 and certain purchase power contracts (see Note 6). The NUG entities 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 2009 is summarized in the following table:

Increase (Decrease) in the Fair Value of Derivative Contracts	**Non-Hedge**	**Hedge**	**Total**
		(In millions)	
Change in the Fair Value of Commodity Derivative Contracts:			
Outstanding net liability as of January 1, 2009	$ (304)	$ (41)	$ (345)
Additions/change in value of existing contracts	(673)	(1)	(674)
Settled contracts	347	27	374
Outstanding net liability as of December 31, 2009 (1)	$ (630)	$ (15)	$ (645)
Net Liabilities-Derivative Contracts as of December 31, 2009	$ (630)	$ (15)	$ (645)
Impact of Changes in Commodity Derivative Contracts (2)			
Income Statement effects (pre-tax)	$ (204)	$ -	$ (204)
Balance Sheet effects:			
OCI (pre-tax)	$ -	$ 26	$ 26
Regulatory asset (net)	$ 122	$ -	$ 122

(1) Includes $425 million of non-hedge commodity derivative contracts (primarily with NUGs), which are offset by a regulatory asset.

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

Derivatives are included on the Consolidated Balance Sheet as of December 31, 2009 as follows:

Balance Sheet Classification	**Non-Hedge**	**Hedge**	**Total**
		(In millions)	
Current-			
Other assets	$ -	$ 3	$ 3
Other liabilities	(108)	(17)	(125)
Non-Current-			
Other deferred charges	218	11	229
Other noncurrent liabilities	(740)	(12)	(752)
Net liabilities	$ (630)	$ (15)	$ (645)

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, FirstEnergy relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FirstEnergy uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making (see Note 5). Sources of information for the valuation of commodity derivative contracts as of December 31, 2009 are summarized by year in the following table:

Source of Information - Fair Value by Contract Year	2010	2011	2012	2013	2014	Thereafter	Total
				(In millions)			
Prices actively quoted (1)	$ (11)	$ -	$ -	$ -	$ -	$ -	$ (11)
Other external sources (2)	(369)	(305)	(139)	(44)	-	-	(857)
Prices based on models	-	-	-	-	11	212	223
Total (3)	$ (380)	$ (305)	$ (139)	$ (44)	$ 11	$ 212	$ (645)

(1) Exchange traded.
(2) Broker quote sheets.
(3) Includes $425 million in non-hedge commodity derivative contracts (primarily with NUGs), which are offset by a regulatory asset.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% adverse shift (an increase or decrease depending on the derivative position) in quoted market prices in the near term on its derivative instruments would not have had a material effect on its consolidated financial position (assets, liabilities and equity) or cash flows as of December 31, 2009. Based on derivative contracts held as of December 31, 2009, an adverse 10% change in commodity prices would decrease net income by approximately $9 million after tax 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	2010	2011	2012	2013	2014	There-after	Total	Fair Value
				(Dollars in millions)				
Assets								
Investments Other Than Cash and Cash Equivalents:								
Fixed Income	$ 84	$ 79	$ 95	$ 118	$ 110	$ 1,834	$ 2,320	$ 2,413
Average interest rate	7.1%	7.8%	7.8%	7.6%	8.0%	4.3%	5.0%	
Liabilities								
Long-term Debt:								
Fixed rate	$ 202	$ 336	$ 97	$ 555	$ 529	$ 9,915	$ 11,634	$ 12,350
Average interest rate	5.7%	6.7%	7.7%	5.9%	5.4%	6.5%	6.5%	
Variable rate	$ 62					$ 2,057	$ 2,119	$ 2,152
Average interest rate	3.3%					1.8%	1.8%	
Short-term Borrowings:	$ 1,181						$ 1,181	$ 1,181
Average interest rate	0.7%						0.7%	

We are subject to the inherent interest rate risks related to refinancing maturing debt by issuing new debt securities. As discussed in Note 7 to the consolidated financial statements, our investments in capital trusts effectively reduce future lease obligations, also reducing interest rate risk.

Interest Rate Swap Agreements – Fair Value Hedges

FirstEnergy uses fixed-for-floating interest rate swap agreements to hedge a portion of the consolidated interest rate risk associated with the debt portfolio of its subsidiaries. These derivatives are treated as fair value hedges of fixed-rate, long-term debt issues, protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. Swap maturities, call options, fixed interest rates and interest payment dates match those of the underlying obligations. As of December 31, 2009, the debt underlying the $250 million outstanding notional amount of interest rate swaps had a weighted average fixed interest rate of 6.45%, which the swaps have converted to a current weighted average variable rate of 5.4%. The fair value of the interest rate swaps designated as fair value hedges was immaterial as of December 31, 2009.

Forward Starting Swap Agreements - Cash Flow Hedges

FirstEnergy uses forward starting swap agreements to hedge a portion of the consolidated interest rate risk associated with issuances of fixed-rate, long-term debt securities of its subsidiaries. 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 2009, FirstEnergy terminated forward swaps with a notional value of $2.8 billion and recognized losses of approximately $18.5 million, of which the ineffective portion recognized as an adjustment to interest expense was immaterial. The remaining effective portions will be amortized to interest expense over the life of the hedged debt.

Forward Starting Swaps	December 31, 2009 Notional Amount	Maturity Date	Fair Value	December 31, 2008 Notional Amount	Maturity Date	Fair Value
			(In millions)			
Cash flow hedges	$ -	2009	-	100	2009	$ (2)
	100	2010	-	100	2010	(2)
	-	2019	-	100	2019	1
	$ 100		$ -	$ 300		$ (3)

Equity Price Risk

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 plan provides defined benefits based on years of service and compensation levels. FirstEnergy also provides 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. The benefit plan assets and obligations are remeasured annually using a December 31 measurement date or as significant triggering events occur. In 2009, FirstEnergy remeasured its other postretirement benefit plans on May 31, 2009, and its qualified defined pension plan on August 31, 2009, as discussed below.

FirstEnergy's other postretirement benefits plans were remeasured as of May 31, 2009 as a result of a plan amendment announced on June 2, 2009, which reduced future health care coverage subsidies paid by FirstEnergy on behalf of plan participants. The remeasurement and plan amendment resulted in a $48 million reduction in FirstEnergy's net postretirement benefit cost (including amounts capitalized) for 2009 (see Note 3). This reduction was partially offset by an additional $13 million of net postretirement benefit cost (including amounts capitalized) related to an additional liability created by the VERO offered by FirstEnergy to qualified employees (see Note 3).

On September 2, 2009, FirstEnergy elected to remeasured its qualified defined pension plan due to a $500 million voluntary contribution made by the Utilities and ATSI. The remeasurement and voluntary contribution decreased FirstEnergy's accumulated other comprehensive income by approximately $494 million ($304 million, net of tax) and reduced FirstEnergy's net postretirement benefit cost (including amounts capitalized) for 2009 by $7 million (see Note 3). Increases in plan assets from investment gains during 2009 resulted in an increase to the plans' funded status of $349 million on and an after-tax decrease to common stockholders' equity of $19 million. The overall actual investment result during 2009 was a gain of 13.6% compared to an assumed 9% positive return. Based on a 6% discount rate, 2010 pre-tax net periodic pension and OPEB expense will be approximately $89 million. As of December 31, 2009, the pension plan was underfunded. FirstEnergy currently estimates that additional cash contributions will be required beginning in 2012.

Nuclear decommissioning trust funds have been established to satisfy NGC's and our Utilities' nuclear decommissioning obligations. As of December 31, 2009, approximately 16% of the funds were invested in equity securities and 84% 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 $295 million as of December 31, 2009. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $29 million reduction in fair value as of December 31, 2009. 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 as other-than-temporary impairments. On June 18, 2009, the NRC informed FENOC that its review tentatively concluded that a shortfall existed in the decommissioning trust fund for Beaver Valley Unit 1. On November 24, 2009, FENOC submitted a revised decommissioning funding calculation using the NRC formula method based on the renewed license for Beaver Valley Unit 1, which extended operations until 2036. FENOC's submittal demonstrated that there was a de minimis shortfall. On December 11, 2009, the NRC's review of FirstEnergy's methodology for the funding of decommissioning of this facility concluded that there was reasonable assurance of adequate decommissioning funding at the time permanent termination of operations is expected. FirstEnergy continues to evaluate the status of its funding obligations for the decommissioning of these nuclear facilities.

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, 2009, the largest credit concentration was with Morgan Stanley, which is currently rated investment grade, representing 7.3% of our total approved credit risk.

REGULATORY MATTERS

Regulatory assets that do not earn a current return totaled approximately $187 million as of December 31, 2009 (JCP&L - $36 million, Met-Ed - $114 million, and Penelec - $37 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 and Penelec. The following table discloses regulatory assets by company:

Regulatory Assets	December 31, 2009	December 31, 2008	Increase (Decrease)
		(In millions)	
OE	$ 465	$ 575	$ (110)
CEI	546	784	(238)
TE	70	109	(39)
JCP&L	888	1,228	(340)
Met-Ed	357	413	(56)
Penelec	9	- [1]	9
ATSI	21	31	(10)
Total	$ 2,356	$ 3,140	$ (784)

(1) Penelec had net regulatory liabilities of approximately $137 million as of December 31, 2008. 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, 2009	December 31, 2008	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 1,100	$ 1,452	$ (352)
Customer shopping incentives	154	420	(266)
Customer receivables for future income taxes	329	245	84
Loss on reacquired debt	51	51	-
Employee postretirement benefits	23	31	(8)
Nuclear decommissioning, decontamination and spent fuel disposal costs	(162)	(57)	(105)
Asset removal costs	(231)	(215)	(16)
MISO/PJM transmission costs	148	389	(241)
Fuel costs	369	214	155
Distribution costs	482	475	7
Other	93	135	(42)
Total	$ 2,356	$ 3,140	$ (784)

Ohio

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. On January 21, 2009, the PUCO granted the Ohio Companies' application in part 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 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. The PUCO granted these applications for rehearing on March 18, 2009 for the purpose of further consideration. The PUCO has not yet issued a substantive Entry on Rehearing.

SB221, which became effective on July 31, 2008, required all electric utilities to file an ESP, and permitted the filing of an MRO. On July 31, 2008, the Ohio Companies filed with the PUCO a comprehensive ESP and a separate MRO. The PUCO denied the MRO application; however, the PUCO later granted the Ohio Companies' application for rehearing for the purpose of further consideration of the matter. The PUCO has not yet issued a substantive Entry on Rehearing. 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. In response to the PUCO's December 19, 2008 order, which significantly modified and approved the ESP as modified, the Ohio Companies notified the PUCO that they were withdrawing and terminating the ESP application in addition to continuing their rate plan then in effect as allowed by the terms of SB221. On December 31, 2008, the Ohio Companies conducted a CBP for the procurement of electric generation for retail customers from January 5, 2009 through March 31, 2009. The average winning bid price was equivalent to a retail rate of 6.98 cents per KWH. The power supply obtained through this process provided generation service to the Ohio Companies' retail customers who chose not to shop with alternative suppliers. On January 9, 2009, the Ohio Companies requested the implementation of a new fuel rider to recover the costs resulting from the December 31, 2008 CBP. The PUCO ultimately approved the Ohio Companies' request for a new fuel rider to recover increased costs resulting from the CBP but denied OE's and TE's request to continue collecting RTC and denied the request to allow the Ohio Companies to continue collections pursuant to the two existing fuel riders. The new fuel rider recovered the increased purchased power costs for OE and TE, and recovered a portion of those costs for CEI, with the remainder being deferred for future recovery.

On January 29, 2009, the PUCO ordered its Staff to develop a proposal to establish an ESP for the Ohio Companies. 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. Specifically, the Amended ESP provided that generation would be provided by FES at the average wholesale rate of the CBP described above for April and May 2009 to the Ohio Companies for their non-shopping customers; for the period of June 1, 2009 through May 31, 2011, retail generation prices would be based upon the outcome of a descending clock CBP on a slice-of-system basis. The Amended ESP further provided that the Ohio Companies will not seek a base distribution rate increase, subject to certain exceptions, with an effective date of such increase before January 1, 2012, that CEI would agree to write-off approximately $216 million of its Extended RTC regulatory asset, and that the Ohio Companies would 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. The Amended ESP also addressed a number of other issues, including but not limited to, rate design for various customer classes, and resolution of the prudence review and the collection of deferred costs that were approved in prior proceedings. On February 26, 2009, the Ohio Companies filed a Supplemental Stipulation, which was signed or not opposed by virtually all of the parties to the proceeding, that supplemented and modified certain provisions of the February 19, 2009 Stipulation and Recommendation. Specifically, the Supplemental Stipulation modified the provision relating to governmental aggregation and the Generation Service Uncollectible Rider, provided further detail on the allocation of the economic development funding contained in the Stipulation and Recommendation, and proposed additional provisions related to the collaborative process for the development of energy efficiency programs, among other provisions. The PUCO adopted and approved certain aspects of the Stipulation and Recommendation on March 4, 2009, and adopted and approved the remainder of the Stipulation and Recommendation and Supplemental Stipulation without modification on March 25, 2009. Certain aspects of the Stipulation and Recommendation and Supplemental Stipulation took effect on April 1, 2009 while the remaining provisions took effect on June 1, 2009.

The CBP auction occurred on May 13-14, 2009, and resulted in a weighted average wholesale price for generation and transmission of 6.15 cents per KWH. The bid was for a single, two-year product for the service period from June 1, 2009 through May 31, 2011. FES participated in the auction, winning 51% of the tranches (one tranche equals one percent of the load supply). Subsequent to the signing of the wholesale contracts, four winning bidders reached separate agreements with FES with the result that FES is now responsible for providing 77 percent of the Ohio Companies' total load supply. The results of the CBP were accepted by the PUCO on May 14, 2009. FES has also separately contracted with numerous communities to provide retail generation service through governmental aggregation programs.

On July 27, 2009, the Ohio Companies filed applications with the PUCO to recover three different categories of deferred distribution costs on an accelerated basis. In the Ohio Companies' Amended ESP, the PUCO approved the recovery of these deferrals, with collection originally set to begin in January 2011 and to continue over a 5 or 25 year period. The principal amount plus carrying charges through August 31, 2009 for these deferrals totaled $305.1 million. The applications were approved by the PUCO on August 19, 2009. Recovery of this amount, together with carrying charges calculated as approved in the Amended ESP, commenced on September 1, 2009, and will be collected in the 18 non-summer months from September 2009 through May 2011, subject to reconciliation until fully collected, with $165 million of the above amount being recovered from residential customers, and $140.1 million being recovered from non-residential customers.

SB221 also requires electric distribution utilities to implement energy efficiency programs. Under the provisions of SB221, the Ohio Companies are required to achieve a total annual energy savings equivalent of approximately 166,000 MWH in 2009, 290,000 MWH in 2010, 410,000 MWH in 2011, 470,000 MWH in 2012 and 530,000 MWH in 2013, with additional savings required through 2025. Utilities are also required to reduce peak demand in 2009 by 1%, with an additional .75% reduction each year thereafter through 2018. The PUCO may amend these benchmarks in certain, limited circumstances, and the Ohio Companies have filed an application with the PUCO seeking such amendments. On January 7, 2010, the PUCO amended the 2009 energy efficiency benchmarks to zero, contingent upon the Ohio Companies meeting the revised benchmarks in a period of not more than three years. The PUCO has not yet acted upon the application seeking a reduction of the peak demand reduction requirements. The Ohio Companies are presently involved in collaborative efforts related to energy efficiency, including filing applications for approval with the PUCO, as well as other implementation efforts arising out of the Supplemental Stipulation. On December 15, 2009, the Ohio Companies filed the required three year portfolio plan seeking approval for the programs they intend to implement to meet the energy efficiency and peak demand reduction requirements for the 2010-2012 period. The PUCO has set the matter for hearing on March 2, 2010. The Ohio Companies expect that all costs associated with compliance will be recoverable from customers.

In October 2009, the PUCO issued additional Entries modifying certain of its previous rules that set out the manner in which electric utilities, including the Ohio Companies, will be required to comply with benchmarks contained in SB221 related to the employment of alternative energy resources, energy efficiency/peak demand reduction programs as well as greenhouse gas reporting requirements and changes to long term forecast reporting requirements. Applications for rehearing filed in mid-November 2009 were granted on December 9, 2009 for the sole purpose of further consideration of the matters raised in those applications. The PUCO has not yet issued a substantive Entry on Rehearing. The rules implementing the requirements of SB221 went into effect on December 10, 2009. The Ohio Companies, on October 27, 2009, submitted an application to amend their 2009 statutory energy efficiency benchmarks to zero. As referenced above, on January 7, 2010, the PUCO issued an Order granting the Ohio Companies’ request to amend the energy efficiency benchmarks.

Additionally under SB221, electric utilities and electric service companies are required to serve part of their load from renewable energy resources equivalent to 0.25% of the KWH they serve in 2009. In August and October 2009, the Ohio Companies conducted RFPs to secure RECs. The RFPs sought renewable energy RECs, including solar and RECs generated in Ohio in order to meet the Ohio Companies’ alternative energy requirements as set forth in SB221 for 2009, 2010 and 2011. The RECs acquired through these two RFPs will be used to help meet the renewable energy requirements established under SB221 for 2009, 2010 and 2011. On December 7, 2009, the Ohio Companies filed an application with the PUCO seeking a force majeure determination regarding the Ohio Companies’ compliance with the 2009 solar energy resources benchmark, and seeking a reduction in the benchmark. The PUCO has not yet ruled on that application.

On October 20, 2009, the Ohio Companies filed an MRO to procure electric generation service for the period beginning June 1, 2011. The proposed MRO would establish a CBP to secure generation supply for customers who do not shop with an alternative supplier and would be similar, in all material respects, to the CBP conducted in May 2009 in that it would procure energy, capacity and certain transmission services on a slice of system basis. However, unlike the May 2009 CBP, the MRO would include multiple bidding sessions and multiple products with different delivery periods for generation supply designed to reduce potential volatility and supplier risk and encourage bidder participation. A technical conference was held on October 29, 2009. Hearings took place in December 2009 and the matter has been fully briefed. Pursuant to SB221, the PUCO has 90 days from the date of the application to determine whether the MRO meets certain statutory requirements. Although the Ohio Companies requested a PUCO determination by January 18, 2010, on February 3, 2010, the PUCO announced that its determination would be delayed. Under a determination that such statutory requirements are met, the Ohio Companies would be able to implement the MRO and conduct the CBP.

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.

On February 20, 2009, Met-Ed and Penelec filed with the PPUC a generation procurement plan covering the period January 1, 2011 through May 31, 2013. The 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 proposed a staggered procurement schedule, which varies by customer class, through the use of a descending clock auction. On August 12, 2009, Met-Ed and Penelec filed a settlement agreement with the PPUC for the generation procurement plan covering the period January 1, 2011, through May 31, 2013, reflecting the settlement on all but two issues. The settlement plan proposes a staggered procurement schedule, which varies by customer class. On September 2, 2009, the ALJ issued a Recommended Decision (RD) approving the settlement and adopted the Met-Ed and Penelec’s positions on two reserved issues. On November 6, 2009, the PPUC entered an Order approving the settlement and finding in favor of Met-Ed and Penelec on the two reserved issues. Generation procurement began in January 2010.

On May 22, 2008, the PPUC approved Met-Ed and Penelec annual updates to the TSC rider for the period June 1, 2008, through May 31, 2009. The TSCs included a component for under-recovery of actual transmission costs incurred during the prior period (Met-Ed - $144 million and Penelec - $4 million) and 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 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 Met-Ed and Penelec have concluded. On August 11, 2009, the ALJ issued a Recommended Decision to the PPUC approving Met-Ed's and Penelec's TSCs as filed and dismissing all complaints. Exceptions by various interveners were filed and reply exceptions were filed by Met-Ed and Penelec. On January 28, 2010, the PPUC adopted a motion which denies the recovery of marginal transmission losses through the TSC for the period of June 1, 2007 through March 31, 2008, and instructs Met-Ed and Penelec to work with the parties and file a petition to retain any over-collection, with interest, until 2011 for the purpose of providing mitigation of future rate increases starting in 2011 for their customers. Met-Ed and Penelec are now awaiting an order, which is expected to be consistent with the motion. If so, Met-Ed and Penelec plan to appeal such a decision to the Commonwealth Court of Pennsylvania. Although the ultimate outcome of this matter cannot be determined at this time, it is the belief of the companies that they should prevail in any such appeal and therefore expect to fully recover the approximately $170.5 million ($138.7 million for Met-Ed and $31.8 million for Penelec) in marginal transmission losses for the period prior to January 1, 2011.

On May 28, 2009, the PPUC approved Met-Ed's and Penelec's annual updates to their TSC rider for the period June 1, 2009 through May 31, 2010 subject to the outcome of the proceeding related to the 2008 TSC filing described above, as required in connection with the PPUC's January 2007 rate order. For Penelec's customers the new TSC resulted in an approximate 1% decrease in monthly bills, reflecting projected PJM transmission costs as well as a reconciliation for costs already incurred. The TSC for Met-Ed's customers increased to recover the additional PJM charges paid by Met-Ed in the previous year and to reflect updated projected costs. In order to gradually transition customers to the higher rate, the PPUC approved Met-Ed's proposal to continue to recover the prior period deferrals allowed in the PPUC's May 2008 Order and defer $57.5 million of projected costs to a future TSC to be fully recovered by December 31, 2010. Under this proposal, monthly bills for Met-Ed's customers would increase approximately 9.4% for the period June 2009 through May 2010.

Act 129 became effective in 2008 and addresses issues such as: energy efficiency and peak load reduction; generation procurement; time-of-use rates; smart meters; and alternative energy. Among other things Act 129 requires utilities to file with the PPUC an energy efficiency and peak load reduction plan by July 1, 2009, setting forth the utilities' plans to reduce energy consumption by a minimum of 1% and 3% by May 31, 2011 and May 31, 2013, respectively, and to reduce peak demand by a minimum of 4.5% by May 31, 2013. On July 1, 2009, Met-Ed, Penelec, and Penn filed EE&C Plans with the PPUC in accordance with Act 129. The Pennsylvania Companies submitted a supplemental filing on July 31, 2009, to revise the Total Resource Cost test items in the EE&C Plans pursuant to the PPUC's June 23, 2009 Order. Following an evidentiary hearing and briefing, the Pennsylvania Companies filed revised EE&C Plans on September 21, 2009. In an October 28, 2009 Order, the PPUC approved in part, and rejected in part, the Pennsylvania Companies' filing. Following additional filings related to the plans, including modifications as required by the PPUC, the PPUC issued an order on January 28, 2010, approving, in part, and rejecting, in part the Pennsylvania Companies' modified plans. The Pennsylvania Companies filed final plans and tariff revisions on February 5, 2010 consistent with the minor revisions required by the PPUC. The PPUC must approve or reject the plans within 60 days.

Act 129 also required utilities to file by August 14, 2009 with the PPUC smart meter technology procurement and installation plan to provide for the installation of smart meter technology within 15 years. On August 14, 2009, Met-Ed, Penelec and Penn jointly filed a Smart Meter Technology Procurement and Installation Plan. Consistent with the PPUC's rules, this plan proposes a 24-month assessment period in which the Pennsylvania Companies will assess their needs, select the necessary technology, secure vendors, train personnel, install and test support equipment, and establish a cost effective and strategic deployment schedule, which currently is expected to be completed in fifteen years. Met-Ed, Penelec and Penn estimate assessment period costs at approximately $29.5 million, which the Pennsylvania Companies, in their plan, proposed to recover through an automatic adjustment clause. A Technical Conference and evidentiary hearings were held in November 2009. Briefs were filed on December 11, 2009, and Reply Briefs were filed on December 31, 2009. An Initial Decision was issued by the presiding ALJ on January 28, 2010. The ALJ's Initial Decision approved the Smart Meter Plan as modified by the ALJ, including: ensuring that the smart meters to be deployed include the capabilities listed in the PPUC's Implementation Order; eliminating the provision of interest in the 1307(e) reconciliation; providing for the recovery of reasonable and prudent costs minus resulting savings from installation and use of smart meters; and reflecting that administrative start-up costs be expensed and the costs incurred for research and development in the assessment period be capitalized. Exceptions are due on February 17, 2010, and Reply Exceptions are due on March 1. The Pennsylvania Companies expect the PPUC to act on the plans in early 2010.

Legislation addressing rate mitigation and the expiration of rate caps has been introduced in the legislative session that ended in 2008; several bills addressing these issues were introduced in the 2009 legislative session. The final form and impact of such legislation is uncertain.

On February 26, 2009, the PPUC approved a Voluntary Prepayment Plan requested by Met-Ed and Penelec that provides an opportunity for residential and small commercial customers to prepay an amount on their monthly electric bills during 2009 and 2010. Customer prepayments earn interest at 7.5% and will be used to reduce electricity charges in 2011 and 2012.

On March 31, 2009, Met-Ed and Penelec submitted their 5-year NUG Statement Compliance filing to the PPUC in accordance with their 1998 Restructuring Settlement. Met-Ed proposed to reduce its CTC rate for the residential class with a corresponding increase in the generation rate and the shopping credit, and Penelec proposed to reduce its CTC rate to zero for all classes with a corresponding increase in the generation rate and the shopping credit. While these changes would result in additional annual generation revenue (Met-Ed - $27 million and Penelec - $59 million), overall rates would remain unchanged. On July 30, 2009, the PPUC entered an order approving the 5-year NUG Statement, approving the reduction of the CTC, and directing Met-Ed and Penelec to file a tariff supplement implementing this change. On July 31, 2009, Met-Ed and Penelec filed tariff supplements decreasing the CTC rate in compliance with the July 30, 2009 order, and increasing the generation rate in compliance with the Pennsylvania Companies' Restructuring Orders of 1998. On August 14, 2009, the PPUC issued Secretarial Letters approving Met-Ed and Penelec's compliance filings.

By Tentative Order entered September 17, 2009, the PPUC provided for an additional 30-day comment period on whether "the Restructuring Settlement allows NUG over-collection for select and isolated months to be used to reduce non-NUG stranded costs when a cumulative NUG stranded cost balance exists." In response to the Tentative Order, the Office of Small Business Advocate, Office of Consumer Advocate, York County Solid Waste and Refuse Authority, ARIPPA, the Met-Ed Industrial Users Group and Penelec Industrial Customer Alliance filed comments objecting to the above accounting method utilized by Met-Ed and Penelec. Met-Ed and Penelec filed reply comments on October 26, 2009. On November 5, 2009, the PPUC issued a Secretarial Letter allowing parties to file reply comments to Met-Ed and Penelec's reply comments by November 16, 2009, and reply comments were filed by the Office of Consumer Advocate, ARIPPA, and the Met-Ed Industrial Users Group and Penelec Industrial Customer Alliance. Met-Ed and Penelec are awaiting further action by the PPUC.

On February 8, 2010, Penn filed with the PPUC a generation procurement plan covering the period June 1, 2011 through May 31, 2013. The 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 proposed a staggered procurement schedule, which varies by customer class, through the use of a descending clock auction. The PPUC is required to issue an order on the plan no later than November 8, 2010.

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 30, 2009, the accumulated deferred cost balance totaled approximately $98 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 DPA 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 March 13, 2009, JCP&L filed its annual SBC Petition with the NJBPU that includes a request for a reduction in the level of recovery of TMI-2 decommissioning costs based on an updated TMI-2 decommissioning cost analysis dated January 2009. This matter is currently pending before the NJBPU.

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.

On January 28, 2009, the NJBPU adopted an order establishing the general process and contents of specific EMP plans that must be filed by New Jersey electric and gas utilities in order to achieve the goals of the EMP. Such utility specific plans are due to be filed with the BPU by July 1, 2010. At this time, FirstEnergy and JCP&L cannot determine the impact, if any, the EMP may have on their operations.

In support of former New Jersey Governor Corzine's Economic Assistance and Recovery Plan, JCP&L announced a proposal to spend approximately $98 million on infrastructure and energy efficiency projects in 2009. Under the proposal, an estimated $40 million would be spent on infrastructure projects, including substation upgrades, new transformers, distribution line re-closers and automated breaker operations. In addition, approximately $34 million would be spent implementing new demand response programs as well as expanding on existing programs. Another $11 million would be spent on energy efficiency, specifically replacing transformers and capacitor control systems and installing new LED street lights. The remaining $13 million would be spent on energy efficiency programs that would complement those currently being offered. The project relating to expansion of the existing demand response programs was approved by the NJBPU on August 19, 2009, and implementation began in 2009. Approval for the project related to energy efficiency programs intended to complement those currently being offered was denied by the NJBPU on December 1, 2009. Implementation of the remaining projects is dependent upon resolution of regulatory issues including recovery of the costs associated with the proposal.

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. 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. On October 29, 2009, FirstEnergy, with another Company, filed an additional settlement agreement with FERC to resolve their outstanding claims. FirstEnergy is actively pursuing settlement agreements with other parties to the case. On December 8, 2009, certain parties sought a writ of mandamus from the DC Circuit Court of Appeals directing FERC to issue an order on the Initial Decision. The Court agreed to hold this matter in abeyance based upon FERC's representation to use good faith efforts to issue a substantive ruling on the initial decision no later than May 27, 2010. If FERC fails to act, the case will be submitted for briefing in June. The outcome of this matter cannot be predicted.

PJM Transmission Rate

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 on the content of the compliance filings 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. AEP's 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 (Opinion 494) 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, the FERC's April 19, 2007, and January 31, 2008, orders were appealed to the federal Court of Appeals for the D.C. Circuit. The Illinois Commerce Commission, the PUCO and another party have also appealed these orders to the Seventh Circuit Court of Appeals. The appeals of these parties and others were consolidated for argument in the Seventh Circuit and the Seventh Circuit Court of Appeals issued a decision on August 6, 2009. The court found that FERC had not marshaled enough evidence to support its decision to allocate costs for new 500+ kV facilities on a postage-stamp basis and, based on this finding, remanded the rate design issue back to FERC. A request for rehearing and rehearing en banc by two Companies was denied by the Seventh Circuit on October 20, 2009. On October 28, 2009, the Seventh Circuit closed its case dockets and returned the case to FERC for further action on the remand order. In an order dated January 21, 2010, FERC set the matter for "paper hearings" – meaning that FERC called for parties to submit comments or written testimony pursuant to the schedule described in the order. FERC identified nine separate issues for comments, and directed PJM to file the first round of comments on February 22, 2010, with other parties submitting responsive comments on April 8, 2010 and May 10, 2010.

The FERC's orders on PJM rate design prevented 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 postage-stamp basis reduces the cost 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. On November 14, 2008, PJM submitted revisions to its tariff to incorporate cost responsibility assignments for below 500 kV upgrades included in PJM's Regional Transmission Expansion Planning process in accordance with the settlement. The remaining merchant transmission cost allocation issues were the subject of a hearing at the FERC in May 2008. On November 19, 2009, FERC issued Opinion 503 agreeing that RTEP costs should be allocated on a pro-rata basis to merchant transmission companies. On December 22, 2009, a request for a rehearing of FERC's Opinion No. 503 was made. On January 19, 2010, FERC issued a procedural order noting that FERC would address the rehearing requests in a future order.

RTO Consolidation

On August 17, 2009, FirstEnergy filed an application with the FERC requesting to consolidate its transmission assets and operations into PJM. Currently, FirstEnergy's transmission assets and operations are divided between PJM and MISO. The consolidation would make the transmission assets that are part of ATSI, whose footprint includes the Ohio Companies and Penn, part of PJM. Most of FirstEnergy's transmission assets in Pennsylvania and all of the transmission assets in New Jersey already operate as a part of PJM. Key elements of the filing include a "Fixed Resource Requirement Plan" (FRR Plan) that describes the means whereby capacity will be procured and administered as necessary to satisfy the PJM capacity requirements for the 2011-12 and 2012-13 delivery years; and also a request that ATSI's transmission customers be excused from the costs for regional transmission projects that were approved through PJM's RTEP process prior to ATSI's entry into PJM (legacy RTEP costs). The integration is expected to be complete on June 1, 2011, to coincide with delivery of power under the next competitive generation procurement process for the Ohio Companies. To ensure a definitive ruling at the same time FERC rules on its request to integrate ATSI into PJM, on October 19, 2009, FirstEnergy filed a related complaint with FERC on the issue of exempting the ATSI footprint from the legacy RTEP costs.

On September 4, 2009, the PUCO opened a case to take comments from Ohio's stakeholders regarding the RTO consolidation. FirstEnergy filed extensive comments in the PUCO case on September 25, 2009, and reply comments on October 13, 2009, and attended a public meeting on September 15, 2009 to answer questions regarding the RTO consolidation. Several parties have intervened in the regulatory dockets at the FERC and at the PUCO. Certain interveners have commented and protested particular elements of the proposed RTO consolidation, including an exit fee to MISO, integration costs to PJM, and cost-allocations of future transmission upgrades in PJM and MISO.

On December 17, 2009, FERC issued an order approving, subject to certain future compliance filings, ATSI's move to PJM. FirstEnergy's request to be exempted from legacy RTEP costs was rejected and its complaint dismissed.

On December 17, 2009, ATSI executed the PJM Consolidated Transmission Owners Agreement. On December 18, 2009, the Ohio Companies and Penn executed the PJM Operating Agreement and the PJM Reliability Assurance Agreement. Execution of these agreements committed ATSI and the Ohio Companies and Penn's load to moving into PJM on the schedule described in the application and approved in the FERC Order (June 1, 2011).

On January 15, 2010, the Ohio Companies and Penn submitted a compliance filing describing the process whereby ATSI-zone load serving entities (LSEs) can "opt out" of the Ohio Companies' and Penn's FRR Plan for the 2011-12 and 2012-13 Delivery Years. On January 16, 2010, FirstEnergy filed for clarification or rehearing of certain issues associated with implementing the FRR auctions on the proposed schedule. On January 19, 2010, FirstEnergy filed for rehearing of FERC's decision to impose the legacy RTEP costs on ATSI's transmission customers. Also on January 19, 2010, several parties, including the PUCO and the OCC asked for rehearing of parts of FERC's order. None of the rehearing parties asked FERC to rescind authorization for ATSI to enter PJM. Instead, parties focused on questions of cost and cost allocation or on alleged errors in implementing the move. On February 3, 2010, FirstEnergy filed an answer to the January 19, 2010 rehearing requests of other parties. On February 16, 2010, FirstEnergy submitted a second compliance filing to FERC; the filing describes communications protocols and performance deficiency penalties for capacity suppliers that are taken in FRR auctions.

FirstEnergy will conduct FRR auctions on March 15-19, 2010, for the 2011-12 and 2012-13 delivery years. LSE's in the ATSI territory, including the Ohio Companies and Penn, will participate in PJM's next base residual auction for capacity resources for the 2013-2014 delivery years. This auction will be conducted in May of 2010. FirstEnergy expects to integrate into PJM effective June 1, 2011.

Changes ordered for PJM Reliability Pricing Model (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. 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 discussions. On February 9, 2009, PJM and a group of stakeholders submitted an offer of settlement, which used the PJM December 12, 2008 filing as its starting point, and stated that unless otherwise specified, provisions filed by PJM on December 12, 2008 apply.

On March 26, 2009, the FERC accepted in part, and rejected in part, tariff provisions submitted by PJM, revising certain parts of its RPM. It ordered changes included making incremental improvements to RPM and clarification on certain aspects of the March 26, 2009 Order. On April 27, 2009, PJM submitted a compliance filing addressing the changes the FERC ordered in the March 26, 2009 Order; subsequently, numerous parties filed requests for rehearing of the March 26, 2009 Order. On June 18, 2009, the FERC denied rehearing and request for oral argument of the March 26, 2009 Order.

PJM has reconvened the Capacity Market Evolution Committee (CMEC) and has scheduled a CMEC Long-Term Issues Symposium to address near-term changes directed by the March 26, 2009 Order and other long-term issues not addressed in the February 2009 settlement. PJM made a compliance filing on September 1, 2009, incorporating tariff changes directed by the March 26, 2009 Order. The tariff changes were approved by the FERC in an order issued on October 30, 2009, and are effective November 1, 2009. The CMEC continues to work to address additional compliance items directed by the March 26, 2009 Order. On December 1, 2009, PJM informed FERC that PJM would file a scarcity-pricing design with FERC on April 1, 2010.

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 and FES. This requirement was 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. The FERC conditionally approved MISO's Resource Adequacy proposal on March 26, 2008. 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 April 16, 2009, the FERC issued an additional order on rehearing and compliance, approving MISO's proposed financial settlement provision for Resource Adequacy. The MISO Resource Adequacy program was implemented as planned and became effective on June 1, 2009, the beginning of the MISO planning year. On June 17, 2009, MISO submitted a compliance filing in response to the FERC's April 16, 2009 order directing it to address, among others, various market monitoring and mitigation issues. On July 8, 2009, various parties submitted comments on and protests to MISO's compliance filing. FirstEnergy submitted comments identifying specific aspects of the MISO's and Independent Market Monitor's proposals for market monitoring and mitigation and other issues that it believes the FERC should address and clarify. On October 23, 2009, FERC issued an order approving a MISO compliance filing that revised its tariff to provide for netting of demand resources, but prohibiting the netting of behind-the-meter generation.

FES Sales to Affiliates

FES supplied all of the power requirements for the Ohio Companies pursuant to a Power Supply Agreement that ended on December 31, 2008. On January 2, 2009, FES signed an agreement to provide 75% of the Ohio Companies' power requirements for the period January 5, 2009 through March 31, 2009. Subsequently, FES signed an agreement to provide 100% of the Ohio Companies' power requirements for the period April 1, 2009 through May 31, 2009. On March 4, 2009, the PUCO issued an order approving these two affiliate sales agreements. FERC authorization for these affiliate sales was by means of a December 23, 2008 waiver of restrictions on affiliate sales without prior approval of the FERC. Rehearing was denied on July 31, 2009. On October 19, 2009, FERC accepted FirstEnergy's revised tariffs.

On May 13-14, 2009, FES participated in a descending clock auction for PLR service administered by the Ohio Companies and their consultant, CRA International. FES won 51 tranches in the auction, and entered into a Master SSO Supply Agreement to provide capacity, energy, ancillary services and transmission to the Ohio Companies for a two-year period beginning June 1, 2009. Other winning suppliers have assigned their Master SSO Supply Agreements to FES, five of which were effective in June, two more in July, four more in August and ten more in September, 2009. FES also supplies power used by Constellation to serve an additional five tranches. As a result of these arrangements, FES serves 77 tranches, or 77% of the PLR load of the Ohio Companies.

On November 3, 2009, FES, Met-Ed, Penelec and Waverly restated their partial requirements power purchase agreement for 2010. The Fourth Restated Partial Requirements Agreement (PRA) continues to limit the amount of capacity resources required to be supplied by FES to 3,544 MW, but requires FES to supply essentially all of Met-Ed, Penelec, and Waverly's energy requirements in 2010. Under the Fourth Restated Partial Requirements Agreement, Met-Ed, Penelec, and Waverly (Buyers) assigned 1,300 MW of existing energy purchases to FES to assist it in supplying Buyers' power supply requirements and managing congestion expenses. FES can either sell the assigned power from the third party into the market or use it to serve the Met-Ed/Penelec load. FES is responsible for obtaining additional power supplies in the event of failure of supply of the assigned energy purchase contracts. Prices for the power sold by FES under the Fourth Restated Partial Requirements Agreement were increased to $42.77 and $44.42, respectively for Met-Ed and Penelec. In addition, FES agreed to reimburse Met-Ed and Penelec, respectively, for congestion expenses and marginal losses in excess of $208 million and $79 million, respectively, as billed by PJM in 2010, and associated with delivery of power by FES under the Fourth Restated Partial Requirements Agreement. The Fourth Restated Partial Requirements Agreement terminates at the end of 2010.